WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

June 28, 2024

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

Attention: Jo-Anne Galarneau
Executive Director and Board Secretary

Dear Ms. Galarneau:

Re: Newfoundland Power's 2025 Capital Budget Application

Enclosed are the original and 10 copies of Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") *2025 Capital Budget Application* (the "Application").

The Application seeks an order approving the Company's proposed 2025 capital budget and fixing and determining Newfoundland Power's average rate base for 2023.

Amendments to the *Public Utilities Act* (the "Act") became effective in May 2023. Regarding section 41 of the Act, the amendments provide that a utility shall not proceed with any improvement or addition to its property where the cost exceeds $750,000 without prior approval of the Board.

Projects and programs greater than $750,000 are set out in Schedule B to the Application and comply with the spirit and intent of the Board's *Capital Budget Application Guidelines (Provisional)* effective January 2022 as more fully described in Schedule B.

Projects and programs $750,000 and under are outlined in Schedule C to the Application including a description of each project or program.

A copy of the Application has been forwarded directly to Ms. Shirley Walsh, Senior Legal Counsel of Newfoundland and Labrador Hydro, and Mr. Dennis Browne, the Consumer Advocate.

A PDF of the Application is available to the Board and interested parties via Newfoundland Power's stranded website at https://ftp.nfpower.nf.ca/. The Application is also publicly available via the Company's website (newfoundlandpower.com).

Newfoundland Power Inc.
55 Kenmount Road • P.O. Box 8910 • St. John's, NL A1B 3P6
PHONE (709) 737 5500 ext. 6200 • **FAX** (709) 737-2974 • **dfoley@newfoundlandpower.com**

We trust the foregoing and enclosed are in order. If you have any questions, please contact the undersigned.

Yours truly,

Dominic Foley
Legal Counsel

Enclosures

cc.	Shirley Walsh Newfoundland and Labrador Hydro	Dennis Browne, K.C. Browne Fitzgerald Morgan & Avis

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Newfoundland Power Inc.
2025 Capital Budget Application

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APPLICATION

SUPPORTING MATERIALS

IN THE MATTER OF the *Public Utilities Act* (the "Act"); and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to sections 41 and 78 of the Act:
(a) approving its 2025 Capital Budget; and
(b) fixing and determining its 2023 rate base.

2025 Capital Budget Application

IN THE MATTER OF the *Public Utilities Act* (the "Act"); and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:
(a) approving its 2025 Capital Budget; and
(b) fixing and determining its 2023 rate base.

TO: The Board of Commissioners of Public Utilities (the "Board")

THE APPLICATION OF Newfoundland Power Inc. ("Newfoundland Power") **SAYS THAT:**

1. Newfoundland Power is a corporation duly organized and existing under the laws of the Province of Newfoundland and Labrador, is a public utility within the meaning of the Act, and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. Schedule A to this Application provides a summary of Newfoundland Power's proposed capital expenditures for which it is seeking approval as follows:

   (a) proposed single-year 2025 capital expenditures in the amount of $79,468,000 comprising projects and programs costing in excess of $750,000;

   (b) proposed single-year 2025 capital expenditures of $10,850,000 comprising projects and programs costing $750,000 and under;

   (c) proposed multi-year projects commencing in 2025 with capital expenditures of $18,219,000 in 2025, $46,145,000 in 2026 and $9,816,000 in 2027; and

   (d) ongoing multi-year projects previously approved in Order No. P.U. 36 (2021) and Order No. P.U. 2 (2024) with capital expenditures of $19,414,000 in 2025 and $297,000 in 2026 (the "Previously Approved Multi-Year Projects").

3. The proposed 2025 Capital Budget includes contributions toward the cost of improvements or additions to property that Newfoundland Power intends to demand from its customers in 2025 including an estimated amount of $2,500,000 in contributions in aid of construction which shall be calculated in a manner approved by the Board.

4. There has been no change in the scope, nature, or magnitude of the Previously Approved Multi-Year Projects, with the exception of the capital project to rebuild Transmission Line 94L, originally approved in 2021. Newfoundland Power is seeking additional expenditures totalling $12,560,000, with $3,485,000 in 2025 and $9,075,000 in 2026 to complete the remainder of the project. Additional details on the project are contained within report *3.2 Transmission Line 94L Rebuild* filed as part of the Application.

5. Schedule B to this Application provides detailed descriptions of the proposed projects and programs in excess of $750,000.

6. Schedule C to this Application outlines proposed projects and programs $750,000 and under.

7. The proposed expenditures as set out in Schedules A, B and C to this Application are necessary for Newfoundland Power to continue to provide service and facilities which are reasonably safe and adequate and are just and reasonable as required pursuant to section 37 of the Act.

8. Schedule D to this Application shows Newfoundland Power's actual average rate base for 2023 of $1,290,079,000.

9. Newfoundland Power requests that the Board make an Order:

   (a) pursuant to section 41 of the Act, approving Newfoundland Power's proposed construction and purchase of improvements or additions to its property to be completed in 2025 in the amount of $127,951,000 as set out in Schedules A, B and C to this Application comprising:

      i. single-year project and program expenditures in excess of $750,000 in the amount of $79,468,000;
      ii. single-year project and program expenditures $750,000 and under in the amount of $10,850,000;
      iii. multi-year projects with 2025 expenditures of $18,219,000; and
      iv. previously approved multi-year projects with 2025 expenditures of $19,414,000.

   (b) pursuant to section 41 of the Act, approving Newfoundland Power's proposed multi-year construction and purchase of improvements or additions to its property for future years in the amount of $46,145,000 in 2026 and $9,816,000 in 2027 as set out in Schedules A and B to this Application; and

   (c) pursuant to section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2023 in the amount of $1,290,079,000 as set out in Schedule D to this Application.

10. Communication with respect to this Application should be forwarded to the attention of Dominic Foley, Legal Counsel to Newfoundland Power.

DATED at St. John's, Newfoundland and Labrador, this 28th day of June, 2024.

NEWFOUNDLAND POWER INC.

Dominic Foley

Dominic Foley
Legal Counsel to Newfoundland Power Inc.
P.O. Box 8910
55 Kenmount Road
St. John's, NL A1B 3P6

Telephone: (709) 737-5500 ext. 6200
Telecopier: (709) 737-2974

IN THE MATTER OF the *Public Utilities Act* (the "Act"); and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:
(a) approving its 2025 Capital Budget; and
(b) fixing and determining its 2023 rate base.

AFFIDAVIT

I, Byron Chubbs, of the Town of Paradise, in the Province of Newfoundland and Labrador, Professional Engineer, make oath and say as follows:

1. THAT I am Vice President, Engineering and Energy Supply of Newfoundland Power Inc.;

2. THAT I have read and understand the foregoing Application; and

3. THAT, to the best of my knowledge, information and belief, all matters, facts and things set out in this Application are true.

SWORN TO before me at the City of St. John's in the Province of Newfoundland and Labrador this 28th day of June, 2024:

Dominic Foley

Barrister, NL

Byron Chubbs

2025 CAPITAL BUDGET SUMMARY

Expenditure Type	Budget ($000s)
Single-Year Projects and Programs Over $750,000	79,468
Single-Year Projects and Programs $750,000 and Under	10,850
Multi-Year Projects Commencing in 2025	18,219
Multi-Year Projects Approved in Previous Years	19,414
Total	**$ 127,951**

Asset Class	Budget ($000s)
Distribution	59,464
Substations	15,952
Transmission	18,064
Generation - Hydro	7,267
Generation - Thermal	318
Information Systems	11,009
Telecommunications	994
General Property	4,010
Transportation	5,042
Unforeseen Allowance	750
General Expenses Capitalized	5,081
Total	**$ 127,951**

2025 CAPITAL BUDGET
SINGLE-YEAR PROJECTS AND PROGRAMS
OVER $750,000

Projects and Programs	**Budget ($000s)**
Distribution	
Extensions	13,402
Reconstruction	7,425
Replacement Transformers	6,340
LED Street Lighting Replacement	5,654
New Transformers	5,623
Rebuild Distribution Lines	5,115
Relocate/Replace Distribution Lines for Third Parties	3,528
New Services	3,208
New Street Lighting	2,460
Distribution Feeder Automation	1,125
Feeder Additions for Load Growth	960
Replacement Street Lighting	884
Total Distribution	**$55,724**
Substations	
Substation Replacements Due to In-Service Failures	4,927
Northwest Brook Substation Refurbishment and Modernization	4,175
Total Substations	**$9,102**
Transmission	
Transmission Line Maintenance	2,884
Total Transmission	**$2,884**

2025 CAPITAL BUDGET
SINGLE-YEAR PROJECTS AND PROGRAMS
OVER $750,000

Projects and Programs	Budget ($000s)
Generation - Hydro	
Mobile Hydro Plant Penstock Refurbishment	825
Total Generation - Hydro	**$825**
Information Systems	
System Upgrades	1,408
Shared Server Infrastructure	970
Cybersecurity Upgrades	940
Application Enhancements	914
Total Information Systems	**$4,232**
Telecommunications	
VHF Radio System Replacement	870
Total Telecommunications	**$870**
Unforeseen Allowance	
Allowance for Unforeseen Items[1]	750
Total Unforeseen Allowance	**$750**
General Expenses Capitalized	
General Expenses Capitalized	5,081
Total General Expenses Capitalized	**$5,081**
Total	**$79,468**

[1] The *Allowance for Unforeseen Items* has been included as part of single-year projects and programs over $750,000 as Newfoundland Power is seeking approval of this project pursuant to Section V.A.7 of the *Capital Budget Application Guidelines (Provisional),* effective January 2022.

2025 CAPITAL BUDGET
SINGLE-YEAR PROJECTS AND PROGRAMS
$750,000 AND UNDER

Projects and Programs	**Budget ($000s)**
Distribution	
Distribution Feeder PEP-02 Refurbishment	667
Distribution Feeder SMV-01 Refurbishment	654
Replacement Meters	648
New Meters	457
Replacement Services	445
Allowance for Funds Used During Construction	220
Total Distribution	**$3,091**
Substations	
Substation Protection and Control Replacements	685
Substation Ground Grid Upgrades	609
Total Substations	**$1,294**
Transmission	
Wood Pole Retreatment	600
Total Transmission	**$600**
Generation - Hydro	
Hydro Plant Replacements Due to In-Service Failures	731
La Manche Canal Bridge Replacement	530
Total Generation - Hydro	**$1,261**
Generation - Thermal	
Thermal Plant Replacements Due to In-Service Failures	318
Total Generation - Thermal	**$318**

2025 CAPITAL BUDGET
SINGLE-YEAR PROJECTS AND PROGRAMS
$750,000 AND UNDER

Projects and Programs	**Budget ($000s)**
Information Systems	
Personal Computer Infrastructure	720
Network Infrastructure	470
Total Information Systems	**$1,190**
Telecommunications	
Communications Equipment Upgrades	124
Total Telecommunications	**$124**
General Property	
Additions to Real Property	682
Building Accessibility Improvements	650
Specialized Tools and Equipment	595
Tools and Equipment	589
Physical Security Upgrades	456
Total General Property	**$2,972**
Total	**$10,850**

2025 CAPITAL BUDGET
MULTI-YEAR PROJECTS

Multi-Year Projects Commencing in 2025

Class	Project Description	2025	2026	2027	Total
Distribution	Distribution Feeders SCT-01 & BLK-01 Relocation[2]	649	1,140	-	1,789
Substations	Summerville Substation Refurbishment and Modernization	511	4,510	-	5,021
Substations	Lockston Substation Refurbishment and Modernization	305	4,521	-	4,826
Substations	Gander Substation Power Transformer Replacement	17	3,905	263	4,185
Substations	Pulpit Rock Substation Power Transformer Replacement	17	2,905	-	2,922
Transmission	New Transmission Line from Lewisporte to Boyd's Cove	1,886	9,283	9,553	20,722
Transmission	Transmission Line 94L Rebuild	3,485	9,075		12,560
Generation - Hydro	Mount Carmel Pond Dam Refurbishment	3,608	1,008	-	4,616
Information Systems	Asset Management Technology Replacement	3,479	4,534	-	8,013
Information Systems	Outage Management System Upgrade	1,811	1,459	-	3,270
General Property	Port Union Building Replacement	278	1,003	-	1,281
Transportation	Replace Vehicles and Aerial Devices 2025-2026	2,173	2,802	-	4,975
	Total	**$18,219**	**$46,145**	**$9,816**	**$74,180**

2 This project is required for completion of the *Transmission Line 94L Rebuild* project.

2025 CAPITAL BUDGET
MULTI-YEAR PROJECTS

Multi-Year Projects Approved in Previous Years

Class	Project Description	2024	2025	2026	Total
Substations	Islington Substation Refurbishment and Modernization[3]	308	4,706	-	5,014
Transmission	Transmission Line 146L Rebuild[4]	2,152	9,209	-	11,361
Generation - Hydro	Lookout Brook Hydro Plant Refurbishment[5]	362	1,573	-	1,935
Information Systems	Microsoft Enterprise Agreement[6]	297	297	297	891
General Property	Gander Building Renovation[7]	175	760	-	935
Transportation	Replace Vehicles and Aerial Devices 2024-2025[8]	1,940	2,869	-	4,809
	Total	**$5,234**	**$19,414**	**$297**	**$24,945**

3 Approved in Order No. P.U. 2 (2024). See Newfoundland Power's *2024 Capital Budget Application*, Schedule B, pages 63 to 66.
4 Approved in Order No. P.U. 2 (2024). See Newfoundland Power's *2024 Capital Budget Application*, Schedule B, pages 80 to 83.
5 Approved in Order No. P.U. 2 (2024). See Newfoundland Power's *2024 Capital Budget Application*, Schedule B, pages 90 to 93.
6 Approved in Order No. P.U. 2 (2024). See Newfoundland Power's *2024 Capital Budget Application*, Schedule B, pages 121 to 123.
7 Approved in Order No. P.U. 2 (2024). See Newfoundland Power's *2024 Capital Budget Application*, Schedule B, pages 125 to 129.
8 Approved in Order No. P.U. 2 (2024). See Newfoundland Power's *2024 Capital Budget Application*, Schedule B, pages 131 to 135.

2025 CAPITAL PROJECTS AND PROGRAMS

OVER $750,000

2025 CAPITAL PROJECTS AND PROGRAMS OVER $750,000

The Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") issued provisional *Capital Budget Application Guidelines* (the "Provisional Guidelines") on December 20, 2021. The Provisional Guidelines provide direction for utility capital budget applications filed pursuant to section 41 of the *Public Utilities Act*, including the organization of applications and the information that is required to be provided in support of proposed capital expenditures.

The Provisional Guidelines require capital expenditures to be organized by:

(i) Investment Classification

Capital expenditures are to be classified as either: (i) Mandatory expenditures that are prescribed by a governing body or the Board; (ii) Access expenditures that a utility is obligated to perform to provide customers with service; (iii) System Growth expenditures that are required to meet forecast changes in customer electricity requirements; (iv) Renewal expenditures that are required to replace or refurbish existing electrical system assets and maintain service to customers; (v) Service Enhancement expenditures that are required to meet system operations requirements in a more efficient and/or effective manner; or (vi) General Plant expenditures that are required for assets that are not part of the electrical system.

(ii) Category

Capital expenditures are to be categorized as either projects or programs. Projects correspond to individual capital investments that are typically non-repetitive in nature and include defined schedules and budgets. Programs are capital investments composed of high volume, repetitive, like-for-like capital replacements, enhancements, or additions where budgets are renewed annually.

(iii) Materiality

Capital expenditures are to be segmented by materiality as either: (i) less than $1,000,000; (ii) between $1,000,000 and $5,000,000; or (iii) greater than $5,000,000. Materiality is to be based on the "all in" capital cost up to the time the asset enters service.

Schedule B to the Application details the capital expenditures proposed for 2025, including the investment classification, category and "all in" capital cost of each proposed expenditure. Expenditures are grouped by asset class. Within each asset class, projects are presented first followed by programs. Both projects and programs are ordered from the highest materiality segment to the lowest.

The Provisional Guidelines are structured such that the classification, categorization and materiality of capital expenditures determines the information required for each project and program. Newfoundland Power has met the information requirements of the Provisional Guidelines when the required information is available.

Where the required information is not available, the Company has endeavoured to provide other available information to meet the spirit and intent of the requirements. The Company is currently undertaking a review of its asset management practices that, among other matters, will evaluate options to meet the information requirements contained in the Provisional Guidelines.

The following provides an overview of the information provided within Schedule B to the Application for each project and program proposed for 2025:

(i) Project/Program Description

These sections provide information on the objective and scope of projects and programs. Information on the schedules of capital projects is also provided. A schedule is not provided for programs where the work is ongoing throughout the year.

(ii) Project/Program Budget

These sections provide a breakdown of the proposed budget and costing methodology for each capital project and program.

While Newfoundland Power does not use estimate classifications, as referenced in the Provisional Guidelines, budget estimates for projects and programs are expected to be accurate within a range of plus or minus 10%.

(iii) Program Trend

The Provisional Guidelines require trending data for programs, including the number of assets installed or replaced each year and the average unit cost per installation or replacement. This data is provided in limited cases where it was available. The limited availability of this data reflects the fact that many programs involve corrective and preventative maintenance of a wide range of assets and unit-based information has not historically been tracked. Options to provide more granular trending data are being evaluated as part of the Company's ongoing asset management review.

In Newfoundland Power's view, trends for individual programs can be reasonably observed in total program costs over time. The *Program Trend* sections therefore provide graphs of five-year historical, current budget year, and five-year forecast expenditures for each program.

(iv) Asset Background

These sections provide information on asset history, age and condition where applicable and where not otherwise addressed in the *Risk Assessment* sections. Where quantitative information is not available, qualitative assessments based on engineering judgment have been provided. For projects over $5 million, more detailed information is provided in reports prepared by Professional Engineers or other qualified experts.

(v) Assessment of Alternatives

Newfoundland Power considered all alternatives listed in the Provisional Guidelines when assessing alternatives for projects and programs. The relevance of the listed alternatives varies depending on the nature of individual projects and programs. The *Assessment of Alternatives* sections discuss only those alternatives the Company has identified as relevant, and are provided for projects and programs in excess of $1 million, with the exception of expenditures classified as Access. Cost-benefit analyses are provided for projects and programs where multiple viable alternatives were identified in order to determine the least-cost alternative.

(vi) Risk Assessment

The Provisional Guidelines require that projects and programs classified as Renewal, Service Enhancement or General Plant be evaluated for risk mitigation, and that risk mitigation be calculated in conformance with an internationally recognized standard. The Provisional Guidelines also require projects and programs be provided in the form of a prioritized list with prioritization based on calculations of risk mitigation or reliability improvement.

Newfoundland Power does not currently have the data or software necessary to provide calculations of risk mitigation or reliability improvement. To comply with the spirit and intent of the Provisional Guidelines, the Company developed a methodology to provide consistency in its assessment of risks across projects and programs. The methodology uses a risk matrix where priority is determined based on assessments of probability and consequence. The methodology may evolve as the Company completes its asset management review.

Figure 1 shows the risk matrix.

Probability Values		Priority Score				
Near Certain	5	5	10	15	20	25
Likely	4	4	8	12	16	20
Possible	3	3	6	9	12	15
Unlikely	2	2	4	6	8	10
Rare	1	1	2	3	4	5
		1 Negligible	2 Minor	3 Moderate	4 Serious	5 Critical
		Consequence Values				

Figure 1 - Risk Matrix

Using the matrix, capital expenditures receive a score of 1 to 25. Scores between 1 and 4 are considered Low priority. Scores from 5 to 9 are considered Medium priority. Scores from 10 to 16 are considered Medium-High priority. Scores of 20 and 25 are considered High priority.

A detailed description of the risk matrix methodology is provided in Appendix C to the *2025 Capital Budget Overview* filed with the Application.

Newfoundland Power also considered risks of assets becoming stranded for each proposed project and program. The risk assessment sections identify risks of asset stranding where relevant.

Newfoundland Power submits that overall the Application includes comprehensive information that clearly describes the Application's proposals and demonstrates that all proposed capital expenditures are necessary to provide customers with access to safe and reliable service at the lowest possible cost.

2025 CAPITAL BUDGET

SCHEDULE B TABLE OF CONTENTS

DISTRIBUTION

Title:	**LED Street Lighting Replacement**
Asset Class:	**Distribution**
Category:	**Project**
Investment Classification:	**Service Enhancement**
Budget:	**$5,654,000**

PROJECT DESCRIPTION

The *LED Street Lighting Replacement* project involves the replacement of existing High Pressure Sodium ("HPS") street light fixtures with Light Emitting Diode ("LED") fixtures.

Newfoundland Power adopted LED street lighting as its service standard in 2019 following Board approval in Order No. P.U. 2 (2019). In 2021, the Company commenced implementation of a plan to provide all Street and Area Lighting customers with LED fixtures within six years.[1] Expenditures proposed for 2025 represent the fifth year of this plan.[2] Approximately 10,000 street light fixtures are forecast to be replaced with LED fixtures in 2025.[3] Street light fixtures will be replaced on an ongoing basis throughout the year in response to street light trouble calls.

PROJECT BUDGET

The budget for the *LED Street Lighting Replacement* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2025 for the *LED Street Lighting Replacement* project.

Table 1
LED Street Lighting
Replacement Project
2025 Budget
($000s)

Cost Category	2025
Material	4,135
Labour – Internal	1,184
Labour – Contract	335
Engineering	-
Other	-
Total	$5,654

1 See Newfoundland Power's *2021 Capital Budget Application, Volume 1, LED Street Lighting Replacement Plan.*
2 Expenditures associated with the first four years of the *LED Street Lighting Replacement Plan* were approved by the Board in Order No. P.U. 37 (2020), Order No. P.U. 36 (2021), Order No. P.U. 38 (2022), and Order No. P.U. 2 (2024).
3 See Newfoundland Power's *2021 Capital Budget Application, Volume 1, LED Street Lighting Replacement Plan* for planned street light replacements in each year of the plan.

Proposed expenditures for the *LED Street Lighting Replacement* project total $5,654,000 for 2025.

ASSET BACKGROUND

LED street lights provide three primary customer benefits in comparison to HPS street lights:

(i) *Lower overall costs for customers* – The capital cost of installing a LED fixture is approximately twice that of an HPS fixture. However, LED fixtures require 60% less energy to provide equivalent lighting output and require far less maintenance. Current customer rates for LED street lights are between 12% and 44% lower than rates for HPS street lights.[4]

(ii) *Better lighting quality* – LED street lights emit white light, whereas the light emitted by HPS street lights appears orange. The white light of LED street lights provides a more accurate representation of colours at night, which improves nighttime visibility. LED street lights are also directional, which prevents light from spilling onto areas not intended to be lit, such as a customer's residence.

(iii) *More reliable service* – LED street lights are over three times as reliable as HPS street lights. On average, LED street lights experience an outage every 20 or more years. By comparison, HPS street lights experience an outage every six years on average.

Newfoundland Power filed its *LED Street Lighting Replacement Plan* with the Company's *2021 Capital Budget Application*. This plan aims to provide all Street and Area Lighting customers with the benefits of LED street lights by 2026.

The *LED Street Lighting Replacement Plan* is consistent with current Canadian utility practice and has also received the support of the largest municipal organization in the province, Municipalities Newfoundland and Labrador.[5] In addition to lower overall costs for customers, better lighting quality, and more reliable service, the *LED Street Lighting Replacement Plan* also reduces demand requirements on the provincial electricity system.[6]

ASSESSMENT OF ALTERNATIVES

Two alternatives were identified in developing the *LED Street Lighting Replacement Plan*.

The first alternative to implementing the plan in 2021 was to maintain the status quo. This would have involved continuing the Company's maintenance program for HPS street lights and installing an LED fixture only when an HPS fixture could not be repaired. The assessment of this alternative showed that approximately 1,700 HPS street lights would have been replaced

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4 Current Rates are reflected in the *Schedule of Rates, Rules and Regulations* effective July 1, 2023.
5 See Newfoundland Power's *2021 Capital Budget Application, Volume 1, LED Street Lighting Replacement Plan Appendix A and Appendix D*.
6 Ibid, Appendix B, page B-1. The transition from HPS street lights to LED street lights reduces demand requirements on the Island Interconnected System by 4.0 MW.

with LED equivalents annually. More than 30 years would be required to provide all customers with LED street lights.

The second alternative assessed was to discontinue the maintenance program for HPS street lights and install an LED fixture in response to all street lighting trouble calls received from customers. The assessment showed approximately 10,000 HPS street lights would be replaced with LED equivalents annually under this alternative. This is referred to as the accelerated approach. All customers would be provided with LED street lights in six years.

An economic analysis provided as part of Newfoundland Power's *2021 Capital Budget Application* determined that the accelerated approach would reduce energy and maintenance costs to customers by approximately $52 million over 20 years, providing a positive net benefit to customers of approximately $4.9 million.[7]

An updated economic analysis was provided as part of Newfoundland Power's *2023 Capital Budget Application*. The updated analysis showed that the continued execution of the *LED Street Lighting Replacement Plan* continues to be in the best interest of customers.[8]

Without continuing to execute the Company's *LED Street Lighting Replacement Plan*, a maintenance program for HPS street lights would be required and customers would pay the higher rates associated with HPS street lights. Deferring the *LED Street Lighting Replacement* project would result in customers continuing to pay higher rates for street lighting, which would be inconsistent with the provincial power policy.[9]

The accelerated installation of LED street lights continues to be the recommended alternative.

RISK ASSESSMENT

The *LED Street Lighting Replacement* project will provide an economic benefit for Street and Area Lighting customers.

By continuing to execute the *LED Street Lighting Replacement* project, customers will be provided with the lower rates of LED street lights immediately upon installation. It is estimated that customer rates for approximately 10,000 street lights will be reduced by between 12% and 44% in 2025 by executing this project.

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7 Ibid., Appendix B.
8 See Order No. P.U. 38 (2022), page 18, lines 17-23.
9 See Order No. P.U. 38 (2022), page 18, lines 25-27.

Table 2 summarizes the risk assessment of the 2025 *LED Street Lighting Replacement* project.

Table 2 LED Street Lighting Replacement Project Risk Assessment Summary		
Consequence	Probability	Risk
Serious (4)	Near Certain (5)	High (20)

Based on this assessment, not proceeding with the *LED Street Lighting Replacement* project would pose a High (20) risk to the delivery of least-cost service to customers.

JUSTIFICATION

The *LED Street Lighting Replacement* project is required to provide reliable service to Street and Area Lighting customers at the lowest possible cost.

Title:	**Feeder Additions for Load Growth**
Asset Class:	**Distribution**
Category:	**Project**
Investment Classification:	**System Growth**
Budget:	**$960,000**

PROJECT DESCRIPTION

The *Feeder Additions for Load Growth* project involves addressing overload conditions and providing additional capacity to address system load growth. For 2025, the *Feeder Additions for Load Growth* proposed project includes:

(i) A section of Airport ("APT") Substation distribution feeder APT-02 will be upgraded from two-phase to three-phase to address an overload condition that has developed as a result of customer connection growth and service upgrades in the area of Portugal Cove. The cost of completing the required upgrades is $375,000.

(ii) A section of Goulds ("GOU") Substation distribution feeder GOU-03 will be upgraded from two-phase to three-phase to address an overload condition that has developed as a result of customer connection growth and service upgrades in the Goulds area. The cost of completing the required upgrades is $585,000.

Design work for the *Feeder Additions for Load Growth* project will be completed in the first quarter of 2025. Construction will begin in the second quarter and will be completed by the end of the fourth quarter of 2025.

Additional information on this project is included in report *1.1 Feeder Additions for Load Growth*.

PROJECT BUDGET

The budget for the *Feeder Additions for Load Growth* project is based on detailed engineering estimates of individual budget items.

Table 1 provides a breakdown of expenditures proposed for 2025 for the *Feeder Additions for Load Growth* project.

Table 1
Feeder Additions for Load Growth Project
2025 Budget
($000s)

Cost Category	2025
Material	297
Labour – Internal	294
Labour – Contract	322
Engineering	47
Other	-
Total	$960

Proposed expenditures for the *Feeder Additions for Load Growth* project total $960,000 for 2025.

ASSET BACKGROUND

Distribution feeder APT-02 serves 949 customers in Portugal Cove. A 1.6 kilometre section of distribution feeder extending Neary's Pond Road is overloaded. Load growth on this two-phase line can be attributed to customer connection growth and electrical service upgrades in the area. The number of customers supplied by this two-phase line has increased by 27% over the last 15 years.

Distribution feeder GOU-03 serves 1,713 customers in the Goulds area. A 2.4 kilometre section of distribution feeder extending from Main Road along Petty Harbour Road is overloaded. Load growth on this two-phase line can be attributed to customer connection growth along Groves Road and electrical service upgrades in the area. The number of customers supplied by this two-phase line has increased by 28% over the last 15 years.

ASSESSMENT OF ALTERNATIVES

There are generally five categories of alternatives to address overloaded conductor: feeder balancing, load transfers, feeder upgrades, feeder additions and non-wires alternatives. The applicability of each category depends on factors such as available tie points to surrounding feeders, the amount of conductor overload, physical limitations of line construction, and the effect of offloading strategies on adjacent feeders.

APT-02

A 1.6 kilometre section of distribution feeder APT-02 is overloaded. Two categories of alternatives that are generally available to address overloaded conductor are not applicable to APT-02. Feeder balancing is not applicable because transferring load from Phase C onto Phase B would result in both phases being overloaded. A new feeder build is not a viable option due to the magnitude of the associated costs. A load transfer onto PUL-04 was also considered, due to its relative proximity to APT-02. However, there is insufficient capacity on power transformer PUL-T2 to accommodate the additional load from APT-02. As a result, the alternatives evaluated to mitigate the overloaded section of distribution feeder APT-02 include: (i) upgrading the tap from two-phase to three-phase; and (ii) a non-wires alternative ("NWA").

The capital cost of the alternative to upgrade the 1.6 kilometre section of APT-02 from two-phase to three-phase to resolve the overload condition is estimated to be $375,000.
The non-wires alternative would utilize commercial-grade battery storage technology to provide capacity to alleviate the overload condition during peak load conditions. A preliminary capital cost estimate for the procurement of a battery storage solution for this application is approximately $397,000, and would have an expected lifetime of approximately 15 years.[10]

Of the technically viable alternatives considered, upgrading the overloaded section of distribution feeder APT-02 from two-phase to three-phase is least cost. This is therefore the recommended alternative to address the identified overload condition.

GOU-03

A 2.4 kilometre section of distribution feeder on GOU-03 is overloaded. Two categories of alternatives that are generally available to address overloaded conductor are not applicable to distribtion feeder GOU-03. Feeder balancing is not applicable as the individual phases on the identified section of GOU-03 are already overloaded. A new feeder build is not viable due to the magnitude of the associated costs. As a result, the alternatives evaluated to mitigate the overloaded section of distribution feeder GOU-03 include: (i) a load transfer; (ii) upgrading from two-phase to three-phase; and (iii) a NWA.

The load transfer alternative would involve transferring load from distribution feeder GOU-03 to Petty Harbour ("PHR") substation distribution feeder PHR-01. This would require upgrading two kilometres of single-phase distribution to three-phase. In addition, a new 1.0 kilometre section

[10] Based on current battery storage costs of $574/kWh obtained from *Cost Projections for Utility-Scale Battery Storage: 2023 Update,* June 2023, prepared for the National Renewable Energy Laboratory by Cole et al, the estimated procurement cost of this solution is $397,000. According to Cole et al., the median lifetime of utility scale battery systems is 15 years.

of three-phase distribution line would be required to connect the overloaded section of distribution feeder GOU-03 to PHR-01. A 12.5 kV to 4.16 kV step-down transformer would also be required to facilitate the connection of two feeders with varying distribution voltages. Costs associated with the work are estimated to be $875,000.

The alternative of upgrading from two-phase to three-phase would involve upgrading the 2.4 kilometre section of single-phase distribution line along Petty Harbour Road to three-phase 1/0 AASC conductor to resolve the overloaded conductor. The capital cost associated with this work is estimated to be $585,000.

The non-wires alternative would utilize commercial-grade battery storage technology to provide capacity to alleviate the overload condition during peak load conditions. A preliminary capital cost estimate for the procurement of a battery storage solution for this application is approximately $1,322,000, and would have an expected lifetime of approximately 15 years.[11]

Of the technically viable alternatives considered, upgrading the overloaded section of distribution feeder GOU-03 from two-phase to three-phase is least cost. This is therefore the recommended alternative to address the identified overload condition.

JUSTIFICATION

The *Feeder Additions for Load Growth* project is required to provide customers equitable access to an adequate supply of power. The project will address overload conditions on three distribution feeders resulting from customer growth in the St. John's and Goulds areas in order to provide customers with safe and adequate service.

[11] Based on current battery storage costs of $574/kWh obtained from *Cost Projections for Utility-Scale Battery Storage: 2023 Update,* June 2023, prepared for the National Renewable Energy Laboratory by Cole et al, the estimated procurement cost of this solution is $1,322,000. According to Cole et al., the median lifetime of utility scale battery systems is 15 years.

Title: **Distribution Feeders SCT-01 and BLK-01 Relocation**
Asset Class: **Distribution**
Category: **Project**
Investment Classification: **Renewal**
Budget: **$649,00 in 2025; $1,140,000 in 2026**

PROJECT DESCRIPTION

The *Distribution Feeder SCT-01 and BLK-01 Relocation* project involves relocating sections of the St. Catherine's ("SCT") substation distribution feeder and Blaketown ("BLK") substation distribution feeder to accommodate the *Transmission Line 94L Rebuild* project. Due to space constraints on the chosen route for the transmission line rebuild, sections of the SCT-01 and BLK-01 distribution feeders must be underbuilt on the new line to enable the transmission corridor.

This project will occur concurrently with the construction of 94L during 2025 and 2026. Engineering for the SCT-01 relocation will occur in the first quarter of 2025 with construction completed in the fourth quarter. Engineering for the relocation of BLK-01 will follow in the first quarter of 2026 with construction completed by the end of the fourth quarter.

Additional information on this project is included in report *3.2 Transmission Line 94L Rebuild*.

PROJECT BUDGET

The budget for the *Distribution Feeder SCT-01 and BLK-01 Relocation* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2025 and 2026 for the *Distribution Feeder SCT-01 and BLK-01 Relocation* project.

Table 1
Distribution Feeder SCT-01 and BLK-01 Relocation
2025 and 2026 Budget
($000s)

Cost Category	2025	2026	Total
Material	214	377	591
Labour – Internal	182	319	501
Labour – Contract	48	86	134
Engineering	55	97	152
Other	150	261	411
Total	$649	$1,140	$1,789

Proposed expenditures for the *Distribution Feeder SCT-01 and BLK-01 Relocation* project total $649,000 in 2025 and $1,140,000 in 2026.

ASSET BACKGROUND

Distribution feeder SCT-01 serves approximately 760 customers on the Avalon Peninsula in the communities of St. Catherine's and Colinet.

Distribution feeder BLK-01 serves approximately 1,700 customers on the Avalon Peninsula from Old Shop and South Dildo in the north, through Whitbourne and continues on to Markland in the south.

Both distribution feeders are crossed at points by the existing 94L transmission line. When 94L is reconstructed in the road right-of-way, sections of both feeders will be within the transmission corridor. In order to effectively manage the transmission corridor, sections of both feeders will be underbuilt on the new 94L transmission structures in the roadside. The costs of completing the *Distribution Feeder SCT-01 and BLK-01 Relocation* project have been included in the NPV analysis for the least cost alternative in the *Transmission Line 94L Rebuild* project.

RISK ASSESSMENT

The *Distribution Feeder SCT-01 and BLK-01 Relocation* project is necessary to permit the completion of the least cost alternative in the *Transmission Line 94L Rebuild* project. Construction of another alternative other than the least cost alternative would result in an increase in the NPV analysis in excess of $2.5 million.

Table 2 summarizes the risk assessment of the 2025 and 2026 *Distribution Feeder SCT-01 and BLK-01 Relocation* project.

Table 2
Distribution Feeder SCT-01 and BLK-01 Relocation
Risk Assessment Summary

Consequence	Probability	Risk
Critical (5)	Likely (4)	High (20)

Based on this assessment, not proceeding with the *Distribution Feeder SCT-01 and BLK-01 Relocation* project would pose a High (20) economic risk to customers.

JUSTIFICATION

The *Distribution Feeder SCT-01 and BLK-01 Relocation* project is required to ensure the delivery of reliable service to approximately 2,500 customers. The relocation of *SCT-01 and BLK-01* is necessary to permit the completion of *Transmission Line 94 Rebuild* is the least cost option to address existing deterioration and deficiencies and mitigate risks of equipment failure.

Title:	**Distribution Feeder Automation**
Asset Class:	**Distribution**
Category:	**Project**
Investment Classification:	**Service Enhancement**
Budget:	**$1,125,000**

PROJECT DESCRIPTION

The *Distribution Feeder Automation* project involves increasing automation of the distribution system through the installation of downline reclosers. Downline reclosers are pole-mounted devices that divide a distribution feeder into multiple segments. These devices are controlled remotely to: (i) isolate a fault so only a portion of customers on a feeder experience an outage, instead of all customers; and (ii) systematically restore power to customers following a prolonged outage.[12]

Downline reclosers are installed in locations that are intended to optimize their benefits for customers. Optimal locations for downline reclosers are selected based on the Company's established deployment scenarios, a distribution feeder's geographic location, customer demographics, and other factors.

A total of 14 downline reclosers are planned for installation in 2025. These downline reclosers will be installed under three deployment scenarios:[13]

(i) *Scenario 1* – Deployment of a single downline recloser such that approximately one third of the feeder load is downstream of the downline recloser, and the remaining two thirds of the load is upstream.

(ii) *Scenario 2* – Deployment of multiple downline reclosers on a feeder such that approximately one third of the feeder load is upstream of the first downline recloser, one third of the load is between the first and second downline recloser, and the remaining one third of the load is downstream of the second downline recloser. This is typically used for larger feeders with the highest number of customers.

(iii) *Scenario 3* – Deployment of downline reclosers at normally open tie locations on feeders that have downline reclosers installed.

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12 For example, customers served by GOU Substation feeder GOU-01 experienced an outage in December 2021. A downline recloser was operated to mitigate issues associated with cold load pick-up. The operation of this downline recloser avoided an additional outage to over 1,000 customers served by that feeder.

13 For more information on these deployment scenarios, see report *4.5 Distribution Feeder Automation* included with Newfoundland Power's *2020 Capital Budget Application.*

Table 1 lists the downline reclosers to be installed in 2025 and the associated deployment scenario.

Table 1
2025 Downline Recloser Installations

Feeders	Number of Devices	Deployment Scenario
PUL-02	1	Scenario 2
PUL-03	2	Scenario 2
PUL-01/PUL-03 TIE	1	Scenario 3
APT-01/RRD-10 TIE	1	Scenario 3
PUL-04/PUL-05 TIE	1	Scenario 3
HOL-03	1	Scenario 1
SMV-01	1	Scenario 1
LOK-01	2	Scenario 2
WAL-04	1	Scenario 1
FRN-01	1	Scenario 1
COB-01	1	Scenario 1
WAL-02/FRN-01 TIE	1	Scenario 3

Procurement of material is expected to commence in the first quarter of 2025. Design work for this project is expected to be completed by the end of the second quarter of 2025. Installation of the downline reclosers will commence in the third quarter with all downline reclosers installed by year-end.

PROJECT BUDGET

The budget for the *Distribution Feeder Automation* project is based on detailed engineering estimates.

Table 2 provides a breakdown of expenditures proposed for 2025 for the *Distribution Feeder Automation* project.

Table 2
Distribution Feeder Automation Project
2025 Budget
($000s)

Cost Category	2025
Material	721
Labour – Internal	91
Labour – Contract	128
Engineering	50
Other	135
Total	$1,125

Proposed expenditures for the *Distribution Feeder Automation* project total $1,125,000 for 2025.

ASSET BACKGROUND

Downline reclosers are pole-mounted devices that operate automatically to restore service to customers and can be controlled remotely by the System Control Center. The devices sectionalize distribution feeders such that an equipment failure only affects customers downstream of a device, rather than all customers on a distribution feeder.

Newfoundland Power established an approach to increasing automation of its distribution system in report *4.5 Distribution Feeder Automation* included with its *2020 Capital Budget Application*.[14] Automation of the distribution system through the installation of downline reclosers provides operational benefits during customer outages, particularly major events.

Because downline reclosers are operated remotely, field crews can focus on restoring service to customers. Restoration efforts are also more efficient as the sectionalizing of feeders means portions no longer need to be patrolled to identify the cause and location of outages.[15] A more efficient response to customer outages improves restoration times and decreases costs to customers.

Past experience indicates the benefits of downline reclosers can be substantial. Downline reclosers are routinely operated to restore service to customers following equipment failures.

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14 There are 145 automated downline reclosers in the Company's service territory as of June 2024.
15 Given the size of Newfoundland Power's service territory, long drives to identify the cause of outages are not uncommon. Reducing the length of distribution feeder to be patrolled reduces the time necessary to locate faults and provides cost benefits to customers.

The operational benefits of downline reclosers are most pronounced during major events.[16] For example, the operation of five downline reclosers during a severe blizzard in January 2020 avoided approximately 3.5 million customer outage minutes without the assistance of field crews. This allowed field crews to focus on restoring service to customers who were affected by the blizzard. The operation of 12 downline reclosers during Hurricane Larry in September 2021 avoided approximately 3.8 million customer outage minutes, allowing field crews to focus on restoration efforts for customers who were affected by the storm. The operation of six downline reclosers during Hurricane Fiona on the west coast in September 2022 avoided approximately 1.7 million customer outage minutes.

While most pronounced during severe weather, the benefits of downline reclosers also materialize during normal, day-to-day operations. Reliability benefits are realized on a regular basis as these devices operate in response to equipment failures to restore service to customers.[17] Efficiency benefits are also routinely realized through a reduction in patrol times for feeders.

The 14 downline reclosers to be installed in 2025 will provide operational benefits in responding to customer outages throughout Newfoundland Power's service territory. Six of the 14 devices will be installed on the Northeast Avalon on distribution feeders supplying customers in the St. John's and Portugal Cove-St. Phillips areas. The remainder will be installed in more rural areas of the Company's service territory.[18] These distribution feeders provide service to over 16,000 customers.

RISK ASSESSMENT

The *Distribution Feeder Automation* project will mitigate risks to the delivery of reliable service to customers.

Major components on Newfoundland Power's distribution system are aging beyond the industry average expected service lives, including overhead conductor and wooden support structures. Equipment failures on the distribution system are trending upward, with an increase of approximately 6% over the last decade.[19] At the same time, major events due to severe weather are becoming more frequent throughout the Company's service territory.[20]

These conditions pose a serious risk to the delivery of reliable service to Newfoundland Power's customers going forward. Continuing to automate the distribution system through the installation of downline reclosers will help mitigate this increasing risk by supporting an efficient

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16 The term *"major events"* refers to external events that exceed the design parameters or operational limits of the electrical system.
17 For example, the operation of two downline reclosers in December 2021 quickly restored service to 1,600 customers served by Dunville Substation distribution feeder DUN-01 following an equipment failure.
18 An outage to customers located in more rural areas of the Company's service territory can result in longer response times. This can be a result of the prolonged time to travel to the area, the length of the distribution feeder requiring patrol, and the time required to locate a fault and begin restoration. The installation of downline reclosers in these areas provides operational efficiencies as the sectionalizing of feeders means portions no longer need to be patrolled to identify the cause and location of outages. Reducing the length of distribution feeder to be patrolled reduces the time necessary to locate faults and provides cost benefits.
19 See the *2025-2029 Capital Plan, Section 2.4 - Asset Condition Outlook.*
20 See the *2025-2029 Capital Plan, Section 2.3 - Operations Outlook.*

and effective response to customer outages. The benefits of downline reclosers can be substantial, particularly during major events, and are routinely observed each year as the devices automatically operate to avoid customer outages.

Table 3 summarizes the risk assessment of the 2025 *Distribution Feeder Automation* project.

Table 3
Distribution Feeder Automation Project
Risk Assessment Summary

Consequence	Probability	Risk
Serious (4)	Near Certain (5)	High (20)

Based on this assessment, not proceeding with the *Distribution Feeder Automation* project would pose a High (20) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Distribution Feeder Automation* project is required to provide customers with reliable service at the lowest possible cost as it will support maintaining Newfoundland Power's efficiency and effectiveness in response to customer outages.

Title: **Extensions**
Asset Class: **Distribution**
Category: **Program**
Investment Classification: **Access**
Budget: **$13,402,000**

PROGRAM DESCRIPTION

The *Extensions* program involves the construction of primary and secondary distribution lines to connect new customers to the electrical system. Extensions to distribution lines are constructed upon requests from developers or contractors and individual customers. The program also includes upgrades to the capacity of existing lines to accommodate customers increased electrical system loads.

PROGRAM BUDGET

The budget for the *Extensions* program is based on a forecast of new customer connections and an average cost per connection under this program. The average cost per connection is calculated based on historical data. Historical annual expenditures for this program over the most recent five-year period are expressed in current-year dollars ("Adjusted Costs"). The Adjusted Costs are divided by the number of new customers in each year to derive a cost per connection. The average of these costs is inflated by the GDP Deflator for Canada for non-labour costs and the Company's internal labour inflation rate for labour costs, and then multiplied by the forecast number of new customers for the budget year.[21]

Table 1 provides the cost per customer connection for the *Extensions* program from 2020 to 2025.

Table 1
Extensions Program
Cost per Customer

Year	2020	2021	2022	2023	2024F	2025F
Total (000s)	$10,561	$12,427	$12,489	$15,145	$13,205	$13,402
Adjusted Costs (000s)[1]	$12,742	$14,214	$13,540	$15,582	$13,205	-
New Customers	2,062	2,448	2,646	2,372	2,329	2,220
Cost/Customer[1]	$6,179	$5,806	$5,117	$6,569	$5,670	$6,037

[1] 2024 dollars

Newfoundland Power is forecasting 2,220 new customer connections in 2025 at a cost per connection under the *Extensions* program of $6,037.

[21] Effective 2023, labour costs associated with this program include a direct allocation of amounts previously included in General Expenses Capitalized ("GEC"), as approved in Order No. P.U. 3 (2022).

Table 2 provides a breakdown of expenditures proposed for 2025 for the *Extensions* program.

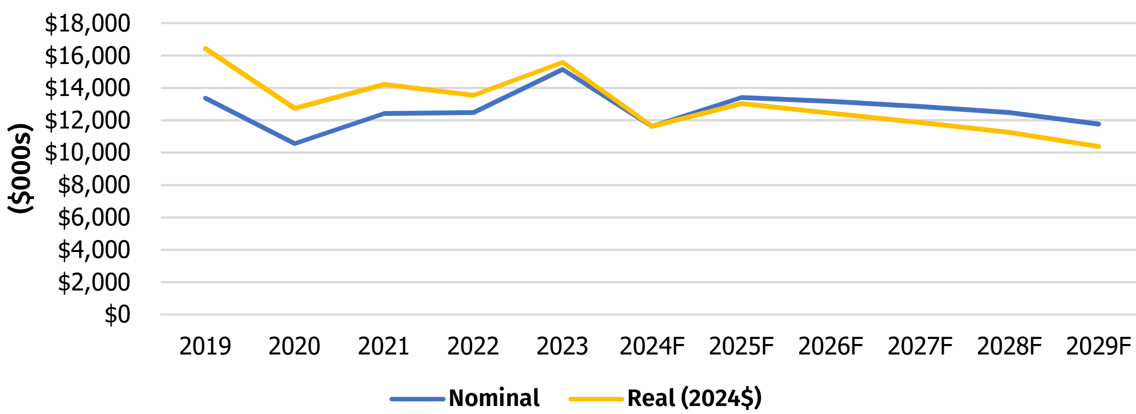
Table 2 Extensions Program 2025 Budget ($000s)	
Cost Category	2025
Material	4,729
Labour – Internal	3,986
Labour – Contract	2,388
Engineering	1,642
Other	657
Total	$13,402

Proposed expenditures for the *Extensions* program total $13,402,000 for 2025.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Extensions* program from 2019 to 2029.[22]

Figure 1
Extensions Program Expenditures
(2019 - 2029F)



Annual expenditures under the *Extensions* program are expected to decrease due to a forecast decline in new customer connections. Annual expenditures under this program averaged

[22] For forecast expenditures for the *Extensions* program, see the *2025-2029 Capital Plan, Appendix A*, page A-2.

approximately $12.9 million from 2019 to 2024, or approximately $14.3 million when adjusted for inflation. Annual expenditures under this program are forecast to average approximately $12.7 million over the next five years.

ASSET BACKGROUND

Newfoundland Power operates approximately 9,400 kilometres of distribution line. Extensions to distribution lines are constructed upon request from developers or contractors constructing new subdivisions, as well as individual customers who require connection to the electrical system. The scope and cost of individual extensions varies depending on the nature of the request and the location of the customer to be connected.

JUSTIFICATION

The *Extensions* program is required to provide customers with equitable access to an adequate supply of power as it enables the connection of new customers to the distribution system and the upgrading of existing lines to accommodate increased electrical system loads.

Title: **Reconstruction**
Asset Class: **Distribution**
Category: **Program**
Investment Classification: **Renewal**
Budget: **$7,425,000**

PROGRAM DESCRIPTION

Reconstruction is a corrective maintenance program that involves the replacement of deteriorated or damaged distribution structures and electrical equipment. The program addresses high-priority deficiencies that are identified during inspections or recognized during operational problems, including customer outages and trouble calls.

PROGRAM BUDGET

The budget for the *Reconstruction* program is based on a historical average. Historical annual expenditures for this program over the most recent five-year period are expressed in current-year dollars as Adjusted Costs. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada for non-labour costs and the Company's internal labour inflation rate for labour costs.[23]

Table 1 provides the annual expenditures for the *Reconstruction* program from 2020 to 2024.

Table 1
Reconstruction Program
Historical Expenditures
(000s)

Year	2020	2021	2022	2023	2024F
Total	$6,275	$5,959	$6,179	$7,622	$6,953
Adjusted Costs[1]	$7,574	$6,858	$6,759	$7,856	$6,953

1 2024 dollars

The average annual adjusted cost for the *Reconstruction* program was approximately $7.2 million from 2020 to 2024.

23 Effective 2023, labour costs associated with this program include a direct allocation of amounts previously included in GEC, as approved in Order No. P.U. 3 (2022).

Table 2 provides a breakdown of expenditures proposed for 2025 for the *Reconstruction* program.

Table 2
Reconstruction Program
2025 Budget
($000s)

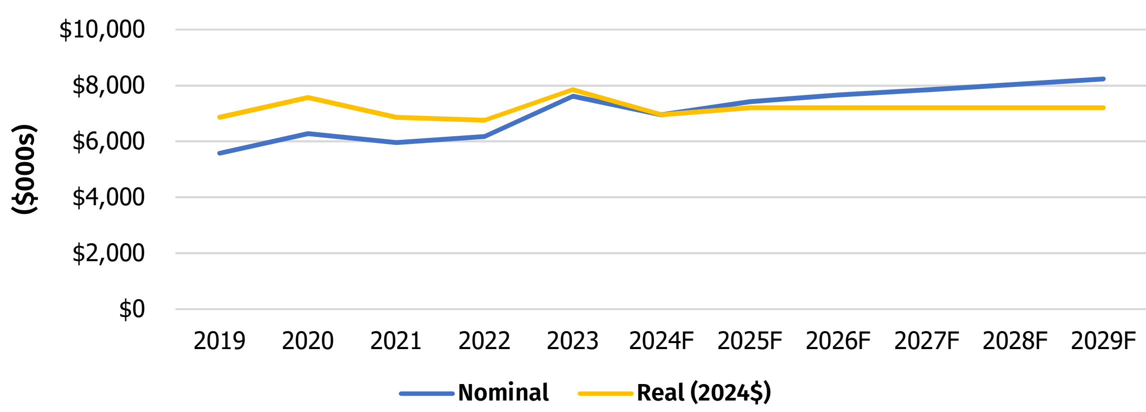
Cost Category	2025
Material	1,810
Labour – Internal	3,082
Labour – Contract	1,228
Engineering	809
Other	496
Total	$7,425

Proposed expenditures for the *Reconstruction* program total $7,425,000 for 2025.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Reconstruction* program from 2019 to 2029.[24]

Figure 1
Reconstruction Program Expenditures
(2019 - 2029F)



[24] For forecast annual expenditures for the *Reconstruction* program, see the *2025-2029 Capital Plan, Appendix A,* page A-2.

Annual expenditures under this program averaged approximately $6.6 million from 2020 to 2024, or approximately $7.2 million when adjusted for inflation. Annual expenditures are forecast to average approximately $7.8 million over the next five years.

ASSET BACKGROUND

The *Reconstruction* program involves the replacement of distribution system assets that have failed in service, are at imminent risk of failure, or present a safety hazard to employees and the general public. This includes high-priority deficiencies identified during inspections that require remediation immediately or within one month, such as wood poles with serious cracks. It also includes deficiencies arising during normal operations, such as broken poles resulting from storm damage and vehicle accidents.

ASSESSMENT OF ALTERNATIVES

The *Reconstruction* program is a corrective maintenance program that addresses distribution system assets that have failed, are at imminent risk of failure, or present a safety hazard to employees and the public. These include failures resulting from severe weather and vehicle accidents, and those identified through inspection. There is no viable alternative to replacing failed distribution equipment in a timely manner as deferring this work would lead to the unreliable operation of the distribution system and safety hazards for customers and the general public.

RISK ASSESSMENT

The *Reconstruction* program will mitigate risks to the delivery of safe and reliable service to customers by addressing high-priority deficiencies on the distribution system.

The distribution system includes approximately 232,000 wooden support structures and overhead conductor on approximately 9,400 kilometres of distribution line. Industry experience indicates an average expected useful service life of 54 years for distribution wooden support structures and 50 years for distribution overhead conductor. Approximately 14% of wooden support structures on Newfoundland Power's distribution system have exceeded 54 years in service. Approximately 23% of distribution overhead conductor has exceeded 50 years in service.[25]

The effect of age on Newfoundland Power's distribution system can be observed through its recent experience with equipment failures. Equipment failures on the distribution system are trending upward, with an increase of 6% over the last decade. This increase is primarily being driven by overhead conductor, insulators and poles that have become deteriorated due to their age.

An average of 528 deficiencies were corrected annually under the *Reconstruction* program from 2019 to 2023, ranging from 386 in 2022 to 760 in 2023. A single deficiency can result in outages to dozens or hundreds of customers. Examples of the types of deficiencies addressed under the *Reconstruction* program include severely rotted and broken poles and crossarms,

[25] For more information, see the *2025-2029 Capital Plan, Section 2.4.2 Distribution.*

broken insulators and damaged conductor. The probability of failure of components in this condition is near certain.

Table 3 summarizes the risk assessment of the *Reconstruction* program.

Table 3 Reconstruction Program Risk Assessment Summary		
Consequence	Probability	Risk
Critical (5)	Near Certain (5)	High (25)

Based on this assessment, not proceeding with the *Reconstruction* program would pose a High (25) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Reconstruction* program is required to provide safe and reliable service to customers at the lowest possible cost as it permits the timely correction of high-priority deficiencies on the distribution system that result in customer outages and unsafe operation of the electrical system.

Title:	**Rebuild Distribution Lines**
Asset Class:	**Distribution**
Category:	**Program**
Investment Classification:	**Renewal**
Budget:	**$5,115,000**

PROGRAM DESCRIPTION

Rebuild Distribution Lines is a preventative maintenance program that involves the planned replacement of deteriorated distribution structures and electrical equipment identified through inspections or engineering reviews. The program includes both the rebuilding of sections of distribution line and the selective replacement of line components, such as deteriorated poles, crossarms, conductor, cutouts, and insulators.

The following 44 distribution feeders will undergo inspection in 2024 with planned preventative maintenance in 2025:

CAB-01	GAR-01	HWD-09	MOL-02	PAB-05	TRP-01
CAR-02	GBY-03	KEN-05	MOL-04	SCR-01	TWG-02
CAT-03	GLV-01	LET-01	MOL-05	SCR-02	WAL-04
CLV-03	GOU-03	LEW-01	MOL-06	SLA-03	WAL-05
DLK-04	GRH-03	LEW-03	MOL-08	SLA-07	
GAL-04	HGR-01	LEW-04	MOL-09	SPF-02	
GAN-01	HWD-06	MMT-01	MSY-02	SPF-03	
GAN-02	HWD-07	MOL-01	OXP-01	STX-01	

The specific deficiencies to be corrected on these distribution feeders will depend on the outcomes of the inspections completed throughout 2024, as described below.

PROGRAM BUDGET

The budget for the *Rebuild Distribution Lines* program is based on a historical average. Historical annual expenditures for this program over the most recent five-year period are expressed in current-year dollars as Adjusted Costs. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada for non-labour costs and the Company's internal labour inflation rate for labour costs.[26]

[26] Effective 2023, labour costs associated with this program include a direct allocation of amounts previously included in GEC, as approved in Order No. P.U. 3 (2022).

Table 1 shows annual expenditures for the *Rebuild Distribution Lines* program from 2020 to 2024.

Table 1 Rebuild Distribution Lines Historical Expenditures (000s)					
Year	2020	2021	2022	2023	2024F
Total	$4,477	$4,143	$3,956	$5,085	$4,974
Adjusted Costs[1]	$5,407	$4,786	$4,349	$5,245	$4,974

1 2024 dollars

The average annual adjusted cost for the *Rebuild Distribution Lines* program was approximately $5.0 million from 2020 to 2024.

Table 2 provides a breakdown of expenditures proposed for 2025 for the *Rebuild Distribution Lines* program.

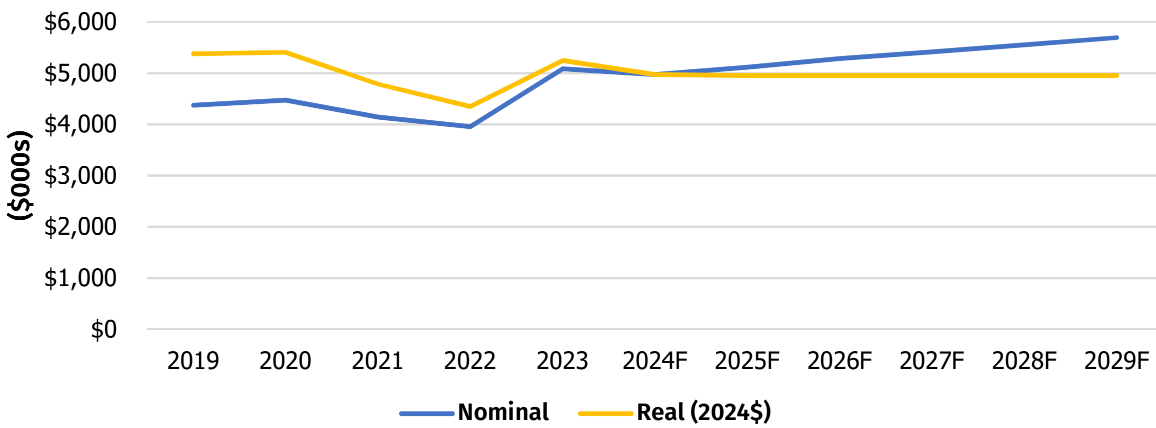
Table 2 Rebuild Distribution Lines 2025 Budget ($000s)	
Cost Category	2025
Material	1,491
Labour – Internal	2,616
Labour – Contract	570
Engineering	278
Other	160
Total	$5,115

Proposed expenditures for the *Rebuild Distribution Lines* program total $5,115,000 for 2025.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Rebuild Distribution Lines* program from 2019 to 2029.[27]

Figure 1
Rebuild Distribution Lines Program Expenditures
(2019 - 2029F)



Annual expenditures under this program averaged approximately $4.5 million from 2019 to 2024, or approximately $5.0 million when adjusted for inflation. Annual expenditures are forecast to average approximately $5.4 million over the next five years.

ASSET BACKGROUND

The *Rebuild Distribution Lines* program involves the planned replacement of distribution system assets identified during feeder inspections. Feeder inspections are completed on a seven-year cycle in accordance with Newfoundland Power's *Distribution Inspection and Maintenance Practices.* Feeder inspections assess the condition of structures, hardware, insulators, conductor, primary devices, and switches.

Deficiencies identified during inspections are prioritized for correction based on severity. High-priority deficiencies that require correction within a month are addressed under the *Reconstruction* program. Other deficiencies are addressed in a planned manner under the *Rebuild Distribution Lines* program. For example, a wood pole with a serious crack is required to be replaced within a week to a month under the *Reconstruction* program. A wood pole that has rotted and failed a core test or has severe woodpecker holes would be addressed within a year under the *Rebuild Distribution Lines* program.

27 For forecast annual expenditures for the *Rebuild Distribution Lines* program, see the *2025-2029 Capital Plan, Appendix A,* page A-2.

ASSESSMENT OF ALTERNATIVES

Newfoundland Power has approximately 300 distribution feeders. Each distribution feeder is inspected on a seven-year cycle. The seven-year inspection cycle for distribution feeders was established in 2004.

Reducing the pace of the *Rebuild Distribution Lines* program would involve reducing the pace of the Company's inspection cycle for its distribution system. Given the age and condition of the distribution system, there is a high probability that reducing the pace of the current inspection cycle would increase the frequency of in-service equipment failures.

In-service equipment failures on the distribution system are trending upward. Further increases in equipment failures on the distribution system would place upward pressure on Newfoundland Power's ability to respond to customer outages. Ultimately, this would be expected to result in reduced service reliability for customers and higher costs as additional work would be completed in an unplanned fashion under emergency conditions.

Reducing the pace of the *Rebuild Distribution Lines* program is therefore not a viable alternative based on the age and condition of Newfoundland Power's distribution system.

RISK ASSESSMENT

The *Rebuild Distribution Lines* program mitigates risks to the delivery of reliable service to customers by addressing deficiencies identified on the distribution system in a planned manner.

The distribution system includes approximately 232,000 wooden support structures and overhead conductor on approximately 9,400 kilometres of distribution line. Industry experience indicates an average expected useful service life of 54 years for distribution wooden support structures and 50 years for distribution overhead conductor. Approximately 14% of wooden support structures on Newfoundland Power's distribution system have exceeded 54 years in service. Approximately 23% of distribution overhead conductor has exceeded 50 years in service.[28]

The effect of age on Newfoundland Power's distribution system can be observed through its recent experience with equipment failures. Equipment failures on the distribution system are trending upward, with an increase of 6% over the last decade. The upward trend in equipment failures is primarily driven by overhead conductor, insulators and poles that have become deteriorated due to their age and exposure to climatic conditions.

An average of 1,985 deficiencies were corrected annually under the *Rebuild Distribution Lines* program from 2019 to 2023, ranging from 1,368 in 2019 to 2,438 in 2021. These deficiencies were corrected through a combination of rebuilding sections of distribution feeders and the selective replacement of line components.

[28] For more information, see the *2025-2029 Capital Plan, Section 2.4.2 Distribution.*

The *Rebuild Distribution Lines* program will address deficiencies on 44 distribution feeders in 2025. These feeders serve an average of approximately 1,000 customers. The deficiencies on these distribution feeders are likely to result in outages to these customers if not addressed. Table 3 summarizes the risk assessment of the *Rebuild Distribution Lines* program.

Table 3
Rebuild Distribution Lines Program
Risk Assessment Summary

Consequence	Probability	Risk
Critical (5)	Likely (4)	High (20)

Based on this assessment, not proceeding with the *Rebuild Distribution Lines* program would pose a High (20) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Rebuild Distribution Lines* program is required to provide reliable service to customers at the lowest possible cost as it permits the planned correction of deficiencies identified on the distribution system that would otherwise result in customer outages.

Title:	**Relocate/Replace Distribution Lines for Third Parties**
Asset Class:	**Distribution**
Category:	**Program**
Investment Classification:	**Access**
Budget:	**$3,528,000**

PROGRAM DESCRIPTION

The *Relocate/Replace Distribution Lines for Third Parties* program is necessary to accommodate third-party requests to relocate or replace distribution lines. The relocation or replacement of distribution lines results from: (i) work initiated by municipal, provincial and federal governments; (ii) work initiated by telecommunications companies; and (iii) requests from customers.[29]

PROGRAM BUDGET

The budget for the *Relocate/Replace Distribution Lines for Third Parties* program is based on a historical average. Historical annual expenditures for this program over the most recent five-year period are expressed in current-year dollars as Adjusted Costs. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada for non-labour costs and the Company's internal labour inflation rate for labour costs.[30]

The scope of relocation or replacement of distribution lines varies annually based on the nature of requests received from third parties. The cost of relocating or replacing distribution lines also varies based on the type and quantity of work required. Estimated contributions from customers and requesting parties associated with this project are included in the estimated contributions in aid of construction referenced in the Application.

29 Also included is distribution work associated with the installation and relocation of communications cables used by the Company's various protection and control systems.

30 Effective 2023, labour costs associated with this program include a direct allocation of amounts previously included in GEC, as approved in Order No. P.U. 3 (2022).

Table 1 provides annual expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program from 2020 to 2024.

Table 1 Relocate/Replace Distribution Lines for Third Parties Program Historical Expenditures (000s)					
Year	2020	2021	2022	2023	2024F
Total	$2,745	$3,060	$3,055	$3,109	$3,766
Adjusted Costs[1]	$3,314	$3,514	$3,322	$3,203	$3,766

1 2024 dollars

The average annual adjusted cost for the *Relocate/Replace Distribution Lines for Third Parties* program was approximately $3.4 million from 2020 to 2024.

Table 2 provides a breakdown of expenditures proposed for 2025 for the *Relocate/Replace Distribution Lines for Third Parties* program.

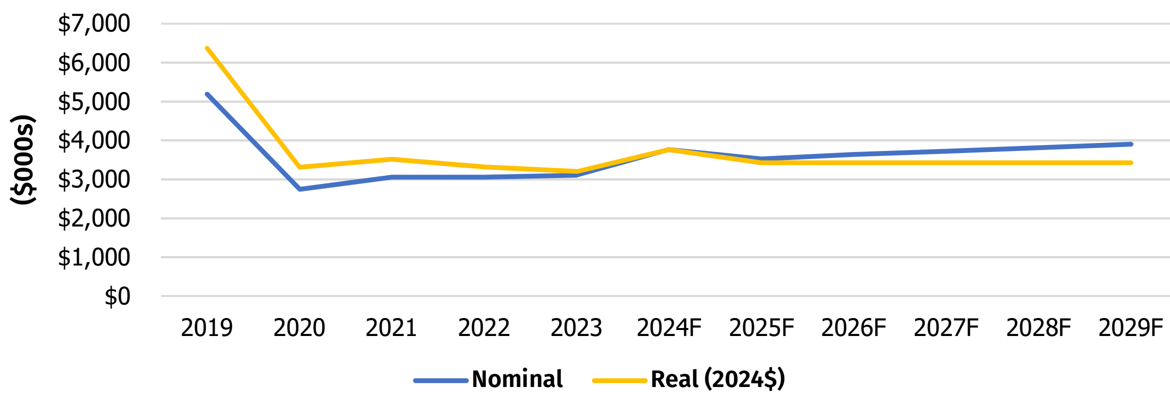
Table 2 Relocate/Replace Distribution Lines for Third Parties Program 2025 Budget ($000s)	
Cost Category	2025
Material	1,001
Labour – Internal	1,225
Labour – Contract	618
Engineering	477
Other	207
Total	$3,528

Proposed expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program total $3,528,000 for 2025.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program from 2019 to 2029.[31]

Figure 1
Relocate/Replace Distribution Lines for Third Parties
Program Expenditures
(2019 - 2029F)



Annual expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program vary depending on the quantity and scope of the requests received.[32] Annual expenditures under this program averaged approximately $3.1 million from 2020 to 2024, or approximately $3.4 million when adjusted for inflation. Annual expenditures are forecast to average approximately $3.7 million over the next five years.

ASSET BACKGROUND

Relocations or replacements of distribution lines are required annually to accommodate requests from third parties. Examples include requests from governments to relocate structures in order to accommodate road widening, and requests from telecommunications companies to replace structures to accommodate the supply of fibre optic internet service.

An average of 306 requests from third parties were received under the *Relocate/Replace Distribution Lines for Third Parties* program from 2019 to 2023.

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31 For forecast annual expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program, see the *2025-2029 Capital Plan, Appendix A,* page A-2.

32 Expenditures were higher in 2019 due to an increase in the capital programs of the Company's joint use partners, Bell Aliant and Rogers Communications, which resulted in an increase in third-party requests. See the *2019 Capital Expenditure Report*, Note 14.

JUSTIFICATION

The *Relocate/Replace Distribution Lines for Third Parties* program is required to maintain safe and adequate facilities as it permits the replacement or relocation of distribution lines at the request of third parties.

Title:	**Replacement Transformers**
Asset Class:	**Distribution**
Category:	**Program**
Investment Classification:	**Renewal**
Budget:	**$6,340,000**

PROGRAM DESCRIPTION

The *Replacement Transformers* program includes the cost of purchasing distribution system transformers to replace units that have deteriorated or failed in service.

PROGRAM BUDGET

The budget for the *Replacement Transformers* program is based on a historical average. Historical annual expenditures for this program over the most recent three-year period is expressed in current-year dollars as Adjusted Costs. The estimate for the budget year is calculated by taking the average of the Adjusted Costs, adding a forecasted 11% increase in material costs and inflating it using the GDP Deflator for Canada. [33] In addition, the 2025 budget reflects increases to maintain required inventory levels. [34]

Table 1 provides annual expenditures for the *Replacement Transformers* program from 2022 to 2024.

Table 1
Replacement Transformers Program
Historical Expenditures
(000s)

Year	2022	2023	2024F
Total	$3,873	$3,411	$5,802
Adjusted Costs[1]	$4,014	$3,475	$5,802

[1] 2024 dollars

The average annual adjusted cost for the *Replacement Transformers* program was approximately $4.4 million from 2022 to 2024.

[33] The change to a three-year average was necessitated by higher than average material costs. Distribution transformer costs increased 37% from 2020 to 2024 and is expected to increase approximately 11% more in 2025.

[34] The average quantity of distribution transformers purchased from 2014 to 2018 was approximately 1,980 annually, the average purchased from 2019 to 2023 was approximately 1,500.

Table 2 provides a breakdown of expenditures proposed for 2025 for the *Replacement Transformers* program.

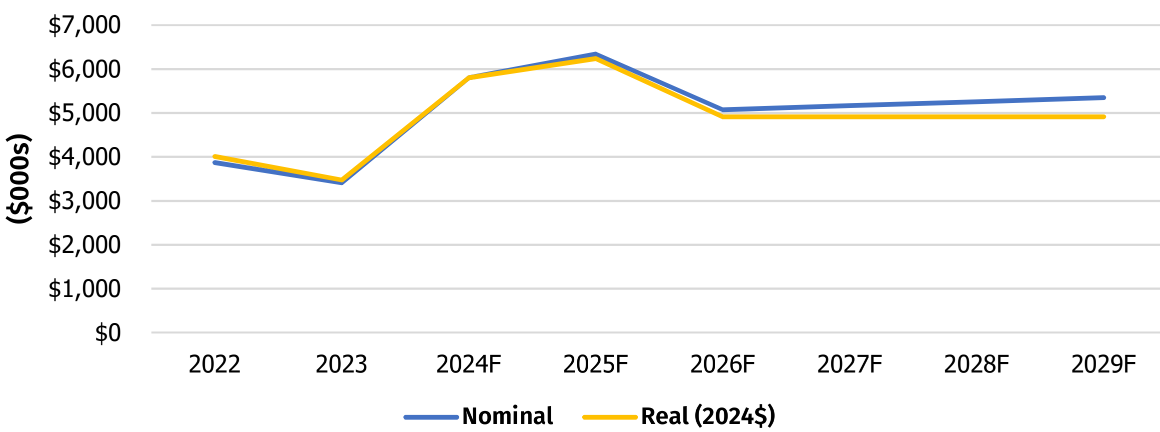
Table 2 Replacement Transformers Program 2025 Budget ($000s)	
Cost Category	2025
Material	6,340
Labour – Internal	-
Labour – Contract	-
Engineering	-
Other	-
Total	$6,340

Proposed expenditures for the *Replacement Transformers* program total $6,340,000 for 2025.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Replacement Transformers* program from 2022 to 2029.[35]

Figure 1
Replacement Transformers Program Expenditures
(2022 - 2029F)



[35] For forecast annual expenditures for the *Replacement Transformers* program, see the *2025-2029 Capital Plan, Appendix A*, page A-2.

Annual expenditures under this program averaged approximately $4.36 million from 2022 to 2024, or approximately $4.43 million when adjusted for inflation. Annual expenditures are forecast to average approximately $5.4 million over the next five years.

ASSET BACKGROUND

There are approximately 66,000 distribution transformers in operation throughout Newfoundland Power's service territory. Distribution transformers convert distribution system voltages to lower voltages required to supply customers' premises. They are typically pole-mounted and are exposed to environmental conditions. The Company also maintains a number of padmount transformers.

Distribution transformers are inspected in accordance with Newfoundland Power's *Distribution Inspection and Maintenance Practices.* Transformers are inspected for rust and oil leaks. Transformers that are leaking or are rusted to the point that a leak appears imminent must be replaced. Inspections also check for other deficiencies, including broken bushings and damaged hardware.

The age profile of the Company's distribution transformers reflects its implementation of pole-mounted units with stainless steel tanks beginning in 2001. The majority of the Company's transformers have been in service for less than 20 years, with approximately 7% in service for 40 years or more.

ASSESSMENT OF ALTERNATIVES

The *Replacement Transformers* program is required to replace transformers that have failed in service or have deteriorated, including transformers exhibiting severe rust. Replacing these transformers is necessary to restore service to customers following equipment failure, and to avoid the risk of environmental contamination or customer outages when severe deterioration is observed. There are no viable alternatives to replacing failed and deteriorated transformers.

RISK ASSESSMENT

The *Replacement Transformers* program mitigates risks to the environment and the delivery of reliable service to customers associated with transformer failure.

Transformers are replaced upon failure or imminent risk of failure. An average of 637 transformers were replaced annually from 2019 to 2023, ranging from 461 in 2022 to 754 in 2023. The failure of a single transformer can result in outages to multiple customers. The failure of a transformer can also result in environmental damage. Pole-top transformers typically contain over 30 litres of oil, while padmount transformers can contain approximately 2,000 litres of oil. Failure and deterioration of transformers can result in oil leaks that lead to environmental contamination.

Table 3 summarizes the risk assessment of the *Replacement Transformers* program.

Table 3 Replacement Transformers Program Risk Assessment Summary		
Consequence	Probability	Risk
Serious (4)	Near Certain (5)	High (20)

Based on this assessment, not proceeding with the *Replacement Transformers* program would pose a High (20) risk to the environment and to the delivery of reliable service to customers.

JUSTIFICATION

The *Replacement Transformers* program is required to provide reliable service to customers at the lowest possible cost as it permits the replacement of transformers that have failed or are at imminent risk of failure.

Title:	**New Transformers**
Asset Class:	**Distribution**
Category:	**Program**
Investment Classification:	**Access**
Budget:	**$5,623,000**

PROGRAM DESCRIPTION

The *New Transformers* program includes the cost of purchasing transformers to serve customer growth.

PROGRAM BUDGET

The budget for the *New Transformers* program is based on a historical average. Historical annual expenditures for this program over the most recent three-year period is expressed in current-year dollars as Adjusted Costs. The estimate for the budget year is calculated by taking the average of the Adjusted Costs, adding a forecasted 11% increase in material costs and inflating it using the GDP Deflator for Canada. [36] In addition, the 2025 budget reflects increases to maintain required inventory levels. [37]

Table 1 shows annual expenditures for the *New Transformers* program from 2022 to 2024.

Table 1
New Transformers Program
Historical Expenditures
(000s)

Year	2022	2023	2024F
Total	$3,434	$2,999	$5,145
Adjusted Costs[1]	$3,559	$3,081	$5,145

1 2024 dollars

The average annual adjusted cost for the *New Transformers* program was approximately $3.9 million from 2022 to 2024.

36 The change to a three-year average was necessitated by higher than average material costs. Distribution transformer costs increased 37% from 2020 to 2024 and is expected to increase approximately 11% more in 2025.

37 The average quantity of distribution transformers purchased from 2014 to 2018 was approximately 1,980 annually, the average purchased from 2019 to 2023 was approximately 1,500.

Table 2 provides a breakdown of expenditures proposed for 2025 for the *New Transformers* program.

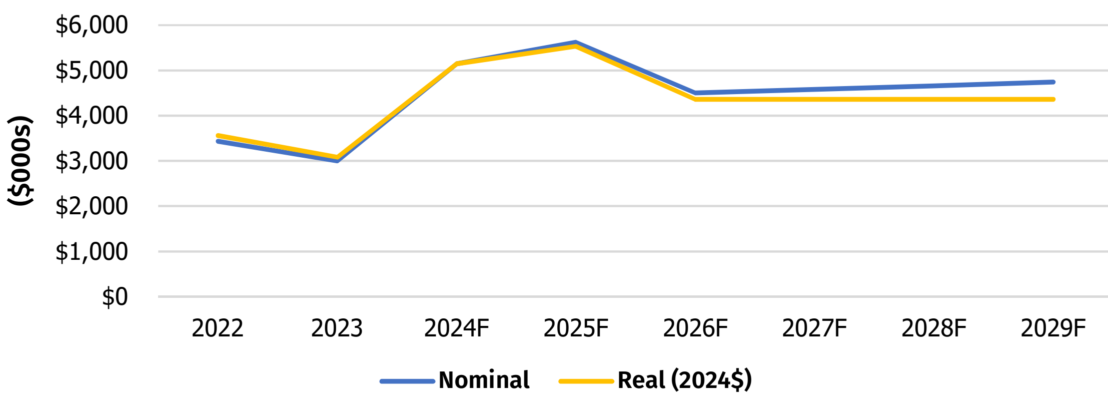
Table 2 New Transformers Program 2025 Budget ($000s)	
Cost Category	2025
Material	5,623
Labour – Internal	-
Labour – Contract	-
Engineering	-
Other	-
Total	$5,623

Proposed expenditures for the *New Transformers* program total $5,623,000 for 2025.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *New Transformers* program from 2022 to 2029.[38]

Figure 1
New Transformers Program Expenditures
(2022 - 2029F)



38 For forecast annual expenditures for the *New Transformers* program, see the *2025-2029 Capital Plan, Appendix A,* page A-2.

Annual expenditures under this program averaged approximately $3.86 million from 2022 to 2024, or $3.93 million when adjusted for inflation. Annual expenditures under this program are forecast to average approximately $4.8 million over the next five years.

ASSET BACKGROUND

Distribution transformers convert distribution system voltages to lower voltages required to supply customers' premises. A single distribution transformer is capable of providing service to multiple customers.

The number of new transformers required to be installed varies annually based on customer growth and load density on sections of distribution feeders. An average of approximately 1,140 new transformers were installed annually from 2019 to 2023.

JUSTIFICATION

The *New Transformers* program is required to provide equitable access to an adequate supply of power as it permits the installation of transformers required to supply customers' premises with electricity service.

Title:	**New Services**
Asset Class:	**Distribution**
Category:	**Program**
Investment Classification:	**Access**
Budget:	**$3,208,000**

PROGRAM DESCRIPTION

The *New Services* program involves the installation of service wires to connect new customers to the distribution system.

PROGRAM BUDGET

The budget for the *New Services* program is based on a forecast of new customer connections and the cost per connection. The cost per connection is calculated based on historical data. Historical annual expenditures for the program over the most recent five-year period are expressed in current-year dollars as Adjusted Costs. The Adjusted Costs are divided by the number of customer connections in each year to derive a cost per connection. The average of these costs is inflated by the GDP Deflator for Canada for non-labour costs and the Company's internal labour inflation rate for labour costs, and then multiplied by the forecast number of new customers for the budget year.[39]

Table 1 provides annual expenditures for the *New Services* program from 2020 to 2025.

Table 1
New Services Program
Cost per Customer

Year	2020	2021	2022	2023	2024F	2025F
Total (000s)	$2,283	$2,936	$3,469	$3,260	$3,230	$3,208
Adjusted Costs (000s)[1]	$2,759	$3,397	$3,844	$3,366	$3,230	-
New Customers	2,062	2,448	2,646	2,372	2,329	2,220
Cost/customer[1]	$1,338	$1,388	$1,453	$1,419	$1,387	$1,445

1 2024 dollars

Newfoundland Power is forecasting 2,220 new customer connections in 2025 at a cost per connection of $1,445.

39 Effective 2023, labour costs associated with this program include a direct allocation of amounts previously included in GEC, as approved in Order No. P.U. 3 (2022).

Table 2 provides a breakdown of expenditures proposed for 2025 for the *New Services* program.

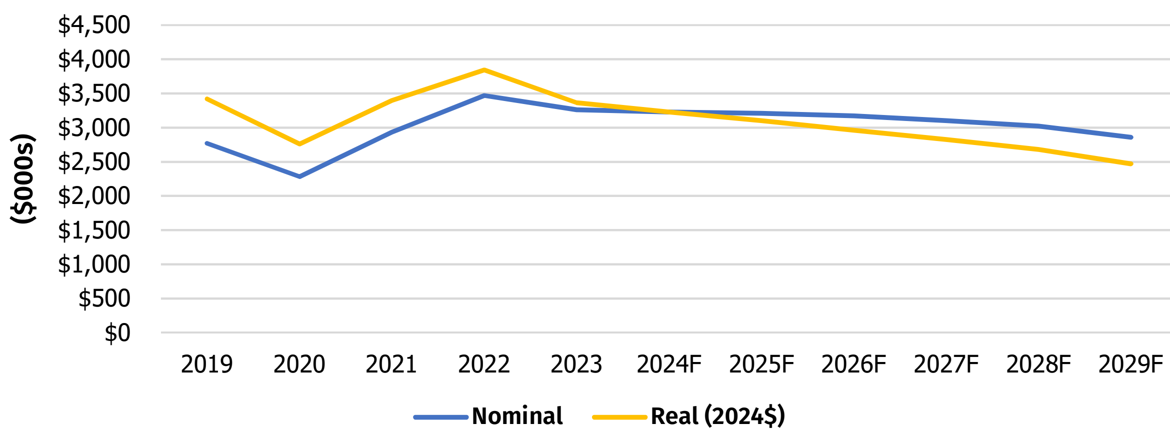
Table 2 New Services Program 2025 Budget ($000s)	
Cost Category	2025
Material	978
Labour – Internal	1,810
Labour – Contract	103
Engineering	235
Other	82
Total	$3,208

Proposed expenditures for the *New Services* program total $3,208,000 for 2025.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *New Services* program from 2019 to 2029.[40]

Figure 1
New Services Program Expenditures
(2019 - 2029F)



40 For forecast annual expenditures for the *New Services* program, see the *2025-2029 Capital Plan, Appendix A*, page A-2.

Annual expenditures under this program averaged approximately $3.0 million from 2019 to 2024, or $3.3 million when adjusted for inflation. Annual expenditures under this program are forecast to average approximately $3.1 million over the next five years.

ASSET BACKGROUND

Service wires are low-voltage wires that connect a customer's electrical service equipment to transformers on the distribution system. New service wires are installed upon request from developers or contractors constructing new subdivisions, as well as individual customers who require electricity service connection. The scope and cost of an individual service varies based on the nature of the request and the location of the customer to be connected.

JUSTIFICATION

The *New Services* program is required to provide equitable access to an adequate supply of power as it permits the installation of service wires necessary to connect customers' premises to the electrical system.

Title:	**New Street Lighting**
Asset Class:	**Distribution**
Category:	**Program**
Investment Classification:	**Access**
Budget:	**$2,460,000**

PROGRAM DESCRIPTION

The *New Street Lighting* program involves the installation of new street lighting fixtures based on customers' service requests. A street light installation includes the fixture, pole mounting bracket, street light wire and dedicated street light poles.

PROGRAM BUDGET

The budget for the *New Street Lighting* program is based on a historical average. Historical annual expenditures for the program over the most recent five-year period are expressed in current-year dollars as Adjusted Costs. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada for non-labour costs and the Company's internal labour inflation rate for labour costs.[41]

Table 1 provides the annual expenditures for the *New Street Lighting* program from 2020 to 2024.

Table 1
New Street Lighting Program
Historical Expenditures
(000s)

Year	2020	2021	2022	2023	2024F
Total	$2,608	$1,494	$2,209	$2,267	$2,429
Adjusted Costs[1]	$3,145	$1,701	$2,376	$2,329	$2,429

[1] 2024 dollars

The average annual adjusted cost for the *New Street Lighting* program was approximately $2.4 million from 2020 to 2024.

[41] Effective 2023, labour costs associated with this program include a direct allocation of amounts previously included in GEC, as approved in Order No. P.U. 3 (2022).

Table 2 provides a breakdown of expenditures proposed for 2025 for the *New Street Lighting* program.

Table 2
New Street Lighting Program
2025 Budget
($000s)

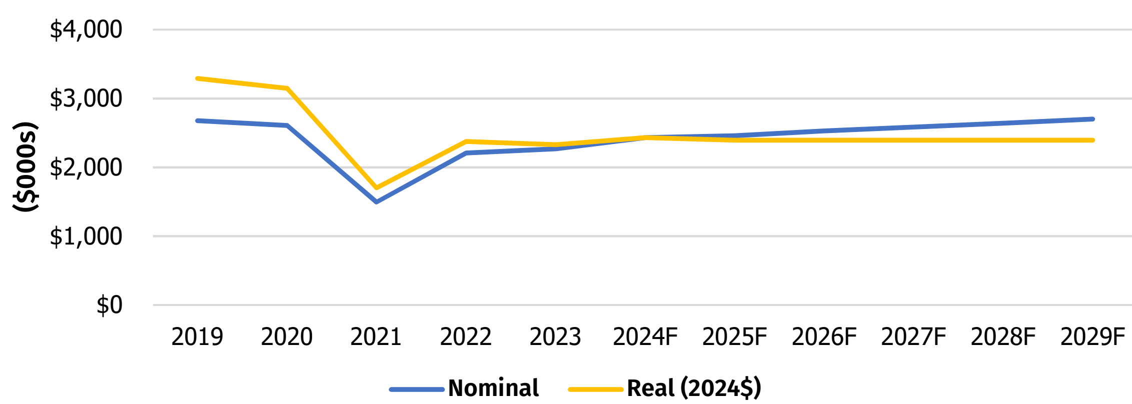
Cost Category	2025
Material	1,427
Labour – Internal	618
Labour – Contract	302
Engineering	55
Other	58
Total	$2,460

Proposed expenditures for the *New Street Lighting* program total $2,460,000 for 2025.

PROGRAM TREND

Figure 1 shows historical and forecast annual expenditures for the *New Street Lighting* program from 2019 to 2029.[42]

Figure 1
New Street Lighting Program Expenditures
(2019 - 2029F)



42 For forecast annual expenditures for the *New Street Lighting* program, see *2025-2029 Capital Plan, Appendix A*, page A-2.

Annual expenditures for the *New Street Lighting* program vary depending upon the number and scope of requests received from customers. Annual expenditures under this program averaged approximately $2.3 million from 2019 to 2024, or approximately $2.5 million when adjusted for inflation. Annual expenditures under this program are forecast to average approximately $2.6 million over the next five years.

ASSET BACKGROUND

Newfoundland Power adopted LED street lighting as its service standard in 2019 following the approval of customer rates in Order No. P.U. 2 (2019). All new street lights installed under the *New Street Lighting* program are LED technology. A single Street and Area Lighting customer may request the installation of one or multiple street lights. An average of 566 new street lights were installed annually from 2019 to 2023, ranging from a low of 421 in 2022 to a high of 697 in 2020.

JUSTIFICATION

The *New Street Lighting* program is required to provide customers with equitable access to the Company’s Street and Area Lighting service as it permits the installation of new street lights upon the request of a customer.

Title: **Replacement Street Lighting**
Asset Class: **Distribution**
Category: **Program**
Investment Classification: **Renewal**
Budget: **$884,000**

PROGRAM DESCRIPTION

The *Replacement Street Lighting* program involves the replacement of failed street light poles and hardware, including overhead and underground wiring and pole-mounting brackets.

PROGRAM BUDGET

The budget for the *Replacement Street Lighting* program is based on a historical average. Historical annual expenditures for the program over the most recent four-year period are expressed in current-year dollars as Adjusted Costs. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada for non-labour costs and the Company's internal labour inflation rate for labour costs.[43]

Table 1 provides a breakdown of expenditures proposed for 2025 for the *Replacement Street Lighting* program.

Table 1
Replacement Street Lighting Program
2025 Budget
($000s)

Cost Category	2025
Material	583
Labour – Internal	137
Labour – Contract	147
Engineering	9
Other	8
Total	$884

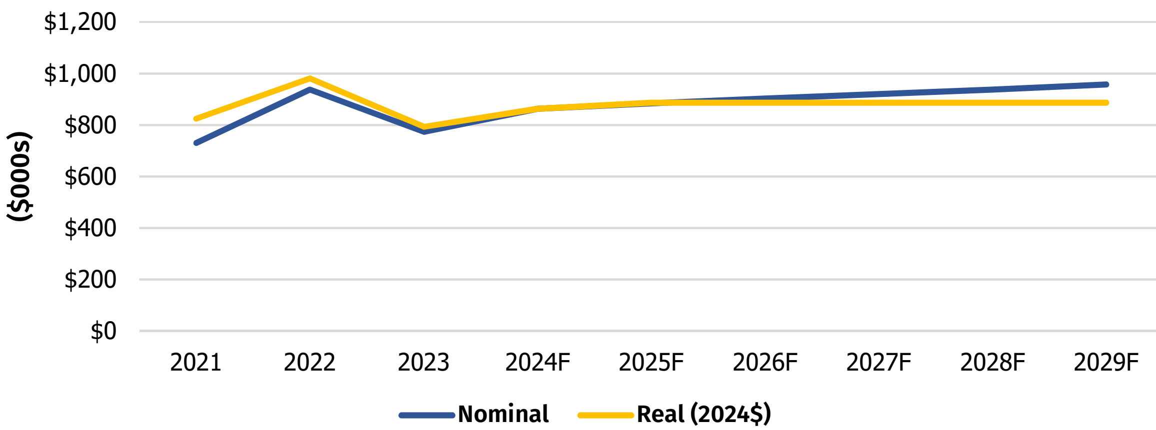
Proposed expenditures for the *Replacement Street Lighting* program total $884,000 for 2025.

[43] Effective 2023, labour costs associated with this program include a direct allocation of amounts previously included in GEC, as approved in Order No. P.U. 3 (2022).

PROGRAM TREND

Figure 1 shows historical and forecast annual expenditures for the *Replacement Street Lighting* program from 2021 to 2029.[44]

Figure 1
Replacement Street Lighting Program Expenditures
(2021 - 2029F)



The scope of the current *Replacement Street Lighting* program was established in 2021. Prior to 2021, the program included costs associated with the replacement of HPS street light fixtures. Annual expenditures under this program averaged approximately $826,000 from 2021 to 2024, or approximately $866,000 when adjusted for inflation. Annual expenditures under this program are forecast to average approximately $921,000 over the next five years.

ASSET BACKGROUND

Newfoundland Power currently provides service to approximately 12,000 Street and Area Lighting customers. There are approximately 67,000 street lights in operation throughout the Company's service territory. Approximately 44,000 of these street lights have LED fixtures. The remainder have HPS fixtures, which are expected to be replaced in accordance with the *LED Street Lighting Replacement Plan.*[45]

Street light maintenance is conducted upon receiving trouble calls from customers. A response to a street light trouble call may require the replacement of a street light fixture or the replacement of various other hardware components. The replacement of street lighting fixtures is addressed under the *LED Street Lighting Replacement* project and the replacement of other hardware and dedicated street light poles is addressed under the *Replacement Street Lighting* program.

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44 For forecast annual expenditures for the *Replacement Street Lighting* program, see *2025-2029 Capital Plan, Appendix A*, page A-2.
45 See the *2021 Capital Budget Application, LED Street Lighting Replacement Plan*.

RISK ASSESSMENT

The *Replacement Street Lighting* program will mitigate risks to the delivery of safe and reliable service to Street and Area Lighting customers by addressing the failure of dedicated street light poles and hardware.

The Company's Street and Area Lighting service is essential to public safety. The failure of street lighting components can result in outages to Street and Area Lighting customers. Street lighting components can also pose a safety hazard upon failure, such as a failure of a pole mounting bracket that causes a fixture to become detached from a pole, or the failure of a dedicated street light pole.

The *Replacement Street Lighting* program supports the reliable operation of approximately 67,000 street lights currently in service. Deficiencies are addressed under this program as identified during normal operations and upon the receipt of a trouble call from customers reporting a street light outage.

Table 2 summarizes the risk assessment of the *Replacement Street Lighting* program.

Table 2
Replacement Street Lighting Program
Risk Assessment Summary

Consequence	Probability	Risk
Moderate (3)	Near Certain (5)	Medium-High (15)

Based on this assessment, not proceeding with the *Replacement Street Lighting* program would pose a Medium-High (15) risk to the delivery of safe and reliable service to customers.

JUSTIFICATION

The *Replacement Street Lighting* program is required to provide safe and reliable service to its customers at the lowest possible cost as it permits the replacement of failed components that result in outages to Street and Area Lighting customers.

SUBSTATIONS

Title: **Summerville Substation Refurbishment and Modernization**
Asset Class: **Substations**
Category: **Project**
Investment Classification: **Renewal**
Budget (Multi-Year): **$511,000 in 2025; $4,510,000 in 2026**

PROJECT DESCRIPTION

The *Summerville Substation Refurbishment and Modernization* project involves the replacement and modernization of deteriorated equipment at Summerville ("SMV") Substation located in the Summerville area. The equipment requiring replacement was identified through inspections, engineering assessments and operating experience.

The proposed 2025 and 2026 scope of work for the *Summerville Substation Refurbishment and Modernization* project includes:

- (i) Expand the existing yard;
- (ii) Construct a new control building;
- (iii) Construct new 66 kV and 25 kV steel structures to replace deteriorated wood structures;
- (iv) Construct new spill containment foundations for existing transformer and voltage regulators;
- (v) Install two new 66 kV breakers;
- (vi) Replace deteriorated 66 kV and 25 kV switches;
- (vii) Install 66 kV potential transformer;
- (viii) Install new 25 kV combined current and potential transformer;
- (ix) Install new digital relays and the associated communications equipment;
- (x) Upgrade and extend the ground grid;
- (xi) Install new security cameras; and
- (xii) Install varmint protection on all 25 kV equipment.

Engineering design and procurement of long lead time equipment will be completed in 2025. Construction will begin in the second quarter of 2026 and will be completed early in the fourth quarter of 2026. Commissioning of the substation will be completed during the fourth quarter of 2026.

Additional information on this project is provided in Appendix A of report *2.1 2025 Substation Refurbishment and Modernization* filed with the Application.

PROJECT BUDGET

The budget for the *Summerville Substation Refurbishment and Modernization* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2025 and 2026 for the *Summerville Substation Refurbishment and Modernization* project.

Table 1
Summerville Substation Refurbishment and Modernization Project Budget
($000s)

Cost Category	2025	2026	Total
Material	213	3,452	3,665
Labour – Internal	34	330	364
Labour - Contract	-	-	-
Engineering	261	396	657
Other	3	332	335
Total	$511	$4,510	$5,021

Proposed expenditures for the *Summerville Substation Refurbishment and Modernization* project are $511,000 in 2025 and $4,510,000 in 2026 for a total project budget of $5,021,000.

ASSET BACKGROUND

The refurbishment and modernization of individual substations is based on the condition of core infrastructure and equipment as introduced in 2007 under the *Substation Refurbishment and Modernization Plan*. The plan involves a structured and comprehensive approach to preventative and corrective maintenance for critical substation assets.

As part of its preventative and corrective maintenance program, Newfoundland Power's substations are inspected eight times annually. Inspection results are incorporated into the Company's annual update of its *Substation Refurbishment and Modernization Plan*. The current plan includes the refurbishment and modernization of 20 substations over the next five years. The forecast increase in refurbishment and modernization projects reflects the age and condition of the Company's substation assets.

An assessment of Newfoundland Power's substation assets shows that critical substation equipment and infrastructure are reaching the end of their useful service lives and are prone to deterioration or obsolescence.[46] Continued execution of the *Substation Refurbishment and Modernization Plan* is therefore necessary to replace obsolete and deteriorated equipment and infrastructure.

In 2025, Newfoundland Power is proposing to refurbish and modernize SMV Substation. The substation was built in 1969 as a distribution substation. A condition assessment determined the substation contains a significant amount of deteriorated and obsolete equipment. Several

[46] For details of the assessment, see the *2025 Capital Budget Application,* report *2.1 2025 Substation Refurbishment and Modernization, Section 2.2*.

pieces of equipment are at end of life, including: (i) 66 kV and 25 kV wood pole structures; and (ii) 66 kV and 25 kV switches. Additionally, new transformer and voltage regulator spill containment foundations and upgrades to the substation's ground grid are necessary.

ASSESSMENT OF ALTERNATIVES

There are generally two alternative approaches to addressing maintenance in substations: (i) the replacement of specific components at various substations, which is prioritized based on the condition and criticality of a specific piece of equipment; and (ii) the refurbishment and modernization of individual substations based on the overall condition of those substations.

In the case of SMV Substation, the number of components requiring preventative and corrective maintenance at this time justifies the requirement to refurbish and modernize the substation in 2025 and 2026. Deferral of the SMV Substation refurbishment and modernization project would increase the risk that some components will fail in service, which would result in outages to approximately 1,130 customers in the Charleston, Princeton, Summerville, Plate Cove, and King's Cove areas. Deferring this project is therefore not a viable alternative.

RISK ASSESSMENT

The *Summerville Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to customers in the Summerville area.

SMV Substation provides service to approximately 1,130 customers in the Charleston, Princeton, Summerville, Plate Cove, and King's Cove area. Equipment failure in the SMV Substation exposes all customers supplied by SMV Substation to the risk of outages. The time to restore service to customers depends on the nature of the failure and could range from several hours up to 36 hours.

SMV Substation contains equipment that is deteriorated, obsolete, and at end of life which increases the probability of outages to customers. The 66 kV and 12.5 kV wood pole structures in the substation are deteriorated and require replacement. The majority of the switches require replacement based on their age and mechanical condition.

Power transformer SMV-T1 and the voltage regulators contain large amounts of insulating oil and lack standard spill containment. Proper spill containment is required to mitigate the risk of an environmental incident if an oil spill were to occur. Remediation costs associated with oil spills can be significant. In addition, a spill containment foundation will minimize the surface area of an oil spill and thus provides fire protection benefits.

There are deficiencies identified with the ground grid at SMV Substation that pose a risk to safe and reliable operation of the electric equipment. The substation has sections where there is no ground grid, and the fence grounding is insufficient. The purpose of ground grid upgrades is to reduce the risk of exposure to electric shock or electrocution through step and touch potential. An insufficient ground grid can also affect continuity of service if there is an inadequate ground path, which is required for proper equipment operation.

Given the condition assessment of SMV substation, the probability of failure is likely.

Table 2 summarizes the risk assessment for the *Summerville Substation Refurbishment and Modernization* project.

Table 2 Summerville Substation Refurbishment and Modernization Project Risk Assessment Summary		
Consequence	Probability	Risk
Serious (4)	Likely (4)	Medium-High (16)

Overall, the condition of SMV Substation poses a Medium-High (16) risk to the delivery of reliable, safe, and environmentally responsible service to customers. Action is required in 2025 and 2026 to mitigate these risks for customers.

JUSTIFICATION

The *Summerville Substation Refurbishment and Modernization* project is required to provide reliable service to customers at the lowest possible cost. Addressing deteriorated and obsolete equipment identified through an engineering assessment will support the continued delivery of reliable service to customers in the Summerville area.

Title:	**Northwest Brook Substation Refurbishment and Modernization**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget:	**$4,175,000**

PROJECT DESCRIPTION

The *Northwest Brook Substation Refurbishment and Modernization* project involves the replacement and modernization of deteriorated equipment at Northwest Brook ("NWB") Substation located in the Northwest Brook area. The equipment requiring replacement was identified through inspections, engineering assessments and operating experience.

The proposed 2025 scope of work for the *Northwest Brook Substation Refurbishment and Modernization* project includes:

(i) Construct a new control building;
(ii) Replace 25kV wooden cross arms in poor condition;
(iii) Construct new concrete spill containment foundations for existing transformer and existing voltage regulators;
(iv) Install two new 138 kV breakers and one 25 kV breaker to replace the existing high-speed ground switch;
(v) Replace deteriorated 138 kV and 25 kV switches;
(vi) Install new 138 kV and 25 kV potential transformers;
(vii) Replace obsolete electromechanical relays with new digital relays and associated communications equipment;
(viii) Upgrade and extend the ground grid;
(ix) Install new security cameras; and
(x) Install varmint protection on all 25 kV equipment.

Engineering design and procurement of long lead time equipment will be completed in the first quarter of 2025. Construction will begin in the second quarter and will be completed early in the fourth quarter of 2025. Commissioning of the substation will be completed by the end of 2025.

Additional information on this project is provided in Appendix B of report *2.1 2025 Substation Refurbishment and Modernization* filed with the Application.

PROJECT BUDGET

The budget for the *Northwest Brook Substation Refurbishment and Modernization* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2025 for the *Northwest Brook Substation Refurbishment and Modernization* project.

Table 1 Northwest Brook Substation Refurbishment and Modernization Project 2025 Budget ($000s)	
Cost Category	Total
Material	3,033
Labour - Internal	257
Labour - Contract	0
Engineering	643
Other	242
Total	$4,175

Proposed expenditures for the *Northwest Brook Substation Refurbishment and Modernization* project total $4,175,000 in 2025.

ASSET BACKGROUND

The refurbishment and modernization of individual substations is based on the condition of core infrastructure and equipment as introduced in 2007 under the *Substation Refurbishment and Modernization Plan*. The plan involves a structured and comprehensive approach to preventative and corrective maintenance for critical substation assets.

As part of its preventative and corrective maintenance program, Newfoundland Power's substations are inspected eight times annually. Inspection results are incorporated into the Company's annual update of its *Substation Refurbishment and Modernization Plan*. The current plan includes the refurbishment and modernization of 20 substations over the next five years. The forecast increase in refurbishment and modernization projects reflects the age and condition of the Company's substation assets.

An assessment of Newfoundland Power's substation assets shows that critical substation equipment and infrastructure are reaching the end of their useful service lives and are prone to deterioration or obsolescence.[47] Continued execution of the *Substation Refurbishment and Modernization Plan* is therefore necessary to replace obsolete and deteriorated equipment and infrastructure.

In 2025, Newfoundland Power is proposing to refurbish and modernize NWB Substation. The substation was built in 1992 as a distribution substation. A condition assessment determined

[47] For details of the assessment, see the *2025 Capital Budget Application,* report *2.1 2025 Substation Refurbishment and Modernization, Section 2.2*.

the substation contains a significant amount of deteriorated and obsolete equipment. Several pieces of equipment are at end of life, including: (i) the 25 kV wood pole crossarms; (ii) 138 kV and 25 kV switches and (iii) the electromechanical protection relays. Additionally, new transformer and voltage regulator spill containment foundations and upgrades to the substation's ground grid are necessary.

ASSESSMENT OF ALTERNATIVES

There are generally two alternative approaches to addressing maintenance in substations: (i) the replacement of specific components at various substations, which is prioritized based on the condition and criticality of a specific piece of equipment; and (ii) the refurbishment and modernization of individual substations based on the overall condition of those substations.

In the case of NWB Substation, the number of components requiring preventative and corrective maintenance at this time justifies the requirement to refurbish and modernize the substation in 2025.

Deferral of the refurbishment and modernization project would increase the risk that components will fail in service, which would result in outages to approximately 1,790 customers in the North West Brook – Ivany's Cove area. Deferring this project is therefore not a viable alternative.

RISK ASSESSMENT

The *Northwest Brook Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to customers in the North West Brook – Ivany's Cove area.

NWB Substation provides service to approximately 1,790 customers in the North West Brook – Ivany's Cove area. Equipment failure in the NWB Substation exposes all customers supplied by NWB Substation to the risk of outages. The time to restore service to customers depends on the nature of the failure and could range from several hours up to 36 hours.

NWB Substation contains equipment that is deteriorated, obsolete, and at end of life which increases the probability of outages to customers. The 25 kV wood pole structure crossarms in the substation have deteriorated and require replacement. The majority of the switches require replacement based on their age and mechanical condition. The electromechanical protection relays are obsolete and are no longer industry standard.

Power transformer NWB-T1 and the voltage regulators contain large amounts of insulating oil and lack standard spill containment. Proper spill containment is required to mitigate the risk of an environmental incident if an oil spill were to occur. Remediation costs associated with oil spills can be significant. In addition, a spill containment foundation will minimize the surface area of an oil spill and thus provides fire protection benefits.

There are deficiencies identified with the ground grid at NWB Substation that pose a risk to safe and reliable operation of the electrical equipment. The substation has sections where there is no ground grid, and other areas where there is no connection between the main ground grid and the fence. The purpose of ground grid upgrades is to reduce the risk of exposure to electric shock or electrocution through step and touch potential. An insufficient ground grid can also affect continuity of service if there is an inadequate ground path, which is required for proper equipment operation.

Given the condition assessment of NWB substation, the probability of failure is likely.

Table 2 summarizes the risk assessment for the *Northwest Brook Substation Refurbishment and Modernization* project.

Table 2
Northwest Brook Substation Refurbishment and Modernization Project Risk Assessment Summary

Consequence	Probability	Risk
Serious (4)	Likely (4)	Medium-High (16)

Overall, the condition of NWB Substation poses a Medium-High (16) risk to the delivery of reliable, safe, and environmentally responsible service to customers. Action is required in 2025 to mitigate these risks for customers.

JUSTIFICATION

The *Northwest Brook Substation Refurbishment and Modernization* project is required to provide reliable service to customers at the lowest possible cost. Addressing deteriorated and obsolete equipment identified through an engineering assessment will support the continued delivery of reliable service to customers in the North West Brook – Ivany's Cove area.

Title: **Lockston Substation Refurbishment and Modernization**
Asset Class: **Substations**
Category: **Project**
Investment Classification: **Renewal**
Budget (Multi-Year): **$305,000 in 2025; $4,521,000 in 2026**

PROJECT DESCRIPTION

The *Lockston Substation Refurbishment and Modernization* project involves the replacement and modernization of deteriorated equipment at Lockston ("LOK") Substation located in the Lockston area. The equipment requiring replacement was identified through inspections, engineering assessments and operating experience.

The proposed 2025 and 2026 scope of work for the *Lockston Substation Refurbishment and Modernization* project includes:

(i) Remove LOK-T1, LOK-T2, LOK-T4, 46 kV equipment;
(ii) Install new 66 kV to 6.9 kV, 5 MVA power transformer including new concrete spill containment foundation;
(iii) Complete a yard extension;
(iv) Construct new 66 kV, 12.5 kV, and 6.9 kV steel structures to replace deteriorated wood structures;
(v) Install new 66 kV circuit breaker to replace the existing high-speed ground switch;
(vi) Replace deteriorated 66 kV, 12.5 kV, and 6.9 kV switches;
(vii) Install new digital relays and the associated communications equipment;
(viii) Upgrade and extend the ground grid;
(ix) Install new security cameras; and
(x) Install varmint protection on all 12.5 kV and 6.9 kV equipment.

Engineering design and procurement of long lead time equipment will be completed in 2025. Construction will begin in the second quarter of 2026 and will be completed early in the fourth quarter of 2026. Commissioning of the substation will be completed during the fourth quarter of 2026.

Additional information on this project is provided in Appendix C of report *2.1 2025 Substation Refurbishment and Modernization* filed with the Application.

PROJECT BUDGET

The budget for the *Lockston Substation Refurbishment and Modernization* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2025 and 2026 for the *Lockston Substation Refurbishment and Modernization* project.

Table 1
Lockston Substation Refurbishment and Modernization Project
Project Budget
($000s)

Cost Category	2025	2026	Total
Material	8	3,636	3,644
Labour – Internal	34	188	222
Labour - Contract	0	0	0
Engineering	260	397	657
Other	3	300	303
Total	$305	$4,521	$4,826

Proposed expenditures for the *Lockston Substation Refurbishment and Modernization* project are $305,000 in 2025 and $4,521,000 in 2026 for a total project budget of $4,826,000.

ASSET BACKGROUND

The refurbishment and modernization of individual substations is based on the condition of core infrastructure and equipment as introduced in 2007 under the *Substation Refurbishment and Modernization Plan*. The plan involves a structured and comprehensive approach to preventative and corrective maintenance for critical substation assets.

As part of its preventative and corrective maintenance program, Newfoundland Power's substations are inspected eight times annually. Inspection results are incorporated into the Company's annual update of its *Substation Refurbishment and Modernization Plan*. The current plan includes the refurbishment and modernization of 20 substations over the next five years. The forecast increase in refurbishment and modernization projects reflects the age and condition of the Company's substation assets.

An assessment of Newfoundland Power's substation assets shows that critical substation equipment and infrastructure are reaching the end of their useful service lives and are prone to deterioration or obsolescence.[48] Continued execution of the *Substation Refurbishment and Modernization Plan* is therefore necessary to replace obsolete and deteriorated equipment and infrastructure.

In 2025 and 2026, Newfoundland Power is proposing to refurbish and modernize LOK Substation. The substation was built in 1956 as a generation and transmission substation. A condition assessment determined the substation contains a significant amount of deteriorated

[48] For details of the assessment, see the *2025 Capital Budget Application,* report *2.1 2025 Substation Refurbishment and Modernization, Section 2.2*.

and obsolete equipment. Several pieces of equipment are at end of life, including: (i) power transformers LOK-T1, LOK-T2, and LOK-T4; (ii) 66 kV, 12.5 kV, and 6.9 kV wood pole structures; (iii) 66 kV and 12.5 kV switches; and (iv) oil-filled 66 kV potential transformers. Additionally, new transformer spill containment foundations and upgrades to the substation's ground grid are necessary.

ASSESSMENT OF ALTERNATIVES

There are generally two alternative approaches to addressing maintenance in substations: (i) the replacement of specific components at various substations, which is prioritized based on the condition and criticality of a specific piece of equipment; and (ii) the refurbishment and modernization of individual substations based on the overall condition of those substations.

In the case of LOK Substation, the number of components requiring preventative and corrective maintenance at this time justifies the requirement to refurbish and modernize the substation in 2025 and 2026.

Deferral of the LOK Substation refurbishment and modernization project would increase the risk that some components will fail in service, which could expose up to approximately 1,100 customers to the risk of outages. Deferring this project is therefore not a viable alternative.

RISK ASSESSMENT

The *Lockston Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to customers in the Lockston area.

LOK Substation provides service to approximately 1,100 customers in the Lockston area. Equipment failure in the LOK Substation exposes all customers supplied by LOK Substation to the risk of outages. The time to restore service to customers depends on the nature of the failure and could range from several hours up to 36 hours.

LOK Substation contains equipment that is deteriorated, obsolete, and at end of life which increases the probability of outages to customers. The 66 kV, 12.5 kV, and 6.9 kV wood pole structures in the substation have deteriorated and require replacement. The majority of the switches require replacement based on their age and mechanical condition. Three oil-filled 66 kV potential transformers are at end of life and require replacement.

Generation power transformer LOK-T1 has a main tank PCB contamination of 82 ppm and bushings that range between 78 and 85 ppm.[49] Power transformers LOK-T1, LOK-T2 and LOK-T4 are connected in a non-standard configuration, operate at a non-standard voltage that no longer exists on the system outside of Lockston substation, and are approaching end of life and require replacement.

There are deficiencies identified with the ground grid at LOK Substation that pose a risk to safe and reliable operation of the electric equipment. The substation has sections where there is no

[49] The phase-out of PCBs is mandated by *Government of Canada PCB Regulation (SOR/2008-273)*, and requires that transformer bushings, breakers and instrument transformers with PCB concentrations of greater than 50 ppm be removed from service by the end of 2025.

ground grid, and other areas where there is no connection between the main ground grid and the fence. The purpose of ground grid upgrades is to reduce the risk of exposure to electric shock or electrocution through step and touch potential. An insufficient ground grid can also affect continuity of service if there is an inadequate ground path, which is required for proper equipment operation.

Given the condition assessment of LOK substation, the probability of failure is likely.

Table 2 summarizes the risk assessment for the *Lockston Substation Refurbishment and Modernization* project.

Table 2
Lockston Substation Refurbishment and Modernization Project
Risk Assessment Summary

Consequence	Probability	Risk
Serious (4)	Likely (4)	Medium-High (16)

Overall, the condition of LOK Substation poses a Medium-High (16) risk to the delivery of reliable, safe, and environmentally responsible service to customers. Action is required in 2025 and 2026 to mitigate these risks for customers.

JUSTIFICATION

The *Lockston Substation Refurbishment and Modernization* project is required to provide reliable service to customers at the lowest possible cost. Addressing deteriorated and obsolete equipment identified through an engineering assessment will support the continued delivery of reliable service to customers in the Lockston area.

Title:	**Gander Substation Power Transformer Replacement**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$17,000 in 2025; $3,905,000 in 2026; $263,000 in 2027**

PROJECT DESCRIPTION

The *Gander Substation Power Transformer Replacement* project involves the replacement of the Gander ("GAN") Substation power transformer GAN-T2. GAN-T2 is deteriorating, and an assessment of alternatives determined that the unit should be replaced.

The proposed 2025, 2026 and 2027 scope of work for the *Gander Substation Power Transformer Replacement* project includes:

(i) Remove power transformer GAN-T2; and,
(ii) Install and commission new 138 kV to 66 kV, 41.6 MVA power transformer at Boyd's Cove Substation

As described in report *3.1 Gander – Twillingate Transmission System Planning Study*, as a result of the relatively weak 66 kV transmission network in the Gander – Twillingate area and the deteriorating condition of transmission line 108L, the Company is recommending the construction of a new 138 kV transmission line from Lewisporte ("LEW") Substation to Boyd's Cove ("BOY") Substation. This would improve system voltages in the Gander - Twillingate area and permit the retirement of 108L. This also eliminates the need for a 138-66 kV system transformer at GAN Substation. As a result, GAN-T2 can be relocated to BOY Substation creating a fully redundant transmission system loop.

Engineering design and procurement of the new power transformer will be completed in 2025. The new system power transformer is expected to arrive towards the end of 2026. This would align with the construction of the proposed new transmission line between LEW and BOY substations, and allow for the new system power transformer to be installed at BOY substation in 2027.

PROJECT BUDGET

The budget of the *Gander Substation Power Transformer Replacement* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2025, 2026 and 2027 for the *Gander Substation Power Transformer Replacement* project.

Table 1
Gander Substation Power Transformer Replacement Project
Project Budget
($000s)

Cost Category	2025	2026	2027	Total
Material	0	3,797	81	3,878
Labour - Internal	0	2	11	13
Labour - Contract	0	0	0	0
Engineering	14	18	73	105
Other	3	88	98	189
Total	$17	$3,905	$263	$4,185

ASSET BACKGROUND

All power transformers receive regular maintenance on a 12-year cycle. GAN-T2 last underwent full maintenance in September of 2022. Additionally, all power transformers undergo annual oil sampling to monitor their condition.

Dissolved gas in oil analysis of GAN-T2 oil samples since June of 2022 indicated high-energy arcing in the transformer oil. This was further supported by Transformer Condition Assessments™ ("TCA") from TJ/H2b Analytic Services Incorporated ("TJ/H2b").[50]

GAN-T2 continues to be monitored.

ASSESSMENT OF ALTERNATIVES

Three alternatives were assessed to address the condition of power transformer GAN-T2: (i) Condition based maintenance; (ii) Repair; and (iii) Proactive replacement.

In the event of a GAN-T2 failure, a portable substation would be required to restore service to customers promptly and safely. Newfoundland Power aims to have one portable substation available at all times for emergency backup purposes. However, a portable substation that is

[50] For details of the assessments, see the *2025 Capital Budget Application, report 2.2 Substation Power Transformer Replacements, section 2.0*.

deployed in response to a power transformer failure can be required to remain in service for up to 24 to 36 months.

Given the age and condition of the Company's power transformer fleet, it is reasonable to expect multiple power transformer failures could occur over the same time period. This would expose customers to a risk of even longer duration outages, and potentially impact the Company's annual capital and maintenance programs for substations.

Repairing GAN-T2 would require it to be removed from service for 18-24 months requiring the long-term installation of a portable substation or spare power transformer. This would again put additional pressure on the Company's portable and spare transformer fleet creating an unacceptable risk to customers. A repaired transformer does not have the benefits of a new transformer, including the improved quality, reliability, and service life.

These risks to customer reliability are amplified by the increasing delivery lead times of power transformers, the Company's limited emergency response capabilities, and the increased possibility of transformer failure due to the Company's aging fleet.

Deferral of the *Gander Substation Power Transformer Replacement* project would increase the risk of failure, which could expose up to approximately 6,513 customers to the risk of outages. Deferring this project is therefore not a viable alternative.[51]

RISK ASSESSMENT

The *Gander Substation Power Transformer Replacement* project will mitigate risks to the delivery of reliable service to customers from the Gander – Twillingate area.

The length of time required to restore service to customers following the failure of a power transformer varies depending on whether it is possible to transfer load to another transformer in the substation or an adjacent substation, as well as the availability and proximity of a portable substation.

In the event of a GAN-T2 failure, the load cannot be transferred to an adjacent substation, meaning a portable substation would be required to restore service to customers. Furthermore, there is only one spare power transformer in Newfoundland Power's fleet of spares capable of replacing GAN-T2.

Over the last three years, delivery times of power transformers have increased from an average of 34 weeks in 2019 to an average of 117 weeks in 2024. An increase in delivery times for replacement transformers represents a risk that additional time could be required to respond to transformer failures.

Overall, an increased probability of power transformer failures, combined with a diminished inventory of spare units, has the potential to place considerable pressure on the availability of portable substations. Extended delivery times for replacements have the potential to exacerbate

51 GAN-T2 provides service to 2,323 customers at Jonathan's Pond ("JON") and Gander Bay ("GBY") Substations and also Transmission Line 102L which feeds Roycefield ("RFD") Substation. However, a GAN-T2 failure increases the risk of outages for all of the approximately 6,513 customers in the Gander Bay area.

this risk. Reduced availability of portable substations exposes the Company's customers to an increased risk of extended outages.

Table 2 summarizes the risk assessment for the *Gander Substation Power Transformer Replacement* project.

Table 2
Gander Substation Power Transformer Replacement Project
Risk Assessment Summary

Consequence	Probability	Risk
Serious (4)	Likely (4)	Medium-High (16)

Overall, the condition of power transformer GAN-T2 poses a Medium-High (16) risk to the delivery of reliable, safe, and environmentally responsible service to customers. Action is required in 2025, 2026 and 2027 to mitigate these risks for customers.

JUSTIFICATION

The *Gander Substation Power Transformer Replacement* project is required to provide reliable service to customers at the lowest possible cost. Addressing the deteriorating power transformer will support the continued delivery of reliable service to customers in the Gander Bay area.

Title:	**Pulpit Rock Substation Power Transformer Replacement**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$17,000 in 2025; $2,905,000 in 2026**

PROJECT DESCRIPTION

The *Pulpit Rock Substation Power Transformer Replacement* project involves the replacement of the Pulpit Rock ("PUL") Substation power transformer PUL-T2.

The proposed 2025 and 2026 scope of work for the *Pulpit Rock Substation Power Transformer Replacement* project includes:

(i) Remove power transformer PUL-T2; and,
(ii) Install and commission new 66 kV to 12.5/25 kV, 25 MVA power transformer.

Engineering design and procurement of the new power transformer will be completed in the first quarter of 2025. Construction will begin in the third quarter of 2026 and will be completed early in the fourth quarter of 2026. Commissioning of the new power transformer will be completed by the end of 2026. For additional details, see report *2.2 Substation Power Transformer Replacements.*

PROJECT BUDGET

The budget of the *Pulpit Rock Substation Power Transformer Replacement* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2025 and 2026 for the *Pulpit Rock Substation Power Transformer Replacement* project.

Table 1
Pulpit Rock Substation Power Transformer Replacement
Project Budget
($000s)

Cost Category	2025	2026	Total
Material	0	2,645	2,645
Labour - Internal	0	13	13
Labour - Contract	0	0	0
Engineering	14	91	105
Other	3	156	159
Total	$17	$2,905	$2,922

ASSET BACKGROUND

All power transformers receive regular maintenance on a 12-year cycle. PUL-T2 last underwent full maintenance in February of 2019. Additionally, all power transformers undergo annual oil sampling to monitor their condition.

Dissolved gas in oil analysis of PUL-T2 oil samples since May of 2022 indicated high-energy arcing in the transformer oil. This was further supported by Transformer Condition Assessments™ ("TCA") from TJ/H2b Analytic Services Incorporated ("TJ/H2b").[52]

In July of 2022, PUL-T2 was de-energized and electrical testing was completed on the unit which continued to show signs of deterioration. An internal inspection was completed in September of 2022 which showed signs of structure deficiencies.

After the inspection, PUL-T2 was placed back in service and continues to be monitored.

ASSESSMENT OF ALTERNATIVES

Three alternatives were assessed to address the condition of power transformer PUL-T2: (i) Condition Based Maintenance; (ii) Repair; and (iii) Proactive replacement.

In the event of a PUL-T2 failure, a portable substation would be required to restore service to customers promptly and safely. Newfoundland Power aims to have one portable substation available at all times for emergency backup purposes. However, a portable substation that is deployed in response to a power transformer failure can be required to remain in service for up to 24 to 36 months.

Given the age and condition of the Company's power transformer fleet, it is reasonable to expect multiple power transformer failures could occur over the same time period. This would expose customers to a risk of even longer duration outages, and potentially impact the Company's annual capital and maintenance programs for substations.

Repairing PUL-T2 would require it to be removed from service for 18-24 months requiring the long-term installation of a portable substation or spare power transformer. This would again put additional pressure on the Company's portable and spare transformer fleet creating an unacceptable risk to customers. A repaired transformer does not have the benefits of a new transformer, including the improved quality, reliability, and service life.

These risks to customer reliability are amplified by the increasing delivery lead times of power transformers, the Company's limited emergency response capabilities, and the increased possibility of transformer failure due to the Company's aging fleet.

Deferral of the *Pulpit Rock Substation Power Transformer Replacement* project would increase the risk of failure, which could expose up to approximately 6,724 customers to the risk of outages. Deferring this project is therefore not a viable alternative.

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52 For details of the assessments, see the *2025 Capital Budget Application*, *report 2.2 Substation power Transformer Replacements, section 2.0*.

RISK ASSESSMENT

The *Pulpit Rock Substation Power Transformer Replacement* project will mitigate risks to the delivery of reliable service to customers in the communities of Torbay, Portugal Cove – St. Philip's, Pouch Cove, and Logy Bay – Middle Cove – Outer Cove.

The length of time required to restore service to customers following the failure of a power transformer varies depending on whether it is possible to transfer load to another transformer in the substation or an adjacent substation, as well as the availability and proximity of a portable substation.

In the event of a PUL-T2 failure, PUL-T1 is unable to supply the existing peak load without being severely overloaded. A portable substation would be required to restore service to customers. Furthermore, there is only one spare power transformer in Newfoundland Power's spare fleet capable of replacing PUL-T2.

Over the last three years, delivery times of power transformers have increased from an average of 34 weeks in 2019 to an average of 117 weeks in 2024. An increase in delivery times for replacement transformers represents a risk that additional time could be required to respond to transformer failures.

Overall, an increased probability of power transformer failures, combined with a diminished inventory of spare units, has the potential to place considerable pressure on the availability of portable substations. Extended delivery times for replacements have the potential to exacerbate this risk. Reduced availability of portable substations exposes the Company's customers to an increased risk of extended outages.

Table 2 summarizes the risk assessment for the *Pulpit Rock Substation Power Transformer Replacement* project.

Table 2
Pulpit Rock Substation Power Transformer Replacement Project
Risk Assessment Summary

Consequence	Probability	Risk
Serious (4)	Likely (4)	Medium-High (16)

Overall, the condition of PUL-T2 power transformer poses a Medium-High (16) risk to the delivery of reliable, safe, and environmentally responsible service to customers. Action is required in 2025 and 2026 to mitigate these risks for customers.

JUSTIFICATION

The *Pulpit Rock Substation Power Transformer Replacement* project is required to provide reliable service to customers at the lowest possible cost. Addressing the deteriorating power transformer will support the continued delivery of reliable service to customers in the communities of Torbay, Portugal Cove – St. Philip's, Pouch Cove, and Logy Bay – Middle Cove – Outer Cove.

Title:	**Substation Replacements Due to In-Service Failures**
Asset Class:	**Substations**
Category:	**Program**
Investment Classification:	**Renewal**
Budget:	**$4,927,000**

PROGRAM DESCRIPTION

The *Substation Replacements Due to In-Service Failures* program involves replacing substation equipment that has failed as a result of storm damage, lightning strikes, vandalism, electrical or mechanical failure, corrosion damage, technical obsolescence or failure during maintenance testing. Substation equipment that fails in service requires immediate attention as it is essential to the reliability of supply to customers. The program therefore includes costs associated with maintaining an inventory of spare parts necessary to permit a timely response to substation equipment failures.

PROGRAM BUDGET

The budget for the *Substation Replacements Due to In-Service Failures* program is based on a historical average. Historical annual expenditures under this program over the most recent five-year period are expressed in current-year dollars as Adjusted Costs. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada for non-labour costs and the Company's internal labour inflation rate for labour costs.[53]

Table 1 provides the annual expenditures for the *Substation Replacements Due to In-Service Failures* program from 2020 to 2024.

Table 1
Substation Replacements Due to In-Service Failures Program
Historical Expenditures
(000s)

Year	2020	2021	2022	2023	2024F
Total	3,684	4,113	4,562	5,101	4,797
Adjusted Cost[1]	4,441	4,676	4,877	5,238	4,797

[1] 2024 dollars

The average annual adjusted cost for the *Substation Replacements Due to In-Service Failures* program was approximately $4.8 million from 2020 to 2024.

[53] Effective 2023, labour costs associated with this program include a direct allocation of amounts previously included in GEC, as approved in Order No. P.U. 3 (2022).

Table 2 provides a breakdown of expenditures proposed for 2025 for the *Substation Replacements Due to In-Service Failures* program.

Table 2
Substation Replacements Due to In-Service Failures Program
2025 Budget
($000s)

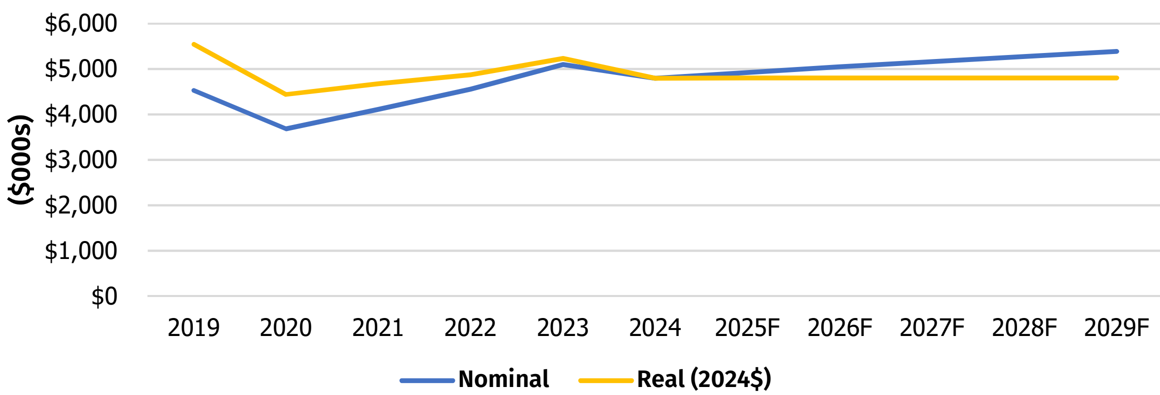
Cost Category	2025
Material	3,255
Labour – Internal	1,089
Labour – Contract	7
Engineering	321
Other	255
Total	$4,927

Proposed expenditures for the *Substation Replacements Due to In-Service Failures* program total $4,927,000 for 2025.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Substation Replacements Due to In-Service Failures* program from 2019 to 2029.[54]

Figure 1
Substation Replacements Due to In-Service Failures
Program Expenditures
(2019 - 2029F)



Annual expenditures under the *Substation Replacements Due to In-Service Failures* program averaged approximately $4.5 million from 2019 to 2024, or approximately $4.9 million when adjusted for inflation.[55] Annual expenditures are forecast to average approximately $5.2 million over the next five years.

ASSET BACKGROUND

Newfoundland Power operates 131 substations containing approximately 4,000 pieces of electrical equipment.

The need to replace substation equipment is determined based on in-service failures, testing, inspections, and operating experience. An adequate inventory of spare equipment and parts is necessary to enable the Company to respond quickly to in-service failures. The size of the inventory is based on past experience and engineering judgment, as well as consideration of the impact that the loss of a particular item would have on the electrical system.

The volume of equipment required to be replaced under the *Substation Replacements Due to In-Service Failures* program varies annually. Historically, major equipment failures in substations have included power transformers, circuit breakers and reclosers, and switches. Five power

[54] For forecast annual expenditures for the *Substation Replacements Due to In-Service Failures* program, see the *2025-2029 Capital Plan, Appendix A*, page A-3.
[55] Expenditures in 2019 were higher as a result of two failed power transformers that required repair. See the *2019 Capital Expenditure Report*, Note 5.

transformers were replaced or repaired under this program from 2019 to 2023.[56] Over the same period, an average of eight circuit breakers and reclosers and 11 switches also required replacement annually.

Newfoundland Power's operations are exposed to increasing risk of substation equipment failures as assets are aging beyond their expected useful service lives. This includes power transformers, bulk-oil circuit breakers, switches, and indoor switchgear. For more on the age and condition of substation assets, see report *2.1 2025 Substation Refurbishment and Modernization*.

ASSESSMENT OF ALTERNATIVES

The *Substation Replacements Due to In-Service Failures* program addresses equipment at substations that fails in service or is at imminent risk of failure. This program allows Newfoundland Power to respond to equipment failures that occur throughout normal operations. While alternative strategies, such as the deployment of portable substations, are used to minimize customer outages during equipment failure, there is no viable alternative to replacing failed substation equipment as substations are critical to the provision of reliable service to customers.

RISK ASSESSMENT

The *Substation Replacements Due to In-Service Failures* program will mitigate risk to the delivery of reliable service to customers.

Individual substations provide service to an average of approximately 2,400 customers, with the largest substation providing service to over 10,000 customers. Substations are maintained to operate to a high standard of reliability and, as a result, have not had a material impact on the average service reliability provided to customers in recent years. However, when substation failures occur they can result in significant customer outages. For example, a power transformer failure at Bonavista Substation in 2018 resulted in 3.7 million customer outage minutes. Equipment replaced under the *Substation Replacements Due to In-Service Failures* program has either failed or is at imminent risk of failure.

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[56] The *Substation Replacements Due to In-Service Failures* program allows for the timely repair of power transformers, the installation of spares in response to failures and the procurement and installation of smaller units. However, the procurement and installation of a new large capacity power transformer is not typically covered under this program due to the magnitude of the associated costs and long lead time for manufacturing.

Table 3 summarizes the risk assessment of the *Substation Replacements Due to In-Service Failures* program.

Table 3 Substation Replacements Due to In-Service Failures Program Risk Assessment Summary		
Consequence	Probability	Risk
Critical (5)	Near Certain (5)	High (25)

Based on this assessment, deferring the *Substation Replacements Due to In-Service Failures* program would pose a High (25) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Substation Replacements Due to In-Service Failures* program is required to provide reliable service to customers at the lowest possible cost as it permits the replacement of substation equipment that has failed or is at imminent risk of failure.

TRANSMISSION

Title:	**New Transmission Line from Lewisporte to Boyd's Cove**
Asset Class:	**Transmission**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$1,886,000 in 2025; $9,283,000 in 2026; $9,553,000 in 2027**

PROJECT DESCRIPTION

The *Gander – Twillingate Transmission System Planning Study* (the "Study") consists of a three-year project to construct a new 138 kV transmission line between Lewisporte ("LEW") and Boyd's Cove ("BOY") Substations from 2025 to 2027.

The Study identified a 66 kV transmission undervoltage condition in the Gander - Twillingate area that is in violation of Newfoundland Power's system planning criteria. The Study further identified that Transmission Line 108L has deteriorated and requires replacement. By constructing a new 138 kV transmission line between LEW and BOY substations, the system planning voltage violation can be mitigated and Transmission Line 108L can be retired.

The transmission construction project is proposed as a multi-year project between 2025 and 2027. Engineering and pre-construction activities, including securing environmental and development permits and approvals, acquiring property rights, completing brush clearing of the new right-of-way, collecting topographic data, finalizing the engineering and design, and ordering materials will be completed in the first year. Completing all of this work in the first year allows for the Company to better manage lengthening timelines related to project approvals, environmental assessments, and permitting associated with transmission line rebuild projects. The second and third years will involve establishing construction contracts, procuring materials, and construction of the new line.

Additional information on this project is provided in report *3.1 Gander Twillingate Transmission System Planning Study* filed with the Application.

PROJECT BUDGET

The budget for the *New Transmission Line from Lewisporte to Boyd's Cove* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed from 2025 to 2027 for the project.

Table 1
New Transmission Line from Lewisporte to Boyd's Cove
2025-2027 Budget
($000s)

Cost Category	2025	2026	2027	Total
Engineering	242	83	85	410
Labour – Contract	0	5,061	5,208	10,269
Labour – Internal	53	110	114	277
Material	0	3,483	3,584	7,067
Other	1,591	546	562	2,699
Total	$1,886	$9,283	$9,553	$20,722

Proposed expenditures for the *New Transmission Line from Lewisporte to Boyd's Cove* project total $20,722,000, including $1,886,000 in 2025, $9,283,000 in 2026, and $9,553,000 in 2027.

ASSET BACKGROUND

The 66 kV transmission network supplying the Gander - Twillingate area (the "Study Area") consists of transmission lines 108L, 114L, 142L, and 140L. In total, these lines serve 6,513 Newfoundland Power customers through the following substations: Gander Bay ("GBY"), Summerford ("SUM"), Twillingate ("TWG"), and Jonathan's Pond ("JON"). In addition, the 66 kV transmission network supplies approximately 1,800 Newfoundland and Labrador Hydro ("Hydro") customers on Fogo Island and Change Islands through Hydro's Farewell Head ("FHD") Terminal Station. Supply to FHD Terminal Station is through Hydro's 66 kV Transmission Line TL254 and is wheeled through Newfoundland Power's 66 kV transmission network at BOY Substation.

System Planning Voltage Violation

Newfoundland Power's System Planning Criteria requires that transmission-level voltages operate between 0.95-1.05 per-unit ("pu") during normal conditions. During the most recent winter seasons, transmission supply voltages to BOY, SUM and TWG substations have consistently operated below 0.95 pu.

Transmission Line 108L

Transmission Line 108L was built in 1965 and is among the oldest in the Company's service territory. It is supplied from Gander ("GAN") Substation and is 44 kilometres in length and provides the primary source of supply to JON and GBY substations. A normally-open switch at GBY Substation permits Transmission Line 108L to connect to Transmission Line 114L and BOY Substation for emergency backup purposes[57].

The line consists of approximately 396 Single Pole structures with 2/0 ACSR nonstandard conductor.[58] The conductor is approximately 60 years old and is approaching the end of the typical useful service life for transmission line conductor.[59]

In 2024, Newfoundland Power initiated an engineering assessment of Transmission Line 108L in response to the line's deteriorating condition. A detailed inspection of the line was completed to quantify its overall condition. The engineering assessment included a detailed inspection ground inspection. This detailed inspection determined that 238 of the structures across the line, contain wood poles which are deteriorated to the point where they require replacement. On a single pole transmission line, the wood pole is the main component of each structure. It provides the primary support for the structure; all other components are inherently dependent upon the wood pole for support. Having a large percentage of wood poles across the line in deteriorated condition increases the risk of a failure to the line.

Additionally, the assessment determined that other structure components across the line were deteriorated. A total of 108 structures were identified as having other deficiencies such as damaged or deteriorated crossarms, missing timber cribs, cracked insulators or missing or damaged hardware and damaged conductor.

Further details on the condition of Transmission Line 108L can be found in report *3.1 Gander Twillingate Transmission System Planning Study* filed with the Application.

The engineering assessment, in conjunction with the low transmission voltages observed in the area, prompted a detailed system planning study to determine the least-cost solution to continue to provide reliable electric service to the area.

Transmission Lines 114L and 142L

Transmission Line 114L was built in 1972 and connects GBY Substation to BOY Substation. Transmission Line 142L was built in 1978 and supplies BOY Substation from Cobb's Pond ("COB") Substation. Transmission Line 142L directly connects to Transmission Line 114L in back-country approximately 1.7 kilometres from GBY Substation, in an area known as Clarke's Head.

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57 The primary function of the normally-open switch is to reduce the risk of customer outages, while also avoiding a voltage collapse and potential overloads under contingency scenarios. When closed, a fault on the 66 kV system at JON or GBY substations would result in an outage to approximately 6,000 customers supplied by SUM, TWG and FHD. Furthermore, if closed, a fault on the transmission lines 142L and 114L network would result in a widespread undervoltage condition to the remaining section, as well as an overload to GAN-T2 under peak conditions.

58 ACSR is a bare overhead conductor with aluminum outer strands and a steel core.

59 The typical useful service life of transmission overhead conductor is 63 years.

Together, transmission lines 114L and 142L form the primary source of supply to SUM and TWG substations and FHD Terminal Station, with Transmission Line 108L also serving as a source of backup supply to the area when the normally-open switch at GBY Substation is closed.

ASSESSMENT OF ALTERNATIVES

Ensuring normal operating voltages is critical to the reliability of the Gander – Twillingate 66 kV transmission network. Newfoundland Power evaluated several alternatives to mitigate the observed transmission voltage violation while also ensuring reliable supply to customers served by Transmission Line 108L, which has deteriorated and requires replacement. These are: (i) convert Transmission Line 142L to 138 kV and extend the line to BOY Substation, and rebuild Transmission Line 108L; (ii) build a new 138 kV transmission line between LEW and BOY substations, extend Transmission Line 142L into GBY Substation, and retire Transmission Line 108L; and (iii) a non-wires alternative at SUM Substation for voltage support, and rebuild Transmission Line 108L.

The assessment of alternatives included a net present value analysis to determine the least-cost alternative to addressing the deteriorated condition of Transmission Line 108L while also maintaining normal operating voltages to the Study Area. The assessment determined that building a new 138 kV Transmission Line between LEW and BOY substations, extending Transmission Line 142L into GBY Substation, and retiring Transmission Line 108L is the least-cost alternative to addressing the identified issues.

RISK ASSESSMENT

The *New Transmission Line from Lewisporte to Boyd's Cove* project will mitigate risks to the delivery of reliable service to customers in the Study Area. Due to their criticality in serving customers, Newfoundland Power's transmission lines must operate within defined voltage limits, and must be maintained to operate to a high standard of reliability.[60] All transmission lines, including Transmission Line 108L, are maintained in accordance with the Company's *Transmission Inspection and Maintenance Practices*.[61]

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60 Reliability indices are lagging indicators that encompass historical issues on the electrical system. Waiting for reliability on the transmission system to degrade before undertaking capital investments would result in a poor quality of service being experienced by large numbers of customers for several years. Newfoundland Power relies on an assessment of a transmission line's condition and its criticality in serving customers when determining whether a transmission line should be rebuilt.

61 Over the last 10 years, approximately $262,000 has been spent on corrective and preventative maintenance of Transmission Line 108L.

The 66 kV transmission voltages downstream of BOY Substation are the lowest in the Company's service territory, and are consistently lower than the Company's planning criteria for transmission voltages. This is partly due to the relatively low 138 kV infeed voltages at COB and GAN Substations, but primarily a result of the combined length and overall load served through the 66 kV Gander – Twillingate area network.[62]

Over the course of the most recent 2023 to 2024 winter season, the incoming 66 kV transmission voltage at TWG has been below 0.95 pu for approximately 31% of the entire period. Furthermore, this voltage was below the emergency limit of 0.90 pu for 6.5 hours during the winter period, with a record low of 0.873 pu observed on the most recent seasonal peak day of January 24, 2024. [63]

In addition to the observed voltage violations, the Company uses power system modeling software to model the transmission network under forecast load conditions. The latest transmission models indicate that the transmission voltages at and downstream of BOY Substation will continue to worsen over time, especially as additional load resulting from electrification continues to materialize.

Transmission Line 108L plays a critical role in the Gander - Twillingate area. An outage to Transmission Line 108L results in a direct outage to over 2,300 customers supplied by the JON and GBY substations, as well as a loss of backup supply to approximately 6,000 customers in the areas of Summerford and Twillingate, including Hydro's customers on Fogo and Change Islands.

The criticality of the Gander - Twillingate transmission system and its inability to operate at normal voltages, in conjunction with an increased probability of failure result in a high risk to the delivery of reliable service to a significant number of Newfoundland Power's customers.

Table 2 summarizes the risk assessment of the *New Transmission Line from Lewisporte to Boyd's Cove* project.

Table 2
New Transmission Line from Lewisporte to Boyd's Cove
Risk Assessment Summary

Consequence	Probability	Risk
Critical (5)	Likely (4)	High (20)

Based on this assessment, not proceeding with the *New Transmission Line from Lewisporte to Boyd's Cove* project would pose a High (20) risk to the delivery of reliable service to customers.

62 The 66 kV network serving the Gander - Twillingate area is comprised of 107km of 66 kV transmission lines serving a forecasted load of 32.1 MVA. Other 66 kV networks in the Company's service territory include: 50L/55L, which supply 20.5 MVA over 43.3 km of 66 kV transmission lines; and 94L/95L, which supply 8.1 MVA over 50.5 km of 66 kV transmission lines. Other 66 kV networks spanning long distances and serving high loads either have additional sources of generation, such as in the Wesleyville and Port-Aux-Basques areas, or have sufficient redundancy through looped configurations, such as the St. John's 66 kV network.

63 A per unit value of 0.873 on a 66 kV system is 57.6 kV; on a 120V system, it is 104.8V.

JUSTIFICATION

The *New Transmission Line from Lewisporte to Boyd's Cove* project is required to ensure the delivery of reliable service to customers in the Gander – Twillingate area network. An assessment of alternatives determined that constructing a new 138 kV transmission line between LEW and BOY substations and retiring Transmission Line 108L is the least cost option to maintain reliable service to customers.

Title:	**Transmission Line 94L Rebuild**
Asset Class:	**Transmission**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$3,485,000 in 2025; $9,075,000 in 2026**

PROJECT DESCRIPTION

In 2021, Newfoundland Power received approval for the *Transmission Line 94L Rebuild* project (the "Project") as a part of its *2022 Capital Budget Application*. The Project was intended to include a complete rebuild of Transmission Line 94L between Riverhead ("RVH") Substation and Blaketown ("BLK") Substation. The project was to be completed over the course of three years and was necessary to address the deteriorated condition of the existing Transmission Line 94L.

Recent issues encountered during the execution of the Project have resulted in project costs increasing significantly. As a result of an apparent change in materiality Newfoundland Power is resubmitting the project for further review by The Board pursuant to the Provisional Guidelines.[64]

Based on the results of this review, Newfoundland Power intends to rebuild the remaining sections of Transmission Line 94L as a multi-year project in 2025 and 2026. The newly constructed line will continue to connect St. Catherine's ("SCT") Substation and BLK Substation as approved in Newfoundland Power's *2022 Capital Budget Application*, however the planned right-of-way will be relocated to follow a series of provincial road right-of-ways as opposed to being constructed cross country as originally approved. In 2025, the Company plans to construct approximately 12.5 kilometres of transmission line between SCT Substation and Route 81 – Markland Road. In 2026, the remaining 27.5 kilometres of the new line between Route 81 – Markland Road and BLK Substation will be completed.

Additional information on this project is provided in report *3.2 Transmission Line 94L Rebuild* filed with the Application.

[64] See the Provisional Guidelines, page 5, which states, *"If there is a material change in a subsequent year the expenditures will be subjected to further review. A change will be considered material if the nature or scope of the project change such that original rationale provided is no longer applicable or where the revised forecast expenditure exceeds the approved amount by 10% or more".*

PROJECT BUDGET

The updated budget for the *Transmission Line 94L Rebuild* project is based on engineering estimates developed during the review of the Project.

Table 1 provides a breakdown of planned expenditures from 2025 to 2026 required to complete the execution of the *Transmission Line 94L Rebuild* project.

Table 1
Transmission Line 94L Rebuild Project
2025-2026 Budget
($000s)

Description	2025	2026	Total
Engineering	52	53	105
Labour - Contract	2,094	5,306	7,400
Labour - Internal	24	164	188
Material	903	2,321	3,224
Other	412	1,231	1,643
Total	$3,485	$9,075	$12,560

The new cost of the revised transmission scope for the *Transmission Line 94L Rebuild* project is estimated to be $12,560,000, including $3,485,000 in 2025 and $9,075,000 in 2026.

ASSET BACKGROUND

Transmission Line 94L is a 66 kV H-Frame radial line running between BLK Substation on the Trans-Canada Highway near Whitbourne, and RVH Substation located in Riverhead, St. Mary's Bay. This line provides the only source of supply for SCT and RVH substations along with Trepassey ("TRP") Substation via Transmission Line 95L. In total, the three substations serve approximately 2,500 customers.

The *Transmission Line 94L Rebuild* project was approved by the Board as a part of Newfoundland Power's *2022 Capital Budget Application* as a multi-year project. The Project was to be completed over the span of three years, beginning in 2022 and ending in 2024. The transmission line as a whole was divided into three scopes of work, each roughly 20 kilometres in length, with Newfoundland Power planning to complete one of the scopes in each year of the Project. In total, the approved *Transmission Line 94L Rebuild* project would include 61 kilometres of new transmission line constructed over three years at an estimated cost of $13,095,000.

In early 2022, Newfoundland Power began the execution of Scope 1 of the *Transmission Line 94L Rebuild* project. Prior to beginning any construction activities, the Project had to undergo an Environmental Assessment. Delays in the approval process resulted in a formal approval of the Project not being obtained until September 2022, ultimately delaying the start of construction activities on Scope 1 until the following year.

In early 2023, Newfoundland Power solicited bids from contractors for the construction of Scope 1. The contractor pricing that was received was higher than anticipated, but following an evaluation of other available alternatives to Scope 1, it was determined that the proposed alternative remained the least cost option consistent with prior approval. As a result, the Company proceeded with the execution of Scope 1. This scope of the Project was completed and put into service in 2023 at a cost of $7,899,000.

While construction activities for Scope 1 were ongoing, Newfoundland Power issued the tender for the construction of Scope 2. In reviewing the submitted bids, it was determined that contractor pricing had come in higher than anticipated.

The contractor pricing received for Scope 2 resulted in an increase to the overall forecasted cost of the Project. The forecasted increase in cost represented more than a 10% increase over the original cost estimate. As a result, Newfoundland Power determined that the project required further review by the Board pursuant to the Provisional Guidelines.[65]

ASSESSMENT OF ALTERNATIVES

As Transmission Line 94L is a radial line, it provides the sole supply of electricity to the approximately 2,500 customers served by SCT, RVH, and TRP substations. In its review of the project, Newfoundland Power evaluated two alternatives to replace the remaining sections of Transmission Line 94L and ensure it was proceeding with the least cost option for customers. The two alternatives that were assessed are: (i) rebuild Transmission Line 94L as approved in Newfoundland Power's *2022 Capital Budget Application*; and (ii) rebuild Transmission Line 94L between SCT and BLK substations in a revised right-of-way.

The assessment of alternatives included a net present value analysis to determine the least-cost alternative to rebuilding the remaining sections of Transmission Line 94L. The assessment determined that Alternative 2, which involves rebuilding Transmission Line 94L between SCT and BLK substations in a revised right-of-way is the least-cost alternative. For additional details see report *3.2 Transmission Line 94L Rebuild* filed with the Application.

65 See the Provisional Guidelines, section *V. Guidelines, A. Annual Capital Budget Applications, 6. Multi-year Projects,* page 5 of 18.

RISK ASSESSMENT

As detailed in Newfoundland Power's *2022 Capital Budget Application* filing of the Project, the *Transmission Line 94L Rebuild* project will mitigate risks to the delivery of reliable service to the 2,500 customers supplied by SCT, RVH and TRP Substations. Due to their criticality in serving customers, Newfoundland Power's transmission lines must be maintained to operate to a high standard of reliability.[66] All transmission lines, including Transmission Line 94L, are maintained in accordance with the Company's *Transmission Inspection and Maintenance Practices*.

The line's sub-standard design and deteriorated condition exposes it to an increased probability of failure going forward. Based on these factors the probability of failure is therefore likely.

As Transmission Line 94L is a radial line, it serves as the sole source of supply for approximately 2,500 customers. An equipment failure on Transmission Line 94L would result in outages to all customers served by the line located beyond the section of line where the failure occurred. With sections of the transmission line located back country in areas with limited access, significant time can be required to restore service to customers.[67]

Due to the number of customers directly affected by an outage to Transmission Line 94L, the consequence of failure is critical.

Table 2 summarizes the risk assessment of the *Transmission Line 94L Rebuild* project.

Table 2
Transmission Line 94L Rebuild Project
Risk Assessment Summary

Consequence	Probability	Risk
Critical (5)	Likely (4)	High (20)

Based on this assessment, not proceeding with the *Transmission Line 94L Rebuild* project would pose a High (20) risk to the delivery of reliable service to customers.

66 Reliability indices are lagging indicators that encompass historical issues on the electrical system. Waiting for reliability on the transmission system to degrade before undertaking capital investments would result in a poor quality of service being experienced by large numbers of customers for several years. Newfoundland Power relies on an assessment of a transmission line's condition and its criticality in serving customers when determining whether a transmission line should be rebuilt.

67 An unplanned outage on Transmission Line 94L on December 19, 2023 resulted in a 12-hour restoration time for customers.

JUSTIFICATION

The *Transmission Line 94L Rebuild* project is required to ensure the delivery of reliable service to approximately 2,500 customers. A review of the Project and an updated assessment of alternatives determined that rebuilding Transmission Line 94L between SCT and BLK substations in a revised right- of-way is the least cost option to address existing deterioration and deficiencies, and mitigate risks of equipment failures.

Title:	**Transmission Line Maintenance**
Asset Class:	**Transmission**
Category:	**Program**
Investment Classification:	**Renewal**
Budget:	**$2,884,000**

PROGRAM DESCRIPTION

The *Transmission Line Maintenance* program involves the replacement of transmission line infrastructure that has failed or is at risk of failure. The program also includes a component to accommodate third-party requests to relocate or replace sections of transmission lines. Third-party requests typically have contributions in aid of construction, which offset capital costs.

PROGRAM BUDGET

The budget for the *Transmission Line Maintenance* program is based on a historical average. Historical annual program expenditures over the most recent five-year period are expressed in current-year dollars as Adjusted Costs. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada for non-labour costs and the Company's internal labour inflation rate for labour costs.[68]

Table 1 provides the annual expenditures for the *Transmission Line Maintenance* program from 2020 to 2024.

Table 1
Transmission Line Maintenance Program
Historical Expenditures
($000s)

Year	2020	2021	2022	2023	2024F
Total	$2,139	$2,404	$2,488	$3,449	$2,651
Adjusted Cost[1]	$2,575	$2,713	$2,625	$3,539	$2,651

1 2024 dollars.

The average annual adjusted cost for the *Transmission Line Maintenance* program was approximately $2.8 million from 2020 to 2024.

68 Effective 2023, labour costs associated with this program include a direct allocation of amounts previously included in GEC, as approved in Order No. P.U. 3 (2022).

Table 2 provides a breakdown of expenditures proposed for 2025 for the *Transmission Line Maintenance* program.

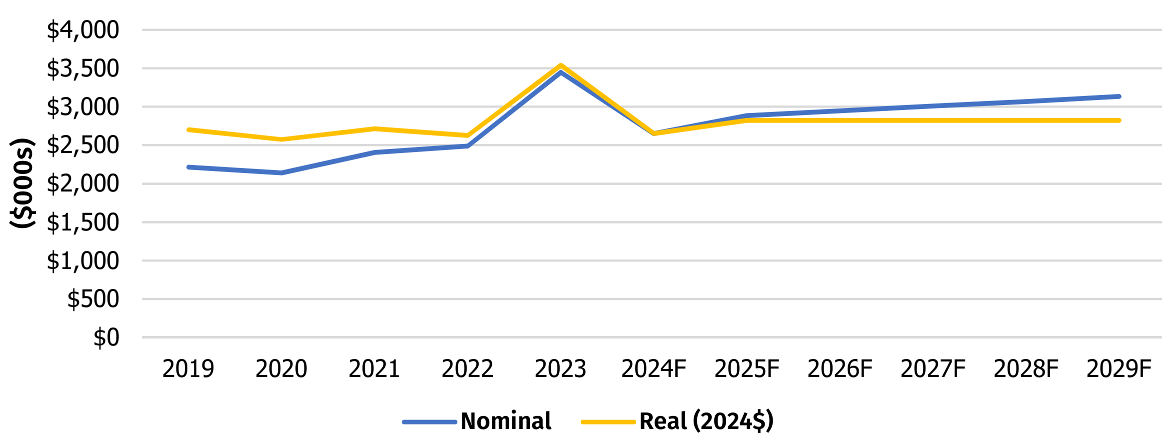
Table 2 Transmission Line Maintenance Program 2025 Budget ($000s)	
Cost Category	2025
Material	1,040
Labour – Internal	482
Labour – Contract	1,065
Engineering	89
Other	208
Total	$2,884

Proposed expenditures for the *Transmission Line Maintenance* program total $2,884,000 for 2025.

PROGRAM TREND

Figure 1 provides historical and forecast costs for the *Transmission Line Maintenance* program from 2019 to 2029.[69]

Figure 1
Transmission Line Maintenance Program Expenditures
(2019 - 2029F)



[69] For forecast annual expenditures for the *Transmission Line Maintenance* program, see the *2025-2029 Capital Plan, Appendix A,* page A-4.

Annual expenditures under this program averaged approximately $2.6 million from 2019 to 2024, or approximately $2.8 million when adjusted for inflation. Annual expenditures are forecast to average approximately $3.0 million over the next five years.

ASSET BACKGROUND

Newfoundland Power owns and operates 111 transmission lines, which span approximately 2,000 kilometres. Virtually all of the Company's transmission lines operate at 66 kV or 138 kV.[70] Individual transmission lines range in length from two kilometres to 94 kilometres, with an average length of 19 kilometres.

The *Transmission Line Maintenance* program includes both corrective and preventative maintenance. Each transmission line is inspected annually to identify deficiencies. Identified deficiencies are prioritized for maintenance based on the severity of deterioration observed in the field. Corrective maintenance includes replacing components that have failed or where failure is imminent, including broken poles and sagging conductor. Preventative maintenance includes replacing components that are likely to fail within the next year, including poles and crossarms with serious cracks.

The number of deficiencies addressed under the *Transmission Line Maintenance* program varies annually. From 2019 to 2023, an average of 108 poles, 96 framing structures and 1,106 pieces of hardware were replaced annually due to corrective and preventative maintenance requirements.

ASSESSMENT OF ALTERNATIVES

The *Transmission Line Maintenance* program is required to replace transmission line equipment that has failed in-service or is at risk of failure. While alternative strategies, such as the operation of mobile generation, are used to minimize customer outages during equipment failure, there is no viable alternative to replacing failed transmission equipment as it is critical to the operation of the transmission system used to provide service to customers.

The program also includes a component to accommodate third-party requests for relocating sections or replacing sections of transmission lines, which cannot be deferred or re-paced.

RISK ASSESSMENT

The *Transmission Line Maintenance* program will mitigate risks to the delivery of reliable service to customers by addressing transmission line equipment that has failed or is at risk of failure.

Transmission lines are the backbone of the electricity system providing service to customers. Transmission lines are maintained to operate to a high standard of reliability and, as a result, have not had a material impact on the average service reliability provided to customers in recent years. However, while the transmission system operates reliably overall, equipment

[70] There is one transmission line, designated as 3L, that operates at 33 kV.

failures can result in significant customer outages. For example, an outage to Transmission Line 65L during a severe blizzard in January 2020 resulted in approximately 2.1 million outage minutes to customers on the Avalon Peninsula.

Newfoundland Power's operations are exposed to increasing risks of equipment failures due to the age of its transmission assets.

Table 3 provides a summary of the age of the Company's transmission lines.

Table 3
Transmission Line Age

Age (Years)	1-10	11-20	21-30	31-40	41-50	51-60	61-65	Total
Kilometres	293	262	126	141	753	389	22	1,986
Percentage of Total	15%	13%	6%	7%	38%	20%	1%	100%

As show in Table 3, 21% of Newfoundland Power's transmission lines have been in service for over 50 years. An additional 38% of transmission lines have been in service for between 41 and 50 years. As transmission lines age, annual maintenance of these assets will continue to be critical to the provision of reliable service to customers.

Addressing deficiencies with transmission assets is essential to providing reliable service to customers as the failure of a single transmission line component can result in outages to thousands of customers. Equipment replaced under the *Transmission Line Maintenance* program has either failed, is at imminent risk of failure or is likely to fail within the next year.

Table 4 summarizes the risk assessment of the *Transmission Line Maintenance* program.

Table 4
Transmission Line Maintenance Program
Risk Assessment Summary

Consequence	Probability	Risk
Critical (5)	Near Certain (5)	High (25)

Based on this assessment, not proceeding with the *Transmission Line Maintenance* program would pose a High (25) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Transmission Line Maintenance* program is required to provide reliable service to customers at the lowest possible cost as it permits the correction of deficiencies and failures on the transmission system that have been identified through annual inspection and operating experience.

GENERATION - HYDRO

Title: **Mobile Hydro Plant Penstock Refurbishment**
Asset Class: **Generation – Hydro**
Category: **Project**
Investment Classification: **Renewal**
Budget: **$825,000**

PROJECT DESCRIPTION

The proposed *Mobile Hydro Plant Penstock Refurbishment* project involves refurbishing the Mobile Hydroelectric Plant Penstock (the "Mobile Penstock" or the "penstock"), located in eastern Newfoundland in the community of Mobile.

The 2025 *Mobile Hydro Plant Refurbishment* project will include:

(i) Replacement of the penstock protective coating system;
(ii) Refurbishment of the penstock expansion joints; and
(iii) Replacement of one (1) rocker style connection.

In 2025, procurement and design of the penstock components will occur. Project execution will take approximately 16 weeks to complete and will begin in the second quarter of 2025. The existing protective coating system will be removed, the new protective coating installed, rocker style connection replaced, and the expansion joints refurbished during the third and fourth quarters of 2025. The plant will be returned to service in the fourth quarter.

PROJECT BUDGET

The budget for the *Mobile Hydro Plant Penstock Refurbishment* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2025 for the *Mobile Hydro Plant Penstock Refurbishment* project.

Table 1 Mobile Hydro Plant Penstock Refurbishment Project 2025 Budget ($000s)	
Cost Category	2025
Material	746
Labour – Internal	7
Labour – Contract	-
Engineering	40
Other	32
Total	$825

Proposed expenditures for the *Mobile Hydro Plant Penstock Refurbishment* project total $825,000 in 2025.

ASSET BACKGROUND

The Mobile Hydroelectric Plant (the "Plant") was commissioned in 1951 with a capacity of 11.0 MVA under a net head of approximately 114.6 metres. The Plant contains a single vertical 13,000 hp Francis turbine manufactured by Voith Hydro coupled to a Canadian Westinghouse generator. The Plant is connected to the Island Interconnected System at Mobile Substation and has provided 73 years of reliable energy production. The Plant is also routinely placed into service at the request of Newfoundland and Labrador Hydro.

A condition assessment and corresponding risk assessment determined that the Mobile Hydroelectric Plant penstock must be refurbished or upgraded to ensure the continued safe and reliable operation of the Plant. Equipment identified for refurbishment through the condition assessment includes the protective coating system, expansion joints and a rocker style connection.

Protective coating systems are used to protect bare steel from exposure to environmental conditions such as rain, salt spray and sunlight. Protective coating systems protect steel from corrosion and loss of steel thickness. After sufficient material loss structures will no longer be able to resist applied loads.

The penstock protective coating system was originally installed along the steel penstock shell, ring girders, rocker style connections, anchor bolts and expansion joints. The protective coating system has failed along the entire length of the steel penstock. Coating loss varies along the length of the penstock, ranging from approximately 10% to 100% in areas. Overall, the penstock has lost a significant percentage of its protective coating system.

Figure 1 shows the extent of protective coating loss.

Figure 1: Protective Coating Loss

Steel expands and contracts when exposed to temperature variations by expanding in warm temperatures and contracting in cold temperatures. The steel penstock is rigidly connected to the Plant and surge tank at both ends as well as three intermediate anchor blocks. Rocker style connections and expansion joints allow penstock movement along its length to compensate for expansion and contraction due to temperature changes in the steel.

There are four expansion joints installed along the length of the penstock, working in conjunction with the 25 rocker style connections to allow for penstock movement. Leakage has occurred in all four expansion joints. Leaks have occurred in the vicinity of the grease injection ports as well as along the sliding surface where the expansion joints meet the penstock shell. Evidence on the interior of the penstock of the sliding surface, specifically the loss of organic material surrounding the expansion joint, shows that the joints are still providing stress relief as designed.

Figure 2 shows an expansion joint leak on the penstock.

Figure 2: Expansion Joint Leakage

Penstock supports and bedding ensure the penstock remains stable without undesired movement. Without support the penstock would deflect and induce stresses into the penstock structure that would cause components to fail. Penstock supports consist of steel ring girders that support the weight of water and the penstock shell. These ring girders are connected to concrete bases with rocker style connections. The rocker style connections are then affixed to the concrete foundations with steel anchor bolts. Structural granular fill material is placed under the concrete foundations to form the completed penstock support system.

The steel ring girder, rocker style connections and anchor bolts are in good condition with the exception of one (1) rocker style connection which has failed in shear. The rocker style connections are showing rotation which indicates movement of the penstock primarily in one direction. The rocker style connections have not rotated to their full extent, which allows them some ability to continue performing as intended. Concrete foundations are in good condition with no significant cracking or material loss visible. Penstock bedding beneath the structure is in good condition.

Figure 3 shows the failed rocker style connection.

Figure 3: Rocker Style Connection

RISK ASSESSMENT

The *Mobile Hydro Plant Penstock Refurbishment* project will provide an economic benefit for customers by ensuring the continued production of low-cost energy.

Protective coatings are designed to protect structural steel systems from corrosion. In areas subject to salt spray, such as coastal environments, the expected life is shorter than in less corrosive environments. Protective coating systems require replacement to ensure continued protection of the structural steel elements. Protective coating systems require replacement periodically to ensure their integrity is maintained and the underlying material is protected.

The Mobile penstock is original to the plant's construction and will be 74 years old in 2025. If protective coatings are not replaced the penstock life expectancy will be reduced. The failure of the expansion joints and rocker connection also increases the likelihood of failure in the Mobile penstock. Based on the current condition of the Mobile Plant penstock, the probability of failure is possible.

Table 2 summarizes the risk assessment of the *Mobile Hydro Plant Penstock Refurbishment* project.

Table 2
Mobile Hydro Plant Penstock Refurbishment Project
Risk Assessment Summary

Consequence	Probability	Risk
Critical (5)	Possible (3)	Medium-High (15)

Based on this assessment, not proceeding with the *Mobile Hydro Plant Penstock Refurbishment* project would pose a Medium-High (15) risk to the delivery of least-cost service to customers.

JUSTIFICATION

The *Mobile Hydro Plant Penstock Refurbishment* project is required to provide reliable service to customers at the lowest possible cost. The Mobile Plant continues to provide low-cost energy to customers. Completing required upgrades to the penstock in 2025 will minimize Plant downtime and ensure the continued provision of low-cost energy to customers.

Title:	**Mount Carmel Pond Dam Refurbishment**
Asset Class:	**Generation – Hydro**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$3,608,000 in 2025; and $1,008,000 in 2026**

PROJECT DESCRIPTION

The proposed *Mount Carmel Pond Dam Refurbishment* project involves the replacement of the deteriorated spillway structure and automation of the outlet gate at Mount Carmel Pond. Mount Carmel Pond Spillway is part of the Cape Broyle – Horsechops Hydroelectric Development (the "CBHC Development") and is located on the Avalon Peninsula near the town of Cape Broyle. By replacing the spillway structure and automating the outlet gate, Newfoundland Power will ensure reliable winter capacity and energy availability into the future.

The 2025 *Mount Carmel Pond Dam Refurbishment* project will include:

(i) Replacement of the overflow spillway structure;
(ii) Enhancements to the public safety infrastructure; and
(iii) Automation of the outlet gate including gate replacement.

Design and procurement for the new spillway structure will be completed in the first quarter of 2025. Construction of the new spillway structure will be completed between the second and fourth quarters of 2025 prior to the winter season. The automation of the outlet gate will be completed by the fourth quarter of 2026. There will be no required generation unit outages associated with this project.

PROJECT BUDGET

The budget for the *Mount Carmel Pond Dam Refurbishment* project is based on engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2025 for the *Mount Carmel Pond Dam Refurbishment* project.

Table 1
Mount Carmel Pond Dam Refurbishment Project Budget
($000s)

Cost Category	2025	2026	Total Cost
Material	3,370	842	4,212
Labour – Internal	4	6	10
Labour – Contract	0	0	0
Engineering	162	54	216
Other	72	106	178
Total	$3,608	$1,008	$4,616

Proposed expenditures for the *Mount Carmel Pond Dam Refurbishment* project total $4,616,000, with $3,608,000 in 2025 and $1,008,000 in 2026.

ASSET BACKGROUND

The CBHC Development consists of two generating plants, the Cape Broyle hydroelectric generating plant; and the Horsechops hydroelectric generating plant. The Cape Broyle Plant was commissioned in 1954 with a capacity of 7.0 MVA under a net head of approximately 54.8 metres. The Horsechops Plant was commissioned in 1954 with a capacity of 9.0 MVA under a net head of approximately 85.3 metres.

The Mount Carmel Pond spillway was constructed in 1954 and is original to the CBHC Development. The outlet gate was also installed in 1954 and is original to the CBHC Development. The outlet gate requires manual operation by hydro plant operations staff as no electricity for controls equipment is present at the site. The spillway and outlet gate have been in service for 70 years.

Newfoundland Power became aware of damage to the spillway structure in the spring of 2023. During the 2022/2023 winter operating season, ice loading occurred on the structure's timber stop logs and vertical steel stoplog supports which exceeded the design capacity of the structure. The vertical supports yielded to the stress and deformed in the downstream direction occurred.

ASSESSMENT OF ALTERNATIVES

Newfoundland Power identified and assessed two alternatives for the *Mount Carmel Pond Dam Refurbishment* project. The alternatives included: (i) refurbishing the dam in 2025 and 2026; and (ii) reducing the full supply level of Mount Carmel Pond by 1.2 metres.

The assessment determined that completing the refurbishment in 2025 and 2026 is the least-cost alternative. The assessment was based on marginal supply costs. Foregoing the refurbishment of the spillway will result in reducing on peak winter capacity. Losing this capacity will result in higher cost for customers.

A lifecycle cost analysis of the CBHC development completed in connection with this project proposed shows that the benefits of the development's production exceed the cost of production.[71] This analysis shows a net benefit of Plant production is between 7.12 ¢/kWh and 7.28 ¢/kWh based on the most recent marginal cost estimates.[72] The lifecycle cost analysis confirms that continued operation of the Plant will provide an economic benefit for Newfoundland Power's customers over the longer term. For additional details, see report *4.1 Mount Carmel Pond Dam Refurbishment*.

RISK ASSESSMENT

The Mount Carmel Pond spillway has failed in service. The stop log supports can no longer resist the applied loading from water and ice on the structure, therefore removal of the timber stoplogs is necessary to prevent further damage to the spillway structure. Removing the stop logs will result in the loss of 1.2 metres of storage in the Mount Carmel Pond reservoir. The storage in the Mount Carmel Pond reservoir provided by 1.2 meters of spillway freeboard equates to approximately 3.49 GWh. Using marginal cost methodology, the value of this storage varies between $770,000 and $1,920,000 annually over a ten-year period depending upon the year and the availability of winter reservoir recharges as described above.

Table 2 summarizes the risk assessment of *Mount Carmel Pond Dam Refurbishment* project.

Table 2
Hydro Facility Rehabilitation Project
Risk Assessment Summary

Consequence	Probability	Risk
Likely (4)	Near Certain (5)	High (20)

Based on this assessment, not proceeding with the *Mount Carmel Pond Dam Refurbishment* project would pose a High (20) risk to the delivery of least-cost service to customers.

71 Details on the benefits of the Plant's production are detailed in Table A-3, Lifecycle Analysis Results on page A-5 of Appendix A of the *2025 Capital Budget Application,* report *4.1 Mount Carmel Pond Spillway Replacement*.

72 Marginal supply costs are based on Hydro's October 2023 marginal cost update.

JUSTIFICATION

The *Mount Carmel Pond Dam Refurbishment* project is required to provide reliable service to customers at least cost. The Mount Carmel Pond spillway and gatehouse are critical to the CBHC hydroelectric development continuing to provide low-cost capacity and energy to customers. Completing these upgrades will ensure a continued adequate electrical capacity through the winter months.

INFORMATION SYSTEMS

Title: **Application Enhancements**
Asset Class: **Information Systems**
Category: **Project**
Investment Classification: **General Plant**
Budget: **$914,000**

PROJECT DESCRIPTION

The *Application Enhancements* project includes the enhancement of multiple software applications in 2025 to reduce costs to customers or improve customer service delivery. The proposed 2025 projects include:

(i) business modernization; and
(ii) takeCHARGE website enhancement.

This project also includes an item for various minor enhancements to respond to unforeseen requirements encountered throughout the year.

Execution of the 2025 *Application Enhancements* project will better enable Newfoundland Power to meet customers' service expectations at the lowest possible cost.

PROJECT BUDGET

The budget for the *Application Enhancements* project is based on cost estimates for the individual budget items.

Table 1 provides a breakdown of expenditures proposed for 2025 for the *Application Enhancements* project.

Table 1
Application Enhancements Project
2025 Budget
($000s)

Cost Category	2025
Material	75
Labour – Internal	589
Labour – Contract	-
Engineering	-
Other	250
Total	$914

Proposed expenditures for the *Application Enhancements* project total $914,000 for 2025.

ASSET BACKGROUND

The items included under the 2025 *Application Enhancements* project are:

(i) *Business Modernization ($350,000)*

Newfoundland Power routinely seeks to utilize technology to help streamline operations and back office business processes. In recent years, investments in foundational technology such as digital forms, robotic process automation, enterprise reporting and service desk technology can be further enhanced and expanded to provide additional business efficiencies. This includes automating manual repetitive processes, developing data and analytics dashboards, developing workflows to streamline operations, digitizing manual paper-based processes and utilizing artificial intelligence.

This project would consist of various business modernization initiatives by leveraging and/or enhancing existing technology. This will include enhancing business processes in Operations, Human Resources, Finance, Safety, Technology, Regulatory and Customer Relations.

Examples of initiatives to be considered under this project include:

(i) Enterprise reporting and data analytics will provide the ability to pull data from multiple sources in a secure and efficient manner. This would streamline manual reporting efforts and also provide a central reporting tool for information sharing in a secure and auditable manner. Examples include financial reporting, credit and collections reporting as well as KPI reporting for customer service;

(ii) Digitizing paper-based forms and manual processes will achieve operational efficiencies and provide customer benefits. Examples include the digitization of many basic inspection forms used in Safety, Environment and Operations;

(iii) Developing additional workflows to automate manual repetitive tasks across departments on a priority basis. This would also include opportunities for Generative Artificial Intelligence ("GAI"). This would streamline operations and reduce manual efforts;

(iv) Expanding the footprint of the IT Service Management tool to implement automation such as employee onboarding processes for Human Resources. This would also include opportunities for automatic technology issue resolution through utilization of patterns and GAI.

This project would provide the opportunity to continually improve manual processes and create operational efficiencies in an agile fashion by enhancing and expanding existing technology investments. Utilizing modern technology will also provide cybersecurity improvements such as controlled access to data, auditing and enabling modern access controls. This will also improve data protection in securing customer and corporate information.

(ii) *takeCHARGE Website Enhancement ($75,000)*

This enhancement will update the takeCHARGE website to ensure customers continue to have access to up-to-date information on customer energy conservation and electrification initiatives. The takeCHARGE website has been an integral part of the Company's customer energy conservation programs since 2009. The website serves as the primary communication channel to provide customers with information on available programs and rebates, as well as energy conservation education and awareness resources. There were over 643,000 visits to the takeCHARGE website in 2023.

(iii) *Various Minor Enhancements ($489,000)*

Various Minor Enhancements allows Newfoundland Power to respond to unforeseen requirements that occur throughout the year, such as legislative and compliance changes, and employee-identified enhancement opportunities for improving customer service and operational efficiency.

Examples of enhancements previously completed under this item include: (i) the development of a rotating outages dashboard to assist the System Control Centre during under supply events; (ii) compliance reporting enhancements for sustainability and environment; (iii) the development of a Disaster Recovery Solution for high volume call answering system; (iv) improved performance testing of the high volume call answering system during upgrades and patching; and (v) the development of dashboards for the System Control Centre to track emergency calls from customers.

Continuation of this project allows enhancements to be completed as identified, which advances both operational efficiency and organizational effectiveness in serving customers. The process of estimating the budget for Various Minor Enhancements is based on the historical average cost of executing this work over the most recent three-year period adjusted for inflation.

ASSESSMENT OF ALTERNATIVES

The application enhancements identified for 2025 will advance operational efficiency and provide cost savings for customers. Deferring the 2025 *Application Enhancements* project would defer the realization of these cost savings and customer service benefits. Deferring this project is therefore not a viable alternative.

RISK ASSESSMENT

The *Application Enhancements* project provides benefits to customers by enhancing software applications to reduce manual processes.

The Business Modernization project will streamline Company operations by utilizing existing technology to modernize legacy business processes and develop efficiencies. It will also reduce cyber and data management risk through the inherent benefits available in modern technology. The takeCHARGE Website Enhancement will improve the information available to customers on energy conservation and electrification, and the Various Minor Enhancements item will provide flexibility to take advantage of opportunities to improve the Company's operating efficiency throughout the year.

Table 2 summarizes the risk assessment of the 2025 *Application Enhancements* project.

Table 2
Application Enhancements Project
Risk Assessment Summary

Consequence	Probability	Risk
Moderate (3)	Near Certain (5)	Medium-High (15)

Based on this assessment, not proceeding with the 2025 *Application Enhancements* project would pose a Medium-High (15) risk to the delivery of least-cost service to customers.

JUSTIFICATION

The *Application Enhancements* project is required to provide reliable service to customers at the lowest possible cost as it will permit operating efficiencies to be achieved that result in lower overall costs to customers.

Title: **Outage Management System Upgrade**
Asset Class: **Information Systems**
Category: **Project**
Investment Classification: **General Plant**
Budget (Multi-Year): **$1,811,000 in 2025; and $1,459,000 in 2026;**

PROJECT DESCRIPTION

The *Outage Management System Upgrade* project involves upgrading the Company's Outage Management System ("OMS") over two years commencing in 2025. This timeframe will ensure the upgraded system is implemented prior to the expiration of vendor support as of November 1, 2026. The upgraded OMS will continue to deliver functionality equivalent to that of the existing system, including the monitoring, analysis, dispatching and communications of outages.

Additional information on this project is provided in report *6.1 Outage Management System Upgrade* filed with the Application.

PROJECT BUDGET

The budget for the *Outage Management System Upgrade* project is based on detailed cost estimates.

Table 1 provides a breakdown of expenditures proposed for 2025 for the *Outage Management System Upgrade* project.

Table 1
Outage Management System Upgrade
2025 Budget
($000s)

Cost Category	2025	2026	Total
Material	-	-	-
Labour – Internal	905	619	1,524
Labour – Contract	-	-	-
Engineering	-	-	-
Other	906	840	1,746
Total	$1,811	$1,459	$3,270

Proposed expenditures for the *Outage Management System Upgrade* project total $3,270,000, with $1,811,000 in 2025, and $1,459,000 in 2026.

ASSET BACKGROUND

Newfoundland Power's OMS is a cornerstone of reliability management and plays a critical role in outage assessment, outage response and customer communications.

Newfoundland Power modernized it OMS technology in 2019 by implementing a commercial OMS system consistent with Canadian utility best practice. The current OMS is integrated with the Company's Geographic Information System ("GIS"), and uses this integration to determine outage customer counts and provide predictive analysis on fault location.

The Company upgrades its operational technologies on a required basis to maintain vendor support for bug fixes, software updates and to protect against potential cybersecurity vulnerabilities. The Company's OMS requires, at minimum, a minor upgrade before November 1, 2026 to remain supported by the vendor. Another major upgrade will be required by 2028 to allow the OMS to remain compatible with the Company's GIS. A net present value analysis determined that completing a major upgrade in 2026 is the most economical option for customers.

RISK ASSESSMENT

OMS is a critical business application for Newfoundland Power. The Company maintains vendor support for all critical business applications, including OMS. Vendor support ensures that critical applications operate reliably and securely during the day-to-day provision of service to customers. Unsupported applications are more prone to failure and cybersecurity threats.

Given the criticality of OMS in customer service and outage response functions, as well as integrations to other critical business systems, continuing to operate OMS without vendor support is not a viable option.[73]

The software vendor has indicated that the version of OMS will require an upgrade as the current version will no longer be supported as of November 1, 2026. The probability of adverse consequences arising from losing access to this software is likely. This could impair the Company's critical operational response capabilities.

[73] Continuing to operate the existing version of the OMS without support would mean increased cybersecurity risks, as patching of identified vulnerabilities would no longer be provided from the vendor, as well as operational risk should the system cease to function. A cybersecurity incident affecting the OMS could potentially put sensitive customer information at risk.

Table 2 summarizes the risk assessment of the *Outage Management System Upgrade*

Table 2 Outage Management System Upgrade Risk Assessment Summary		
Consequence	Probability	Risk
Serious (4)	Likely (4)	Medium-High (16)

Based on this assessment, not proceeding with the *Outage Management System Upgrade* project would pose a Medium-High (16) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Outage Management Upgrade* project is required to ensure the secure and reliable operation of information systems that are essential to the delivery of service to customers.

Title:	**Asset Management Technology Replacement**
Asset Class:	**Information Systems**
Category:	**Project**
Investment Classification:	**General Plant**
Budget (Multi-Year):	**$3,479,000 in 2025; and $4,534,000 in 2026;**

PROJECT DESCRIPTION

The *Asset Management Technology Replacement* project involves replacing the Company's asset management technology with a modern equivalent. The current technology will no longer be supported by the vendor as of January 1, 2027.

Newfoundland Power will replace the existing technology over a two-year period, with a proposed start date of 2025. This timeframe will ensure a replacement solution is implemented prior to the end of life of the existing system.

Additional information on this project is provided in report *6.2 Asset Management Technology Replacement* filed with the Application.

PROJECT BUDGET

The budget for the *Asset Management Technology Replacement* project is based on detailed cost estimates.

Table 1 provides a breakdown of expenditures proposed for 2025 for the *Asset Management Technology Replacement* project.

Table 1
Asset Management Technology Replacement
2025-2026 Budget
($000s)

Cost Category	2025	2026	Total
Material	1,794	2,512	4,306
Labour – Internal	1,357	1,694	3,051
Labour – Contract	-	-	-
Engineering	-	-	-
Other	328	328	656
Total	$3,479	$4,534	$8,013

Proposed expenditures for the *Asset Management Technology Replacement* project total $8,013,000, with $3,479,000 in 2025 and $4,534,000 in 2026.

ASSET BACKGROUND

Newfoundland Power manages its assets to ensure safe, reliable service of electricity to customers in an environmentally responsible manner. In the early 2000s, the Company shifted from reactive maintenance to preventative, implementing a cyclical approach to inspections, testing and scheduled maintenance. A commercial asset management technology was implemented in 2003 and is used to manage the Company's transmission, distribution, substation, and generation assets.

The asset management technology supports asset management practices and is the central repository for asset information. It is used to plan and track preventative and corrective maintenance work including inspections, maintenance and testing. It is a critical business application and is also integrated with other core applications, such as the Company's Workforce Management System and Geographic Information System ("GIS").

High-quality asset information forms the foundation of effective asset management. Access to consistent, reliable information underpins decisions about managing the asset's lifecycle. A consistent, repeatable approach is required for making asset-related decisions. The decision-making process is aided by data and technology. Information collected in the technology is used as an input for asset related reporting, informing data-related decisions and capital expenditures.

The asset management technology is at the end of its useful life and requires replacement. The existing contract is expiring and the vendor is discontinuing support of the system on January 1, 2027. Replacement is required to eliminate the risk of the technology failing while unsupported, disrupting Company operations and asset management practices. Replacement with a modern equivalent aligns with industry best practice and will allow the Company to meet current requirements and provide a foundation for enhancements as asset management matures.

ASSESSMENT OF ALTERNATIVES

The company identified and assessed three alternatives to replacing its asset management technology: (i) do nothing; (ii) replace with a modern equivalent; and (iii) replace with advanced functionality.

Implementing Alternative 2 avoids the risk of continuing to operate an unsupported technology while ensuring the replacement technology is a modern equivalent solution that is right sized for Newfoundland Power's operations. This will avoid interruptions to the Company's operations and asset management procedures and enable the Company to explore new opportunities as it moves through its asset management journey.

RISK ASSESSMENT

The *Asset Management Technology Replacement* project is required to eliminate the risk of the technology failing while unsupported, disrupting Company operations and asset management practices. It is used daily by employees and supports the majority of the Company's asset management workflows.

The vendor has indicated that the current technology will no longer be supported as of January 1, 2027. Vendor support ensures that critical applications operate reliably and securely. Unsupported applications are more prone to failure and are at risk of cybersecurity threats and breaches.

Given the criticality of the Company's asset management technology, as well as integrations to other critical business systems, continuing to operate the Technology without vendor support is not a viable option.

Table 2 summarizes the risk assessment of the *Asset Management Technology Replacement*

Table 2
Asset Management Technology Replacement
Risk Assessment Summary

Consequence	Probability	Risk
Serious (4)	Likely (4)	Medium-High (16)

Based on this assessment, not proceeding with the *Asset Management Technology Replacement* project would pose a Medium-High (16) risk to the Company operations.

JUSTIFICATION

The *Asset Management Technology Replacement* project is required to maintain Company operations and asset management practices. The current asset management technology will no longer be supported by the vendor as of January 1, 2027. The Company will replace the existing technology with a modern equivalent, starting in 2025. Replacement of the Technology is in alignment with industry best practice and will allow the Company to continue asset management practises, while providing a foundation for asset management maturity.

Title:	**System Upgrades**
Asset Class:	**Information Systems**
Category:	**Project**
Investment Classification:	**General Plant**
Budget:	**$1,408,000**

PROJECT DESCRIPTION

The *System Upgrades* project involves upgrades to third-party software products that comprise Newfoundland Power's information systems. System upgrades proposed for 2025 involve the Customer Contact Management System ("CCMS") website, Records Management System ("RMS"), Financial Management System and Supervisory Control and Data Acquisition ("SCADA") system.

Upgrades to the CCMS, RMS and Financial Management System are critical to ensure continued vendor support that include bug fixes and security patches. Upgrades to the SCADA system align with industry best practices and maintain system performance, address bug fixes and ensure the latest critical security updates.

The *System Upgrades* project also includes an item for other minor software applications that have either reached the end of vendor support, require bug fixes, security patches, or changes to comply with technology, regulatory or legislative requirements.

PROJECT BUDGET

The budget for the *System Upgrades* project is based on cost estimates for the individual budget items.

Table 1 provides a breakdown of expenditures proposed for 2025 for the *System Upgrades* project.

Table 1 System Upgrades Project 2025 Budget ($000s)	
Cost Category	2025
Material	70
Labour – Internal	848
Labour – Contract	-
Engineering	-
Other	490
Total	$1,408

Proposed expenditures for the *System Upgrades* project total $1,408,000 for 2025.

ASSET BACKGROUND

System upgrades, including the timing of required upgrades, are largely determined by the third-party vendors for each system. As vendors release new versions of systems that improve performance and address known issues, such as cybersecurity weaknesses, previous versions may no longer be supported. Periodic system upgrades are required to ensure continued vendor support and to minimize risks to customers. As the cybersecurity landscape continues to evolve, software vendors have been required to increase the frequency of system upgrades. Many vendors now require annual system upgrades or critical patches to maintain support.

The system upgrades proposed for 2025 are:

(i) *Customer Contact Management System ($495,000)*

This item involves upgrading the CCMS to a version that continues to be fully supported by the vendor.

Newfoundland Power's CCMS was installed in 2017 and was last upgraded in 2020. CCMS is the primary information system used at the Company's Customer Contact Centre to facilitate customer calls, emails and webchats. In 2023, the Customer Contact Centre responded to approximately 177,000 agent handled calls, 194,000 IVR handled calls, 113,000 emails and 22,000 webchats from customers.

The CCMS accepts and automatically routes all incoming calls, emails and webchats to Customer Service Representatives with the necessary skillsets to respond effectively. It also connects outgoing calls to customers with Customer Service Representatives and generates reports on the types of customer contacts received and the Company's effectiveness in responding.

Newfoundland Power's current version of the CCMS will no longer be supported by the vendor as of December 2025. Upgrading the CCMS is required to ensure continued vendor support and availability of critical contact center communications for customers. Remaining current with the latest versions of software will also help protect customers' personal information against evolving cybersecurity threats and is necessary to ensure it continues to operate in a stable and supported environment. This will enable the Company to continue responding efficiently and effectively to customers' inquiries.

The project is anticipated to commence in the first quarter of 2025 and will be completed in the third quarter.

(ii) *Financial Management System Upgrade ($121,000)*

This item involves upgrading the Company's Financial Management System to a version that continues to be fully supported by the vendor.

Newfoundland Power's Financial Management System was implemented in 2002. It is used on a daily basis to manage the Company's financial resources, project accounting, and procurement and inventory processes. The Financial Management System communicates with other Company information systems to ensure the automatic flow of information relating to purchasing functions, electronic invoicing and warehouse management. This automation achieves efficiencies in the day-to-day management of financial processes.

For 2025, the proposed upgrade of the Company's Financial Management System will apply the latest software release available from the vendor. Commencing with the 2023 upgrade, the vendor introduced a new policy that requires upgrades on an annual cycle. The 2025 upgrade is required in order to receive vendor support, bug fixes, new features and security updates necessary to keep pace with evolving cybersecurity threats.

The project is anticipated to commence in the second quarter of 2025 and will be completed in the third quarter.

(iii) *Records Management System Upgrade ($274,000)*

This item involves an upgrade to Newfoundland Power's RMS to a version that continues to be fully supported by the vendor.

Newfoundland Power last upgraded RMS in 2020. RMS provides employees and business partners with the ability to efficiently and securely store and share information via the Internet. It is also used to manage regulatory filings, corporate financial information, and other engineering and operations-related documentation.

The Company's existing version of RMS will be no longer supported by the vendor as of July 2026. Upgrading the system is necessary to ensure continued operation of the system in a stable and supported environment. This will enable Newfoundland Power to continue storing and sharing information with employees and business partners in an efficient and secure manner.

The project is anticipated to commence in the first quarter of 2025 and will be completed in the fourth quarter.

(iv) *SCADA System Upgrade ($98,000)*

This item involves upgrading the Company's SCADA system to ensure system operations benefit from the latest system and security updates available from the vendor.

Newfoundland Power's current SCADA system was implemented in 2016. The SCADA system is used by the Company's System Control Centre to monitor and control the electrical system on a real-time basis. Frequent functionality and security upgrades of SCADA systems have become industry best practice. Newfoundland Power completes annual upgrades of its SCADA system in accordance with industry best practice.

For 2025, the proposed upgrade of the Company's SCADA system will ensure consistent and effective system operation and will apply the latest security updates and available features. The upgrade will ensure the SCADA system continues to provide real-time monitoring of the Company's electrical system assets across its service territory.

The project is anticipated to commence in the first quarter of 2025 and will be completed in the second quarter.

(v) *Various Minor Upgrades ($420,000)*

This item involves upgrading other minor software applications that have either reached the end of vendor support, require bug fixes, security patches, or changes to comply with technology, regulatory or legislative requirements.

Unstable and unsupported software products can negatively impact operating efficiencies and customer service delivery. Maintaining the over 190 software applications Newfoundland Power uses in providing service to customers requires implementing a variety of minor system upgrades throughout the year. These upgrades ensure continued vendor support, improve compatibility with different devices and applications, minimize software vulnerabilities, remove outdated features, and improve software stability.

New versions of third-party software products are generally designed to address identified deficiencies, thereby improving performance and allowing the Company to take advantage of new functionality. New software versions also typically include necessary cybersecurity improvements. Newfoundland Power assesses these security improvements to ensure the Company maintains a secure computing environment. The timing of the upgrades is based on a review of the risks and operational experience of the systems under consideration.

The process of estimating the budget for Various Minor Upgrades is based on the historical average cost of executing this work over the most recent three-year period adjusted for inflation.

ASSESSMENT OF ALTERNATIVES

In considering whether to complete a system upgrade, Newfoundland Power considers the criticality of the system to its operations, the benefits of the upgrade, and whether the upgrade is required to maintain vendor support.

Certain upgrades are relatively minor, do not address material issues with the software, and are not required to maintain vendor support. These software versions can often be skipped and a system upgrade can be deferred to a future version. Other times, a software version provides critical cybersecurity patches, is required as a condition of maintaining vendor support, or provides material improvements in system performance. These upgrades cannot typically be deferred to a future version without threatening system security or performance.

Vendor-mandated upgrades periodically involve major new releases. These upgrades can be substantial in scope and cost, involving substantive changes to a system's architecture, user interface or functionality. When substantial system upgrades are required, Newfoundland Power will consider whether implementing an alternative software product would be lower cost than upgrading existing software.

The upgrades proposed for 2025 are required to maintain the reliability, security and vendor support of Company information systems. These upgrades cannot be deferred without compromising the safe and reliable operation of information systems. The individual upgrades proposed range in cost from approximately $98,000 to $495,000 and do not constitute major product releases that warrant consideration of system replacement. Completing the required system upgrades in 2025 is therefore the only viable alternative.

RISK ASSESSMENT

The *System Upgrades* project is necessary to mitigate risks to the delivery of safe and reliable service to customers by maintaining the security and performance of Company information systems.

Each of the systems to be upgraded in 2025 are essential to Newfoundland Power's operations. Upgrades of the CCMS and Financial Management System are necessary to ensure continued vendor support and to provide for the latest security patches and bug fixes for those systems. The criticality of the SCADA system necessitates annual upgrades to maximize system performance and security. Ensuring continued vendor support mitigates risks associated with system failures.

Failure of these systems would have serious consequences to the delivery of safe and reliable service to customers. As examples, a security failure of the SCADA system could expose the electrical system to external interference, and a security failure of the CCMS could compromise customer personal information.

System upgrades are becoming more frequent due to changes in vendor requirements and the need to manage cybersecurity risks. The system upgrades proposed for 2025 are necessary to mitigate risks of information system failure by implementing the latest bug fixes and cybersecurity patches and to maintain vendor support. As these improvements address known issues with information systems, such as cybersecurity vulnerabilities, the probability of failure is considered likely if these upgrades are not completed.

Table 2 summarizes the risk assessment of the 2025 *System Upgrades* project.

Table 2
System Upgrades Project
Risk Assessment Summary

Consequence	Probability	Risk
Serious (4)	Likely (4)	Medium-High (16)

Based on this assessment, not proceeding with the 2025 *System Upgrades* project would pose a Medium-High (16) risk to the delivery of safe and reliable service to customers.

JUSTIFICATION

The *System Upgrades* project is required to ensure the secure and reliable operation of information systems that are essential to the delivery of service to customers. The proposed upgrades will implement the latest bug fixes and cybersecurity patches available from the vendors and will ensure vendor support is maintained for those systems.

Title: **Shared Server Infrastructure**
Asset Class: **Information Systems**
Category: **Project**
Investment Classification: **General Plant**
Budget: **$970,000**

PROJECT DESCRIPTION

The *Shared Server Infrastructure* project proposes the addition, upgrade and replacement of computer hardware components and related technology associated with shared server infrastructure and peripheral equipment. For 2025, three items are proposed to improve the functionality of Newfoundland Power's shared server infrastructure. These include: (i) Server Infrastructure Upgrades; (ii) Asset Management Server Infrastructure Upgrades; (iii) Electronic Mail System Upgrades.

Implementing this functionality will support the performance and cybersecurity of the computing hardware that underpins the operation of software applications used in providing safe and reliable service to customers at least cost.

PROJECT BUDGET

The budget for the *Shared Server Infrastructure* project is based on cost estimates for the individual budget items.

Table 1 provides a breakdown of expenditures proposed for 2025 for the *Shared Server Infrastructure* project.

Table 1
Shared Server Infrastructure Project
2025 Budget
($000s)

Cost Category	2025
Material	860
Labour – Internal	110
Labour – Contract	-
Engineering	-
Other	-
Total	$970

Proposed expenditures for the *Shared Server Infrastructure* project total $970,000 for 2025.

ASSET BACKGROUND

Newfoundland Power uses a combination of information systems in the day-to-day provision of reliable and responsive service to customers. The availability and performance of these systems depends on the Company's shared server infrastructure and peripheral equipment.

The Company's shared server infrastructure is used for routine operation, testing, and disaster recovery of the Company's corporate applications. Newfoundland Power relies on these shared servers to ensure the efficient operation of systems and applications used in the day-to-day provision of service to customers. Management of these shared servers and their components is essential to ensuring these applications operate effectively at all times.

Three upgrades are proposed for 2025:

(i) *Server Infrastructure Upgrades ($477,000)*

Upgrades are required in 2025 to extend the useful service life of existing server infrastructure. Infrastructure upgrades include installing additional components to increase disk storage and expand processor and memory capacity to accommodate growth in information storage needs and improve the performance of Company applications. As applications are upgraded and accumulate data over time, they require additional processors and memory to maintain an acceptable level of performance. Upgrades are also required to maintain vendor support of the server operating system as well as to meet cybersecurity requirements.[74]

(ii) *Asset Management Server Infrastructure Upgrade ($162,000)*

Upgrades are required in 2025 to replace the current Asset Management System ("AMS") Servers with new servers for the proposed *Asset Management Technology Replacement* project. The new AMS will require new server and storage infrastructure for the new application.

(iii) *Electronic Mail System Upgrades ($331,000)*

Newfoundland Power's current electronic mail system will no longer be supported by the vendor as of October 14, 2025. Upgrades will be performed to the mail system, to upgrade to the latest supported version available to ensure a supportable system, and maintain cyber security standards.

ASSESSMENT OF ALTERNATIVES

Each year, an assessment is completed to identify shared server infrastructure requirements and alternatives available to meet those requirements. The assessment involves identifying server infrastructure and peripheral equipment that either: (i) requires lifecycle replacement based on age and risk of failure; (ii) can be upgraded to extend its useful service life; (iii) must

[74] Microsoft Windows Operating Systems require continual upgrading to maintain vendor support and to continue receiving the latest cybersecurity updates. Upgrades to hardware are often tied directly to software licensing requirements by the vendor and require adjustments to maintain license compliance.

be added based on new computing requirements; or (iv) require upgrading as part of cybersecurity management. The annual assessment considers multiple factors, including vendor support and product roadmaps, the current performance of components, associated costs, the criticality of a component and the consequence in the event of a failure. Upgrades that are not critical to Newfoundland Power's operations are deferred.

Approximately 49% of proposed 2025 expenditures relate to routine upgrades and additions to Newfoundland Power's shared server infrastructure, including the replacement of infrastructure supporting the operation of critical electrical system devices. These upgrades are necessary to accommodate growth in information storage needs, improve performance of Company applications and maintain vendor support. Deferring these upgrades would threaten the secure and reliable operation of hardware and software used in providing service to customers, and would not be prudent.

Approximately 17% of the proposed 2025 expenditures are related to the Infrastructure upgrades required to host the proposed new AMS. This investment in servers and storage will allow the Company's AMS to meet the support requirements set forward by the successful bidder, and to ensure it meets Company standards for reliability and cyber security standards to service customers.

Approximately 34% of proposed 2025 expenditures relate to the replacement of Newfoundland Power's enterprise electronic mail system. This critical infrastructure underpins the Company's ability to communicate internally in day-to-day operations and to provide correspondence to customers. Deferring these upgrades would expose the components to risk of failure and would impede the Company's ability to provide adequate service to customers.

RISK ASSESSMENT

The *Shared Server Infrastructure* project will mitigate risks to the delivery of safe and reliable service to customers.

Newfoundland Power's shared server infrastructure enables the operation of software applications used in providing service to customers, including the SCADA system, and the storage of customer and Company information necessary to run those applications. Instability within computing hardware could result in compromising customer or Company information, losing a software application that is critical to serving customers, or losing the ability to remotely control and monitor the electrical system. The failure of a server could require several days to address.

Research by Gartner Inc. indicates that servers have a useful life of approximately five years.[75] As a result of appropriate investments in its shared server infrastructure, the Company's servers experience an average useful life of about seven years. The probability of instability within computing hardware would be likely if computing hardware is not upgraded and extended beyond its useful life.

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[75] See *Compute Infrastructure: How to Optimize the Management of Life Cycle Variations, Gartner Inc., August 23, 2017.*

Table 2 summarizes the risk assessment of the *Shared Server Infrastructure* project.

Table 2 Shared Server Infrastructure Project Risk Assessment Summary		
Consequence	Probability	Risk
Critical (5)	Likely (4)	High (20)

Based on this assessment, not proceeding with the *Shared Server Infrastructure* project would pose a High (20) risk to the delivery of safe and reliable service to customers.

JUSTIFICATION

The *Shared Server Infrastructure* project is required to provide safe and reliable service to customers at the lowest possible cost. Management of server equipment through this project is essential to the secure and reliable operation of Company technologies used in the provision of service to customers.

Title:	**Cybersecurity Upgrades**
Asset Class:	**Information Systems**
Category:	**Project**
Investment Classification:	**General Plant**
Budget:	**$940,000**

PROJECT DESCRIPTION

The *Cybersecurity Upgrades* project involves upgrades to the Company's cybersecurity infrastructure. Proposed 2025 capital expenditures include new technologies and enhancements to existing technologies to reduce risk and enhance security in the areas of network and firewall security in operation technologies and SCADA environments, and enhancements to service accounts as well as Information and Data Management.

PROJECT BUDGET

The budget for the *Cybersecurity Upgrades* project is based on cost estimates for the individual budget items.

Table 1 provides a breakdown of expenditures proposed for 2025 for the *Cybersecurity Upgrades* project.

Table 1
Cybersecurity Upgrades Project
2025 Budget
($000s)

Cost Category	2025
Material	245
Labour – Internal	525
Labour – Contract	-
Engineering	-
Other	170
Total	$940

Proposed expenditures for the *Cybersecurity Upgrades* project total $940,000 for 2025.

ASSET BACKGROUND

Electrical system assets are operated using a combination of physical and technology infrastructure. Physical infrastructure includes components such as protection and control systems. Technology infrastructure includes components such as networks, software and data. Protecting this infrastructure from threats, including cybersecurity threats, is critically important to the day-to-day provision of safe and reliable service to customers.

RISK ASSESSMENT

The *Cybersecurity Upgrades* project will mitigate risks to the delivery of safe and reliable service to customers by protecting Newfoundland Power's operations and the electrical system against cybersecurity threats.

The risk of cybersecurity incidents has increased materially for utilities as a result of the widespread use of technology. Worldwide spending on cybersecurity is forecast to grow. A 2021 global survey conducted by Gartner Inc., a leading technology advisory firm, indicated that cybersecurity is a top priority for new spending among corporations, with 61% of surveyed companies reporting increased investment.[76]

Newfoundland Power continually assesses its infrastructure to identify measures to improve the Company's cybersecurity. The cybersecurity measures identified for implementation in 2025 will enhance the security of customer and Company information and help protect Newfoundland Power's operations from external interference. A cybersecurity incident could expose the electrical system to external interference or compromise the security of customer or Company information.

Cybersecurity threats are continuously evolving and becoming more sophisticated. Continual improvements in cybersecurity resilience and response capabilities are necessary to respond to this evolving threat.

Table 2 summarizes the risk assessment of the *Cybersecurity Upgrades* project.

Table 2
Cybersecurity Upgrades Project
Risk Assessment Summary

Consequence	Probability	Risk
Critical (5)	Likely (4)	High (20)

Based on this assessment, not proceeding with the *Cybersecurity Upgrades* project would pose a High (20) risk to the delivery of reliable service to customers.

[76] See Gartner Inc., *Gartner Forecasts Worldwide Security and Risk Management Spending to Exceed $150 Billion in 2021*, May 17, 2021.

JUSTIFICATION

The *Cybersecurity Upgrades* project is required to maintain safe and reliable service to customers as investments in cybersecurity are essential to protecting customer and Company information and protecting the electricity system from external interference.

TELECOMMUNICATIONS

Title: **VHF Radio System Replacement**
Asset Class: **Telecommunications**
Category: **Project**
Investment Classification: **General Plant**
Budget: **$870,000**

PROJECT DESCRIPTION

The *VHF Radio System Replacement* project involves replacing the existing Very High Frequency ("VHF") radio system which has reached end-of-life. Proposed 2025 capital expenditures will replace the Newfoundland Power VHF radio system with a satellite Push-To-Talk ("PTT") solution.

The existing radio system is used by personnel in emergency situations, as a backup solution when primary means of communication are unavailable, and for instant truck-to-truck communication during field operations especially in remote locations without cell phone service.

PROJECT BUDGET

The budget for the *VHF Radio System Replacement* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2025 for the *VHF Radio System Replacement* project.

Table 1
VHF Radio System Replacement Project
2025 Budget
($000s)

Cost Category	2025
Material	570
Labour – Internal	150
Labour – Contract	-
Engineering	-
Other	150
Total	$870

Proposed expenditures for the *VHF Radio System Replacement* project total $870,000 for 2025.

ASSET BACKGROUND

The current VHF system was deployed in 2014 and is a trunked radio system provided by Bell Canada ("Bell"). It consists of vehicle-mounted, handheld, and base station radios. The backbone of this system is Bell's core network, which transports VHF communication data between radio repeater sites. Newfoundland Power currently has 308 VHF units deployed.

This system serves as a backup communication avenue during cellular network disruptions, provides communications in remote regions lacking cellular coverage, and facilitates point-to-point immediate communication during line work. Communication tasks may include switching orders, ensuring safety during emergencies, and facilitating fieldwork in remote locations.

The original contract with Bell expired in 2022, at which time the contract transitioned to a series of one-year extension contracts. The vendor has informed Newfoundland Power that there will be no option to extend the contract further and that the existing VHF system will be shut down in June 2024. This date aligns with the roll out of the new P25 system that is being delivered by Bell to the Government of Newfoundland and Labrador.

RISK ASSESSMENT

The *VHF Radio System Replacement* project will mitigate risks to the delivery of reliable service to customers by continuing to provide resilient communications in critical operating tasks.

The existing VHF radio system provides a back-up communication method for Newfoundland Power employees during emergencies, when the cell phone network is non-functional, and when Newfoundland Power employees have to work outside of the cellular coverage area. Communications of this nature are critical for completing tasks such as switching orders, requesting an emergency response and coordinating work between multiple crews.

The vendor has informed the Company that the current system will be shut down in June 2024. Without a reliable source of back-up communications, a risk to employee safety and customer response times is likely.

Table 2 summarizes the risk assessment of the *VHF Radio System Replacement* project.

Table 2
VHF Radio System Replacement Project
Risk Assessment Summary

Consequence	Probability	Risk
Moderate (3)	Near Certain (5)	Medium-High (15)

Based on this assessment, not proceeding with the *VHF Radio System Replacement* project would pose a Medium-High (15) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *VHF Radio System Replacement* project is required to provide reliable service to customers at least cost. A reliable back-up communication method is essential for the safety of employees and the effective coordination of work groups with each other and with the control authority. Procurement of a satellite-based to replace the legacy VHF solution will ensure the continued delivery of reliable service to customers at the least cost.

GENERAL PROPERTY

Title: **Port Union Building Replacement**
Asset Class: **General Property**
Category: **Project**
Investment Classification: **General Plant**
Budget (Multi-Year): **$278,000 in 2025; $1,003,000 in 2026**

PROJECT DESCRIPTION

The *Port Union Building Replacement* project involves the replacement of Newfoundland Power's Port Union District Building (the "Facility"). A new purpose-built building will be constructed adjacent to the existing Facility. The existing building will be demolished upon completion of the new Facility.

The building replacement will be completed over two years to accommodate the design and procurement of the new building. Design and procurement will be completed in 2025. Construction will begin in 2026 and will be completed by the end of the fourth quarter. Additional information on this project is provided in report *5.1 Port Union Building Replacement* filed with the Application.

PROJECT BUDGET

The budget for the *Port Union Building Replacement* project is based on a detailed engineering estimate.

Table 1 provides a breakdown of expenditures proposed for 2025 and 2026 for the *Port Union Building Replacement* project.

Table 1
Port Union Building Replacement Project
2025-2026 Budget
($000s)

Cost Category	2025	2026	Total
Material	235	938	1,173
Labour – Internal	0	5	5
Labour – Contract	0	0	0
Engineering	33	32	65
Other	10	28	38
Total	$278	$1,003	$1,281

Proposed expenditures for the *Port Union Building Replacement* project total $1,281,000, including $278,000 in 2025 and $1,003,000 in 2026.

ASSET BACKGROUND

Newfoundland Power maintains area and district office buildings throughout its service territory. These buildings serve as the base of operations for employees working to provide service to customers. As building components deteriorate and operational requirements evolve, there is an ongoing requirement to renovate, upgrade or replace equipment and systems at these facilities to extend their useful service lives. When maintaining or upgrading an existing building is no longer viable, Newfoundland Power proposes replacement or divestiture of the building.

Newfoundland Power's Facility in Port Union was acquired during the amalgamation of the then Newfoundland Light and Power Company with Union Electric Light and Power in 1966. The Facility was first used as a diesel generating plant, then as a warehouse before being subsequently renovated into its current configuration as a combined warehouse and office space.

The Facility provides support for nine employees and equipment necessary for operations on the Bonavista Peninsula. Four employees (two Powerline Technician Lead Hands and two Powerline Technicians) use the Facility as their daily headquarters. Five additional employees (two Electrical Maintenance persons, one Materials Handler, one Meter Reader and one Customer Service Representative) use the Facility part time while completing work in the service area. The Facility also supports corporate functions, such as emergency material storage required for regional storm response.

Newfoundland Power completed a condition assessment of the Facility in 2024 to identify deteriorated, obsolete and non-standard equipment.

The condition assessment determined that the Facility does not have an adequate fresh air supply which has resulted in moisture damage to interior finishes.[77] In addition, deficiencies are present throughout the building envelope. To provide a suitable healthy workspace, fresh air supply and air treatment must be provided and a vapour barrier installed. Newfoundland Power has determined that correcting the deficiencies in the existing building would not be economic in comparison to a full building replacement.

For further details of the condition assessment and alternatives considered, see report *5.1 Port Union Building Replacement*.

RISK ASSESSMENT

The *Port Union Building Replacement* project will mitigate risks associated with the safe and reliable delivery of service to customers by maintaining adequate workspaces for employees.

The Port Union building allows Newfoundland Power to provide a reasonable response time to trouble calls received from approximately 5,900 customers in the area.[78]

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[77] Section 45 of the *Occupational Health and Safety Regulations, 2009 (Newfoundland and Labrador Regulation 70/09)* details ventilation requirements for a workspace.

[78] The Company targets a two-hour response time to customers for trouble calls. The time required to travel to Bonavista, which is served from the Port Union District Building, to the next closest operations centre in Clarenville is approximately 1.5 hours.

Not proceeding with the *Port Union Building Replacement* project proposed for 2025 and 2026 could hinder Company operations at the Port Union Building and expose employees to potential safety hazards due to the failure of building components. This could negatively impact Newfoundland Power's response time to customers in the area.

Table 2 summarizes the risk assessment of the *Port Union Building Replacement* project.

Table 2
Port Union Building Replacement Project
Risk Assessment Summary

Consequence	Probability	Risk
Moderate (3)	Likely (4)	Medium-High (12)

Based on this assessment, deferring the *Port Union Building Replacement* project would pose a Medium-High (12) risk to the delivery of safe and reliable service to customers.

JUSTIFICATION

The *Port Union Building Replacement* is required to replace deteriorated infrastructure, ensure compliance with occupational health and safety regulations and to ensure adequate facilities are available to provide safe, least-cost, and reliable electrical service to customers in the area. [79]

[79] *Occupational Health and Safety Regulations 2009 (Newfoundland and Labrador Regulation 70/09).*

TRANSPORTATION

Title:	**Replace Vehicles and Aerial Devices 2025-2026**
Asset Class:	**Transportation**
Category:	**Project**
Investment Classification:	**General Plant**
Budget (Multi-Year):	**$2,173,000 in 2025, 2,802,000 in 2026**

PROJECT DESCRIPTION

The *Replace Vehicles and Aerial Devices 2025-2026* project involves the addition and replacement of heavy / medium duty fleet, light duty fleet, passenger and off-road vehicles. Due to long delivery times, Newfoundland Power initiated a multi-year approach to procuring heavy and medium duty fleet vehicles in 2022.

Table 1 summarizes the quantity of vehicles to be replaced beginning in 2025 and continuing into 2026 under this project.

Table 1
2025-2026 Proposed Vehicle Replacements

Category	2025 No. of Units	2026 No. of Units
Passenger Vehicles	21	-
Light Duty Vehicles	1	-
Heavy/Medium Duty Vehicles	-	5
Total	22	5

Newfoundland Power has identified 21 passenger vehicles and 1 light duty vehicle for replacement in 2025 and 5 heavy/medium duty vehicles for replacement in 2026. The project also includes expenditures for the replacement of miscellaneous off-road vehicles in 2025. Detailed inspections of all units will be completed prior to replacement to confirm they have reached the end of their service lives.

PROJECT BUDGET

The budget for the *Replace Vehicles and Aerial Devices 2025-2026* project is based upon the cost estimates of the quantity and types of units to be replaced.

Table 2 provides a breakdown of the proposed expenditures for the *Replace Vehicles and Aerial Devices 2025-2026* project for 2025 and 2026.

Table 2
Replace Vehicles and Aerial Devices
2025-2026 Project
Budget
($000)

Cost Category	2025	2026	Total
Material	2,040	2,802	4,842
Labour – Internal	133	-	133
Labour – Contract	-	-	-
Engineering	-	-	-
Other	-	-	-
Total	$2,173	$2,802	$4,975

Proposed expenditures for the *Replace Vehicles and Aerial Devices 2025-2026* project total approximately $4,975,000, including $2,173,000 in 2025 and $2,802,000 in 2026.

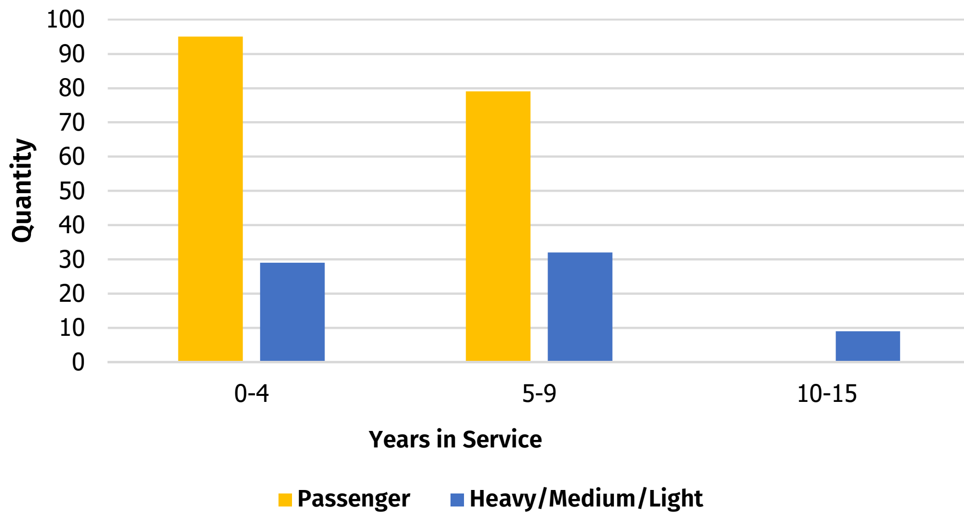
ASSET BACKGROUND

Newfoundland Power maintains a fleet of over 240 vehicles, including heavy/medium duty, light-duty, and passenger vehicles. An adequate fleet of vehicles is necessary to ensure a prompt response to customer outages, customer service requests and other operational requirements.

Heavy-duty fleet vehicles consist of dual axle material handlers with aerial devices, while medium duty fleet vehicles consist of single axle line trucks with aerial devices. Both are primarily used by powerline technician crews for construction and maintenance of the electrical system and in restoring service to customers. Light-duty vehicles consist of service trucks with aerial devices, which are primarily used by powerline technician crews, and heavy-duty vans, which are used by employees at the electrical maintenance centre. Passenger vehicles consist of pickup trucks, SUVs and cars and are primarily used by field workers who require reliable transportation to complete work duties. An adequate fleet of vehicles is necessary to complete capital projects and electrical system maintenance, and ensure a prompt response to customer outages, customers' service requests and other operational requirements.

Figure 1 shows the age distribution of Newfoundland Power's heavy and medium duty vehicles.

Figure 1
Age Distribution of Vehicles



ASSESSMENT OF ALTERNATIVES

Newfoundland Power applies evaluation criteria to determine whether a vehicle requires replacement.[80] The criteria require that an evaluation be completed when individual vehicles reach a certain age or mileage. Heavy and medium vehicles are evaluated for replacement at 10 years of age or odometer readings of 250,000 kilometres.

When these criteria are met, vehicles are inspected by a certified mechanic to assess their condition and any required repairs. An internal review of previously completed maintenance and expenditures is also completed. The results of the inspection and internal review determine whether a vehicle can be economically maintained for additional service or whether it has reached the end of its useful service life. Only vehicles that are identified as being in poor condition and as having reached the end of their useful service lives are replaced.

Deferring the replacement of vehicles that have reached the end of their useful service lives could result in vehicles being out of service for extended periods of time, which would result in reduced crew productivity and impacts on capital project and maintenance completed, as well as reduced response time to customer outages and other service requests. Deferring the replacement of these vehicles would also result in additional maintenance costs that would not practically extend a vehicle's useful service life. For example, heavy-duty vehicles can experience major engine failure that can cost between $30,000 to $40,000 to repair. That

[80] Newfoundland Power's replacement criteria for vehicles were described in the *2016 Capital Budget Application* report *5.1 Vehicle Replacement Criteria*. This report also compared the criteria to those used by other Canadian electrical utilities. It shows the current approach of the Company is consistent with current Canadian utility practice and the least-cost delivery of service to customers.

repair may not ultimately extend the service life of a vehicle due to heavy rust or other deficiencies. Replacement would still be required over the near term, thereby increasing overall costs to customers.

As a result, there is no viable alternative to replacing vehicles that, based on their condition, have reached the end of their useful service lives.

RISK ASSESSMENT

The *Replace Vehicles and Aerial Devices 2025-2026* project will mitigate risks to the delivery of safe and reliable service to customers.

Newfoundland Power actions an average over 38,000 work requests through the work force management system, including approximately 11,000 trouble calls from customers experiencing issues with their service. Ensuring a prompt response to customers' requests, including outages, as well as sufficient resources to complete annual capital projects and regular maintenance of the electrical system, requires an adequate fleet of vehicles

Failing to replace vehicles that are in poor condition and have reached the end of their useful service lives could result in vehicles being out of service for prolonged periods. This could impede Newfoundland Power's response to customer outages as well as maintenance of the electrical system, ultimately leading to reduced service reliability for customers.

The vehicles to be replaced beginning in 2025 will undergo detailed inspections by certified mechanics to confirm they are in poor condition and can no longer be economically maintained for service. The probability of failure if these vehicles were to remain in service is therefore likely.

Table 3 summarizes the risk assessment of the *Replace Vehicles and Aerial Devices 2025-2026* project.

Table 3
Replace Vehicles and Aerial Devices 2025-2026 Project
Risk Assessment Summary

Consequence	Probability	Risk
Serious (4)	Likely (4)	Medium-High (16)

Based on this assessment, not proceeding with the *Replace Vehicles and Aerial Devices 2025-2026* project would pose a Medium-High (16) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Replace Vehicles and Aerial Devices 2025-2026* project is required to provide reliable service to customers at the lowest possible cost. Newfoundland Power requires an adequate fleet of vehicles to respond to customer outages and other service requests, and to maintain the condition of the electrical system. Vehicles to be replaced beginning in 2025 and 2026 are in poor condition and can no longer be economically maintained for additional service.

UNFORESEEN ALLOWANCE

Title:	**Allowance for Unforeseen Items**
Asset Class:	**Unforeseen Allowance**
Category:	**Project**
Investment Classification:	**Mandatory**
Budget:	**$750,000**

PROJECT DESCRIPTION

The *Allowance for Unforeseen Items* is necessary to permit unforeseen capital expenditures that have not been budgeted elsewhere. The purpose of the account is to permit the Company to act expeditiously to respond to events affecting the electrical system in advance of seeking specific approval of the Board. Examples of such expenditures are the replacement of facilities and equipment due to major storm damage or equipment failure.

While the contingencies for which this budget allowance is intended may be unrelated, it is appropriate that the entire allowance be considered as a single capital budget item.

PROJECT BUDGET

An allowance of $750,000 for unforeseen capital expenditures has been included in all of Newfoundland Power's capital budgets in recent years. If the *Allowance for Unforeseen Items* is exceeded in the year, the Company is required to file an application for approval of an additional amount in accordance with the Board's *Capital Budget Application Guidelines (Provisional).*

JUSTIFICATION

This project provides funds for timely service restoration in accordance with Section V.A.7 of the provisional *Capital Budget Application Guidelines – Allowance for Unforeseen Items*.

GENERAL EXPENSES CAPITALIZED

Title:	**General Expenses Capitalized**
Asset Class:	**General Expenses Capitalized**
Category:	**Project**
Investment Classification:	**Mandatory**
Budget:	**$5,081,000**

PROJECT DESCRIPTION

General Expenses Capitalized ("GEC") are general expenses of Newfoundland Power that are capitalized due to the fact that they are related, directly or indirectly, to the Company's capital projects and programs. GEC includes amounts from two sources: (i) direct charges to GEC; and (ii) amounts allocated from specific operating accounts.

PROJECT BUDGET

In Order No. P.U. 3 (1995-96), the Board approved guidelines to determine the expenses of the Company to be included in GEC.[81] The budget estimate of GEC is determined in accordance with the percentage allocations to GEC as presented in Newfoundland Power's *2022/2023 General Rate Application*.[82]

JUSTIFICATION

Certain general expenses are related, either directly or indirectly, to the Company's capital program. GEC is required to implement the Company's capital program and is justified on the same basis as the capital projects to which it relates. Expenses are charged to GEC in accordance with Order No. P.U. 3 (2022) and the methodology presented in Newfoundland Power's *2022/2023 General Rate Application.*

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81 In Order No. P.U. 3 (2022), the Board approved a change in the calculation of GEC to remove pension costs.
82 See Newfoundland Power's *2022/2023 General Rate Application, Volume 2,* report 6 *Review of General Expenses Capitalized.*

2025 CAPITAL PROJECTS AND PROGRAMS

$750,000 AND UNDER

Distribution

Distribution Feeder PEP-02 Refurbishment

Budget: $667,000 *Investment Classification: Renewal* *Category: Project*

This project involves replacing deteriorated underground infrastructure on Loop 33 of Pepperrell ("PEP") Substation distribution feeder PEP-02. Loop 33 of distribution feeder PEP-02 is deteriorated and experiencing increased rates of equipment failure. This project is required to provide reliable service to customers at the lowest possible cost as it will address identified deficiencies and mitigate risks of equipment failure and potential outages to customers in the Newfoundland Drive area of St. John's.

Distribution Feeder SMV-01 Refurbishment

Budget: $654,000 *Investment Classification: Renewal* *Category: Project*

This project involves replacing deteriorated overhead distribution infrastructure on Summerville ("SMV") Substation distribution feeder SMV-01. Distribution feeder SMV-01 is deteriorated and experiencing increased rates of equipment failure. This project is required to provide reliable service to customers at the lowest possible cost as it will address identified deficiencies and mitigate risks of equipment failure and potential outages to customers on the Bonavista Peninsula.

Replacement Meters

Budget: $648,000 *Investment Classification: Renewal* *Category: Program*

This program involves the replacement of deteriorated meters for existing customers, and the sampling and replacement of meters in accordance with the requirements of the *Electricity and Gas Inspection Act*. This program is required to provide reliable service to customers as it permits the replacement of deteriorated or failed meters. The program is also required to maintain compliance with government regulations.

New Meters

Budget: $457,000 *Investment Classification: Access* *Category: Program*

This program involves the purchase and installation of meters for new customers. The Company is forecasting the requirement to install meters to serve 2,220 new customer connections in 2025. This program is required to provide equitable access to an adequate supply of power as it permits the installation of meters required to service customers' premises.

Distribution

Replacement Services

Budget: $445,000 *Investment Classification: Renewal* *Category: Program*

This program involves the replacement of existing service wires to customers' premises upon failure, as well as the installation of larger service wires to accommodate customers' additional loads. This program is required to provide safe and reliable service to customers as it permits the replacement of failed service wires that are necessary to supply customers' premises.

Allowance for Funds Used During Construction

Budget: $220,000 *Investment Classification: Mandatory* *Category: Project*

This project is charged on distribution work orders with an estimated expenditure of less than $50,000 and a construction period in excess of three months. This project is required to implement the Company's capital program and justified on the same basis as the distribution capital expenditures to which it relates.

Substations

Substation Protection and Control Replacements

Budget: $685,000 *Investment Classification: Renewal* *Category: Program*

This program involves replacing substation protection and control systems, including Supervisory Control and Data Acquisition ("SCADA") system equipment and protection relay devices. This program is required to provide reliable service to customers at the lowest possible cost as it permits the replacement of obsolete protection and controls systems at substations.

Substation Ground Grid Upgrades

Budget: $609,000 *Investment Classification: Service Enhancement* *Category: Project*

This project involves upgrading substation ground grids to ensure compliance with *ANSI/IEEE Standard 80-2013 Guide for Safety in AC Substation Grounding*. Deteriorated ground grids in substations can result in unsafe conditions for employees working in the substations with the potential for serious injury or fatality. This project is required to maintain safe and adequate facilities as it will permit the correction of ground grid deficiencies identified at Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") substations.

Transmission

Wood Pole Retreatment

Budget: $600,000 *Investment Classification: Renewal* *Category: Project*

This project involves the retreatment of selected transmission poles with wood preservative. Wood poles are treated with preservative prior to initial installation and the level of preservative is observed to decrease over the service life of the poles. Retreatment of a select vintage of transmission wood poles is intended to increase the level of preservative present in the pole and, therefore, extend its expected service life. Transmission lines are critical infrastructure in the delivery of electricity to customers. Completing this project will support the continued delivery of reliable service to customers throughout Newfoundland Power's service area. Newfoundland Power intends for this project to transition to a program in future years.

Generation – Hydro

Hydro Plant Replacements Due to In-Service Failures

Budget: $731,000 *Investment Classification: Renewal* *Category: Program*

This program involves the replacement or refurbishment of hydro plant equipment due to damage, deterioration, corrosion, technical obsolescence, and in-service failure. This program is required to provide reliable service to customers at the lowest possible cost. The Company's hydro plants continue to provide low-cost energy for customers, localized reliability benefits and a contribution to system capacity.

La Manche Canal Bridge Replacement

Budget: $530,000 *Investment Classification: Renewal* *Category: Project*

This program involves the replacement of the La Manche Canal Bridge. The current bridge is only suitable for pedestrians and needs to be replaced with a bridge capable of allowing heavy equipment to access the canal for planned maintenance activities. The La Manche Canal allows the movement of water from Cape Pond into the Tors Cove-Rocky Pond system. The Company's hydro plants continue to provide low-cost energy for customers, localized reliability benefits and a contribution to system capacity. This project is required to provide reliable service to customers at the lowest possible cost.

Generation – Thermal

Thermal Plant Replacements Due to In-Service Failures

Budget: $318,000 *Investment Classification: Renewal* *Category: Program*

This program involves the replacement or refurbishment of deteriorated thermal plant components that are identified through routine inspections, operating experience, and engineering studies. Thermal generating facilities are operated to provide service to customers during planned and unplanned outages. The refurbishment or replacement of equipment that has failed in service or is at imminent risk of failure is necessary to ensure the continued operation of thermal generating facilities.

Information Systems

Personal Computer Infrastructure

Budget: $720,000 *Investment Classification: General Plant* *Category: Program*

This program is necessary for the replacement or upgrade of personal computers ("PCs") that have reached the end of their service lives. These PCs are essential to the Company's operations and provision of customer service. This program is required to provide reliable service to customers at the lowest possible cost as it permits the replacement of PCs and other equipment that have reached the end of their useful service lives.

Network Infrastructure

Budget: $470,000 *Investment Classification: General Plant* *Category: Project*

This project involves the addition and replacement of network components that provide employees with access to applications and data used in providing efficient and effective service to customers. This project is required to provide reliable service to customers at the lowest possible cost as it permits the replacement of obsolete network equipment that is essential to the Company's day-to-day operations.

Telecommunications

Communications Equipment Upgrades

Budget: $124,000 *Investment Classification: General Plant* *Category: Program*

This program involves the replacement or upgrade of communications equipment, including radio communications equipment associated with electrical system operations, and data communications equipment providing remote monitoring and control capabilities associated with the Company's SCADA system. Adequate communications equipment is essential for the safe and efficient operation of field crews working to provide service to customers. This program is required to provide reliable service to customers at the lowest possible cost as it permits the replacement of failed, obsolete, or deteriorated communications equipment.

General Property

Additions to Real Property

Budget: $682,000 *Investment Classification: General Plant* *Category: Program*

This program involves upgrading, refurbishing, and replacing equipment and facilities due to damage, deterioration, corrosion, in-service failure, and organizational changes. Newfoundland Power maintains district and area offices throughout its service territory to ensure a prompt response to customer outages and other service requests, and facilities for the Company's employees and customers. Building components and systems addressed under this program have failed or are at imminent risk of failure.

Building Accessibility Improvements

Budget: $650,000 *Investment Classification: General Plant* *Category: Project*

This project involves upgrading, refurbishing, and replacing equipment and facilities to improve accessibility at company facilities. Newfoundland Power maintains district and area offices throughout its service territory to ensure a prompt response to customer outages and other service requests. Improving accessibility ensures employees and customers have access to adequate facilities.

Specialized Tools and Equipment

Budget: $595,000 *Investment Classification: General Plant* *Category: Project*

This project is necessary to purchase specialized tools and equipment beyond those provided for in the *Tools and Equipment* program. Newfoundland Power requires an adequate supply of tools and equipment to provide reliable service to customers. The 2025 project includes procurement of fall arrest rescue equipment for line trucks, transformer and generator test equipment, and a forklift. The procurement of specialized tools and equipment is necessary periodically to ensure the safety of employees and to ensure a prompt response to customer outages.

Tools and Equipment

Budget: $589,000 *Investment Classification: General Plant* *Category: Program*

This program is necessary to add or replace tools and equipment used in day-to-day operations to provide safe and reliable service to customers. Newfoundland Power requires an adequate supply of tools, equipment, and office furniture to provide reliable service to customers. The replacement of deteriorated and obsolete equipment is necessary on an ongoing basis to ensure the safety of employees working in offices and the field, and to ensure a prompt response to customer outages.

General Property

Physical Security Upgrades

Budget: $456,000 *Investment Classification: General Plant* *Category: Program*

This program involves upgrading physical security infrastructure at Newfoundland Power's facilities throughout its service territory. This program is required to maintain safe and adequate facilities as it permits upgrades to security infrastructure at Company facilities to ensure the safety of employees and the general public.

Newfoundland Power Inc.
Computation of Average Rate Base
For the Years Ended December 31
($000s)

	2023	2022
Net Plant Investment		
Plant Investment	2,311,786	2,178,072
Accumulated Depreciation	(957,928)	(914,827)
Contributions in Aid of Construction	(47,887)	(45,171)
	$1,305,971	$1,218,074
Additions to Rate Base		
Deferred Pension Costs	101,430	95,095
Credit Facility Costs	105	87
Cost Recovery Deferral – Conservation	20,708	19,359
Cost Recovery Deferral – 2022 Revenue Shortfall	229	459
Cost Recovery Deferral – Load Research and Retail Rate Design Review	189	20
Cost Recovery Deferral – Pension Capitalization	799	-
Customer Finance Programs	1,199	1,472
	$124,659	$116,492
Deductions from Rate Base		
Weather Normalization Reserve	(6,321)	6,576
Demand Management Incentive Account	(978)	107
Other Post-Employment Benefits	84,357	80,151
Customer Security Deposits	653	1,270
Accrued Pension Obligation	5,397	5,300
Accumulated Deferred Income Taxes	30,609	18,076
Refundable Investment Tax Credits	292	-
Excess Earnings Account	3,714	-
	$117,723	$111,480
Year End Rate Base	1,312,907	1,223,086
Average Rate Base Before Allowances	1,267,997	1,211,751
Rate Base Allowances		
Materials and Supplies Allowance	14,778	11,978
Cash Working Capital Allowance	7,304	6,705
Average Rate Base at Year End	$1,290,079	$1,230,434

2025 Capital Budget Overview

June 2024

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1.0 APPLICATION OVERVIEW

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") 2025 Capital Budget totals approximately $127.9 million. The 2025 Capital Budget includes:

(i) Proposed single-year projects and programs in excess of $750,000 in the amount of $79,468,000;
(ii) Proposed single-year projects and programs $750,000 and under in the amount of $10,850,000;
(iii) Proposed multi-year projects with capital expenditures of $18,219,000 in 2025, $46,145,000 in 2026 and $9,816,000 in 2027; and
(iv) Previously approved multi-year projects with capital expenditures of $19,414,000 in 2025, and $297,000 in 2026.

The 2025 Capital Budget includes 22 recurring capital programs and 39 capital projects, six of which have been previously approved. The 2025 Capital Budget is approximately $13.7 million more than the approved *2024 Capital Budget Application*.[1]

Approximately half of the capital expenditures included in the 2025 Capital Budget are associated with the replacement and refurbishment of existing assets. These expenditures are necessary to replace electrical system assets that are deteriorated, deficient or fail in service, or to refurbish assets to extend their useful service lives. The proportion of the 2025 Capital Budget associated with the replacement and refurbishment of existing assets reflects the age and condition of Newfoundland Power's electrical system. For example, the Company is proposing the replacement of two substation power transformers as well as a penstock refurbishment to extend the useful life of assets. Inspections of both the substation power transformers and penstock show considerable deterioration over time.

Approximately one quarter of capital expenditures included in the 2025 Capital Budget are associated with requirements to connect new customers and respond to system load growth. The Company is forecasting 2,220 new customer connections in 2025, as well as the requirement to address load growth on two distribution feeders due to residential development on the Northeast Avalon area.

The remaining one quarter of capital expenditures included in the 2025 Capital Budget are associated with general plant, service enhancement and mandatory expenditures. The largest driver of expenditures in these areas is the *LED Street Lighting Replacement* project which provides customers with lower rates for better quality lighting with a budget of approximately $5.7 million in 2025.

Overall, the 2025 Capital Budget represents the capital additions and improvements necessary to continue providing safe and reliable service to customers at the lowest possible cost.

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[1] The Board approved the *2024 Capital Budget Application* in the amount of $114,252,000 in Order No. P.U. 2 (2024).

2.0 APPLICATION CONTEXT

2.1 Regulatory Framework

Newfoundland Power is the primary distributor of electricity in the Province of Newfoundland and Labrador. The Company serves approximately 87% of all customers in the province.

Newfoundland Power's operations, including its capital investments, are regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") pursuant to the *Public Utilities Act* and the *Electrical Power Control Act, 1994*.[2] The *Public Utilities Act* requires a public utility to provide services and facilities that are reasonably safe and adequate and just and reasonable.[3] The *Electrical Power Control Act, 1994* contains the provincial power policy, which requires that power be delivered to customers at the lowest possible cost, in an environmentally responsible manner, consistent with reliable service.[4]

The Board provided updated provisional *Capital Budget Application Guidelines* (the "Provisional Guidelines") effective January 2022. In issuing the Provisional Guidelines, the Board noted that:

> "*While strict adherence to all aspects of the provisional guidelines may not be possible, the Board asks that the stakeholders make best efforts to respect the spirit and intent of the guidelines*."[5]

The capital expenditures proposed as part of Newfoundland Power's *2025 Capital Budget Application* (the "Application") are necessary to meet the Company's statutory obligations under the *Public Utilities Act* and the *Electrical Power Control Act, 1994*. The Application is organized to comply with the spirit and intent of the Provisional Guidelines. Appendix A summarizes how the capital expenditures proposed in the Application are organized according to the Provisional Guidelines.

2.2 Capital Planning at Newfoundland Power

2.2.1 General

Newfoundland Power's annual capital expenditures are the product of a comprehensive capital planning process. The Company's capital planning process applies sound engineering and objective data to determine which expenditures are required annually to provide customers with access to safe and reliable service at the lowest possible cost.

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2 Section 41 of the *Public Utilities Act* requires, among other provisions, that a public utility submit an annual capital budget of proposed improvements or additions to its property to the Board for its approval.

3 See Section 37(1) of the *Public Utilities Act*.

4 See Section 3 of the *Electrical Power Control Act, 1994*.

5 See correspondence from the Board regarding *Provisional Capital Budget Application Guidelines*, dated December 20, 2021.

The capital planning process commences each year with an update of the Company's five-year capital plan. The capital plan provides a forecast of capital expenditures across all asset classes for the next five years, including the upcoming budget year. The capital plan is updated annually based on the most recent information of forecast customer requirements, asset condition, operational requirements and other factors.

Newfoundland Power's annual capital expenditures include a combination of recurring programs and specific projects. The capital planning process for programs and projects is described below.

2.2.2 Capital Program Planning

Programs include capital investments related to high-volume, repetitive work that is required on an ongoing basis. Programs include:

(i) Capital work required to connect new customers to the electrical system, such as the installation of services and meters;
(ii) Corrective and preventative maintenance programs necessary to maintain the electrical system, including the replacement of equipment that has failed or deteriorated; and
(iii) Capital expenditures necessary to replace or add specific materials used in providing service to customers, such as personal computers, tools and equipment.

Programs required to connect new customers to the electrical system are generally budgeted on the basis of forecast customer requirements. Each year, Newfoundland Power updates its capital plan to reflect its most recent Customer, Energy and Demand Forecast. The Customer, Energy and Demand Forecast estimates new customer connections that are expected over the next five years based on economic inputs from the Conference Board of Canada, such as forecast housing starts. This data is then used to determine forecast expenditures to connect new customers, including forecast expenditures for meters, services, and extensions to the distribution system.

Programs required to complete corrective and preventative maintenance of the electrical system are generally budgeted on the basis of historical expenditures and forecast inflation.[6] Capital requirements for corrective and preventative maintenance programs tend to be reasonably stable over time. Each year, the Company updates its forecast expenditures for these programs based on the most recent five-year average of expenditures and the latest forecast of inflation. This budgeting methodology helps to ensure forecast expenditures reflect the Company's most recent experience with maintaining the electrical system.

Capital expenditures for programs required to replace or add specific materials used in providing service to customers are generally budgeted based on a combination of historical

[6] Inflation is calculated on the basis of the GDP Deflator for Canada for non-labour costs and the Company's internal labour inflation rate for labour costs.

expenditures, forecast inflation, and identified operational requirements. For example, identified operational requirements could include the need to purchase a specific quantity of personal computers.

In forecasting program expenditures, Newfoundland Power reviews any recent variances in actual costs from approved budgets and the reasons for those variances. If significant variances are observed in consecutive years, an analysis is undertaken to determine whether a different budgeting methodology would be more reflective of forecast requirements.[7]

2.2.3 Capital Project Planning

Projects include capital investments for identifiable assets where the required work has a defined schedule, scope and budget based on detailed engineering estimates.

Forecast expenditures related to projects are updated annually to reflect the latest:

(i) Condition assessments of electrical system assets. Information on asset condition is obtained through annual inspection programs, engineering reviews and recent operating experience. This information identifies equipment that is deteriorated, deficient, or has failed and requires replacement or refurbishment to extend its useful service life.

(ii) Forecasts of electrical system load. System load forecasts are produced annually using computer modelling to determine any areas where capital expenditures are required to respond to customers' changing electrical system requirements.

(iii) Changes in economic factors or industry requirements. This can include any changes in engineering standards, regulatory requirements, or economic factors, such as marginal system costs, which could affect requirements for capital expenditures.

(iv) Changes in operational requirements. This can also include changes affecting Company information systems, such as obsolescence or cybersecurity requirements, as well as opportunities identified to enhance operational efficiency or effectiveness.

The annual update of Newfoundland Power's capital plan to reflect this information can result in planned projects being modified, advanced to an earlier year, deferred to future years, or removed entirely from the planning period.

As capital projects move from the forecast period to the budget year, they are examined in detail to further assess the scope and justification of the required work. Once it is determined that a capital expenditure may be necessary, Newfoundland Power assesses all viable alternatives for executing the required work. This includes both alternatives to the scope of a

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[7] For example, Newfoundland Power has adjusted its estimating methodology from a five-year average to a three-year average for the *New Meters, Replacement Meters, New Transformers* and *Replacement Transformers* programs in this budget.

capital expenditure, such as a like-for-like replacement or upgrade, and alternatives that could result in the deferral of capital expenditures.

The 2025 Capital Budget includes five capital projects that were planned for 2025 but have been deferred to future years. There are also four capital projects that were previously deferred or modified and are now proposed for 2025. Appendix B provides the list of the capital projects that were deferred, modified or advanced.

The prioritization and potential deferral of capital expenditures are assessed based on potential risks to customers. This includes engineering assessments of the likelihood that an asset will fail and the potential reliability, safety, environmental or economic consequences for customers if failure were to occur. In 2022, following the issuance of Provisional Guidelines, Newfoundland Power developed a risk matrix to standardize its approach to communicating risks associated with proposed capital expenditures. Appendix C provides the risk matrix methodology and a prioritized list of 2025 capital expenditures.

2.3 Balancing Cost and Service

2.3.1 Service Reliability

Newfoundland Power owns and operates approximately 9,400 kilometres of distribution line, approximately 2,100 kilometres of transmission line, 131 substations, 23 hydro generating plants and six backup generators to serve its customers.

The service reliability experienced by customers primarily reflects the condition of the electrical system. National construction standards are applied to ensure the Company's electrical system is constructed and maintained to withstand local climatic conditions.[8] Long-term asset management strategies, such as the *Substation Refurbishment and Modernization Plan* and *Transmission Line Rebuild Strategy,* provide a structured approach to maintaining the condition of a large volume of electrical system assets. Annual inspections support routine preventative and corrective maintenance programs, with substations inspected eight times annually, transmission lines inspected annually, and distribution lines inspected on a seven-year cycle.

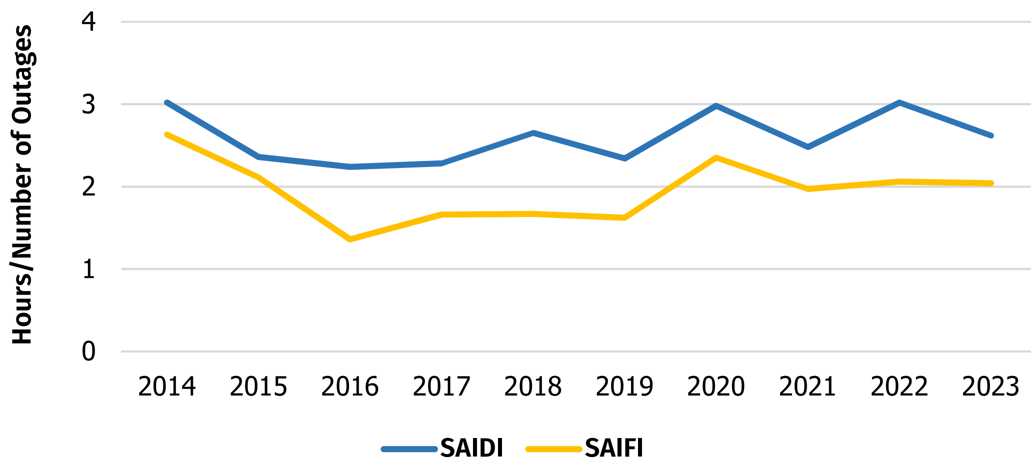
The service reliability experienced by customers also reflects the Company's response when outages occur. Newfoundland Power's operational response requires the deployment of a skilled workforce throughout its service territory, including powerline technicians, technologists and engineers. A combination of operational technologies and adequate tools and equipment are necessary to ensure the effective and efficient deployment of the Company's workforce.

8 The primary engineering standard for distribution and transmission systems is Canadian Standards Association ("CSA") standard *C22.3 No.1-15 Overhead Systems*.

Annual capital expenditures are essential to maintaining both electrical system condition and the Company's operational response. The most recent independent review of Newfoundland Power's engineered operations was conducted by The Liberty Consulting Group ("Liberty") in 2014 and found that the Company's asset management practices and operations conform to good utility practices.[9]

Figure 1 shows the average duration ("SAIDI") and frequency ("SAIFI") of outages to Newfoundland Power's customers from 2014 to 2023 under normal operating conditions.[10]

Figure 1
Newfoundland Power
SAIDI and SAIFI - Normal Operating Conditions
(2014 - 2023)



The frequency and duration of customer outages has been reasonably stable over the last decade under normal operating conditions. The average duration of customer outages has ranged from approximately 2.2 to 3.0 hours per year. The average frequency of customer outages has ranged from approximately 1.4 to 2.6 outages per year.

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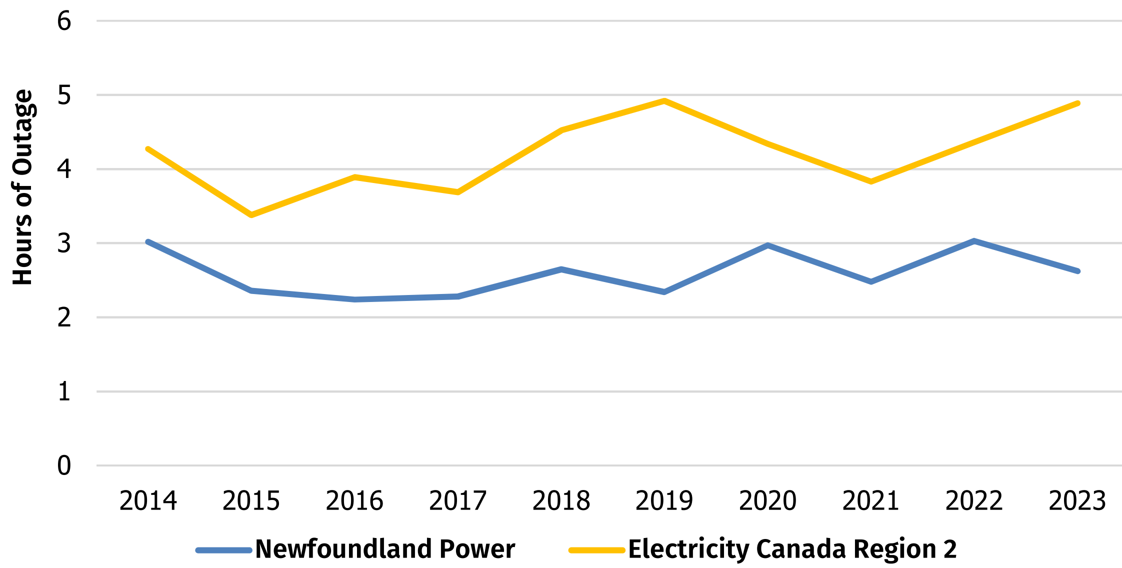
9 Liberty concluded that: "*Newfoundland Power's planning and design of its system, its asset management practices, its system operations, its outage management and emergency practices and its customer communications processes all conform to good utility practices.*" See Liberty, *Executive Summary of Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power Inc.*, December 17, 2014, page ES-1.

10 Newfoundland Power calculates its SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) in accordance with industry guidelines. SAIDI is calculated by dividing the total number of customer outage minutes by the total number of customers served. SAIFI is calculated by dividing the total number of customer interruptions by the total number of customers served. The data shown in Figure 1 does not include customer outages due to major events or loss of supply from Newfoundland and Labrador Hydro.

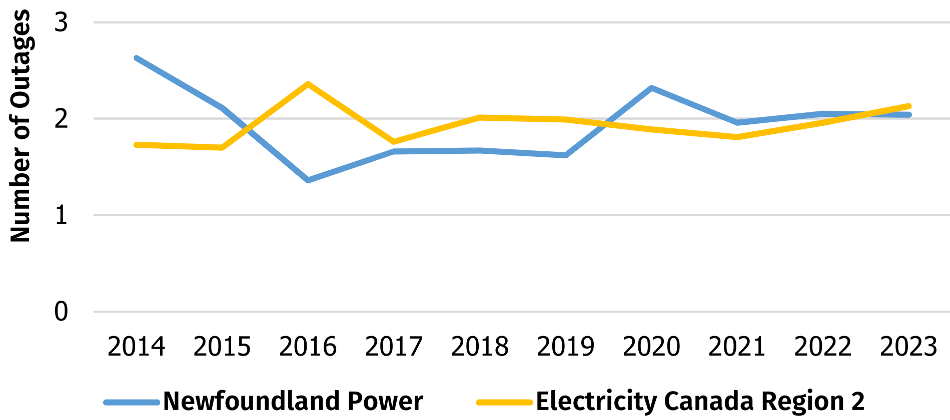
Figures 2 and 3 compare the average duration and frequency of outages to Newfoundland Power's customers to the Canadian average under normal operating conditions from 2014 to 2023.[11]

Figure 2
Newfoundland Power vs. Canadian Average
SAIDI - Normal Operating Conditions
(2014-2023)



[11] At the time of filing, 2023 data from Electricity Canada was not final and is subject to change. The Canadian average reflects Region 2 utilities of Electricity Canada. Region 2 utilities include Canadian utilities that serve a mix of urban and rural markets. These include ATCO Electric, BC Hydro, FortisAlberta, FortisBC, Hydro One, Hydro-Quebec, 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.

Figure 3
Newfoundland Power vs. Canadian Average
SAIFI - Normal Operating Conditions
(2014-2023)



Newfoundland Power's reliability performance has been reasonable over the last decade in comparison to the Canadian average. The Company's average duration of customer outages has been approximately 40% better than the Canadian average.[12] The average frequency of customer outages has been consistent with the Canadian average over this period.[13]

Newfoundland Power is focused on maintaining current levels of overall service reliability for its customers under normal operating conditions. The Company's annual targets for service reliability are based on the most recent five-year average.

While overall levels of service reliability are viewed as acceptable, customers in certain areas experience service reliability that is considerably below Newfoundland Power's corporate average. Appendix D provides a list of the Company's worst performing feeders.

[12] Newfoundland Power's SAIDI averaged approximately 2.6 hours/year from 2014 to 2023. This compares to an Electricity Canada average SAIDI of 4.1 hours/year over the same period.

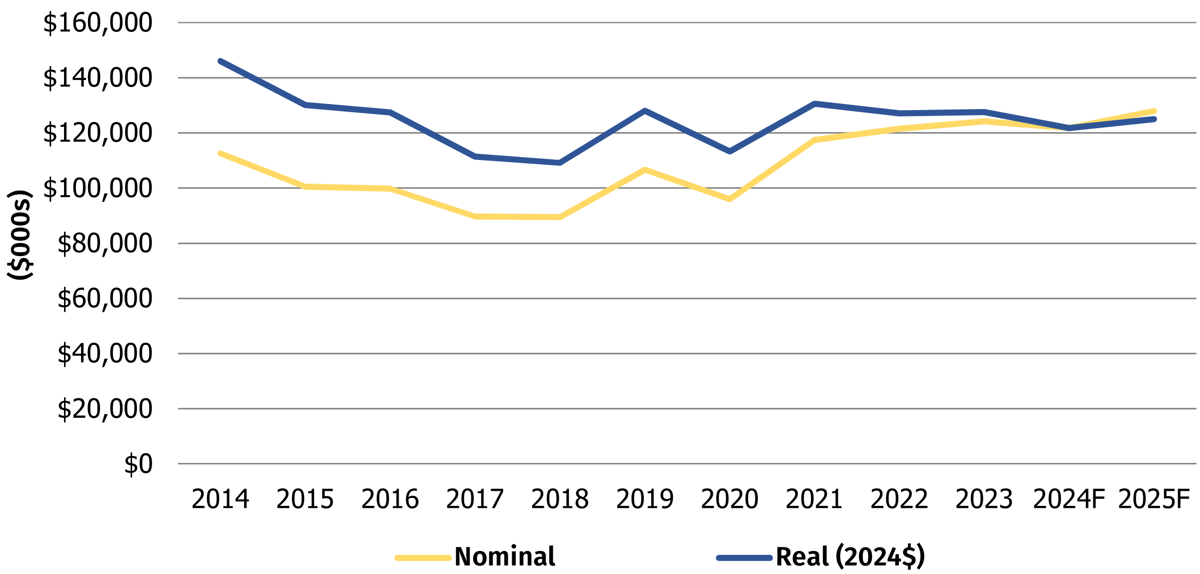
[13] Newfoundland Power's SAIFI averaged approximately 1.9 outages/year from 2014 to 2023. This compares to an Electricity Canada average SAIFI of 1.9 outages/year over the same period.

2.3.2 Capital Expenditures

Newfoundland Power's annual capital expenditures reflect the capital additions, replacements and refurbishments necessary each year to provide safe and reliable service to customers at the lowest possible cost.

Figure 4 provides Newfoundland Power's actual and inflation-adjusted capital expenditures from 2014 to 2024 and the 2025 Capital Budget.

Figure 4
Newfoundland Power Capital Expenditures
(2014-2025F)



Newfoundland Power's capital expenditures have averaged approximately $107 million annually from 2014 to 2024, or $125 million when adjusted for inflation. On an inflation-adjusted basis, annual expenditures have ranged from approximately $109 million in 2018 to $146 million in 2014. The 2025 Capital Budget of approximately $127.9 million is within this range.

2.3.3 Customer Rates

A primary determinant of Newfoundland Power's customer rates is the Company's revenue requirement. Revenue requirement is the aggregate amount of forecast revenue required in a year to cover the Company's cost of serving customers, including operating costs, taxes, depreciation and allowed return on rate base.[14] Customer rates also reflect Newfoundland Power's Customer, Energy and Demand forecasts and Board-approved rate structures.[15] The capital projects proposed in the Application are estimated to increase the Company's annual revenue requirement by approximately $8 million on a *pro forma* basis. The estimate includes increases in depreciation, return on rate base and income taxes and excludes customer benefits associated with proposed capital projects that provide for lower operating and purchased power costs included in Newfoundland Power's revenue requirement.

The proposed refurbishments associated with the Company's Cape Broyle, Horsechops, Mobile and Lockston hydro plants included in the Application will result in the continued provision of low-cost electricity production to customers. Further, the proposed *LED Street Lighting Replacement* project will provide for the full realization of the lower operating and purchased power costs contemplated by the six-year *LED Street Lighting Replacement* plan. The estimate of these customer benefits on Newfoundland Power's annual revenue requirement is approximately $11 million on a *pro forma* basis.

The *pro forma* analysis is practically limited as it does not include potentially higher revenues from growth-related projects, or the long-term effect that fully justified capital expenditures have on minimizing revenue requirements.[16]

The Board has previously recognized the complex relationship between capital investments, revenue requirements and customer rates.[17] The Board has also recognized that fully justified capital expenditures contribute to the delivery of least-cost service to customers.[18]

The complex relationship between revenue requirements, customer rates and capital investments can be observed over the last decade.

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[14] See Order No. P.U. 7 (2002-2003), page 31.

[15] See Order No. P.U. 40 (2005), page 13.

[16] For example, the systematic replacement of deteriorated plant during regular work hours tends to reduce the cost of making emergency repairs due to equipment failures, which often occurs during overtime hours. Other capital expenditures enable efficiencies through technology. These effects will also tend to decrease future revenue requirements.

[17] In Order No. P.U. 40 (2005), the Board stated: "*NP undertakes a capital program and incurs capital expenditures each year and these expenditures impact the revenue requirement in other ways, in addition to depreciation. The portion of capital expenditures incurred for example as a result of customer growth will be offset somewhat by higher revenues from increased energy sales. Other capital expenditures may impact maintenance expenses…these expenses are properly dealt with in the context of a general rate application.*"

[18] In Order No. P.U. 7 (2002-2003), the Board stated: "*From a regulatory perspective, efficient operations, fully justified capital expenditures and a low-cost capital structure all combine to minimize revenue requirement, and hence provide least cost electricity to ratepayers.*"

Table 1 shows Newfoundland Power's actual and inflation-adjusted contribution to revenue requirement in 2016 and 2025.[19]

Table 1
Newfoundland Power
Contribution to Revenue Requirement
($millions)

	2016	2025[20]	Change
Actual	221.1[21]	239.3	8%
Inflation Adjusted[22]	288.8	239.3	-17%

Newfoundland Power's contribution to revenue requirement increased by approximately 8% from 2016 to 2025. On an inflation-adjusted basis, the Company's contribution to revenue requirement decreased by approximately 17%.

Table 2 compares Newfoundland Power's total contribution to average customer rates in cents per kWh in 2016 and 2025.

Table 2
Newfoundland Power
Contribution to Customer Rates
(¢/kWh)

	2016	2025[23]	Change
Actual	3.72	4.23	14%
Inflation Adjusted[24]	4.86	4.23	-13%

19 Based on the Company's 2016 and 2023 test year revenue requirements, excluding purchased power costs. Purchased power costs from Newfoundland and Labrador Hydro account for approximately 65% of the Company's overall revenue requirement.

20 Newfoundland Power's 2023 revenue requirement was $699.2 million. Excluding purchased power costs of $459.9 million, it was $239.3 million. See the Company's *2022/2023 General Rate Application*, Exhibit 7 (Revised), page 2.

21 Newfoundland Power's 2016 revenue requirement was $665.1 million. Excluding purchased power costs of $444.0 million, it was $221.1 million. See the Company's application filed in compliance with Order No. P.U. 18 (2016), Schedule 1, Appendix E, page 1.

22 Inflation adjusted based on the GDP Deflator for Canada.

23 Based on Newfoundland Power's 2023 test year revenue requirement which is reflected in current customer rates, as approved in Order No. P.U. 3 (2022).

24 Inflation adjusted based on the GDP Deflator for Canada.

Newfoundland Power's contribution to average customer rates increased by approximately 14% from 2016 to 2025. On an inflation-adjusted basis, the Company's contribution to average customer rates decreased by 13%.

While Newfoundland Power's contribution to revenue requirement and customer rates has decreased on an inflation-adjusted basis over the past decade, the Company's annual capital investments have averaged over $100 million per year over this period.

In Newfoundland Power's view, the Company's approach to capital planning tends to minimize overall costs to customers over the longer term. This is consistent with the least-cost delivery of reliable service to customers.

2.3.4 Atlantic Canadian Comparison

The four primary distributors of electricity in Atlantic Canada are: (i) Newfoundland Power; (ii) Nova Scotia Power; (iii) NB Power; and (iv) Maritime Electric. Each of these utilities serves customers in a mix of urban and rural areas.

Table 3 compares Newfoundland Power to other Atlantic Canadian utilities on the basis of: (i) growth in aggregate capital investment in transmission and distribution ("T&D") assets from 2013 to 2022; and (ii) the average duration of customer outages over the same period.

Table 3
Atlantic Canadian Comparison
Capital Investment and Service Reliability

	Capital Investment ($Millions)[25]			Service Reliability (SAIDI)
Utility	2013	2022	Growth	2013-2022
Newfoundland Power	1,077	1,580	47%	2.6
Atlantic Canadian Utilities[26]	1,198	1,871	56%	3.9

25 Reflects the average property, plant and equipment in T&D assets of Nova Scotia Power and Maritime Electric. In 2016, NB Power changed accounting standards. Property, plant and equipment is the gross cost of utility assets determined in accordance with generally accepted accounting principles. This information is based on the audited and publicly available financial statements op each utility.

26 The aggregate investment of Nova Scotia Power and Maritime Electric was $2,397 million in 2013 ($2,397 million / 2 = $1,198 million) and $3,743 million in 2022 ($3,743 million / 2 = $1,871 million).

Newfoundland Power's investment in T&D assets has increased at a rate lower than the average of other Atlantic Canadian utilities over the 10-year period ending 2022, with investments among other Atlantic Canadian utilities averaging 56%. Newfoundland Power also observes that, subsequent to NB Power's change in accounting standards, NB Power's property, plant and equipment relating to T&D assets increased by approximately 40% from 2016 to 2022. By comparison, Newfoundland Power's T&D assets increased by approximately 25% over the same period.

From 2016 to 2022, the Company's customers have experienced 33% fewer outage hours in comparison to customers of other Atlantic Canadian utilities.[27] The Company's average outage duration was the lowest of any Atlantic Canadian utility over this period.[28]

Overall, Newfoundland Power's capital investments and service reliability are reasonable in comparison to other Atlantic Canadian utilities.

3.0 SUMMARY OF 2025 EXPENDITURES

3.1 2025 Capital Budget Overall

Newfoundland Power's 2025 Capital Budget totals approximately $127.9 million, including approximately $10.9 million of 2025 expenditures that are $750,000 and under and approximately 19.4 million of 2025 expenditures that were previously approved by the Board.[29] There has been a material change in the scope and magnitude of the previously approved capital project to rebuild Transmission Line 94L. As discussed in report *3.2 Transmission Line 94L Rebuild*, Newfoundland Power completed a detailed assessment of alternatives to ensure the selected alternative continues to be least-cost for customers. Newfoundland Power is seeking an additional $12.6 million over the next two years, including approximately $3.5 million in 2025 for the completion of the project. Appendix E provides an update on previously approved multi-year projects.

The Application also proposes 12 new multi-year projects, including the updated *Transmission Line 94L Rebuild* project. The multi-year projects include expenditures of approximately $18.2 million in 2025.

The following sections provide breakdowns of the 2025 Capital Budget by asset class, category, investment classification and materiality.

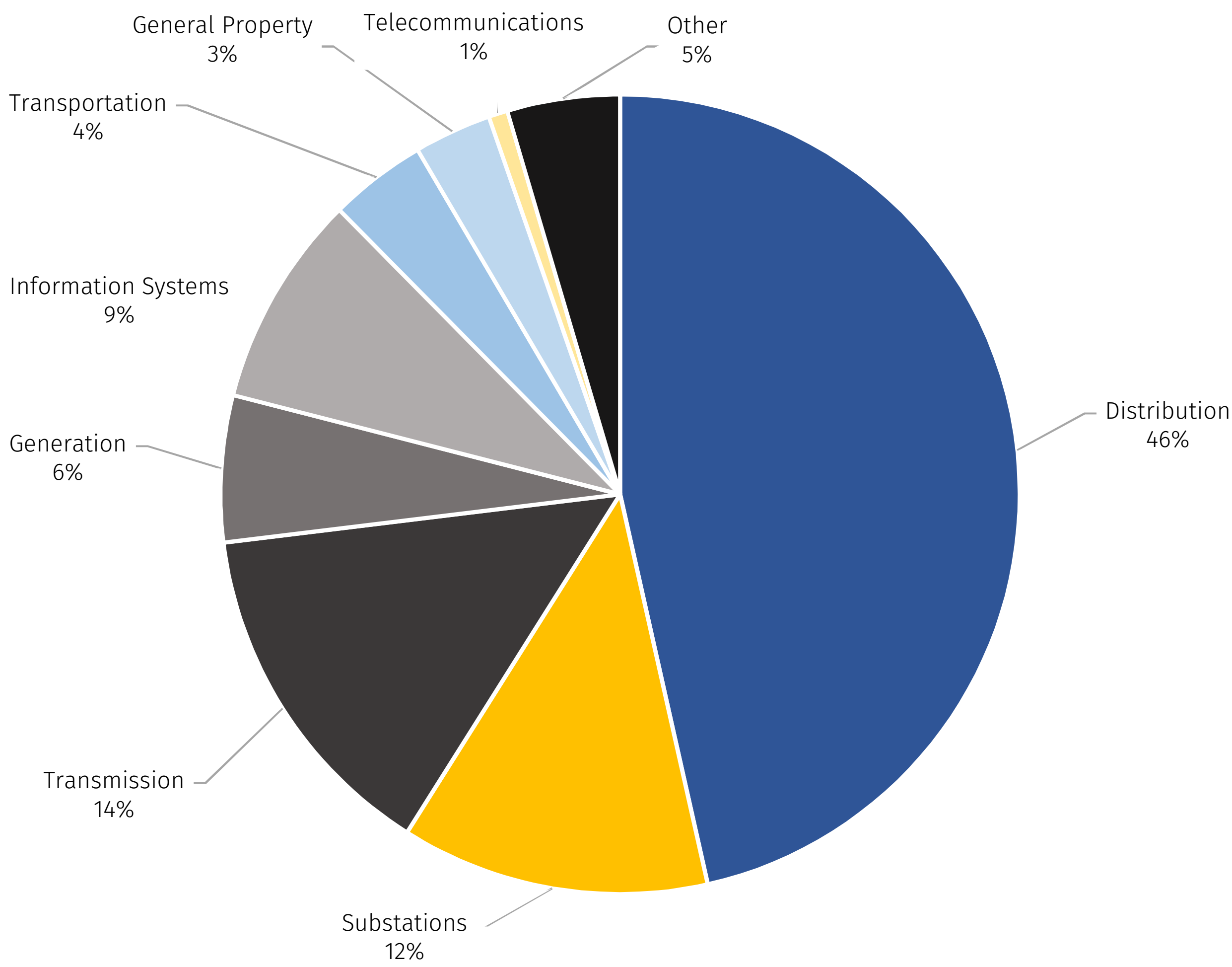
27 (2.6 – 3.9) / 3.9 = -0.33, or -33%.
28 The average SAIDI for the other Atlantic Canadian utilities ranged from 3.1 to 4.5.
29 For expenditures incurred to date, see the *2024 Capital Expenditure Status Report* provided with the Application.

3.2 2025 Capital Budget by Asset Class

Newfoundland Power organizes its annual capital budget by asset class.

Figure 5 provides the 2025 Capital Budget by asset class, including previously approved multi-year projects.

Figure 5
2025 Capital Budget by Asset Class



The Distribution asset class accounts for approximately 46% of capital expenditures for 2025. Approximately half of distribution expenditures are required to connect new customers to the electrical system. Approximately one third relate to preventative and corrective maintenance programs for the distribution system.

The Substations asset class accounts for approximately 12% of capital expenditures for 2025. The majority of substation expenditures relate to the refurbishment and modernization of the Northwest Brook and Islington substations at a combined cost of $8.9 million in 2025.

The Transmission asset class accounts for approximately 14% of capital expenditures for 2025. The majority of transmission expenditures relate to the rebuilding of transmission lines constructed in the 1960s and 1970s. This includes the first year of a multi-year project to construct a new transmission line between Lewisporte and Boyd's Cove Substations in central Newfoundland at a cost of $1.9 million in 2025, $9.3 million in 2026 and $9.6 million in 2027 Transmission expenditures in 2025 also include approximately $9.2 million associated with previously approved multi-year projects.[30]

The Generation asset class accounts for approximately 6% of capital expenditures for 2025. This includes a multi-year project to refurbish the Lookout Brook hydro plant costing $1.6 million in 2025. Generation expenditures also include the refurbishment of the Mobile hydro plant in 2025 with approximately $825,000 to refurbish the penstock. Also included is the start of a multi-year project to replace the spillway which has failed in service at the Mount Carmel Pond Dam, and automate the gate, with expenditures of $3.6 million in 2025 and $1 million in 2026.

The Information Systems asset class accounts for approximately 9% of capital expenditures for 2025. Reduced capital expenditures in this asset class are a result of the conclusion of the *Customer Service System Replacement* project approved by the Board in Order No. P.U. 12 (2021).

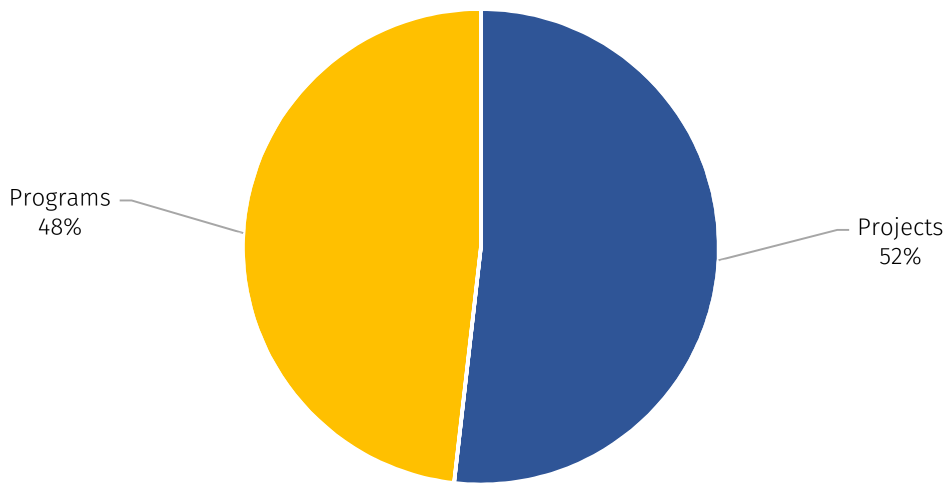
The remaining asset classes account for between 1% and 5% of capital expenditures for 2025.

30 This includes approximately $9.2 million for the rebuild of Transmission Line 146L as approved in Order No. P.U. 2 (2024) as approved in Order No. P.U. 36 (2021).

3.3 2025 Capital Budget by Category

Figure 6 provides a breakdown of Newfoundland Power's 2025 Capital Budget by category, including previously approved multi-year projects.

Figure 6
2025 Capital Budget by Category

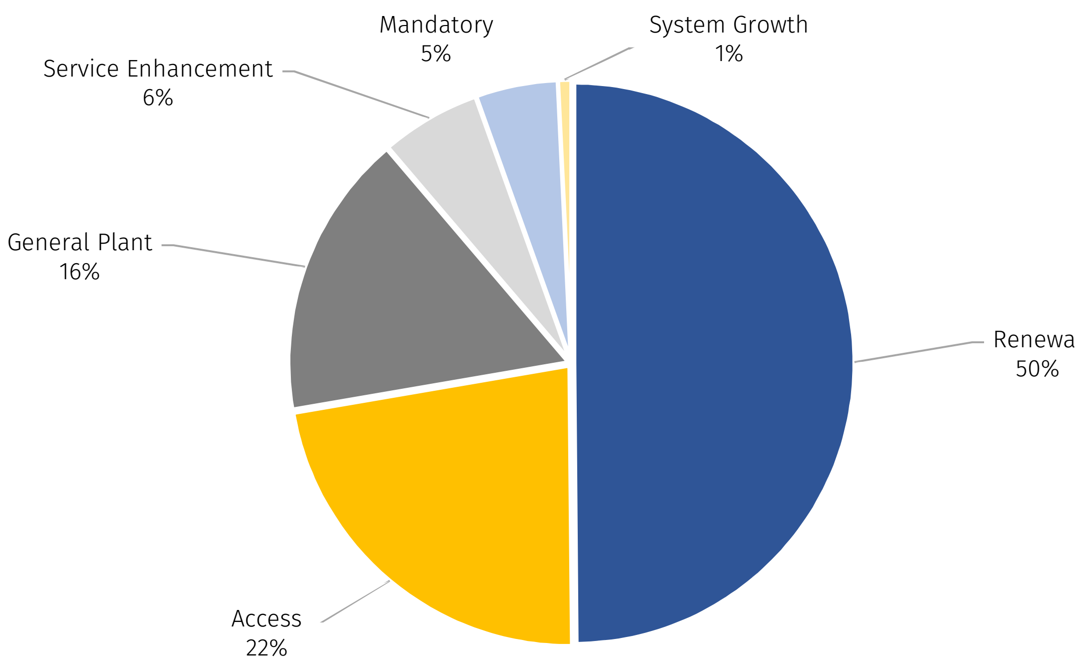


Newfoundland Power's 2025 Capital Budget includes 39 capital projects and 22 capital programs. Capital projects account for approximately 52% of capital expenditures for 2025, with the remaining 48% attributable to recurring programs.

3.4 2025 Capital Budget by Investment Classification

Figure 7 shows Newfoundland Power's 2025 Capital Budget by investment classification, including previously approved multi-year projects.

Figure 7
2025 Capital Budget by Investment Classification



Renewal expenditures account for approximately 50% of capital expenditures for 2025. These expenditures are primarily driven by the age and condition of Newfoundland Power's electrical system. Preventative and corrective maintenance programs account for nearly half of Renewal expenditures in 2025. Capital work under the *Transmission Line Rebuild Strategy* and *Substation Refurbishment and Modernization Plan* account for an additional one third of Renewal expenditures in 2025.

Access expenditures account for approximately 22% of capital expenditures for 2025. These expenditures primarily include programs with budget amounts based on Newfoundland Power's latest forecast of new customer connections. The Company is forecasting a total of 2,220 new customer connections in 2025.

General Plant expenditures account for approximately 16% of capital expenditures for 2025. Information Systems expenditures account for over half of all General Plant expenditures. These expenditures are driven by the need to maintain the reliability and security of software and hardware that support the provision of service to customers. Expenditures within the Transportation asset class are the next largest driver of General Plant expenditures, reflecting the routine replacement of vehicles that have reached the end of their service lives.

Service Enhancement expenditures account for approximately 6% of capital expenditures for 2025. The *LED Street Lighting Replacement* project accounts for the majority of Service Enhancement expenditures in 2025. This project is being completed as part of a six-year plan that commenced in 2021 to provide all Street and Area Lighting customers with LED fixtures. LED street light fixtures offer lower rates, better quality lighting and a more reliable street lighting service.

Mandatory expenditures account for approximately 5% of capital expenditures for 2025. The primary drivers within this classification are Board orders respecting *General Expenses Capitalized ("GEC")*, the *Allowance for Funds Used During Construction*, and the *Allowance for Unforeseen Items*.

System Growth expenditures account for approximately 1% of capital expenditures in 2025. There are three capital projects proposed for 2025 to address system growth. The *Feeder Additions for Load Growth* project addresses localized load growth on two distribution feeders on the Northeast Avalon.

3.5 2025 Capital Budget by Materiality

Table 4 provides an overview of the 2025 Capital Budget by materiality, including previously approved multi-year projects.[31]

Table 4
2025 Capital Budget by Materiality

Threshold	Quantity of Projects/Programs	Total Expenditures ($000s)	Percentage of Total Expenditures
Less than $1 million[32]	30	19,020	15%
$1 million - $5 million	18	37,015	29%
Greater than $5 million	13	71,916	56%
Total	61	$127,951	100%

Of the 61 total capital projects and programs included in the 2025 Capital Budget, 48 are less than $5 million. The 13 capital projects and programs greater than $5 million include the

31 Multi-year capital projects are assigned to a materiality threshold based on the total proposed amount, including the amount proposed for the budget year and any proposed future commitments.

32 This includes 20 capital projects and programs that are $750,000 and under.

previously approved *Transmission Line 146L Rebuild* and *Islington Substation Refurbishment and Modernization* projects. There has been no change in the nature, scope or magnitude of these projects. This also includes expenditures associated with the previously approved *Transmission Line 94L Rebuild* project, for which Newfoundland Power is seeking additional expenditures to complete in 2025 and 2026.

The remaining 11 capital programs and projects greater than $5 million that are proposed for 2025 are:

(i) ***Extensions***, which involves the construction of distribution lines to connect new customers to the electrical system. Capital expenditures for this program total approximately $13.4 million for 2025. The budget estimate is based on historical unit costs and forecast new customer connections.

(ii) ***Reconstruction***, which involves corrective maintenance on the distribution system for high-priority deficiencies identified during inspections. Capital expenditures for this program total approximately $7.4 million for 2025. The budget estimate is based on historical expenditures over the most recent five-year period.

(iii) ***Replacement Transformers***, which involves the cost of replacing or refurbishing distribution system transformers that have deteriorated or failed in service. Capital expenditures for this program for this program total approximately $6.3 million for 2025. The budget estimate is based on historical expenditures over the most recent three-year period.[33]

(iv) ***LED Street Lighting Replacement***, which involves the replacement of existing street lights with LED fixtures in order to provide customers with lower rates for a more reliable service. Capital expenditures for this project total approximately $5.7 million for 2025. The budget estimate is based on detailed engineering estimates.

(v) ***New Transformers,*** which involves the cost of purchasing transformers to serve customer growth. Capital expenditures for this program for this program total approximately $5.6 million for 2025. The budget estimate is based on historical expenditures over the most recent three-year period.[34]

(vi) ***Rebuild Distribution Lines,*** which is a preventive maintenance program on the distribution system for deficiencies identified during inspections. Capital expenditures for this project total approximately $5.1 million for 2025. The budget estimate is based on historical expenditures over the most recent five-year period.

(vii) ***General Expenses Capitalized,*** which consist of general expenses that are capitalized due to being related, directly or indirectly, to the Company's capital projects and programs. Capital expenditures for this project total approximately $5.1 million for 2025. The budget estimate is determined in accordance with the percentage allocations as presented in Newfoundland Power's *2022/2023 General Rate Application*.

[33] Refer to Schedule B for budget estimate methodology explanation.
[34] Ibid.

(viii) ***Transmission Line 94L Rebuild,*** which involves a complete rebuild of Transmission Line 94L between Riverhead and Blaketown substations. Capital expenditures for this project total approximately $3.5 million for 2025 and $9.1 million for 2026. The budget estimate is based on detailed engineering estimates.

(ix) ***Asset Management Technology Replacement,*** which involves the replacement of the Company's core asset management technology over the next two years. Capital expenditures for this project total approximately $3.5 million for 2025 and $4.5 million for 2026. The budget estimate is based on detailed estimates.

(x) ***Summerville Substation Refurbishment and Modernization***, which involves the refurbishment of deteriorated components at Summerville Substation in central Newfoundland identified through engineering assessments over the next two years. Capital expenditures for this project total approximately $511,000 in 2025 and $4.5 million in 2026. The budget estimate is based on detailed engineering estimates.

(xi) ***New Transmission Line from Lewisporte to Boyd's Cove,*** which involves constructing a transmission line between Lewisporte and Boyd's Cove Substations. Capital expenditures for this project total approximately $1.9 million for 2025, $9.3 million for 2026 and $9.6 million for 2027. The budget estimate is based on detailed engineering estimates.

Including previously approved expenditures, the thirteen capital projects and programs exceeding $5 million in materiality account for approximately 56% of capital expenditures for 2025.

APPENDIX A:

Capital Expenditure Classification and Categorization Summary

Table A-1
2025 Capital Budget
Proposed Single-Year Projects and Programs in Excess of $750,000

INVESTMENT CLASSIFICATION	BUDGET ($000s)	ASSET CLASS	CATEGORY
Mandatory			
General Expenses Capitalized	5,081	GEC	Project
Allowance for Unforeseen Items	750	Unforeseen Allowance	Project
Total Mandatory	$5,831		
Access			
Extensions	13,402	Distribution	Program
New Transformers	5.623	Distribution	Program
Relocate/Replace Distribution Lines for Third Parties	3,528	Distribution	Program
New Services	3,208	Distribution	Program
New Street Lighting	2,460	Distribution	Program
Total Access	$28,221		
System Growth			
Feeder Additions for Load Growth	960	Distribution	Project
Total System Growth	$960		
Renewal			
Reconstruction	7,425	Distribution	Program
Replacement Transformers	6,340	Distribution	Program
Rebuild Distribution Lines	5,115	Distribution	Program
Substation Replacements Due to In-Service Failures	4,927	Substations	Program
Northwest Brook Substation Refurbishment and Modernization	4,175	Substations	Project
Transmission Line Maintenance	2,884	Transmission	Program
Replacement Street Lighting	884	Distribution	Program

Table A-1
2025 Capital Budget
Proposed Single-Year Projects and Programs in Excess of $750,000

INVESTMENT CLASSIFICATION	BUDGET ($000s)	ASSET CLASS	CATEGORY
Mobile Hydro Plant Penstock Refurbishment	825	Generation – Hydro	Project
Total Renewal	$32,575		
Service Enhancement			
LED Street Lighting Replacement	5,654	Distribution	Project
Distribution Feeder Automation	1,125	Distribution	Project
Total Service Enhancement	$6,779		
General Plant			
System Upgrades	1,408	Information Systems	Project
Shared Server Infrastructure	970	Information Systems	Project
Cybersecurity Upgrades	940	Information Systems	Project
Application Enhancements	914	Information Systems	Project
VHF Radio System Replacement	870	Telecommunications	Project
Total General Plant	$5,102		
Total	$79,468		

Table A-2 2025 Capital Budget Proposed Single-Year Projects and Programs $750,000 and Under			
INVESTMENT CLASSIFICATION	BUDGET ($000s)	ASSET CLASS	CATEGORY
Mandatory			
Allowance for Funds Used During Construction	220	Distribution	Project
Total Mandatory	$220		
Access			
New Meters	457	Distribution	Program
Total Access	$457		
System Growth			
Total System Growth	$0		
Renewal			
Hydro Plant Replacements Due to In-Service Failures	731	Generation – Hydro	Program
Substation Protection and Control Replacement	685	Substations	Program
Distribution Feeder PEP-02 Refurbishment	667	Distribution	Project
Distribution Feeder SMV-01 Refurbishment	654	Distribution	Project
Replacement Meters	648	Distribution	Program
Wood Pole Retreatment	600	Transmission	Project
La Manche Canal Bridge Replacement	530	Generation – Hydro	Project
Replacement Services	445	Distribution	Program
Thermal Plant Replacements Due to In-service Failure	318	Generation – Thermal	Program
Total Renewal	$5,278		
Service Enhancement			
Substation Ground Grid Upgrades	609	Substations	Project
Total Service Enhancement	$609		

Table A-2
2025 Capital Budget
Proposed Single-Year Projects and Programs $750,000 and Under

INVESTMENT CLASSIFICATION	BUDGET ($000s)	ASSET CLASS	CATEGORY
General Plant			
Personal Computer Infrastructure	720	Information Systems	Program
Additions to Real Property	682	General Property	Program
Building Accessibility Improvements	650	General Property	Project
Specialized Tools and Equipment	595	General Property	Project
Tools and Equipment	589	General Property	Program
Network Infrastructure	470	Information Systems	Project
Physical Security Upgrades	456	General Property	Program
Communications Equipment Upgrades	124	Telecommunications	Program
Total General Plant	$4,286		
Total	$10,850		

Table A-3
2025 Capital Budget
Proposed Multi-Year Projects

TITLE	ASSET CLASS	INVESTMENT CLASSIFICATION	PROJECT / PROGRAM	BUDGET ($000s) 2025	2026	2027	Total
Distribution Feeders SCT-01 and BLK-01 Relocation	Distribution	Renewal	Project	649	1,140	-	1,789
Summerville Substation Refurbishment and Modernization	Substations	Renewal	Project	511	4,510	-	5,021
Lockston Substation Refurbishment and Modernization	Substations	Renewal	Project	305	4,521	-	4,826
Gander Substation Power Transformer Replacement	Substations	Renewal	Project	17	3,905	263	4,185
Pulpit Rock Substation Power Transformer Replacement	Substations	Renewal	Project	17	2,905	-	2,922
New Transmission Line from Lewisporte to Boyd's Cove	Transmission	Renewal	Project	1,886	9,283	9,553	20,722
Transmission Line 94L Rebuild	Transmission	Renewal	Project	3,485	9,075	-	12,560
Mount Carmel Pond Dam Refurbishment	Generation – Hydro	Renewal	Project	3,608	1,008	-	4,616
Asset Management Technology Replacement	Information Systems	General Plant	Project	3,479	4,534	-	8,013
Outage Management System Upgrade	Information Systems	General Plant	Project	1,811	1,459	-	3,270
Port Union Building Replacement	General Property	General Plant	Project	278	1,003	-	1,281
Replace Commercial Vehicles and Aerial Devices 2025-2026	Transportation	General Plant	Project	2,173	2,802	-	4,975
			Total	$18,219	$46,145	$9,816	$74,180

Table A-4 2025 Capital Budget Previously Approved Multi-Year Projects							
TITLE	ASSET CLASS	INVESTMENT CLASSIFICATION	PROJECT/ PROGRAM	BUDGET ($000s)			
				2024	2025	2026	Total
Islington Substation Refurbishment and Modernization	Substations	Renewal	Project	308	4,706	-	5,014
Transmission Line 146L Rebuild	Transmission	Renewal	Project	2,152	9,209	-	11,361
Lookout Brook Hydro Plant Refurbishment	Generation - Hydro	Renewal	Project	362	1,573	-	1,935
Microsoft Enterprise Agreement	Information Systems	General Plant	Project	297	297	297	891
Gander Building Renovation	General Property	General Plant	Project	175	760	-	935
Replace Vehicles and Aerial Devices 2024-2025	Transportation	General Plant	Project	1,940	2,869	-	4,809
			Total	$5,234	$19,414	$297	$24,945

APPENDIX B:

Deferred, Modified and Advanced Capital Expenditures

Deferred, Modified and Advanced Capital Expenditures

The Provisional Guidelines require an explanation of capital expenditures planned for the year but were modified, re-prioritized or deferred until a future year. The Provisional Guidelines also require an explanation of which capital expenditures are proposed for the year after having been deferred in a previous year.

Table B-1 lists the capital expenditures proposed for 2025 that were deferred from previous years or modified through the Company's capital planning process.

Table B-1
2025 Capital Expenditures Deferred or Modified from Previous Years

Project	Description
VHF Radio System Replacement	The Company's VHF radio system will be obsolete in 2025. The replacement of the system was originally planned for 2022.[1] The project was deferred to 2025 to allow further assessment of alternatives. The assessment has now been completed and the project is proposed for 2025.
Mobile Hydro Plant Penstock Refurbishment	The penstock at the Mobile hydro plant requires refurbishment to address its deteriorated condition. The project was originally planned for 2024 and was deferred for further engineering assessment. The assessment has been completed and the project is proposed for 2025.
Asset Management Technology Replacement	Replacement of the Company's existing asset management system was originally planned for inclusion in the 2024 *System Upgrades* project. The project was deferred to align with the end of vendor support as of December 31, 2026 and the timing on the Company's ongoing asset management review. The project is now proposed as a multiyear project for 2025 and 2026.
Lockston Substation Refurbishment and Modernization	Lockston Substation on the Bonavista Peninsula requires refurbishment and modernization to replace and upgrade deteriorated equipment. The project was originally planned for 2024 and was deferred to allow for further engineering assessment. The assessments are now complete and the project is planned for 2025.

1 The five-year capital plan filed with the *2020 Capital Budget Application* included the replacement of the VHF radio system in 2022.

Table B-2 lists the capital expenditures that were planned for 2025 but have been deferred to subsequent years.

Table B-2
Capital Projects Deferred from 2025 to Subsequent Years

Project	Description
Grand Falls 4160 V Conversion	The Grand Falls distribution system is nearing capacity, and the substation contains obsolete switchgear. The project was originally planned for 2025 and has been deferred to allow further engineering assessment of the distribution system and analysis of alternatives. The project is now planned for 2027.
Cape Broyle Hydro Plant Refurbishment	The Cape Broyle Hydro Plant requires refurbishment to replace deteriorated equipment. The project was originally planned for 2025 and 2026. The project has been deferred to allow further engineering assessment of the components in the plant. The project is now planned for 2026 and 2027.
Petty Harbour Substation Refurbishment and Modernization	The Petty Harbour Substation requires refurbishment and modernization to upgrade and replace deteriorated equipment. The project was originally planned for 2025, and has been deferred to allow further engineering assessment of components in the substation and assessment of alternatives for the 33 kV transmission system. The project is now planned for 2027 and 2028.
Rose Blanche Hydro Plant Refurbishment	The Rose Blanche Hydro Plant requires refurbishment to replace deteriorated equipment. This project was originally planned for 2025 and has been deferred to allow for further engineering assessment of components in the plant. The project is now planned for 2028.
Application Enhancements	*Application Enhancements* is an annual capital project to enhance software products that comprise Newfoundland Power's information systems. The project originally planned for 2025 included the re-design of the Company's customer billings. It has been deferred to allow for additional assessment of alternatives.

There are no capital expenditures that were planned for future years but have been advanced to 2025.

APPENDIX C:

Prioritized List of 2025 Capital Expenditures

Prioritized List of 2025 Capital Expenditures

Introduction

Part IV of Appendix A of the Provisional Guidelines requires that capital budget applications include a prioritized list of proposed projects and programs. The Provisional Guidelines stipulate that the prioritized list should be organized by investment classification as:

- Mandatory;
- Access;
- System Growth; or
- Renewal, Service Enhancement and General Plant.

The Provisional Guidelines direct that investments in the Renewal, Service Enhancement and General Plant classifications be ordered by risk mitigated per dollar spent and reliability improvement per dollar spent, and that previously approved multi-year projects within these investment classifications be at the top of the list without those values.

Newfoundland Power does not currently have the software or data necessary to calculate the risk mitigation or reliability improvement values of capital expenditures. Options to derive such values are among the matters being assessed by the Company as part of its ongoing asset management review.[1]

To comply with the spirit and intent of the Provisional Guidelines, Newfoundland Power conducted a review of Canadian utility practice to assess alternative options to evaluate risks in a manner that could produce a list identifying the relative priority of capital expenditures. The review determined that practices for assessing risks vary among utilities.

Following this review, a risk matrix methodology was developed. The risk matrix methodology is designed to assess the risks of not proceeding with capital expenditures identified in the Renewal, Service Enhancement and General Plant investment classifications. The methodology is consistent with Newfoundland Power's long-term approach to assessing risks and provides reasonable consistency in communicating the results of those assessments across asset classes. This, in turn, allows capital expenditures to be presented in the form of a prioritized list with the level of priority based on the degree of risk mitigation provided.

The risk matrix methodology and prioritized list of capital expenditures for 2025 are provided below. The Company expects its approach may evolve going forward as its asset management review is completed.

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[1] Producing quantifiable risk and reliability values to prioritize capital expenditures would require the use of more advanced software. Newfoundland Power commenced an asset management review in 2022. Newfoundland Power has included an update on the progress of the Asset Management Review as Appendix B to the *2025-2029 Capital Plan*. The methodologies used by other utilities to assess risk include: (i) determining risk based on engineering judgment; (ii) using weighted formulas that apply risk-related criteria; (iii) risk matrices that assess probability and consequence; and (iv) advanced software, such as the CopperLeaf Portfolio.

Risk Matrix Methodology

The risk matrix is used to evaluate: (i) the potential consequences of not completing an identified project or program; and (ii) the probability of those consequences occurring if the project or program did not proceed.

Figure C-1 shows the risk matrix.

Probability Values		Priority Score				
Near Certain	5	5	10	15	20	25
Likely	4	4	8	12	16	20
Possible	3	3	6	9	12	15
Unlikely	2	2	4	6	8	10
Rare	1	1	2	3	4	5
		1 Negligible	2 Minor	3 Moderate	4 Serious	5 Critical
		Consequence Values				

Figure C-1 - Risk Matrix

Using the risk matrix, capital projects and programs can receive a score of 1 to 25 based on the assessment of probability and consequence. Values of 1 to 4 are considered Low priority (shaded in green). Values of 5 to 9 are considered Medium priority (shaded in yellow). Values of 10 to 16 are considered Medium-High priority (shaded in orange). Values of 20 or 25 are considered High priority (shaded in red).

The assessment of consequences considered risks to four principal business objectives:

- *Reliability –* Maintain long-term reliable service.
- *Safety –* Protect safety of employees and the public.
- *Environment –* Avoid environmental degradation.
- *Economic –* Advance operational efficiency and effectiveness.

These business objectives are consistent with Newfoundland Power's statutory obligations.[2] A capital project or program may be of consequence to one or more of these business objectives. Once the relevant consequences are identified, values are determined for the severity of these consequences based on guidelines that rely on a combination of quantifiable factors and engineering judgment.

Table C-1 provides the guidelines used in assigning consequence values.

Table C-1
Guidelines for Determining Consequence Values

Consequence	Factors	Other Considerations
Reliability	Number of customers affected by potential outage: 1 – Less than 100 customers 2 – 100 to 500 customers 3 – 500 to 1,000 customers 4 – 1,000 to 5,000 customers 5 – Greater than 5,000 customers	Examples of other considerations include outage duration and frequency, resiliency to severe weather, system configuration (e.g. radial or looped), and the impact on operations of the loss of a technology or piece of equipment.
Safety	Severity of potential safety incident: 1 – First Aid 2 – One Medical Aid 3 – Multiple Medical Aids 4 – Lost Time/Restricted Work 5 – Fatality/Permanent Disability	Examples of other considerations include regulatory compliance (e.g. Occupational Health and Safety Regulations), public safety and cybersecurity.
Environment	Severity of potential environmental incident: 1 – Immaterial Impact 2 – Internal Impact Only 3 – Isolated Off-Site Impact 4 – Widespread Off-Site Impact 5 – Regulatory Requirement Breached	Examples of other considerations include potential impact on local wildlife and biodiversity.
Economic	Overall customer benefit: 1 – Immaterial NPV 2 – \$10,000 to \$100,000 NPV 3 – \$100,000 to \$500,000 NPV 4 – \$500,000 to \$1,000,000 NPV 5 – Greater than \$1,000,000 NPV	Examples of other considerations include annual operating cost impacts, maintenance cost trends and the cost of emergency response.

[2] As outlined in section 2.1, Newfoundland Power is required to provide services and facilities that are reasonably safe and adequate and just and reasonable and to provide customers with reliable service at the lowest possible cost. The Company must also comply with various other provincial and federal regulations, as well as industry standards including environmental, health and safety regulations.

Probability is assessed from the perspective of how likely the identified consequence is to occur if a capital project or program did not proceed.

Probability is based on engineering judgement using a scale of 0% to 100% as follows:

- *Near Certain (5)* – Probable within a range of 91% to 100%.
- *Likely (4)* – Probable within a range of 76% to 90%.
- *Possible (3)* – Probable within a range of 26% to 75%.
- *Unlikely (2)* – Probable within a range of 11% to 25%.
- *Rare (1)* – Probable within a range of 0% to 10%.

For Renewal and General Plant expenditures, the probability value is determined primarily based on asset condition. This includes the level of deterioration identified, obsolescence and other deficiencies. Assessments of probability also consider previous operating experience, including any history of equipment failure, and whether an asset has exceeded its expected useful service life.

For Service Enhancement expenditures, the probability value is determined based on whether the benefit is quantifiable through an economic analysis or can reasonably be expected based on past experience. Potential risks to achieving the benefit are considered in assessing probability, including the results of any associated sensitivity analyses.

Prioritized List of 2025 Capital Expenditures

Table C-2 provides the prioritized list of 2025 capital expenditures in excess of $750,000 by investment classification. In accordance with the Provisional Guidelines, the list is organized by investment classification with previously approved multi-year projects at the top. See Schedule B to the Application for an explanation of the priority scores assigned to each capital project and program in the Renewal, Service Enhancement and General Plant investment classifications.[3]

Table C-2
Prioritized List of 2025 Capital Expenditures

Project/Program Name	Priority Score
Previously Approved Multi-Year Projects	
Islington Substation Refurbishment and Modernization	-
Transmission Line 146L Rebuild	-
Lookout Brook Hydro Plant Refurbishment	-
Gander Building Renovation	-
Microsoft Enterprise Agreement	-
Replace Vehicles and Aerial Devices 2024-2025	-
Mandatory	
General Expenses Capitalized	-
Allowance for Unforeseen Items	-
Access	
Extensions	-
New Transformers	-
New Services	-
New Street Lighting	-
Relocate/Replace Distribution Lines for Third Parties	-
System Growth	
Feeder Additions for Load Growth	-
Renewal, Service Enhancement, General Plant	
Transmission Line Maintenance	25
Reconstruction	25
Substation Replacements Due to In-Service Failures	25
Mount Carmel Pond Dam Refurbishment	20

3 An explanation of the priority score for each capital project and program within the Renewal, Service Enhancement and General Plant investment classifications can be found in the "Risk Assessment" sections of Schedule B to the Application.

Table C-2
Prioritized List of 2025 Capital Expenditures

Project/Program Name	Priority Score
LED Street Lighting Replacement	20
Distribution Feeder Automation	20
Transmission Line 94L Rebuild	20
Distribution Feeders SCT-01 and BLK-01 Relocation	20
New Transmission Line from Lewisporte to Boyd's Cove	20
Rebuild Distribution Lines	20
Cybersecurity Upgrades	20
Shared Server Infrastructure	20
Replacement Transformers	20
Summerville Substation Refurbishment and Modernization	16
Pulpit Rock Substation Power Transformer Replacement	16
Lockston Substation Refurbishment and Modernization	16
Northwest Brook Substation Refurbishment and Modernization	16
Gander Substation Power Transfer Replacement	16
Outage Management System Upgrade	16
Replace Commercial Vehicles and Aerial Devices 2025-2026	16
System Upgrades	16
Asset Management Technology Replacement	16
VHF Radio System Replacement	15
Replacement Street Lighting	15
Mobile Hydro Plant Penstock Refurbishment	15
Application Enhancements	15
Port Union Building Replacement	12

APPENDIX D:

List of Worst Performing Feeders

List of Worst Performing Feeders

The Board's Provisional Guidelines require the utility to provide a list of it's 10 worst performing feeders, including relevant outage statistics compared to the utility average for the past 10 years. The Provisional Guidelines require the list be provided with and without major events.

Newfoundland Power completes an annual assessment of its worst performing feeders as part of its *Distribution Reliability Initiative.* Each distribution feeder is assessed based on its performance over the most recent five-year period. This timeframe is consistent with standard utility practice, as assessments of worst performing feeders typically use three to seven-year time horizons.

The Company's assessment excludes planned outages and outages due to loss of supply and major events. This is consistent with standard industry practice as major events are typically driven by severe weather rather than the condition of the electrical system and are outside of the utility's control.[1] For this reason, Newfoundland Power does not rank the reliability performance of its over 300 distribution feeders including major events.

Newfoundland Power's annual assessment of its worst performing feeders applies five performance measures: (i) customer minutes of interruption; (ii) distribution System Average Interruption Frequency Index ("SAIFI"); (iii) distribution System Average Interruption Duration Index ("SAIDI"); (iv) distribution Customer Hours of Interruption per Kilometre ("CHIKM"); and (v) distribution Customers Interrupted per Kilometre ("CIKM").

For the purposes of compliance with the Provisional Guidelines, Tables D-1 through D-5 on the following pages provide the Company's worst performing feeders based on a 10-year average using the five reliability metrics applied as part of the *Distribution Reliability Initiative.*
Tables D-1 through D-5 do not include outages related to major events as the Company has not historically tracked the performance of its distribution feeders according to this data.

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1 For example, Electricity Canada states: "*While performing an analysis of feeder outages, it is highly recommended that specific outages related to events outside of the utility's control be excluded. Standard practice is to exclude outages due to loss of supply, as well as scheduled events. Most Prominent Events are also excluded, as these are events outside the utility's control and significantly impact utility performance measures.*" See *Worst Performing Feeders, Service Continuity Committee: A New Measures Working Group Whitepaper.*

Table D-1 Unscheduled Distribution-Related Outages 10-Year Average (2014-2023) Sorted by Customer Minutes of Interruption				
Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
SUM-01	7,364	915,240	4.06	8.41
BVS-04	4,381	545,616	2.73	5.66
GLV-02	6,279	544,919	4.10	5.93
DOY-01	5,488	541,249	3.14	5.15
DUN-01	4,609	507,649	4.42	8.15
DLK-03	4,000	474,491	2.82	5.63
SCR-01	2,559	412,056	2.65	7.11
BOT-01	3,296	399,842	1.92	3.89
ROB-01	2,072	398,620	1.92	6.15
BLK-01	4,316	367,852	2.58	3.68
Company Average	1,179	92,523	1.51	1.88

Table D-2 Unscheduled Distribution-Related Outages 10-Year Average (2014-2023) Sorted by Distribution SAIFI				
Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
LGL-02	1,775	159,414	53.23	25.01
SJM-10	120	1,851	17.70	0.54
SJM-11	7,953	243,160	5.47	2.81
BHD-01	4,967	322,804	5.25	5.67
SCT-01	3,483	215,172	4.83	4.91
SCT-02	1,154	105,599	4.50	6.85
DUN-01	4,609	507,649	4.42	8.15
GLV-02	6,279	544,919	4.10	5.93
SUM-01	7,364	915,240	4.06	8.41
TWG-03	1,176	49,983	4.00	2.73
Company Average	1,179	92,523	1.51	1.88

Table D-3 Unscheduled Distribution-Related Outages 10-Year Average (2014-2023) Sorted by Distribution SAIDI				
Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
LGL-02	1,775	159,414	53.23	25.01
SBK-01	4	2,442	1.67	17.37
SUM-02	1,832	316,610	3.02	8.68
SUM-01	7,364	915,240	4.06	8.41
DUN-01	4,609	507,649	4.42	8.15
ROB-02	392	96,168	1.93	7.85
SCR-01	2,559	412,056	2.65	7.11
BUC-02	382	66,136	2.39	6.91
SCT-02	1,154	105,599	4.50	6.85
NCH-03	4	537	3.32	6.33
Company Average	1,179	92,523	1.51	1.88

Table D-4
Unscheduled Distribution-Related Outages
10-Year Average
(2014-2023)
Sorted by Distribution CHIKM

Feeder	Annual Distribution CHIKM
KBR-10	242
WAV-03	236
SJM-06	233
SLA-13	203
PAB-05	203
SJM-04	196
SLA-10	180
PEP-04	180
KBR-13	174
WAL-02	162
Company Average	54

Table D-5 Unscheduled Distribution-Related Outages 10-Year Average (2014-2023) Sorted by Distribution CIKM	
Feeder	Annual Distribution CIKM
SJM-04	263
SJM-11	246
KBR-10	215
WAL-05	179
KEN-01	178
PAB-03	176
SLA-10	175
PEP-01	175
PAB-05	159
KEN-03	154
Company Average	45

APPENDIX E:

Previously Approved Multi-Year Projects

Previously Approved Multi-Year Projects

The Board's Provisional Guidelines require that each year of a multi-year capital project be considered in the initial year of application. The Provisional Guidelines stipulate that, where a utility confirms in its capital budget application in subsequent years that the scope, nature and magnitude of the project continues to be consistent with the original approval, further approval of the project is not required.

The 2025 Capital Budget includes six capital projects that were previously approved by the Board. Capital expenditures for these project total approximately $19,414,000 in 2025.

The following section provides an update on each multi-year project for 2025 that was previously approved by the Board. Newfoundland Power confirms that all projects are proceeding as approved and there has been no change in the scope, nature or magnitude of these projects that would require further approval of the Board.

Title: **Transmission Line 146L Rebuild**
Asset Class: **Transmission**
Category: **Project**
Investment Classification: **Renewal**
2025 Expenditures: **$9,209,000**

The *Transmission Line 146L Rebuild* project was included as a multi-year project in Newfoundland Power's *2024 Capital Budget Application*.[1] Transmission Line 146L plays a critical role in the Central Newfoundland 138 kV transmission system. An outage to Transmission Line 146L results in two sections of the Central Newfoundland 138 kV transmission system becoming radial. When these sections are radially supplied, any single failure on one of these transmission lines could result in outages to between 1,700 and 8,700 customers downstream of the affected line.

The Board approved the *Transmission Line 146L Rebuild* project as a two-year project in Order No. P.U. 2 (2024). The project is proceeding as approved. Engineering and pre-construction activities, including securing permits ad approval, acquiring property rights, completing brush clearing of the new right-of-way, collecting survey data and completion of the engineering design are being completed in 2024. Construction of the new line is to begin in the second quarter of 2025.

Table E-1 provides the approved expenditures for the *Transmission Line 146L Rebuild Project.*

Table E-1
Transmission Line 146L Rebuild
Multi-Year Expenditures
($000s)

Cost Category	2024F	2025F	Total
Material		3,884	3,884
Labour – Internal	-	167	167
Labour – Contract	-	4,645	4,645
Engineering	161	173	334
Other	1,991	340	2,331
Total	$2,152	$9,209	$11,361

Expenditures for the *Transmission Line 146L Rebuild project* total approximately $11,361,000, including $9,209,000 in 2025. For expenditures incurred to date, see the *2024 Capital Expenditure Status Report* filed with the Application.

[1] See Newfoundland Power's *2024 Capital Budget Application,* report *3.1 Transmission Line Rebuild*.

Title: **Islington Substation Refurbishment and Modernization**
Asset Class: **Substations**
Category: **Project**
Investment Classification: **Renewal**
2025 Expenditures: **$4,706,000**

The *Islington Substation Refurbishment and Modernization* project was included as a multi-year project in Newfoundland Power's *2024 Capital Budget Application*.[2] Islington Substation ("ISL") provides service to approximately 1,100 customers in the Islington area. There are also approximately 1,800 customers served by the New Harbour ("NHR") Substation that are affected by faults at ISL Substation as they rely on the same transmission line.

The Board approved the *Islington Substation Refurbishment and Modernization* as a two-year project in Order No. P.U. 2 (2024). The project is proceeding as approved. Engineering design and procurement of replacement components is being completed in 2024, with construction to begin in the second quarter of 2025.

Table E-2 provides the approved expenditures for the *Islington Substation Refurbishment and Modernization* project.

Table E-2
Islington Substation Refurbishment and Modernization Project
Multi-Year Expenditures
($000s)

Cost Category	2024F	2025F	Total
Material	60	3,620	3,680
Labour – Internal	-	193	193
Labour – Contract	-	-	-
Engineering	241	350	591
Other	7	543	550
Total	$308	$4,706	$5,014

Expenditures for the *Islington Substation Refurbishment and Modernization* project total approximately $5,014,000, including $4,706,000 in 2025. For expenditures incurred to date, see the *2024 Capital Expenditure Status Report* filed with the Application.

2 See Newfoundland Power's *2024 Capital Budget Application,* report *2.1 2024 Substation Refurbishment and Modernization*.

Title: **Replace Vehicles and Aerial Devices 2024-2025**
Asset Class: **Transportation**
Category: **Project**
Investment Classification: **General Plant**
2025 Expenditures: **$2,869,000**

The *Replace Vehicles and Aerial Devices 2024-2025* project was included as a multi-year project in Newfoundland Power's *2024 Capital Budget Application.*[3]

The *Replace Vehicles and Aerial Devices 2024-2025* project involves the addition and replacement of heavy/medium-duty, light-duty, passenger and off-road vehicles. In 2022, due to long delivery times associated with the purchase of medium/heavy-duty vehicles, the Company shifted to a multi-year project for vehicle purchases.

The Board approved the *Replace Vehicles and Aerial Devices 2024-2025* project as a two-year project in Order No. P.U. 2 (2024). The project is proceeding as approved. Newfoundland Power identified 25 passenger vehicles and one light duty vehicles for replacement in 2024 and six heavy/medium duty vehicles for replacement in 2025.

Table E-3 provides the approved expenditures for the *Replace Vehicles and Aerial Devices 2024-2025* project.

Table E-3
Replace Vehicles and Aerial Devices 2024-2025
Multi-Year Expenditures
($000s)

Cost Category	2024F	2025F	Total
Material	1,803	2,869	4,672
Labour – Internal	137	-	137
Labour – Contract	-	-	-
Engineering	-	-	-
Other	-	-	-
Total	$1,940	$2,869	$4,809

Expenditures for the *Replace Vehicles and Aerial Devices 2024-2025* project total approximately $4,809,000 with $2,869,000 for 2025. For expenditures incurred to date, see the *2024 Capital Expenditure Status Report* filed with the Application.

[3] See Newfoundland Power's *2024 Capital Budget Application, Schedule B,* pages 131-135.

Title: **Lookout Brook Hydro Plant Refurbishment**
Asset Class: **Generation - Hydro**
Category: **Project**
Investment Classification: **Renewal**
2025 Expenditures: **$1,573,000**

The *Lookout Brook Hydro Plant Refurbishment* project was included as a multi-year project in Newfoundland Power's *2024 Capital Budget Application*.[4]

The *Lookout Brook Hydro Plant Refurbishment* project involves rewinding the Plant generating unit no. 3 ("G3") generator stator, rotor, and exciter. Additionally, the Plant roof, crane and G3 main inlet valve will be replaced.

The Board approved the *Lookout Brook Hydro Plant Refurbishment* project as a two-year project in Order No. P.U. 2 (2024). The project is proceeding as approved.

Table E-4 provides the approved expenditures for the *Lookout Brook Hydro Plant Refurbishment* project.

Table E-4
Lookout Brook Hydro Plant Refurbishment
Multi-Year Expenditures
($000s)

Cost Category	2024F	2025F	Total
Material	184	1,083	1,267
Labour – Internal	64	127	191
Labour – Contract	-	-	-
Engineering	30	60	90
Other	84	303	387
Total	$362	$1,573	$1,935

Expenditures for the *Lookout Brook Hydro Plant Refurbishment* project total approximately $1,935,000 with $1,573,000 for 2025. For expenditures incurred to date, see the *2024 Capital Expenditure Status Report* filed with the Application.

4 See Newfoundland Power's *2024 Capital Budget Application,* report *4.1 2024 Lookout Brook Hydro Plant Refurbishment*.

Title: **Gander Building Renovations**
Asset Class: **General Property**
Category: **Project**
Investment Classification: **General Plant**
2025 Expenditures: **$760,000**

The *Gander Building Renovation* project was included with Newfoundland Power's *2024 Capital Budget Application*.[5] An engineering assessment determined roofing and cladding system failure, deficiencies in the building ventilation and air conditioning, asbestos plaster to be replaced with drywall and light fixtures to be changed to light emitting diode ("LED") for improved energy efficiency.

The Board approved the *Gander Building Renovation* project as a two-year project in Order No. P.U. 2 (2024). The *Gander Building Renovation* project is proceeding as approved.

Table E-5 provides the approved expenditures for the *Gander Building Renovation* project.

Table E-5
Gander Building Renovations
Multi-Year Expenditures
($000s)

Cost Category	2024F	2025F	Total
Material	116	531	647
Labour – Internal	2	8	10
Labour – Contract	-	-	-
Engineering	42	105	147
Other	15	116	131
Total	$175	$760	$935

Expenditures for the *Gander Building Renovation* project total approximately $935,000, including $760,000 in 2025. For expenditures incurred to date, see the *2024 Capital Expenditure Status Report* filed with the Application.

[5] See Newfoundland Power's *2024 Capital Budget Application, Schedule B,* pages 125-129.

Title: **Microsoft Enterprise Agreement**
Asset Class: **Information's Systems**
Category: **Project**
Investment Classification: **General Plant**
2025 Expenditures: **$297,000**

The *Microsoft Enterprise Agreement* covers the purchase of Microsoft software products and provides access to the latest versions of each of software product purchased under this agreement at the lowest cost.

The annual agreement is a fixed price based on the number of eligible employees that use Microsoft software products on Company-assigned personal computers. In 2024, a three-year agreement will be entered into to renew the Microsoft Enterprise Agreement. Under this agreement, the Company will continue to distribute its purchasing costs for these licenses over three years.

The Board approved the *Microsoft Enterprise Agreement* as a three-year project in Order No. P.U. 2 (2024).[6] Table E-6 provides the approved expenditures for the *Microsoft Enterprise Agreement.*

Table E-6
Microsoft Enterprise Agreement
Multi-Year Expenditures
($000s)

Cost Category	2024F	2025F	2026F	Total
Material	297	297	297	891
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	$297	$297	$297	$891

6 See Newfoundland Power's *2024 Capital Budget Application, Schedule B,* pages 121-123.

Expenditures for the *Microsoft Enterprise Agreement* total approximately $891,000 with $297,000 for 2025. For expenditures incurred to date, see the *2024 Capital Expenditure Status Report* filed with the Application.[7]

[7] Newfoundland Power licenses its Microsoft Technology through the use of an Enterprise Agreement. These agreements are normally three years in duration with the current agreement spanning June 2024 to May 2027. The current agreement is approximately $297k per year for a total cost of $891k for the three-year term. Negotiation for the next agreement will occur at least six months prior to the expiration of the current agreement. The next agreement will be valid from June 2027 to May 2030. Newfoundland Power is anticipating an approximate 10% increase in license costs for the Enterprise Agreement for the next renewal period. The next agreement is estimated at approximately $330k per year for a total cost of $990k for the term. These costs are reflected starting in 2027 in the *2025-2029 Capital Plan*.

NEWFOUNDLAND POWER
A FORTIS COMPANY

2025 - 2029 Capital Plan

June 2024

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1.0 PLAN OVERVIEW

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") prepares a five-year capital plan to provide reasonable visibility of future investment priorities. The capital plan incorporates the best available information on future customer, operational and electrical system requirements. All planned investments undergo detailed engineering reviews prior to being submitted for approval to the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board").

The Company's current capital plan forecasts average annual investments of approximately $163 million from 2025 to 2029. This level of investment is expected to be required to continue providing customers with access to safe and reliable service at the lowest possible cost.

Newfoundland Power's operations are focused on maintaining current levels of overall service reliability for customers. While the Company is targeting stability in its reliability performance, the age of its electrical system poses an increasing risk to this objective. The risk of equipment failure is expected to increase as many assets approach or exceed the end of their expected useful service lives, including substation power transformers, distribution and transmission wooden support structures and overhead conductor.

Newfoundland Power is currently undertaking a review of its asset management practices. Through this review, the Company is aiming to ensure the next generation of its asset management technology can effectively meet future requirements. Newfoundland Power has provided an update on its asset management review.

Newfoundland Power's investment priorities over the next five years reflect an increased focus on the planned refurbishment of assets to extend their useful service lives and the replacement of assets that become deteriorated or fail in service. The refurbishment and replacement of existing assets is forecast to account for an average of approximately $98 million of annual capital expenditures from 2025 to 2029, or 60% of total annual expenditures.

The Company is forecasting the replacement of thermal generation units at Greenhill, Wesleyville, and the start of engineering to replace the thermal generation units in Port aux Basques over the next five years. These units have been in service approximately 50 years and have reached the end of their useful service lives. The replacement of these units is forecast to account for approximately $96 million from 2027 to 2029.

The Company's investment priorities over the forecast period reflect a relatively stable level of investment required to connect new customers and respond to system growth. While customer connections are forecast to decline over the next five years, system load growth driven by residential development in urban areas, electrification of heating systems, and electric vehicle adoption is forecast to offset this decline. Responding to customer and system growth is forecast to account for an average of approximately $32 million of annual capital expenditures from 2025 to 2029, or 20% of total annual expenditures.

2.0 PLANNING CONTEXT

2.1 General

Newfoundland Power's investment priorities and five-year capital plan reflect the capital expenditures necessary to meet its statutory obligations under the *Public Utilities Act* and *Electrical Power Control Act, 1994*. The capital plan is updated annually with the latest forecasts of customer and system load growth, anticipated operational requirements and electrical system condition. This section provides an overview of forecast requirements in these areas, which form the basis of the Company's investment priorities over the next five years.

2.2 Customer Outlook

Newfoundland Power has an obligation to provide customers with equitable access to an adequate supply of power.[1] Capital investments are required annually to connect new customers to the electrical system and to respond to increases in electrical system load.

The Company has experienced declining requests for new service connections in recent years due to a decrease in new home construction throughout its service territory. At the same time, system load growth has been concentrated in urban areas.[2] These trends are expected to continue.

Table 1 provides the forecast number of new customer connections from 2025 to 2029.

Table 1
Forecast New Customer Connections
(2025F-2029F)

	2025F	2026F	2027F	2028F	2029F
New Customer Connections	2,220	2,120	2,022	1,919	1,769

New customer connections are forecast to decline from 2,220 in 2025 to 1,769 in 2029. Approximately 39% of new customer connections over the next five years are forecast to occur in the province's largest urban centre, the Northeast Avalon.

System load growth is expected to continue to be driven by residential development in urban areas, government plans to electrify heating systems in provincial buildings, and residential electrification of heating systems.[3] Efforts to electrify provincial buildings and other

1 See section 3(b)(ii) of the *Electrical Power Control Act, 1994.*
2 For example, of 19 *Feeder Additions for Load Growth* projects completed over the last five years, 16 projects have been on the Avalon Peninsula, including 13 on the Northeast Avalon.
3 Transformer capacity additions at Kelligrews and Hardwoods substations are forecast to be required to respond to load growth on the Northeast Avalon.

electrification opportunities are expected to be pursued as part of the Provincial Government's *Renewable Energy Plan*.[4] In 2023 the Provincial Government and Federal Government jointly announced the expansion of a rebate program to support approximately 10,000 homeowners to transition their homes from oil heat to electric heat.[5]

System load growth is also expected to be affected by electric vehicle ("EV") adoption over the forecast period. Newfoundland Power has designed an *EV Load Management Pilot Project* to study options for managing the impact of EVs on peak demand.[6]

Over the longer term, increased peak demand due to EV adoption may result in dynamic rate structures becoming cost-effective for customers. A 2019 market potential study completed by Dunsky Energy Consulting determined that dynamic rates may become cost-effective for customers between 2030 and 2034.[7] Dynamic rate structures will take several years to implement and require investments in Advanced Metering Infrastructure ("AMI").[8] The Company continues to assess the costs and benefits of AMI. Ongoing reviews such as rate design, load research and a Conservation and Demand Management potential study will help inform the business case for AMI technology in the future.

Should customer connections and system load growth vary from forecast, the capital investments required to accommodate this growth will also vary.

2.3 Operations Outlook

Newfoundland Power has an obligation to provide reliable service to its customers at the lowest possible cost. Providing customers with reliable service requires capital investments to maintain the condition of the electrical system and the Company's operational response capabilities when outages occur.

Customers have indicated a reasonable level of satisfaction with Newfoundland Power's service delivery over the last decade.[9] The Company's operations are focused on maintaining current levels of overall service reliability for customers. Annual performance targets for service reliability are established based on the Company's performance over the most recent five-year period, excluding major events.

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4 See the Provincial Government's *Renewable Energy Plan,* section *1.4 Electrify Transport and Space-Heating*.

5 In a news release dated March 13, 2023, the Provincial and Federal Governments announced the new multi-year program to expand their collective efforts for residential home heating rebates. The initiative will assist residents looking to switch from oil furnaces to electricity heating technologies. This program is forecast to continue until at least 2026.

6 The *EV Load Management Pilot Project* was approved by the Board in Order No. P.U. 23 (2023).

7 See *Schedule E – Potential Study Addendum: Demand Response Assessment* filed as part of the *Electrification, Conservation and Demand Management Plan: 2021-2025*.

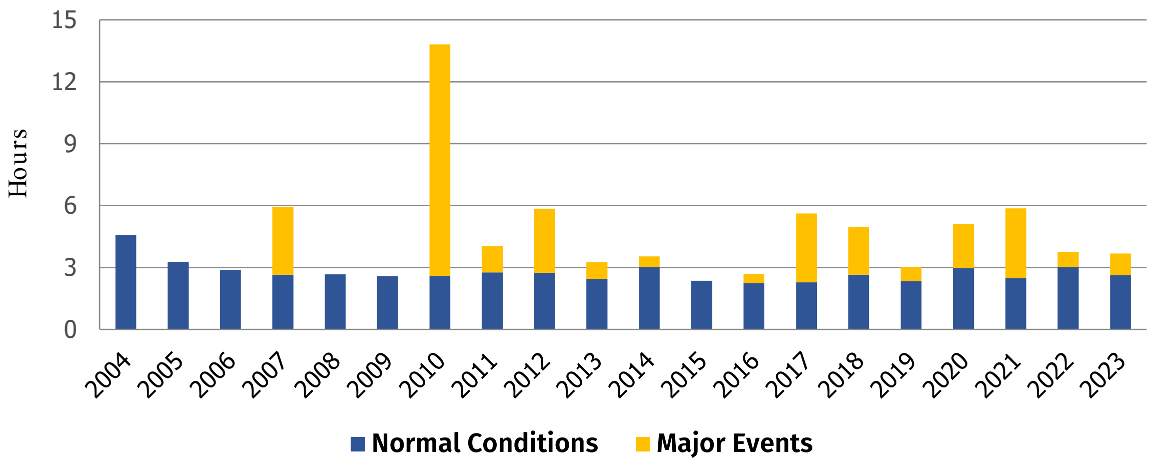
8 For example, Newfoundland Power's deployment of Automated Meter Reading technology required over five years to implement. The deployment of AMI would be more substantial as, in addition to replacing existing meters, the Company would be required to implement new communications infrastructure, a meter data management system, and new customer rate structures.

9 Overall customer satisfaction with Newfoundland Power's service averaged 86% from 2014 to 2023. Customer satisfaction averaged 93% when customers were surveyed about their direct interactions with field staff, including technologists and field service representatives.

For 2025, Newfoundland Power is focusing on maintaining current levels of reliability for customers. Annual performance targets over the ensuing five years are expected to be reasonably consistent with current targets, but may vary depending on actual results over this period.

Figure 1 shows the average duration of outages experienced by Newfoundland Power's customers from 2004 to 2023 including major events.[10]

Figure 1
Newfoundland Power
Outage Duration Including Major Events
(2004 to 2023)



Major customer outages due to severe weather have become more frequent in the Company's service territory, causing customer outages in nine of the last ten years compared to just five years in the prior decade.

While the Company aims to maintain a consistent level of service reliability for customers, severe weather events can have a significant impact on the service provided to customers. Such events exceed the design parameters of the electrical system and may result in widespread damage and extended customer outages. Recent examples include a severe blizzard in January 2020 and Hurricane Fiona in September 2022.[11] Restoring service to

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10 Major events generally affect the duration of outages more than the frequency of outages. For example, a hurricane may result in a single outage that lasts several days. From 2004 to 2023, major events have resulted in an average SAIFI of 0.3, ranging as high as an average SAIFI of 1.2 in 2010.

11 Hurricane Fiona in September 2022 resulted in wind gusts in excess of 170 kilometres per hour. Over a three-day period, Newfoundland Power experienced island wide outages resulting from extreme winds and storm surges associated with Hurricane Fiona. Newfoundland Power employees worked throughout the period to restore power to customers and address safety issues associated with damage caused by the storm. In particular, restoration efforts were impacted on the west coast of the island in the Wreckhouse area, where winds exceeded 120 kilometres per hour all day and into the late evening.

customers following such events typically requires a robust operational response as well as capital investments to repair damage to the electrical system.[12]

The amount of capital investment required to restore service to customers following severe weather is highly variable and presents a risk to Newfoundland Power's customers and its forecast expenditures.[13] This risk highlights the importance of ensuring the electrical system is resilient and designed to standards that reflect local climatic conditions, as well as the importance of maintaining effective emergency response capabilities through measures such as electrical system automation.[14]

The reliability of bulk electricity supply from Newfoundland and Labrador Hydro ("Hydro") also affects the reliability experienced by Newfoundland Power's customers. Hydro's *Reliability and Resource Adequacy Study – 2022 Update* recommends that the Holyrood Thermal Generating Station, as well as the Hardwoods Gas Turbine, remain available as backup generation in the event of a prolonged outage of the Labrador Island Link and until long-term supply sources have been reviewed, approved, and constructed.[15] These matters are currently under review as part of the Board's *Reliability and Resource Adequacy Study Review*.

Newfoundland Power's capital plan currently includes the replacement of thermal generation assets in Wesleyville, Greenhill and Port aux Basques. The Company plans to evaluate the benefits of continuing to operate generation units in these areas on the basis of long-term regional transmission reliability requirements and to support overall system reliability. The evaluation will be coordinated with Hydro to examine the impact that any generation addition or removal will have on Hydro's *Reliability and Resource Adequacy Study*.

Newfoundland Power's operations and capital investments must adapt to increasing cybersecurity risks. Cybersecurity risks have increased materially for critical infrastructure operators in recent years, including electric utilities. Newfoundland Power expects that more frequent upgrades of its operations technologies and computing hardware will be required going forward to manage increasing cybersecurity risks.

Market conditions following the global events like the pandemic and the war in Ukraine continue to pose a risk to Newfoundland Power's *2025-2029 Capital Plan*. Supply chain disruptions have contributed to reduced availability and extended delivery times for certain materials, including heavy-duty vehicles, conductors, meters and power transformers. Inflationary pressure on materials also increased following these global events. In response, the Company has increased

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12 For example, capital expenditures of approximately $7.5 million were required to restore service to customers in 2010 following a severe ice storm and Hurricane Igor. These expenditures were approved in Order Nos. P.U. 17 (2010) and P.U. 35 (2010).

13 The Federal Government has recognized the importance of adapting the Atlantic energy sector to climate change. The Federal Government states "Adaptation to climate change by the energy sector in the Atlantic provinces will require re-examination of design standards for transmission and distribution infrastructure, to enable it to better withstand extreme weather events." See *From Impacts to Adaptation: Canada in a Changing Climate 2007*, Government of Canada, page 154.

14 The principal design standard for distribution and transmission line design in Canada is the CSA standard C22.3 No.1-15, Overhead Systems. This standard recognizes four classifications of weather load conditions for ice accumulation, wind loading, and temperature. These are: (i) medium loading B; (ii) medium loading A; (iii) heavy; and (iv) severe. Newfoundland Power's service territory has heavy and severe loading classifications. Only two other provinces are identified as having severe weather loading areas. These are: (i) parts of northern and southern Manitoba; and (ii) rural parts of eastern Quebec, including the Gaspe Peninsula.

15 See Hydro's *Reliability and Resource Adequacy Study – 2022 Update,* October 3, 2022, page P.6.

its use of multi-year capital projects. This includes substation refurbishment and modernization projects where power transformer replacements are required and the procurement of heavy-duty fleet vehicles. The Company continues to monitor market conditions to assess potential impacts on its operations.

2.4 Asset Condition Outlook

2.4.1 General

Newfoundland Power's electrical system is maintained through a combination of preventative and corrective maintenance programs and long-term asset management strategies. The most recent independent review of Newfoundland Power's engineered operations was conducted by The Liberty Consulting Group in 2014. The review found that the Company's asset management conforms to good utility practice.[16]

A significant portion of Newfoundland Power's electrical system assets were constructed in the 1960s and 1970s following provincial electrification efforts in rural areas. As a result, a large quantity of assets with expected useful service lives of between 50 and 60 years, such as conductor and wooden support structures, are now aging beyond their expected useful service lives. While age is not the primary determinant as to whether an asset requires refurbishment or replacement, it provides a reasonable indication of the probability that an asset may begin to fail.

The effect of age on the condition of Newfoundland Power's electrical system can be observed through its recent experience with equipment failures. An average of approximately 1,100 equipment failures per year were experienced on the distribution system from 2019 to 2023, which represents a 6% increase compared to the previous five-year period.[17] The upward trend in equipment failures is primarily driven by overhead conductor, insulators and poles that have become deteriorated due to their age and exposure to climatic conditions.

Newfoundland Power is exposed to increasing risk of equipment failure going forward due to the age of its electrical system. As detailed below, significant portions of major equipment in the distribution, transmission and substation asset classes have exceeded or are approaching the end of their useful service lives.

Maintaining the safe and reliable operation of the electrical system will require increased investments in the planned refurbishment and replacement of electrical system assets. Newfoundland Power is undertaking a review of its asset management practices to ensure its practices continue to be adequate, given the age of its electrical system, and remain consistent with industry best practices.

Newfoundland Power commenced its asset management review in 2022 to guide the maturation of its asset management practices. The review included three phases: (i) a current

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[16] See The Liberty Consulting Group, *Executive Summary of Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power Inc.*, December 17, 2014, page ES-1.

[17] Includes failures of cutouts, primary conductor, insulators, poles, distribution transformers and other equipment. Does not include service wire failures, which are replaced upon failure and not inspected as part of Newfoundland Power's *Distribution Inspection and Maintenance Practices.*

state assessment; (ii) a target state assessment; and (iii) implementation planning. The current state assessment, which benchmarked the Company's asset management maturity against other utilities and clauses of ISO 55001,[18] was completed in March 2023. The target state assessment, which assess opportunities to advance Newfoundland Power's asset management maturity, and ensure practices continue to be adequate and align with sound utility practice, was completed in March 2024.

The final phase of the Company's asset management review, implementation planning, is ongoing. The implementation planning phase is intended to guide the execution of opportunities to inform the asset management journey. The Company is currently working on the development of an implementation plan, with expected completion by the end of 2024. The implementation plan will include a roadmap for strategic, operational, and data and technological initiatives. For additional details, see Appendix B.

2.4.2 Distribution

Newfoundland Power operates approximately 300 distribution feeders. Distribution feeders are inspected on a seven-year cycle to identify deficiencies. High-priority deficiencies are corrected during the year in which they are identified through the *Reconstruction* program. Other deficiencies are corrected in a planned manner in the following year through the *Rebuild Distribution Lines* program and individual refurbishment projects for feeders where deterioration is most pronounced.

The distribution system performance is addressed through the *Distribution Reliability Initiative*, which targets the worst performing feeders for capital investment.[19]

Newfoundland Power's distribution system includes approximately 232,000 wooden support structures and overhead conductor on approximately 9,500 kilometres of distribution line. Industry experience indicates an average expected useful service life of 54 years for distribution wooden support structures and 50 years for distribution overhead conductor.[20]

The risk of equipment failure on the Company's distribution system is currently high as large quantities of wooden support structures and overhead conductor have exceeded their expected useful service lives.

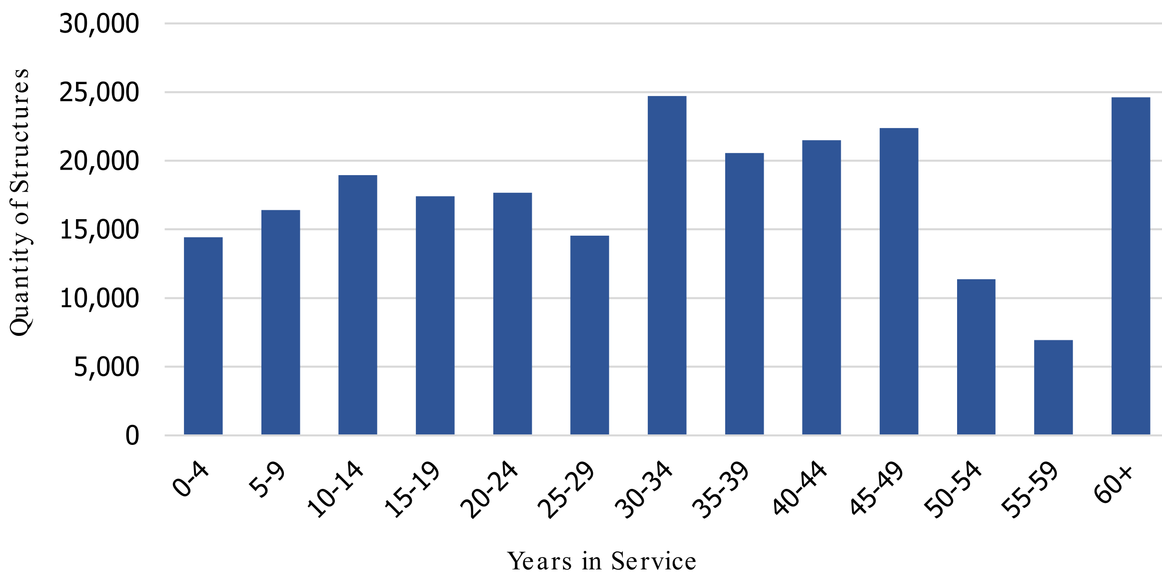
[18] ISO 55001 is an internationally recognized standard for asset management practices.

[19] The *Distribution Reliability Initiative* project has evolved in recent years to include isolated specific sections of feeders or neighbourhoods that are experiencing poor reliability performance. Additionally, the Outage Management System is capable of providing outage data with greater granularity and precision than was previously possible. This data is incorporated into the *Distribution Reliability Initiative* to permit a more targeted approach to required capital upgrades.

[20] The average industry expected useful service lives of distribution assets were derived from information filed with the Federal Energy Regulatory Commission ("FERC"). Electric utilities subject to FERC's jurisdiction are required to file a Form 1 report annually. Form 1 reports are publicly available and provide financial and operational information for electric utilities. A total of 38 utilities were included in the analysis.

Figure 2 provides the age distribution of wooden support structures on the Company's distribution system.

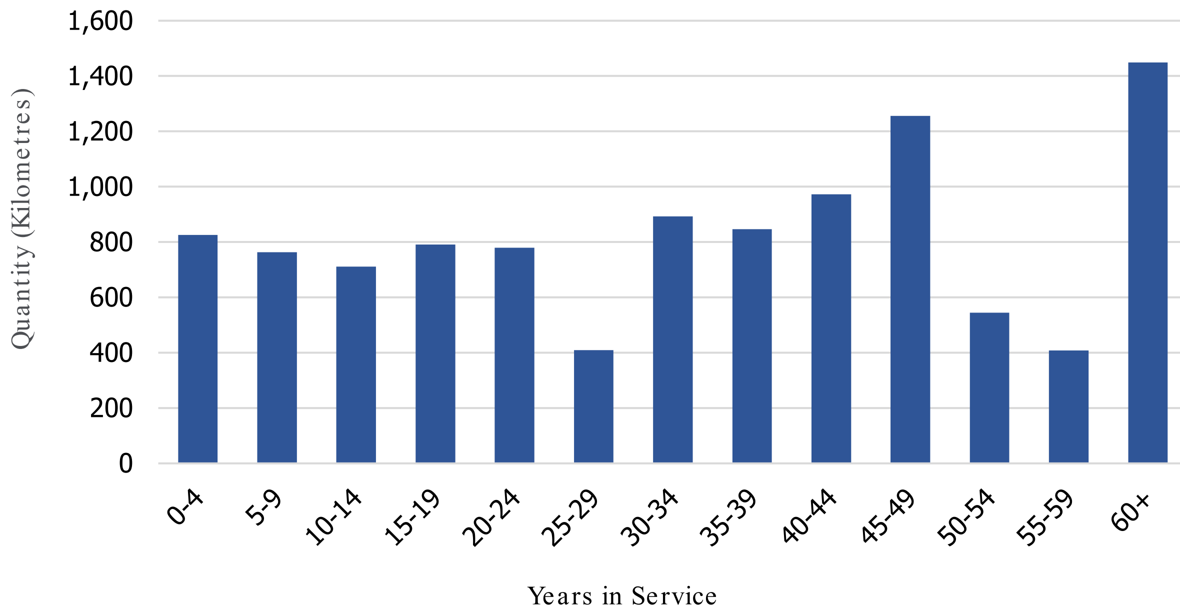
Figure 2
Distribution Wooden Support Structures
Asset Age



Approximately 14% of distribution wooden support structures have exceeded the average industry expected useful service life of 54 years. An additional 15% of distribution wooden support structures will reach 54 years in service over the next decade.

Figure 3 provides the age distribution of overhead conductor on the Company's distribution system.

Figure 3
Distribution Overhead Conductor
Asset Age



Approximately 23% of distribution overhead conductor has currently exceeded the average industry expected useful service life of 50 years. An additional 21% of distribution overhead conductor will reach 50 years in service within the next decade.

2.4.3 Transmission

Transmission lines are the backbone of the electricity system serving customers. Transmission lines are inspected annually to identify deficiencies. Deficiencies are prioritized for correction based on severity through the annual *Transmission Line Maintenance* program. The condition of the transmission system is also maintained through planned rebuild projects completed in accordance with the *Transmission Line Rebuild Strategy*, which targets the Company's oldest and most deteriorated transmission lines.

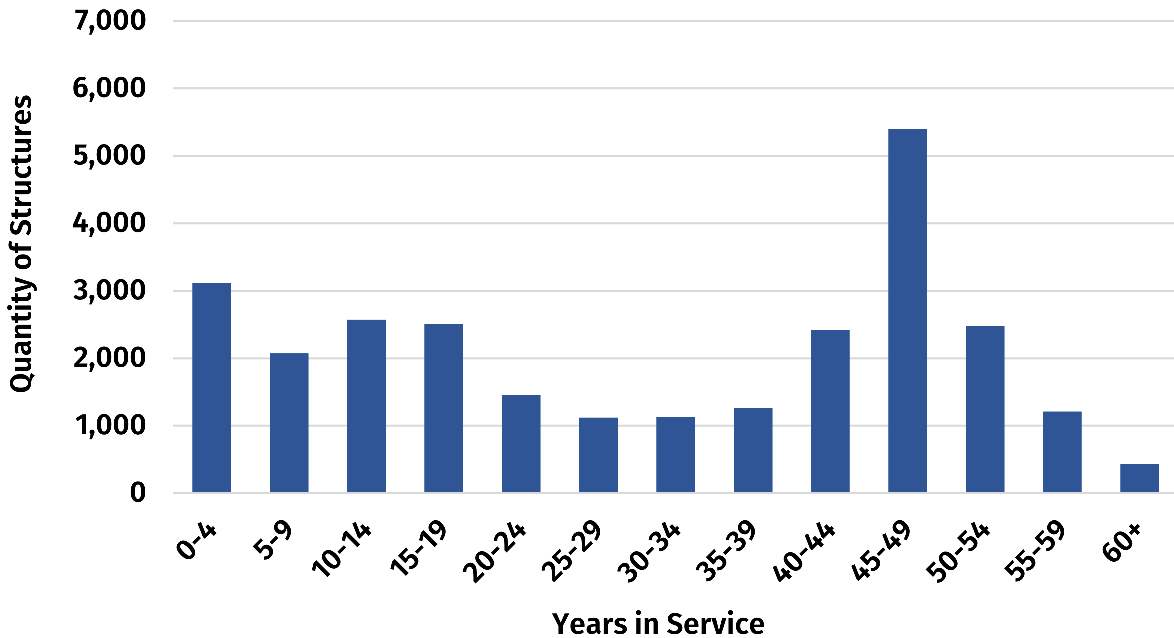
Newfoundland Power's transmission system includes approximately 27,000 wooden support structures and overhead conductor on approximately 2,000 kilometres of transmission line. Industry experience indicates an average expected useful service life of 58 years for transmission wooden support structures and 63 years for transmission overhead conductor.[21]

[21] The average industry expected useful service lives of transmission assets were derived from information filed with FERC. A total of 38 utilities were included in the analysis.

The Company's operations are exposed to an increasing risk of equipment failure on the transmission system going forward due to the age of wooden support structures and overhead conductor.

Figure 4 provides the age distribution of wooden support structures on the Company's transmission system.

Figure 4
Transmission Wooden Support Structures
Asset Age

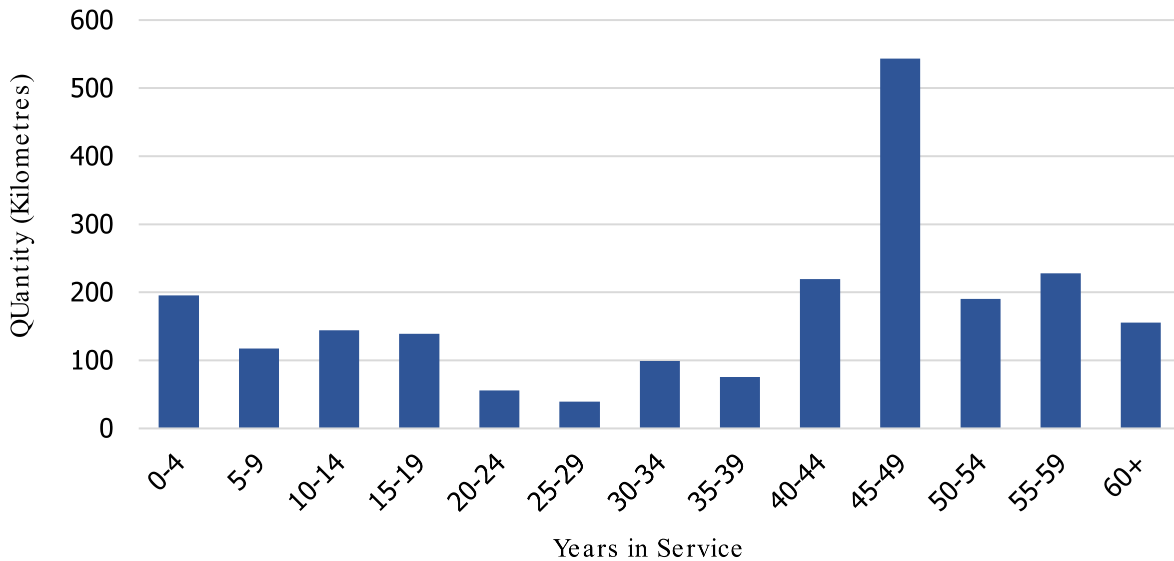


Approximately 2% of transmission wooden support structures have exceeded the average industry expected useful service life of 58 years.[22] An additional 14% of transmission wooden support structures will reach 58 years in service over the next decade.

[22] This is a result of the execution of the Company's *Transmission Line Rebuild Strategy* which commenced in 2006 and will be approximately 82% complete by the end of 2024. The strategy outlined a long-term plan to rebuild the Company's aging transmission lines.

Figure 5 provides the age distribution of overhead conductor on the Company's transmission system.

Figure 5
Transmission Overhead Conductor
Asset Age



Approximately 7% of transmission overhead conductor has currently exceeded the average industry expected useful service life of 63 years. An additional 10% of transmission overhead conductor will reach 63 years in service within the next decade.

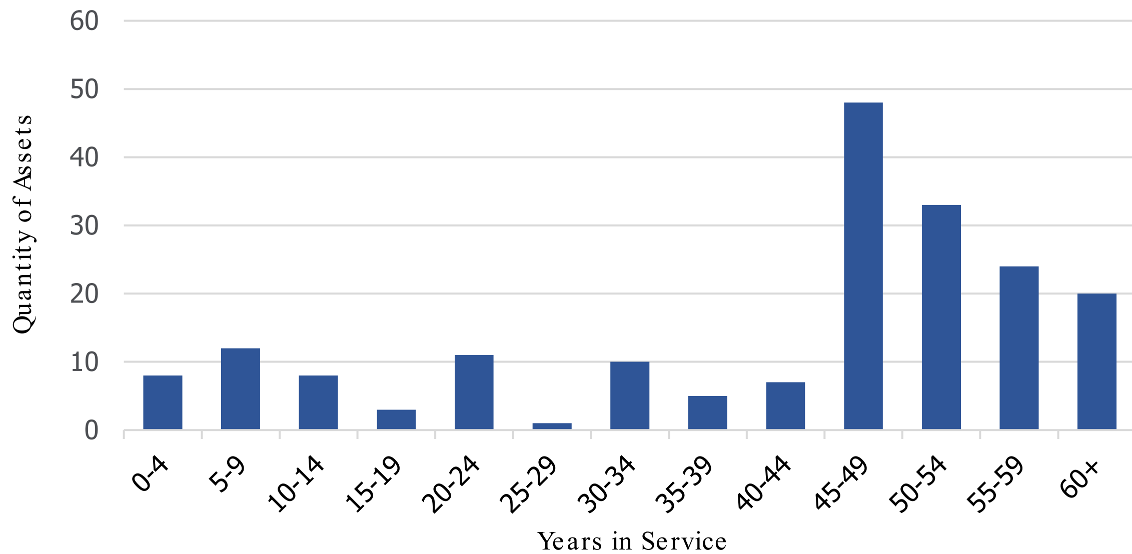
2.4.4 Substations

Newfoundland Power operates 131 substations throughout its service territory. Substations are inspected eight times annually to identify deficiencies and required maintenance. Equipment that fails in service or is at imminent risk of failure is addressed under the *Substation Replacements Due to In-Service Failures* program. Major refurbishment projects are implemented in accordance with the Company's *Substation Refurbishment and Modernization Plan*. The Company has also recently implemented a component-based program to address obsolete substation protection and control systems within Newfoundland Power's substations.

The most critical equipment in substations is power transformers. There are currently 190 power transformers in operation at Newfoundland Power's substations. Industry experience suggests the service life of a power transformer is typically between 30 to 50 years under ideal conditions.[23] Based on the current age profile, the Company's power transformers are exposed to a high risk of equipment failure.

Figure 6 provides the age distribution of Newfoundland Power's substation power transformers.

Figure 6
Substation Power Transformers
Asset Age



Approximately 41% of substation power transformers have exceeded the industry expected useful service life of 50 years. An additional 29% of substation power transformers will reach 50 years in service over the next decade.

2.4.5 Generation

Newfoundland Power operates 23 hydro plants that collectively generate 438 GWh annually at a capacity of 98 MW. These plants provide low-cost electricity to customers. The Company also operates six thermal plants that supply customers experiencing localized outages and provide system support when requested by Hydro.

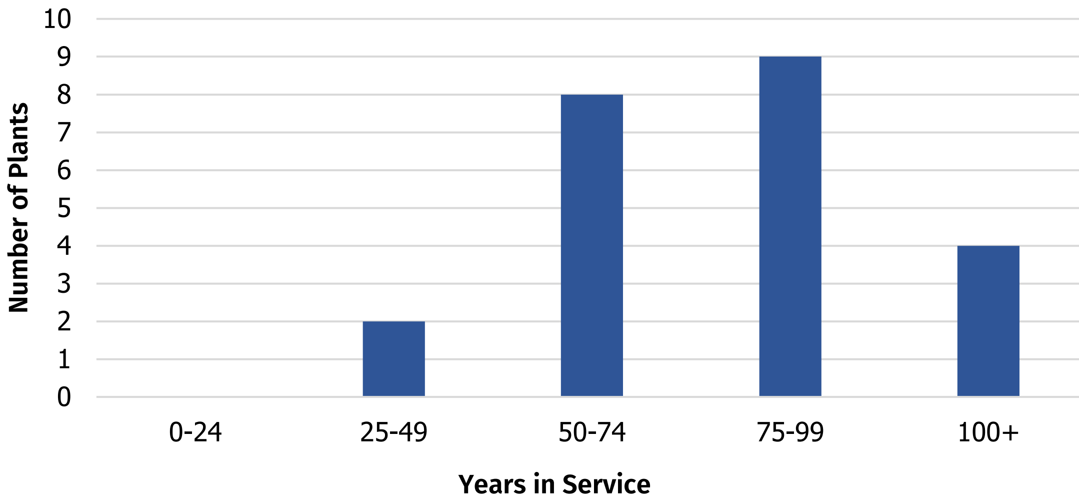
Generating plants are routinely inspected by plant operators to identify deficiencies. Equipment that fails or is at imminent risk of failure is addressed under the *Hydro Plant Replacements Due to In-Service Failures* program, *Thermal Plant Replacements Due to In-Service Failures* program

[23] Practical conditions, such as high ambient temperature, high loading and fault exposure, can reduce the expected service life of power transformers. High temperatures have an adverse effect on the insulating properties inside the transformer and cause the premature aging of power transformers. Insulation deterioration on the windings naturally occurs over time and is accelerated by exposure to high temperatures. Insulation that is found to be degraded is a major indicator that a power transformer has reached end of life. See International Council on Large Electric Systems ("CIGRE"), *Asset Management Decision Making Using Different Risk Assessment Methodologies*, 2013, page 94.

and *Hydro Facility Rehabilitation* project. Major plant refurbishment projects, such as penstock replacements, are accompanied by economic analyses to confirm that continued operation of a plant is least-cost for customers.

Figure 7 provides the number of hydro plants in operation by age as of 2023.

Figure 7
Hydro Plants
Asset Age



Of Newfoundland Power's 23 hydro plants, 17 have been in service for between 50 and 100 years and four have been in service for over 100 years. Many of these plants have undergone refurbishment projects to extend their useful service lives, including generator and turbine refurbishments, protection and control upgrades, and penstock replacements. Based on the current age profile, refurbishment projects are expected to continue to be required to extend the useful service lives of these hydro plants when proven economic for customers.[24]

Newfoundland Power's Greenhill and Wesleyville gas turbines have been in service for 48 years and 54 years, respectively. Inspections have identified that both gas turbines are approaching end of life. In addition, thermal generation units in Port aux Basques have been in service since the 1960s and are also approaching the end of their useful service lives.[25] Replacement projects are expected to be required for the Company's thermal generation assets.

[24] In circumstances where the life extension of a hydro plant is not economic compared with the cost of replacement energy and capacity, the Company will include in the economic analysis the cost associated with decommissioning the hydro plant including the environment and sediment management costs.

[25] The thermal generation supplying the Port aux Basques area consists of the diesel generating unit PAB-G1, which was placed into service in 1969, and the Mobile Gas Turbine #1 ("MGT"), which was placed into service in 1974. MGT is no longer able to be transported due to the deteriorated condition of the trailer chassis. It is now permanently stationed at the Company's Grand Bay Substation on the southwest coast of Newfoundland. This thermal generation, along with Rose Blanche Hydro Plant and other mobile generators, supply the Port aux Basques area for planned and unplanned outages on Hydro's transmission lines TL214 and TL215.

3.0 SUMMARY OF PLANNED EXPENDITURES

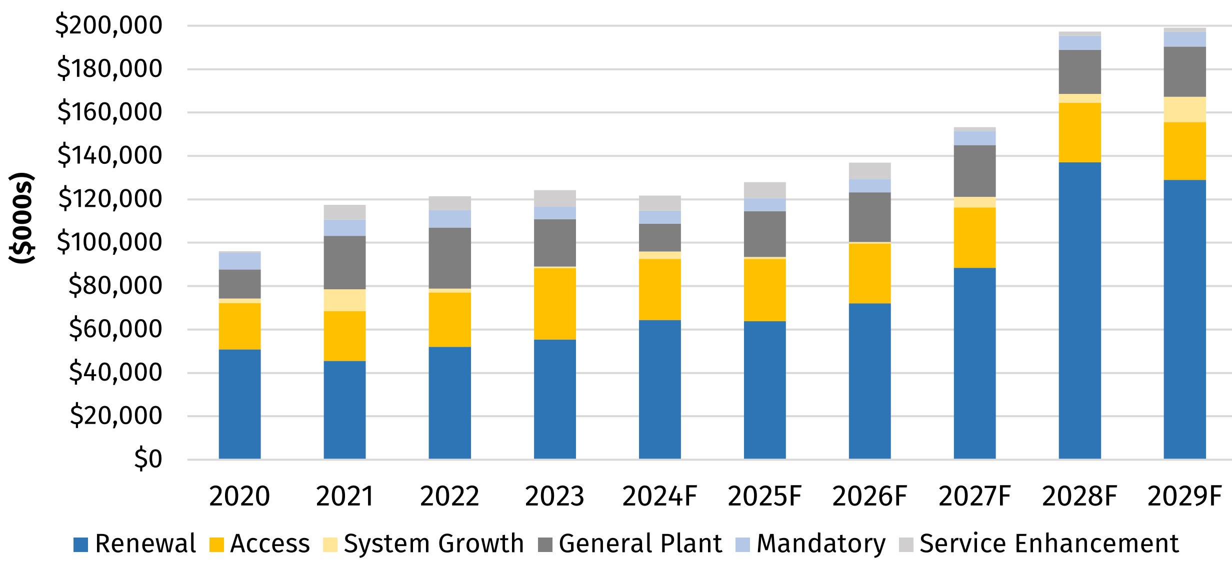
3.1 General

Newfoundland Power's *2025-2029 Capital Plan* forecasts average annual capital expenditures of approximately $163 million from 2025 to 2029. This section provides a breakdown of forecast capital expenditures by investment classification and asset class.[26]

3.2 Planned Expenditures by Investment Classification

Figure 8 provides historical and forecast capital expenditures from 2020 to 2029 by investment classification.

Figure 8
Capital Expenditures by Investment Classification
(2020-2029F)



Forecast increases in capital expenditures over the next five years are primarily observed in the Renewal investment classification. Investments in the Renewal classification are driven by the need to replace or refurbish assets that are deteriorated, deficient or fail in service.[27] Renewal investments are forecast to account for approximately 60% of capital expenditures from 2025 to 2029, compared to approximately 46% over the previous five-year period.

Increases in Renewal investments reflect the age and condition of Newfoundland Power's electrical system. Renewal investments in the Distribution asset class include the continuation of longstanding corrective and preventative maintenance programs, as well as an increase in

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26 Capital expenditures are organized by investment classification in accordance with the Board's provisional *Capital Budget Application Guidelines* effective January 2022.

27 Increases in the Renewal classification in 2028 and 2029 are driven by the planned replacement of the Greenhill and Wesleyville gas turbines.

distribution feeder refurbishment projects. Renewal investments in the Substations and Transmission asset classes reflect increases in the amount of work to be completed under the *Transmission Line Rebuild Strategy* and *Substation Refurbishment and Modernization Plan* over the forecast period. Renewal investments in the Generation asset class reflect both an increase in refurbishment projects for hydro plants, the planned replacement of the Wesleyville and Greenhill gas turbines, and the requirement to address aging thermal generation in Port aux Basques.

Expenditures in other investment classifications are expected to be reasonably stable over the forecast period.

Access and System Growth investments are forecast to account for approximately 20% of annual capital expenditures over the forecast period. This reflects a forecast decline in customer connections over the next five years, which will be offset by increased electrification efforts in both transportation and heating system conversions. Approximately $3.8 million of investments between 2028 and 2029 relate to transformer capacity additions at Kelligrews and Hardwoods substations to respond to load growth on the Northeast Avalon. Investments are also driven by increased system load due to EV adoption, with planned expenditures of approximately $3.7 million by 2029 for distribution system upgrades.

General Plant investments are forecast to account for approximately 14% of annual capital expenditures over the next five years. General Plant investments are expected to continue to be driven by expenditures in the Information Systems asset class. Information Systems account for approximately half of General Plant investments over the forecast period. Capital expenditures for Information Systems are largely driven by more frequent upgrades being required for third-party software products due to increasing cybersecurity threats and vendor requirements.

Service Enhancement investments are forecast to account for approximately 3% of annual capital expenditures over the next five years. Service Enhancement investments reflect continued automation of the distribution system and conclusion of the *LED Street Lighting Replacement Plan* in 2026.

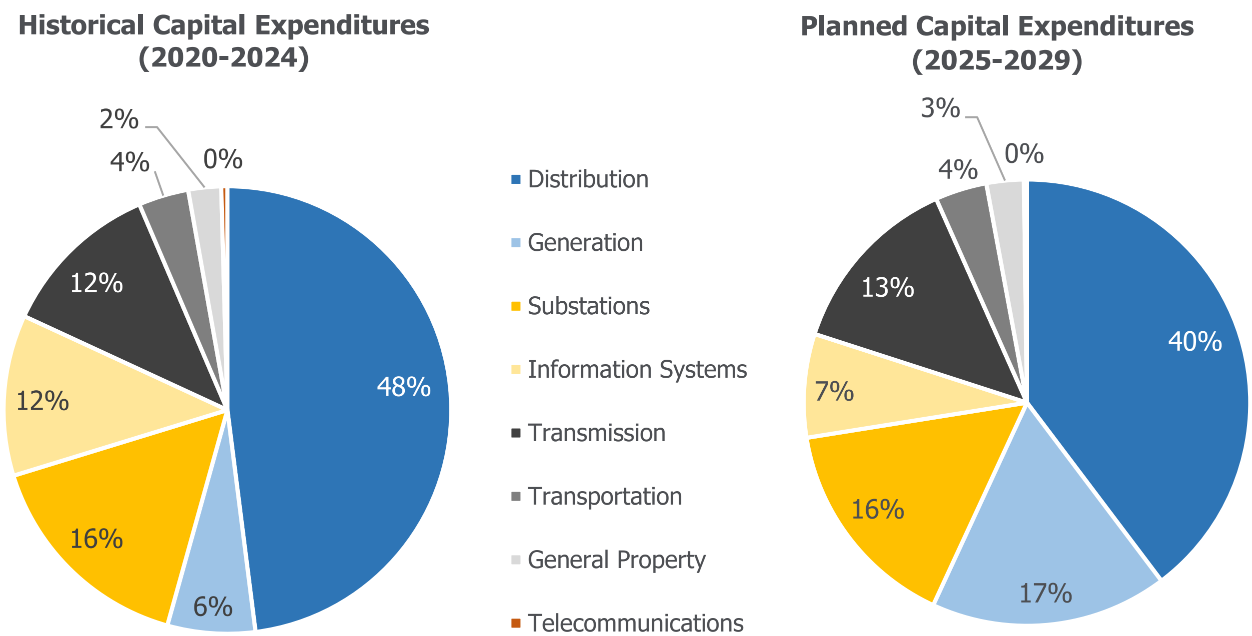
Mandatory investments are forecast to account for approximately 4% of annual capital expenditures over the next five years. Mandatory investments reflect capital expenditures resulting from Board Orders, including *General Expenses Capitalized*, the *Allowance for Unforeseen Items*, and the *Allowance for Funds Used During Construction*.

3.3 Planned Expenditures by Asset Class

3.3.1 Breakdown by Asset Class

Figure 9 provides a comparison of historical and forecast capital expenditures by asset class.[28]

Figure 9
Capital Expenditures by Asset Class



Distribution asset class is forecast to continue to account for the largest proportion of the capital expenditures from 2025 to 2029. The Generation asset class is expected to account for a larger portion of capital expenditures over the forecast period in comparison to the last five years. This is primarily driven by major refurbishment and replacement projects as described below.

[28] Excludes expenditures relating to General Expenses Capitalized and the Allowance for Unforeseen Items.

3.3.2 Distribution

Table 2 provides historical and forecast distribution capital expenditures from 2020 to 2029.

Table 2 Distribution Capital Expenditures ($000s)					
Actual/Forecast					Average
2020	2021	2022	2023	2024F	2020-2024F
44,391	50,951	50,449	57,328	60,815	52,787
Plan					Average
2025B	2026B	2027B	2028B	2029B	2025B-2029B
59,464	58,632	64,956	64,287	63,889	62,246

Distribution capital expenditures are forecast to average approximately $62.2 million annually from 2025 to 2029. This compares to an average of approximately $52.8 million annually over the previous five-year period.

Newfoundland Power's capital maintenance programs for its distribution assets, *Rebuild Distribution Lines* and *Reconstruction*, are planned to continue at a combined average cost of approximately $13.3 million annually. Refurbishment projects for individual distribution feeders are expected to increase over the forecast period, with annual expenditures increasing from approximately $2.0 million in 2025 to approximately $7.1 million in 2029.

Expenditures related to the *Distribution Reliability Initiative* are forecast to average approximately $2.3 million annually as the Company continues to target the worst performing feeders, or specific sections of feeders, on its distribution system.[29]

[29] Each year, Newfoundland Power assesses and ranks the reliability performance of its over 300 distribution feeders and completes targeted capital investments, when appropriate, as part of the *Distribution Reliability Initiative*.

3.3.3 Substations

Table 3 provides historical and forecast substations capital expenditures from 2020 to 2029.

Table 3
Substations
Capital Expenditures
($000s)

Actual/Forecast					Average
2020	2021	2022	2023	2024F	2020-2024F
14,720	15,507	14,252	20,955	22,171	17,521
Plan					**Average**
2025B	2026B	2027B	2028B	2029B	2025B-2029B
15,952	23,299	27,983	26,190	28,669	24,419

Substations expenditures are forecast to average approximately $24.4 million annually from 2025 to 2029. This compares to an average of approximately $17.5 million annually over the previous five-year period.

Increased substations expenditures are driven by the Company's *Substation Refurbishment and Modernization Plan*. Forecast expenditures over the next five years reflect the refurbishment and modernization of 20 substations, including the Islington, and Northwest Brook substations in 2025, and two two-year projects at Lockston and Summerville substations commencing in 2025. The refurbishment and modernization of these substations is necessary to address deteriorated equipment and infrastructure, and to upgrade protection and control systems. The average annual cost for substation refurbishment and modernization projects is approximately $10.8 million from 2025 to 2029. Newfoundland Power is also forecasting to proactively replace an average of two power transformers annually to address the Company's aging power transformer fleet. Power transformer replacements are forecast to cost on average $4.3 million annually from 2025 to 2029.

Forecast substation expenditures also include approximately $5.2 million annually to address in-service equipment failures in substations, as well as other expenditures to upgrade or replace deficient equipment and respond to system load growth.

3.3.4 Transmission

Table 4 provides historical and forecast transmission capital expenditures from 2020 to 2029.

Table 4
Transmission
Capital Expenditures
($000s)

Actual/Forecast					Average
2020	2021	2022	2023	2024F	2020-2024F
10,069	11,279	18,588	9,203	15,064	12,841

Plan					Average
2025B	2026B	2027B	2028B	2029B	2025B-2029B
18,064	21,306	21,230	22,042	21,968	20,922

Transmission capital expenditures are forecast to average approximately $20.9 million annually from 2025 to 2029. This compares to an average of approximately $12.8 million annually over the previous five-year period.

Increased transmission expenditures are driven by an increase in the kilometres of transmission line to be rebuilt annually to complete the *Transmission Line Rebuild Strategy*.[30] Additionally, the construction of a new 138 kV transmission line from Lewisporte to Boyd's Cove substations beginning in 2025 as part of the *Gander – Twillingate Transmission System Planning Study* is expected to cost approximately $21 million over three years. The rebuild of Transmission Line 94L in 2025 and 2026 is expected to cost approximately $12.6 million. Forecast expenditures from 2025 to 2029 include rebuild projects on eight transmission lines throughout the Company's service territory. The average annual cost of transmission line rebuild projects is approximately $12.5 million from 2025 to 2029.

Forecast transmission expenditures also include capital maintenance of transmission line structures at an annual average cost of approximately $3 million.

[30] As of the end of 2024, execution of this strategy will be 82% complete. The lines remaining to be completed in the 2025 to 2029 period include three 138 kV H-frame construction transmission lines. The extended line length for these rebuilds, and the 138 kV H-frame construction, are the primary drivers for the increase in transmission expenditures.

3.3.5 Generation

Table 5 provides historical and forecast generation capital expenditures from 2020 to 2029.

Table 5
Generation
Capital Expenditures
($000s)

Actual/Forecast					Average
2020	2021	2022	2023	2024F	2020-2024F
6,833	9,766	2,869	9,739	5,640	6,969

Plan					Average
2025B	2026B	2027B	2028B	2029B	2025B-2029B
7,585	4,910	9,050	58,257	54,898	26,940

Generation capital expenditures are forecast to average approximately $26.9 million annually from 2025 to 2029.[31] This compares to an average of approximately $7.0 million annually over the previous five-year period.

Increased generation expenditures include the planned replacement of the existing Greenhill and Wesleyville gas turbines in 2028 and 2029.[32] The cost of replacing these gas turbines is approximately $50 million and $45 million, respectively. Expenditures of approximately $1 million are also included in 2029 to start the engineering to replace the thermal units in Port aux Basques.[33]

Increased generation expenditures also reflect a forecast requirement to undertake refurbishment projects at 13 hydro plants over the next five years.

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31 Generation-Hydro capital expenditures are forecast to average approximately $7.4 million annually from 2025 to 2029. Generation-Thermal capital expenditures are forecast to average approximately $29.3 million annually from 2025 to 2029.

32 Options to address the deteriorated condition of the Wesleyville and Greenhill gas turbines are under review as a result of Hydro's Reliability and Resource Adequacy Study – 2022 Update and the uncertainty around supply resources.

33 Newfoundland Power has two thermal generation plants located in Port aux Basques. These include: (i) the 6.0 MW MGT which was placed in service in 1974; and (ii) the 2.5 MW Port aux Basques diesel generator which was placed in service in 1969. Customers on the southwest portion of the province area served by Hydro's radial transmission line TL214. The thermal generation plants located in Port aux Basques are utilized when Hydro is completing maintenance on the transmission line or in response to unscheduled outages to the line.

3.3.6 Information Systems

Table 6 provides historical and forecast information systems capital expenditures from 2020 to 2029.

Table 6 Information Systems Capital Expenditures ($000s)					
Actual/Forecast					Average
2020	2021	2022	2023	2024F	2020-2024F
7,347	15,472	21,495	13,490	6,180	12,797
Plan					Average
2025B	2026B	2027B	2028B	2029B	2025B-2029B
11,009	12,908	11,515	11,299	12,054	11,757

Information systems capital expenditures are forecast to average approximately $11.8 million annually from 2025 to 2029. This compares to an average of approximately $12.8 million annually over the previous five-year period.

Expenditures from 2025 to 2029 are comparable to the previous five-year average. Expenditures from 2025 to 2029 are expected to be driven by more frequent software and hardware upgrades required to manage cybersecurity risks and to meet vendor requirements. Forecast expenditures include upgrades to the Company's Asset Management, Outage Management System and Geographic Information System among others.

3.3.7 Transportation

Table 7 provides historical and forecast transportation capital expenditures from 2020 to 2029.

Table 7
Transportation
Capital Expenditures
($000s)

Actual/Forecast					Average
2020	2021	2022	2023	2024F	2020-2024F
3,515	4,441	3,212	4,967	3,806	3,988
Plan					**Average**
2025B	2026B	2027B	2028B	2029B	2025B-2029B
5,042	5,151	7,914	4,732	6,536	5,875

Transportation capital expenditures are forecast to average approximately $5.9 million annually from 2025 to 2029. This compares to an average of approximately $4.0 million annually over the previous five-year period.

The increase in transportation capital expenditures from 2025 through 2029 primarily reflects inflation and the number of heavy, medium, and light duty fleet and passenger vehicles forecast to be replaced over the period.

3.3.8 General Property

Table 8 provides historical and forecast general property capital expenditures from 2020 to 2029.

Table 8
General Property
Capital Expenditures
($000s)

Actual/Forecast					Average
2020	2021	2022	2023	2024F	2020-2024F
2,459	2,703	2,843	2,686	2,340	2,606

Plan					Average
2025B	2026B	2027B	2028B	2029B	2025B-2029B
4,010	4,545	4,314	4,036	4,259	4,233

General Property capital expenditures are forecast to average approximately $4.2 million annually from 2025 to 2029. This compares to an average of approximately $2.6 million annually over the previous five-year period.

General Property capital expenditures are driven by deterioration in Company-owned buildings. Several of Newfoundland Power's area offices are over 30 years old and certain building components require replacement. Expenditures over the 2025 to 2029 period are driven by refurbishments required at the Company's head office in St. John's and area offices in Grand Falls-Windsor and Corner Brook.

3.3.9 Telecommunications

Table 9 provides historical and forecast telecommunications capital expenditures from 2020 to 2029.

Table 9
Telecommunications
Capital Expenditures
($000s)

Actual/Forecast					Average
2020	2021	2022	2023	2024F	2020-2024F
112	503	593	707	502	483

Plan					Average
2025B	2026B	2027B	2028B	2029B	2025B-2029B
994	128	131	134	338	345

Telecommunications capital expenditures are forecast to average approximately $0.3 million annually from 2025 to 2029. This compares to an average of approximately $0.5 million annually over the previous five-year period.

Expenditures from 2025 to 2029 are comparable to the previous five-year average. Telecommunications expenditures over the next five years are primarily driven by the replacement of the Company's Very High Frequency ("VHF") mobile radio system in 2025.

APPENDIX A:

Capital Projects and Programs: 2025-2029

Table A-1 2025-2029 Capital Plan By Asset Class ($000s)					
Asset Class	2025F	2026F	2027F	2028F	2029F
Distribution	59,464	58,632	64,956	64,287	63,889
Substations	15,952	23,299	27,983	26,190	28,669
Transmission	18,064	21,306	21,230	22,042	21,968
Generation	7,585	4,910	9,050	58,257	54,898
Information Systems	11,009	12,908	11,515	11,299	12,054
Transportation	5,042	5,151	7,914	4,732	6,536
General Property	4,010	4,545	4,314	4,036	4,259
Telecommunications	994	128	131	134	338
Allowance for Unforeseen Items	750	750	750	750	750
General Expenses Capitalized	5,081	5,300	5,454	5,613	5,777
Total	$127,951	$136,929	$153,297	$197,340	$199,138

Table A-2 2025-2029 Capital Plan Distribution ($000s)					
	2025F	2026F	2027F	2028F	2029F
Project					
Feeder Additions for Load Growth	960	800	4,924	2,845	4,170
Distribution Reliability Initiative	0	0	2,000	2,250	2,500
Distribution Feeder Automation	1,125	1,148	1,170	1,194	1,218
LED Street Lighting Replacement	5,654	5,738	0	0	0
Distribution Feeder PEP-02 Refurbishment	667	0	0	0	0
Distribution Feeder SCT-01 and BLK-01 Relocation	649	1,140	0	0	0
Distribution Feeder SMV-01 Refurbishment	654	0	0	0	0
Distribution Feeder Refurbishments	0	2,167	6,624	8,805	7,130
Distribution Feeder Extension - COB-02	0	0	1,216	0	0
Allowance for Funds Used During Construction	220	223	225	228	231
Program					
Extensions	13,402	13,171	12,854	12,480	11,776
Reconstruction	7,425	7,660	7,847	8,037	8,235
Rebuild Distribution Lines	5,115	5,286	5,419	5,554	5,695
New Services	3,208	3,171	3,103	3,021	2,857
Replacement Services	445	460	471	483	495
New Meters	457	448	904	865	774
Replacement Meters	648	573	1,223	1,217	1,150
New Transformers	5,623	4,503	4,582	4,661	4,745
Replacement Transformers	6,340	5,077	5,167	5,256	5,351
New Street Lighting	2,460	2,527	2,583	2,640	2,700
Replacement Street Lighting	884	903	920	938	957
Relocate/Replace Distribution Lines for Third Parties	3,528	3,637	3,724	3,813	3,905
Total	**$59,464**	**$58,632**	**$64,956**	**$64,287**	**$63,889**

Table A-3 2025-2029 Capital Plan Substations ($000s)					
	2025F	2026F	2027F	2028F	2029F
Project					
Substation Ground Grid Upgrades	609	640	672	705	710
Substation Feeder Termination – LEW Substation	0	94	1,500	0	0
Boyds Cove Substation Conversion	0	457	4,068	0	0
New Grounding Transformer – GAN Substation	0	17	1,983	0	0
Grand Falls Substation Conversion	0	0	39	590	0
Grand Falls Substation Switch Replacements	0	0	27	338	0
Northwest Brook Substation Refurbishment & Modernization	4,175	0	0	0	0
Lockston Substation Refurbishment & Modernization	305	4,521	0	0	0
Summerville Substation Refurbishment & Modernization	511	4,510	0	0	0
Islington Substation Refurbishment & Modernization[1]	4,706	0	0	0	0
Gander Substation Power Transformer Replacement	17	3,905	263	0	0
Pulpit Rock Substation Power Transformer Replacement	17	2,905	0	0	0
Power Transformer Replacements	0	160	4,731	4,731	4,731
Substation Refurbishment & Modernization	0	327	8,823	13,559	12,668
Substation Feeder Termination	0	0	0	60	780
Additions Due to Load Growth	0	0	0	216	3,653
Program					
Substation Replacements Due to In-Service Failures	4,927	5,054	5,164	5,275	5,391
Substation Protection and Control Replacements	685	709	713	716	736
Total	$15,952	$23,299	$27,983	$26,190	$28,669

[1] Multi-year capital project approved in Board Order No. P.U. 2 (2024).

Table A-4
2025-2029 Capital Plan
Transmission
($000s)

	2025F	2026F	2027F	2028F	2029F
Project					
Transmission Line 94L Rebuild	3,485	9,075	0	0	0
Transmission Line 146L Rebuild[2]	9,209	0	0	0	0
New Transmission Line from Lewisporte to Boyd's Cove	1,886	9,283	9,553	0	0
Transmission Line Extension - 142L	0	0	1,520	0	0
Transmission Line Rebuild	0	0	7,149	17,974	15,836
Transmission Line Additions	0	0	0	1,000	3,000
Wood Pole Retreatment[3]	600	0	0	0	0
Program					
Transmission Line Maintenance	2,884	2,948	3,008	3,068	3,132
Total	**$18,064**	**$21,306**	**$21,230**	**$22,042**	**$21,968**

2 Multi-year capital project approved in Board Order No. P.U. 2 (2024).
3 Newfoundland Power intends for this project to transition to a program with estimates informed by the 2025 project.

Table A-5 2025-2029 Capital Plan Generation ($000s)					
	2025F	2026F	2027F	2028F	2029F
Project					
Hydro Facility Rehabilitation	0	925	950	975	1,000
La Manche Canal Bridge Replacement	530	0	0	0	0
Mobile Hydro Plant Penstock Refurbishment	825	0	0	0	0
Lookout Brook Hydro Plant Refurbishment[4]	1,573	0	0	0	750
Mount Carmel Pond Dam Refurbishment	3,608	1,008	0	0	0
Rose Blanche Hydro Plant Refurbishment	0	0	0	859	0
Tors Cove Hydro Plant Refurbishment	0	0	0	400	6,800
Horsechops Hydro Plant Refurbishment	0	0	200	3,100	0
Cape Broyle Hydro Plant Refurbishment	0	400	3,700	0	0
Lawn Hydro Plant Refurbishment	0	0	400	1,800	0
Victoria Hydro Plant Refurbishment	0	200	1,700	0	0
Morris Hydro Plant Refurbishment	0	0	0	0	200
Hearts Content Bearing Replacement	0	500	0	0	0
Rocky Pond Bearing Replacement	0	400	0	0	0
Petty Harbour Plant Refurbishment	0	400	0	0	0
Greenhill Gas Turbine Replacement	0	0	1,000	49,000	0
Wesleyville Gas Turbine Replacement	0	0	0	1,000	44,000
Port aux Basques Thermal Generation	0	0	0	0	1,000
Program					
Hydro Plant Replacements Due to In-Service Failures	731	750	766	782	799
Thermal Plant Replacements Due to In-Service Failures	318	327	334	341	349
Total	**$7,585**	**$4,910**	**$9,050**	**$58,257**	**$54,898**

[4] Multi-year capital project approved in Board Order No. P.U. 2 (2024).

Table A-6 2025-2029 Capital Plan Information Systems ($000s)					
	2025F	2026F	2027F	2028F	2029F
Project					
System Upgrades	1,408	1,154	3,232	2,423	5,005
Application Enhancements	914	2,429	2,494	2,508	1,975
Cybersecurity Upgrades	940	950	960	970	855
Microsoft Enterprise Agreement[5]	297	297	330	330	330
Network Infrastructure	470	400	500	355	860
Operations Technology	0	250	1,750	2,000	750
Shared Server Infrastructure	970	700	1,500	1,950	1,500
Outage Management System Upgrade	1,811	1,459	0	0	0
Asset Management Technology Replacement	3,479	4,534	0	0	0
Program					
Personal Computer Infrastructure	720	735	749	763	779
Total	**$11,009**	**$12,908**	**$11,515**	**$11,299**	**$12,054**

5 Multi-year capital project approved in Board Order No. P.U. 2 (2024).

Table A-7
2025-2029 Capital Plan
Transportation
($000s)

	2025F	2026F	2027F	2028F	2029F
Project					
Replace Vehicles and Aerial Devices 2024-2025[6]	2,869	0	0	0	0
Replace Vehicles and Aerial Devices 2025-2026	2,173	2,802	0	0	0
Replace Vehicles and Aerial Devices 2026-2027	0	2.349	3,557	0	0
Replace Vehicles and Aerial Devices 2027-2028	0	0	3,557	1,954	0
Replace Vehicles and Aerial Devices 2028-2029	0	0	0	1,978	3,978
Replace Vehicles and Aerial Devices 2029-2030	0	0	0	0	2,558[7]
Purchase Specialized Offroad Vehicles	0	0	800	800	0
Total	$5,042	$5,151	7,914	4,732	$6,536

6 Multi-year capital project approved in Order No. P.U. 2 (2024).
7 First year of a two-year multi-year project in 2028 and 2029.

Table A-8 2025-2029 Capital Plan General Property ($000s)					
	2025F	2026F	2027F	2028F	2029F
Project					
Company Building Renovations[8]	760	500	1,200	850	1,000
Port Union Building Replacement	278	1,003	0	0	0
Building Accessibility Improvements	650	670	690	710	730
Specialized Tools and Equipment	595	615	635	655	675
Program					
Additions to Real Property	682	694	707	720	733
Physical Security Upgrades	456	465	473	482	491
Tools and Equipment	589	598	609	619	630
Total	$4,010	$4,545	$4,314	$4,036	$4,259

[8] Includes multi-year capital project approved in Board Order No. P.U. 2 (2024).

Table A-9 2025-2029 Capital Plan Telecommunications ($000s)					
	2025F	2026F	2027F	2028F	2029F
Project					
Fibre Optic Cable Build	0	0	0	0	200
VHF Radio System Replacement	870	0	0	0	0
Program					
Communications Equipment Upgrades	124	128	131	134	138
Total	**$994**	**$128**	**$131**	**$134**	**$338**

Table A-10 2025-2029 Capital Plan Allowance for Unforeseen Items ($000s)					
	2025F	2026F	2027F	2028F	2029F
Project					
Allowance for Unforeseen Items	750	750	750	750	750
Total	$750	$750	$750	$750	$750

Table A-11
2025-2029 Capital Plan
General Expenses Capitalized
($000s)

	2025F	2026F	2027F	2028F	2029F
Project					
General Expenses Capitalized	5,081	5,300	5,454	5,613	5,777
Total	$5,081	$5,300	$5,454	$5,613	$5,777

APPENDIX B:

Asset Management Update Report

Asset Management Update Report




May 2024

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 INTRODUCTION

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") approach to asset management has delivered sound outcomes for its customers, including reasonable levels of service and customer satisfaction. While historical results have been sound, the context around asset management is evolving. The Company is focused on maintaining these outcomes while considering overall asset management maturity.

In 2022, Newfoundland Power embarked on a comprehensive asset management review to guide the maturation of their asset management practices.[1] The review included three phases: (i) a current state assessment; (ii) a target state assessment; and (iii) implementation planning. The objective of the review is to ensure the Company's asset management practices are adequate and aligned with sound utility practice, while considering the landscape of its work force, the aging electrical system, upcoming technology obsolescence, and regulatory compliance.

(i) *A current state assessment.* A current state assessment was completed to allow Newfoundland Power to understand where it was in its asset management journey, how it compares to other utilities, and what opportunities are available to enhance practices. This assessment was the first phase of the asset management review and was completed as of March 2023.

(ii) *A target state assessment.* Following the current state assessment, a target state assessment was completed. Its intention was to assess feasible opportunities to advance the Company's asset management journey, to ensure practices continue to be adequate, and align with sound utility practice. The purpose of the target state assessment was not to define a target asset management maturity value or state, but instead help identify opportunities to inform implementation planning. This phase was completed as of the end of March 2024.

(iii) *Implementation planning.* Implementation planning is the final phase in the Company's asset management review. Implementation planning is intended to guide the execution of opportunities identified in the target state assessment, laying the foundation for the Company's continued asset management journey.

The Company's asset management journey is guided by the International Organization for Standardization ("ISO") 55000 standard on asset management. This standard provides guidance on industry best practice for asset management. Newfoundland Power is focused on aligning with the concepts from the ISO 55000 standard, using it to provide overall direction for the organization based upon the objectives that are appropriate for the Company.

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[1] See Newfoundland Power's Asset Management Review, 2022-2024 Assessment Framework in the response to Request for Information for PUB-NP-016 from Newfoundland Power's *2024 Capital budget Application.*

The purpose of this report is to provide an update on Newfoundland Power's asset management review, including the outcomes of the current state, and target state assessments, as well as the progress for implementation planning phase. This update is not intended to provide a descriptive plan for Newfoundland Power's asset management journey going forward.

2.0 CURRENT STATE ASSESSMENT

To initiate the asset management review, a current state assessment was competed. This assessment included utilizing a consultant to benchmark the Company's asset management. The benchmark used a comparison to other utilities using clauses of the ISO 55001 and the Institute of Asset Management ("IAM") assessment tool. This maturity assessment informed the identification of opportunities that could be assessed as part of the asset management review.

Newfoundland Power staff were engaged in a series of interviews, along with a review of the Company's asset management documentation, including information and maintenance practices and asset management strategies. Overall, the Company's maturity was benchmarked as a 1.38 out of four, translating to a maturity between "aware", which means an organization has identified requirements for asset management, and "developing", which means the organization has identified the means through which to meet these requirements. Newfoundland Power's asset management maturity rests above utility average of 1.1.[2]

The consultant used the maturity assessment and its knowledge of industry best practices to identify opportunities that Newfoundland Power could assess as part of its asset management review. 22 opportunities were identified for assessment.[3] Newfoundland Power has organized these opportunities into three categories: (i) organizational approach; (ii) plans and processes; and (iii) data and technology.

(i) **Organizational Approach –** The organizational approach includes the strategic framework and culture within the organization that supports effective asset management. It involves establishing clear goals and objectives aligned with the organization's mission, vision, and strategic values.[4] A strong organizational approach ensures that asset management is integrated into the overall business strategy and fosters a culture of accountability, collaboration, and innovation.[5]

(ii) **Plans and Processes** – Plans and processes focus on the development and implementation of structured plans, policies, and procedures to govern asset management activities. It includes asset management plans that outline the

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2 See footnote 1.
3 Ibid.
4 Key components of the organizational approach include leadership commitment, organizational structure, roles and responsibilities, governance frameworks, and continuous improvement processes.
5 Opportunities within the organizational approach include enhancing knowledge and competencies of employees, and defining the scope of the asset management system within the Company, including management roles, and ensuring asset management is right sized.

strategies, tactics, and resources required to achieve asset management objectives.[6] Robust plans and processes provide a roadmap for managing assets effectively, optimizing resource allocation, and mitigating risks throughout the asset lifecycle.[7]

(iii) **Data and Technology** – Data and technology addresses the importance of data, information, and technology in supporting asset management activities. It involves leveraging data and analytics to make informed decisions, improve asset performance, and optimize resource allocation. Additionally, it includes the use of technology solutions such as asset management technology to enhance asset visibility, control, and optimization. By harnessing data and technology effectively, organizations can enhance asset performance, optimize maintenance practices, and drive continuous improvement in asset management.[8]

3.0 TARGET STATE ASSESSMENT

The second phase of the asset management review consisted of a target state assessment, used to assess opportunities available to ensure Newfoundland Power's asset management practices continue to be adequate, and align with sound public utility practice. This assessment involved grouping the 22 opportunities as defined by the consultant into seven milestones to be completed. The target state assessment has been successful in identifying areas of opportunity for asset management maturity, to be considered in implementation planning. An update of the seven milestones for the target state assessment is provided in the following sections.

3.1 Documentation Gathering

The documentation gathering milestone was completed from October 2022 through March 2023. Its objective was to compile a library of documentation to establish how the Company conducts asset management, and to identify what changes may be required to facilitate its asset management journey. As a result of the documentation gathering milestone, the Company has developed a digital library of asset management documents. Several improvements for documentation were identified as part of the milestone and will be considered during implementation planning.

3.2 Staff Training

The staff training milestone was completed from December 2022 through April 2023. Its objective was to build internal capacity to understand best practices in assessing and implementing asset management practices. The Company has been successful in training 21 employees in the IAM certificate in asset management.[9] Additionally, employees have engaged

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6 This involves various processes such as asset identification and classification, risk assessment, lifecycle management, inspection and maintenance strategies, performance monitoring and change management.

7 Opportunities within plans and processes include developing a strategic asset management plan, reviewing and enhancing documentation, and developing asset management plans.

8 Opportunities for data and technology include enhancing the collection, storage, maintenance, accuracy, completeness and use of data.

9 Number of employees certified as of 4/8/2024.

in industry webinars and conferences from the IAM, the Center for Energy Advancement through Technological Innovation ("CEATI") and other industry associations and groups.

3.3 Pilot Project

The pilot project milestone was completed from December 2022 through May 2023. Its objective was to inform whether Newfoundland Power should implement asset health indices ("AHIs") and quantitative risk modelling, independent of the technology used, as part of its asset management journey. Outcomes provided an understanding of: (i) how the resulting data could benefit operations, capital planning and compliance with regulatory requirements; and (ii) how implementing these analytics would require changes to Newfoundland Power's processes, technology and data.

Outcomes of the pilot project have indicated that AHIs are achievable for the Company. AHIs would be most effectively completed using a stepwise approach. As Newfoundland Power has a large number of assets, it would not be feasible for every asset to have an AHI concurrently. A stepwise approach would consider the benefits of an AHI for each of the critical asset class components and where the information can be used for operational efficiencies. After assets are selected, the appropriate formulas would have to be established to determine parameters and weightings.

Economic lifecycle analysis was used to quantify risk, by identifying the probability of an event occurring and its consequence. The pilot project indicated that Newfoundland Power is currently not in the position to implement quantitative risk modelling. AHIs factor into risk modelling as they are a key determiner in probability of failure of an asset. It would be prudent to determine which assets require risk modelling based on the assets that are being selected for AHIs. As well, large amount of financial inputs, such as the reactive cost of asset replacement, would need refinement to provide a more accurate representation of risk for the assets. Given the requirements of quantifiable risk modeling, further exploration should be completed as asset management is matured.

3.4 Employee Engagement

The employee engagement milestone was completed from February 2023 through April 2023. Its objective was to build awareness of asset management in the Company, and to solicit input and feedback from internal stakeholders to inform the review. Through a series of in-person and virtual sessions in 2023, asset management awareness presentations were delivered including at least one representative from all departments. These sessions included information on asset management fundamentals, and an overview of the Company's framework review. Feedback from the sessions were incorporated into the target state assessment where appropriate.

3.5 Process and Planning Review

The process and planning review was completed from March 2023 through October 2023. The objective was to identify what changes are required to Newfoundland Power's policies, processes and plans to facilitate the next steps in its asset management journey.

Inspection and Maintenance Practices
Through the documentation gathering and review process, opportunities for enhancements have been and are being identified for inspection and maintenance practices. The Company has become more familiar with industry best practice through research, surveys and interaction with other utilities, while educating all asset classes owners on resources for specific asset class management practices. Specific activities included deeper engagements of asset classes with industry groups, and cross asset class learning, and development facilitated by the asset management team. The review has helped determine a requirement to standardize the information for asset decision making.

Operational Processes
Through the documentation gathering and review milestone. The Company has begun the process of reviewing all existing business processes and has created new processes in areas that previously had no established documentation. This will bring clarity to the processes including role and responsibilities. Employee Engagements have helped create better communication with internal subject matter experts as they learn about asset management maturation.[10] To meet the data and resource requirements to mature AHI's and quantifiable risk modeling, enhancements to operational processes will be required.

Investment Planning
Overall, the Company has a well-defined process for investment planning; however, the process has room for enhancements. Staff training has exposed internal subject matter experts to various industry experts and best asset management practices.[11] To implement AHI's and quantifiable risk, information requirements need to be assessed to determine how processes and practices can be improved to meet data requirements for maturation.

Any initiatives as a result of the process and planning review are being evaluated and will be implemented at a time appropriate for the Company.

3.6 Data and Technology

The data and technology assessment was completed from March 2023 through January 2024. Its objective was to assess how to modernize Newfoundland Power's asset management technology prior to obsolescence of existing system. [12]

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10 A subject matter expert is a professional with advanced knowledge in a specific field or area.

11 Engagements with CEATI regarding risk assessment methodologies have advanced the Company's understanding of opportunities as asset management matures.

12 In 2021, Newfoundland Power was informed of the obsolesce of its current asset management technology occurring after December 31st, 2026.

To complete this milestone, a third-party consultant, Asset Management Consultants Limited ("AMCL") was engaged to provide expertise on the identified opportunities. Through consultant engagements, the Company has been able to better understand the technology market, importance of data quality, functional requirements and technical requirements for a replacement technology.

Overall findings of this milestone have provided areas of opportunity for the Company to modernize their technology. Data and technology are important in all aspects of asset management and provides the basis for decision-making. Data must be accessible and be able to be analyzed. Due to obsolescence and the opportunities of modern technology, replacement will allow the Company to meet current requirements and provide a foundation for enhancements as asset management matures.

AMCL has recommended that an Asset Information Strategy be developed. This strategy is meant to treat data as an asset to be managed and would include creating a vision, governance process, data standards and data specifications in alignment with the Global Forum for Maintenance and Asset Management ("GFMAM"). An Asset Information Strategy will be considered in parallel to the technology replacement.

3.7 Resource Assessment

The resource assessment milestone was completed from October 2023 through March 2024. Its objective was to identify the organizational approach, resources and competencies required to meet Newfoundland Power's asset management objectives. This milestone has been completed, documenting the Company's current approach to core asset management functions.

4.0 IMPLEMENTATION PLANNING

Opportunities identified from the target state assessment are being assessed and captured in implementation planning. Any changes required to processes, practices and strategies will be considered as appropriate for Newfoundland Power. These may include updates, renewals, or replacements of existing processes, practices, and strategies.

The implementation planning phase is intended to inform the next phase of the Company's asset management journey. The Company is currently working on the development of an implementation plan that will be completed by the end of 2024. The implementation plan will include a roadmap for strategic, operational, and data and technological initiatives. The implementation plan will consider appropriate timing for other opportunities identified through the target state assessment.

Based on electric utility trends from surveys, internal assessments, and internal stakeholder engagements, the Company is utilizing ISO 55000 standards to guide the implementation plan and provide the foundation for effective asset management practices.[13] Prioritizing alignment with these standards ensures consistency, efficiency, and compliance, supporting the Company's objective to deliver safe, reliable service to customers at least cost in an environmentally friendly matter.

Within the practice of asset management, it is important that organizational objectives be translated down into asset management activities. Various asset management standards, including ISO 55000 and IAM, view this idea as the line of sight. The line-of-sight which provides guidance as to how all asset related documents and activities work together to achieve organizational goals. It provides understanding to stakeholders on how they contribute to the success of asset management. Figure 1 shows the line-of-sight for the asset management system.

Figure 1: Asset Management Line-of-Sight.

Organizational Strategy: The organizational strategy encompasses the Company's mission, values and goals.

Asset Management Policy: An asset management policy is a statement made by the organization intended to define the principals by which it will manage its assets. Newfoundland Power is developing an asset management policy to demonstrate its commitment to asset management to ensure its assets meet the long-term demands and requirements of the Company while balancing cost, risk and performance.

Strategic Asset Management Plan ("SAMP"). A SAMP is a document that describes the long-term strategic approach based upon the corporate principles as stated in the

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13 In 2022, Newfoundland Power issued a survey through CEATI to determine asset management trends among North American utilities. Of 18 responses, 12% of utilities were certified with ISO 55000, 18% aligned with ISO 55000, 41% exploring ISO 55000, and 29% not considering ISO 55000.

policy. The SAMP is used to guide the development of asset management objectives. Newfoundland Power is currently developing a SAMP.

Asset Management Objectives: Newfoundland Power is currently developing a number of asset management objectives highlighting the results the asset management system should deliver. The objectives translate the organizational strategic priorities into asset management objectives that are actionable for each asset class.

Asset Strategies: Asset strategies set out the long-term objectives for managing specific assets, including life extension, obsolescence management, and asset replacement. Newfoundland Power currently has strategies in place for managing assets.[14] Changes to asset strategies will be prioritized based upon the Company priorities and best utility practice.

Asset Management Plan ("AMP"): AMPs describe, in detail, the activities required to be carried out on assets to deliver asset management objectives, and strategies. The AMP includes the approach to the maintenance of an asset from construction to disposal to manage cost, risk and performance.[15]

Asset Management Activities: Asset lifecycle activities encompass the execution of asset operations, I&M and capital work. Asset management activities will be modified as appropriate with changes in strategies.

[14] Current strategies include, but are not limited to the Transmission Line Rebuild strategy, and the Substation Refurbishment and Modernization strategy.
[15] A single AMP may include details of multiple strategies for an asset class.

Figure 2 shows a timeline for activities that are being considered as part of the implementation plan. This timeline is subject to change as the plan is finalized.

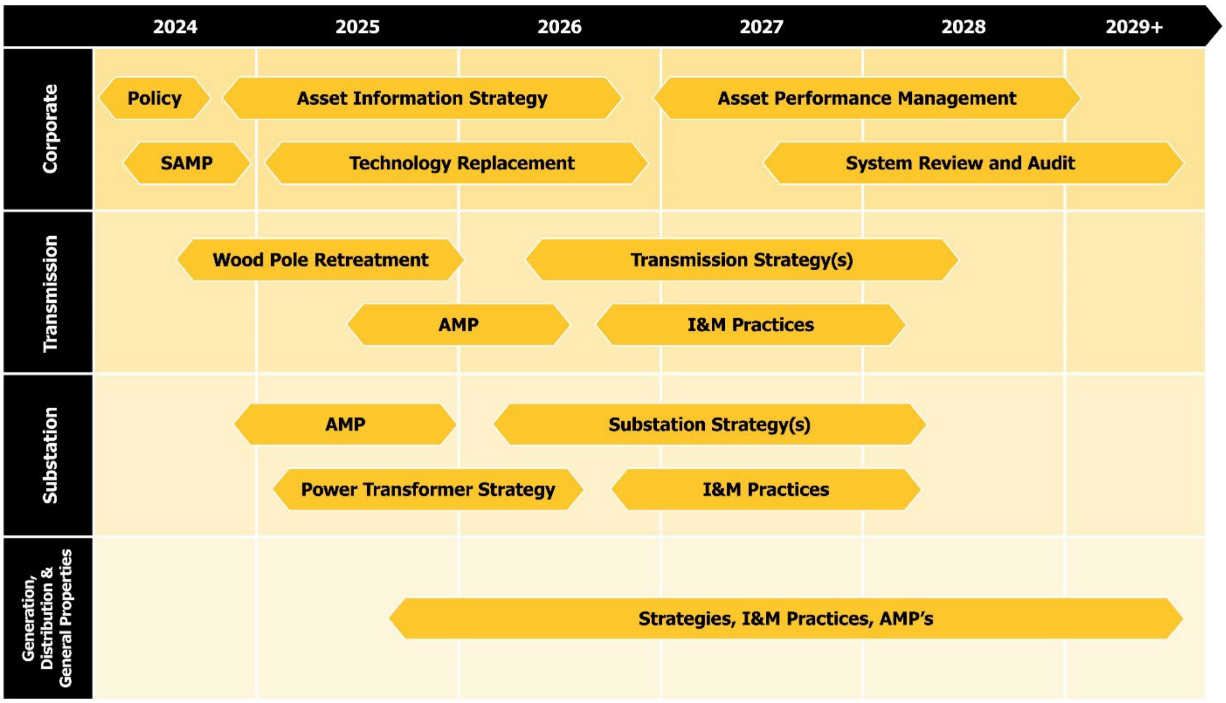

Figure 2: High level Implementation Plan.

Newfoundland Power's existing *Transmission Line Rebuild Strategy* is approaching the end of the defined 10-year plan. As transmission lines play an important role in providing reliable service to customers, additional strategies must be considered. Wood pole retreatment programs are being considered throughout the utility industry, including other utilities in Newfoundland and Labrador. A wood pole retreatment project will allow the Company to support the continued delivery of reliable service to customers.

A significant number of the Company's power transformers have aged beyond the service life typically observed in the industry. This poses an increasing risk of equipment failures that can result in extended outages to thousands of customers. Due to supply chain constraints and procurement lead times, Newfoundland Power must consider a strategy to proactively replace their power transformer fleet.

Starting in 2025, Newfoundland Power will be replacing its current asset management technology due to obsolescence. The new technology will support all functionality of the current technology, with the addition of enhancements that are native to modern solutions. Current businesses process and asset management practices will continue to be supported, while enabling the Company to explore opportunities, such as improving data analytics and increasing the digitalization and utilization of data. Implementation of a modern technology is a stepping stone for asset management maturity.

5.0 Summary

Newfoundland Power has successfully completed the current state assessment and target state assessment of their asset management review. The Company's implementation planning milestone is expected to be completed by year end 2024. The outcomes of the implementation planning phase, will be executed starting in 2025.

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

March 28, 2024

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

Attention: Jo-Anne Galarneau
Executive Director and Board Secretary

Dear Ms. Galarneau:

Re: 2023 Capital Expenditure Report

Enclosed please find Newfoundland Power Inc.'s 2023 Capital Expenditure Report (the "Report"). The Report is presented in compliance with Order No. P.U. 38 (2022) of the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board"), and its subsequent correspondence dated February 8, 2024 confirming the filing date pursuant to section 41 of the *Public Utilities Act*.

The Report provides information on capital expenditures approved in Order Nos. P.U. 14 (2023), P.U. 38 (2022), P.U. 36 (2021), P.U. 12 (2021), P.U. 10 (2021) and P.U. 37 (2020), including actual expenditures to December 31, 2023 and variances between actual and budgeted expenditures by project.

Variances of more than 10% of approved expenditures and $100,000 or greater are explained in the Notes contained in Appendix A to the Report. A discussion of approved capital expenditures in 2023 which were modified, re-prioritized, deferred, re-paced or cancelled is provided in Appendix B. Summaries of Key Performance Indicators in 2023 are provided in Appendix C.

If you have any questions on the enclosed, please contact the undersigned at your convenience.

Yours truly,

Lindsay Hollett
Senior Legal Counsel &
Assistant Corporate Secretary

Enclosure

ec. Shirley Walsh
Newfoundland & Labrador Hydro

Dennis Browne, K.C.
Browne Fitzgerald Morgan & Avis

Newfoundland Power Inc.
55 Kenmount Road • P.O. Box 8910 • St. John's, NL A1B 3P6
PHONE (709) 737-5364 • FAX (709) 737-2974 • **lhollett@newfoundlandpower.com**

2023 Capital Expenditure Report

March 28, 2024

Newfoundland Power Inc.

2023 Capital Expenditure Report

Explanatory Note

This report is filed in compliance with Order No. P.U. 38 (2022) of the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board"), and its subsequent correspondence dated February 8, 2024 confirming the filing date pursuant to section 41 of the *Public Utilities Act*.

Page 1 of the *2023 Capital Expenditure Report* outlines variances from budget of the capital expenditures approved by the Board in Order Nos. P.U. 14 (2023), P.U. 38 (2022), P.U. 36 (2021), P.U. 12 (2021), P.U. 10 (2021) and P.U. 37 (2020). The tables on pages 2 through 14 provide additional detail on capital expenditures in 2023, and also include information on capital projects approved for 2021 and 2022 that were not completed prior to 2023. Page 14 provides additional detail on multi-year projects.

Consistent with the variance criteria outlined in the *Capital Budget Application Guidelines (Provisional)* (the "Provisional Guidelines"), variances of more than 10% of approved expenditure and $100,000 or greater are explained in Appendix A.

For multi-year capital projects, total expenditures to date are reported, compared to total approved budget to date. Variances for multi-year capital projects will be reported in the capital expenditure report in the year following project completion.

Consistent with section V.C of the Provisional Guidelines, a discussion of approved capital expenditures in 2023 which were modified, re-prioritized, deferred, re-paced or cancelled is provided in Appendix B.

Consistent with section V.C of the Provisional Guidelines, summaries of Key Performance Indicators in 2023 are provided in Appendix C.

Newfoundland Power Inc.
2023 Capital Budget Variances
(000s)

	Approved[1]	Actual	Variance
Generation - Hydro	$9,476	$9,525[2]	$49
Generation - Thermal	335	214	(121)
Substations	20,720	20,955[3]	235
Transmission	12,284	9,203[4]	(3,081)
Distribution	53,671	57,328[5]	3,657
General Property	2,505	2,686[6]	181
Transportation	4,968	4,967[7]	($1)
Telecommunications	1,268	707	(561)
Information Systems	12,940	13,490[8]	550
Unforeseen Allowance	750	0	(750)
General Expenses Capitalized	4,000	5,100	1,100
Total	**$122,917**	**$124,175**	**$1,258**

Projects carried forward from prior years	$25,298	

1 Approved in Order Nos. P.U. 14 (2023), P.U. 38 (2022), P.U. 36 (2021), P.U. 12 (2021), P.U. 10 (2021) and P.U. 37 (2020).
2 Includes forecast expenditure of $1,235,000 for *Mobile Hydro Plant Refurbishment* and $300,000 for *Sandy Brook Plant Penstock Replacement* carried forward into 2024.
3 Includes forecast expenditure of $260,000 for *Walbournes Substation Refurbishment and Modernization*, $180,000 for *Molloy's Lane Substation Refurbishment and Modernization*, $1,499,000 for *Substation Spare Transofrmer Inventory* and $46,000 for *MUN-T2 Power Transformer Replacement* carried forward into 2024.
4 Includes forecast expenditure of $2,223,000 for *Transmission Line 55L Rebuild* carried forward into 2024.
5 Includes forecast expenditure of $418,000 for *Distribution Feeder Automation* carried forward into 2024.
6 Includes forecast expenditure of $100,000 for *Company Building Renovations* carried forward into 2024.
7 Includes forecast expenditure of $155,000 for *Replace Vehicles and Aerial Devices 2023-2024* and $1,356,000 for *Replace Vehicles and Aerial Devices 2022-2023* carried forward into 2024.
8 Includes forecast expenditures of $2,125,000 for *Customer Service System Replacement*, $127,000 for *Application Enhancements*, $296,000 for *Shared Server Infrastructure*, $405,000 for *System Upgrades* and $103,000 for *Network Infrastructure* carried forward into 2024.

2023 Capital Expenditure Report
(000s)

	Capital Budget			Actual Expenditure				
	2021 - 2022	2023	Total	2021 - 2022	2023	Carryover	Total	Variance
	A	B	C	D	E	F	G	H
2023 Projects	$ -	$ 122,917	$ 122,917	$ -	$ 113,347	$ 10,828	124,175	$ 1,258
2021-2022 Projects	53,765	-	53,765	35,676	25,298	-	60,974	7,209
Grand Total	**$ 53,765**	**$ 122,917**	**$ 176,682**	**$ 35,676**	**$ 138,645**	**$ 10,828**	**$ 185,149**	**$ 8,467**

Column A	Approved Capital Budget for 2021 and 2022
Column B	Approved Capital Budget for 2023
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2021 and 2022
Column E	Actual Capital Expenditure for 2023
Column F	Capital Projects Carried Forward to 2024
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2023 Capital Expenditure Report
(000s)

Category: Generation - Hydro

	Capital Budget			Actual Expenditure					
	2022	2023	Total	2022	2023	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2023 Projects									
Sandy Brook Hydro Plant Generator Refurbishment	$ -	$ 1,577	$ 1,577	$ -	$ 1,556	$ -	$ 1,556	$ (21)	
Hydro Facility Rehabilitation	-	877	877	-	821	-	821	(56)	
Hydro Plant Replacements Due to In-Service Failures	-	662	662	-	627	-	627	(35)	
	$ -	$ 3,116	$ 3,116	$ -	$ 3,004	$ -	$ 3,004	$ (112)	
2022 Projects									
Hydro Facility Rehabilitation (2022)	$ 2,062	$ -	$ 2,062	$ 1,841	$ 499	$ -	$ 2,340	$ 278	1
	$ 2,062	$ -	$ 2,062	$ 1,841	$ 499	$ -	$ 2,340	$ 278	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2022
Column B	Approved Capital Budget for 2023
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2022
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Column G	Total of Columns D, E and F
Column H	Column G less Column C

2023 Capital Expenditure Report
(000s)

Category: Generation - Thermal

	Capital Budget			Actual Expenditure					
	2022	**2023**	**Total**	**2022**	**2023**	**Carryover**	**Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
2023 Projects									
Thermal Plant Replacements Due to In-Service Failures	$ -	$ 335	$ 335	$ -	$ 214	$ -	$ 214	$ (121)	2
	$ -	$ 335	$ 335	$ -	$ 214	$ -	$ 214	$ (121)	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2022
Column B	Approved Capital Budget for 2023
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2022
Column E	Actual Capital Expenditure for 2023
Column F	Capital Projects Carried Forward to 2024
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2023 Capital Expenditure Report
(000s)

Category: Substations

	Capital Budget			Actual Expenditure					
	2022	2023	Total	2022	2023	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2023 Projects									
Walbournes Substation Refurbishment and Modernization	$ -	$ 4,955	$ 4,955	$ -	$ 4,835	$ 260	$ 5,095	$ 140	
Molloy's Lane Substation Refurbishment and Modernization	-	4,827	4,827	-	4,325	180	4,505	(322)	
Long Pond Substation Capacity Expansion	-	3,313	3,313	-	3,076	-	3,076	(237)	
Substation Spare Transformer Inventory	-	1,500	1,500	-	1	1,499	1,500	-	
Substation Protection and Control Replacements	-	667	667	-	669	-	669	2	
Substation Ground Grid Upgrades	-	563	563	-	511	-	511	(52)	
PCB Bushing Phase-Out	-	425	425	-	450	-	450	25	
Substation Replacements Due to In-Service Failures	-	4,422	4,422	-	5,101	-	5,101	679	3
	$ -	$ 20,672	$ 20,672	$ -	$ 18,968	$ 1,939	$ 20,907	$ 235	
2022 Projects									
Substations Refurbishment and Modernization	$ 7,049	-	$ 7,049	$ 8,009	$ 1,182	$ -	$ 9,191	$ 2,142	4
	$ 7,049	$ -	$ 7,049	$ 8,009	$ 1,182	$ -	$ 9,191	$ 2,142	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2022
Column B	Approved Capital Budget for 2023
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2022
Column E	Actual Capital Expenditure for 2023
Column F	Capital Projects Carried Forward to 2024
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2023 Capital Expenditure Report
(000s)

Category: Transmission

	Capital Budget			Actual Expenditure					
	2021 - 2022	2023	Total	2021 - 2022	2023	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2023 Projects									
Transmission Line Maintenance	-	2,610	$ 2,610	-	3,449	-	3,449	839	5
	$ -	$ 2,610	$ 2,610	$ -	$ 3,449	$ -	$ 3,449	$ 839	
2021 - 2022 Projects									
Transmission Line Extension - 35L	$ 1,343	$ -	$ 1,343	$ 2,112	$ 115	$ -	$ 2,227	$ 884	6
	$ 1,343	$ -	$ 1,343	$ 2,112	$ 115	$ -	$ 2,227	$ 884	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2021 and 2022
Column B	Approved Capital Budget for 2023
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2021 and 2022
Column E	Actual Capital Expenditure for 2023
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Column G	Total of Columns D, E and F
Column H	Column G less Column C

2023 Capital Expenditure Report
(000s)

Category: Distribution

	Capital Budget			Actual Expenditure					
	2021 - 2022	2023	Total	2021 - 2022	2023	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2023 Projects									
LED Street Lighting Replacement	$ -	$ 5,453	$ 5,453	$ -	$ 5,953	$ -	$ 5,953	$ 500	
Corner Brook Acute Care Hospital Redundant Supply	-	2,690	2,690	-	2,467	-	2,467	(223)	
Distribution Feeder Automation	-	1,054	1,054	-	579	418	997	(57)	
Feeder Additions for Load Growth	-	670	670	-	732	-	732	62	
Distribution Feeder SLA-05 Refurbishment	-	565	565	-	595	-	595	30	
Distribution Feeder PEP-02 Refurbishment	-	550	550	-	524	-	524	(26)	
Allowance for Funds Used During Construction	-	247	247	-	288	-	288	41	
Extensions	-	12,218	12,218	-	15,145	-	15,145	2,927	7
Reconstruction	-	6,699	6,699	-	7,622	-	7,622	923	8
Rebuild Distribution Lines	-	4,945	4,945	-	5,085	-	5,085	140	
Relocate/Replace Distribution Lines for Third Parties	-	3,803	3,803	-	3,109	-	3,109	(694)	9
Replacement Transformers	-	3,345	3,345	-	3,411	-	3,411	66	
New Transformers	-	2,967	2,967	-	2,999	-	2,999	32	
New Services	-	2,916	2,916	-	3,260	-	3,260	344	10
New Street Lighting	-	2,618	2,618	-	2,267	-	2,267	(351)	11
Replacement Street Lighting	-	770	770	-	774	-	774	4	
Replacement Meters	-	662	662	-	530	-	530	(132)	12
Replacement Services	-	546	546	-	352	-	352	(194)	13
New Meters	-	297	297	-	510	-	510	213	14
	$ -	$ 53,015	$ 53,015	$ -	$ 56,202	$ 418	$ 56,620	$ 3,605	
2021 - 2022 Projects									
Trunk Feeders	$ 800	$ -	$ 800	$ 476	$ 409	$ -	$ 885	$ 85	
Distribution Reliability Initiative	350	-	350	116	249	-	365	15	
	$ 1,150	$ -	$ 1,150	$ 592	$ 658	$ -	$ 1,250	$ 100	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2021 and 2022
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Column C	Total of Columns A and B
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Column F	Capital Projects Carried Forward to 2024
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2023 Capital Expenditure Report
(000s)

Category: General Property

	Capital Budget			Actual Expenditure					
	2022	**2023**	**Total**	**2022**	**2023**	**Carryover**	**Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
2023 Projects									
Company Building Renovations	$ -	$ 741	$ 741	$ -	$ 726	$ 100	$ 826	$ 85	
Physical Security Upgrades	-	576	576	-	628	-	628	52	
Additions to Real Property	-	654	654	-	677	-	677	23	
Tools and Equipment	-	534	534	-	555	-	555	21	
	$ -	$ 2,505	$ 2,505	$ -	$ 2,586	$ 100	$ 2,686	$ 181	
2022 Projects									
Clarenville Area Office Building Refurbishment	$ 854	$ -	$ 854	$ 787	$ 135	$ -	$ 922	$ 68	
	$ 854	$ -	$ 854	$ 787	$ 135	$ -	$ 922	$ 68	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2022
Column B	Approved Capital Budget for 2023
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2022
Column E	Actual Capital Expenditure for 2023
Column F	Capital Projects Carried Forward to 2024
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2023 Capital Expenditure Report
(000s)

Category: Transportation

	Capital Budget			Actual Expenditure					
	2021 - 2022	2023	Total	2021 - 2022	2023	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2021 Projects									
Purchase Vehicles and Aerial Devices[9]	$ 4,032	$ -	$ 4,032	$ 2,758	$ 1,683	$ -	$ 4,441	$ 409	15
	$ 4,032	$ -	$ 4,032	$ 2,758	$ 1,683	$ -	$ 4,441	$ 409	

* See Appendix A for notes containing variance explanations.

Column A Approved Capital Budget for 2021 and 2022
Column B Approved Capital Budget for 2023
Column C Total of Columns A and B
Column D Actual Capital Expenditure for 2021 and 2022
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Column H Column G less Column C

[9] In 2022, due to long delivery times, Newfoundland Power initiated a multi-year approach to procuring heavy/medium duty fleet vehicles.

2023 Capital Expenditure Report
(000s)

Category: Telecommunications

	Capital Budget			Actual Expenditure					
	2021 - 2022	**2023**	**Total**	**2021 - 2022**	**2023**	**Carryover**	**Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
<u>2023 Projects</u>									
Communications Equipment Upgrades	$ -	$ 118	$ 118	$ -	$ 121	$ -	$ 121	$ 3	
	$ -	$ 118	$ 118	$ -	$ 121	$ -	$ 121	$ 3	
<u>2021 - 2022 Projects</u>									
Fibre Optic Cable Builds	$ 350	$ -	$ 350	$ 332	$ 97	$ -	$ 429	$ 79	
	$ 350	$ -	$ 350	$ 332	$ 97	$ -	$ 429	$ 79	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2021 and 2022
Column B	Approved Capital Budget for 2023
Column C	Total of Columns A and B
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Column H	Column G less Column C

2023 Capital Expenditure Report
(000s)

Category: Information Systems

	Capital Budget			Actual Expenditure					
	2021 - 2022	2023	Total	2021 - 2022	2023	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2023 Projects									
Application Enhancements	$ -	$ 1,538	$ 1,538	$ -	$ 1,529	$ 127	$ 1,656	$ 118	
Shared Server Infrastructure	-	1,176	1,176	-	968	296	1,264	88	
System Upgrades	-	962	962	-	581	405	986	24	
Cybersecurity Upgrades	-	882	882	-	957	-	957	75	
Network Infrastructure	-	419	419	-	329	103	432	13	
Personal Computer Infrastructure	-	600	600	-	672	-	672	72	
	$ -	$ 5,577	$ 5,577	$ -	$ 5,036	$ 931	$ 5,967	$ 390	
2021 - 2022 Projects									
Application Enhancements	$ 978	$ -	$ 978	$ 911	$ 134	$ -	$ 1,045	$ 67	
Network Infrastructure	508	-	508	377	172	-	549	41	
	$ 1,486	$ -	$ 1,486	$ 1,288	$ 306	$ -	$ 1,594	$ 108	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2021 and 2022
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Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2021 and 2022
Column E	Actual Capital Expenditure for 2023
Column F	Capital Projects Carried Forward to 2024
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Column H	Column G less Column C

2023 Capital Expenditure Report
(000s)

Category: Unforeseen Allowance

	Capital Budget 2023	Capital Budget Total	Actual Expenditure 2023	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	
2023 Projects							
Allowance for Unforeseen Items	$ 750	$ 750	$ -	$ -	$ -	$ (750)	16
	$ 750	$ 750	$ -	$ -	$ -	$ (750)	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2023
Column B	Total of Column A
Column C	Actual Capital Expenditure for 2023
Column D	Capital Projects Carried Forward to 2024
Column E	Total of Columns C and D
Column F	Column E less Column B

2023 Capital Expenditure Report
(000s)

Category: General Expenses Capitalized

	Capital Budget 2023	Capital Budget Total	Actual Expenditure 2023	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	
2023 Projects							
General Expenses Capitalized	$ 4,000	$ 4,000	$ 5,100	$ -	$ 5,100	$ 1,100	17
	$ 4,000	$ 4,000	$ 5,100	$ -	$ 5,100	$ 1,100	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2023
Column B	Total of Column A
Column C	Actual Capital Expenditure for 2023
Column D	Capital Projects Carried Forward to 2024
Column E	Total of Columns C and D
Column F	Column E less Column B

2023 Capital Expenditure Report
Multi-Year Projects
(000s)

Category: Multi-Year Projects

	Capital Budget			Actual Expenditure					
	2021 - 2022	2023	Total	2021 - 2022	2023	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
Substations									
MUN-T2 Power Transformer Replacement	$ -	$ 48	$ 48	-	$ 2	$ 46	$ 48	$ -	
Transmission									
Transmission Line 55L Rebuild	-	5,328	5,328	-	3,106	2,223	5,329	1	
Transmission Line 94L Rebuild	4,473	4,346	8,819	552	7,347	-	7,899	(920)	18
Distribution									
Distribution Reliability Initiative	-	656	656	-	708	-	708	52	
Generation - Hydro									
Mobile Hydro Plant Refurbishment	-	1,666	1,666	-	431	1,235	1,666	-	
Sandy Brook Plant Penstock Replacement	400	4,694	5,094	275	4,555	300	5,130	36	
Transportation									
Replace Vehicles and Aerial Devices 2023-2024	-	2,833	2,833	-	1,519	155	1,674	(1,159)	19
Replace Vehicles and Aerial Devices 2022-2023	3,089	2,135	5,224	1,754	3,395	1,356	6,505	1,281	20
Information Systems									
Microsoft Enterprise Agreement	490	245	735	578	293	-	871	136	21
Customer Service System Replacement	25,729	5,917	31,646	13,869	15,651	2,125	31,645	(1)	
Workforce Management System Replacement	808	1,201	2,009	840	1,314	-	2,154	145	
Telecommunications									
St. John's Teleprotection System Replacement	450	1,150	1,600	89	969	-	1,058	(542)	22
	$ 35,439	$ 30,219	$ 65,658	$ 17,957	$ 39,290	$ 7,440	$ 64,687	$ (971)	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2021 and 2022
Column B	Approved Capital Budget for 2023
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2021 and 2022
Column E	Actual Capital Expenditure for 2023
Column F	Capital Projects Carried Forward to 2024
Column G	Total of Columns D, E and F
Column H	Column G less Column C

APPENDIX A:

Variance Notes

Generation – Hydro

1. *Hydro Facility Rehabilitation (2022 Project):*
   Budget: $2,062,000 Actual: $2,340,000 Variance: 278,000

   In 2023, capital expenditures associated with the *Hydro Facility Rehabilitation* project were $278,000, or 13%, higher than the budget estimate. A component of this project involved overhauling turbine Unit 2 at the Petty Harbour hydro plant. Due to the vintage and design of the turbine, many components could not be observed prior to unit disassembly. Upon disassembly of the unit, it was determined that the internal components were more deteriorated than anticipated. As a result, more components within the turbine, mainly the wicket gate operating ring, required replacement.

Generation – Thermal

2. *Thermal Replacements Due to In-Service Failures:*
   Budget: $335,000 Actual: $214,000 Variance: ($121,000)

   The budget estimate for the *Thermal Replacements Due to In-Service Failures* program was based on the five-year historical average. 2023 capital expenditures were $121,000, or 36%, lower than the budget estimate, primarily due to less required work being identified through inspections and engineering assessments as compared to the five-year average.

Substations

3. *Substation Replacements Due to In-Service Failures:*
   Budget: $4,422,000 Actual: $5,101,000 Variance: $679,000

   The budget estimate for the *Replacements Due to In-Service Failures* program was based on the five-year historical average. Capital expenditures in 2023 were $679,000, or 15%, higher than the budget estimate, primarily due to costs associated with corporate spares being higher than the historical average.

4. *Substations Refurbishment and Modernization (2022 Project):*
   Budget: $7,049,000 Actual: $9,191,000 Variance: $2,142,000

   In 2023, capital expenditures for the *Substations Refurbishment and Modernization* project were $2,142,000, or 30%, higher than the budget estimate, primarily due to higher material costs and contractor labour costs as compared to budget estimates. In addition, unexpected site-related issues at the Glovertown and Humber Substations resulted in construction delays and additional costs for unplanned work.

Transmission

5. *Transmission Line Maintenance*
Budget: $2,610,000 Actual: $3,449,000 Variance: $839,000

The budget estimate for the *Transmission Line Maintenance* program was based on the five-year historical average. In 2023, the actual expenditures for the *Transmission Line Maintenance* program were $839,000, or 32%, higher than the budget estimate, primarily due to higher material and contractor labour costs. Additionally, unplanned corrective maintenance activities to address transmission asset failures occurred late in the year, which increased the amount of work required in 2023.

6. *Transmission Line Extension – 35L (2021 Project):*
Budget: $1,343,000 Actual: $2,227,000 Variance: $884,000

In 2023, actual expenditure on the *Transmission Line Extension – 35L* project was $884,000, or 66%, higher than the budget estimate resulting from an increase in materials and contract labour costs.

The budget estimate for the *Transmission Line Extension – 35L* project was based on engineering cost estimates. Original cost estimates were based on building six kilometres of transmission line and construction using wood poles. Due to land and right-of-way issues, the new line extension was routed closer to Winsor Lake, a public water supply. This change in location resulted in a requirement to construct eight kilometres of transmission line using steel poles rather than treated wood poles, which increased the cost of materials and contract labour for the project.

Distribution

7. *Extensions:*
Budget: $12,218,000 Actual: $15,145,000 Variance: $2,927,000

The *Extensions* program budget is determined based on the forecast number of new customer connections and the average historical cost of constructing extensions. In 2023, the actual capital expenditure for the *Extensions* program was $2,927,000, or 24%, higher than the budget estimate.

In 2023 Newfoundland Power entered into a new contract for pole installation services, in which contract labour increased by an average of approximately 23% over the previous, expired, agreement. Additionally, the cost of pole materials increased by an average of approximately 15%. There was also an increase in the number of large-scale extensions to connect customers, including an extension of three-phase distribution line to two dairy farms located in the Town of Cormack.[1]

8. *Reconstruction:*
Budget: $6,699,000 Actual: $7,622,000 Variance: $923,000

The *Reconstruction* program budget estimate is determined based on the five-year historical average. The actual expenditures for the *Reconstruction* program were $923,000, or 14%, higher than the budget estimate. In 2023, major events late in the year resulted in additional work being required as compared to the historical average.

9. *Relocate/Replace Distribution Lines for Third Parties:*
Budget: $3,803,000 Actual: $3,109,000 Variance: ($694,000)

The actual expenditure for the *Relocate/Replace Distribution Lines for Third Parties* program was $694,000, or 18%, lower than the budget estimate.

The *Relocate/Replace Distribution Lines for Third Parties* program budget estimate is determined based on the five-year historical average. In 2023 there was a reduction in work related to the Rogers Fiber to the Home project. As a result, the amount of distribution plant requiring upgrade to accommodate the attachment of new communications plant was below the historical average.

1 A Contribution in Aid of Construction was approved for this work in Order No. P.U. 27 (2023).

Distribution

10. *New Services:*
Budget: $2,916,000 Actual: $3,260,000 Variance: $344,000

The actual expenditure for the *New Services* program was $344,000, or 12%, higher than the budget estimate.

The *New Services* program budget estimate is determined based on the forecast number of new customer connections, and the average historical cost of connecting a new customer. The budget was based on 2,185 new customer connections for 2023, whereas actual customer connections were 2,372, or approximately 9% above plan. Additionally, an increase in larger services, such as 400 A, required larger service conductors, contributing to the increase in costs.[2]

11. *New Street Lighting:*
Budget: $2,618,000 Actual: $2,267,000 Variance: ($351,000)

The 2023 budget for the *New Street Lighting* program was based on the five-year historical average. Actual capital expenditures were $351,000, or 13%, less than the budget estimate, primarily due to a 13% decrease in new street light installations as compared to previous years.

12. *Replacement Meters:*
Budget: $662,000 Actual: $530,000 Variance: ($132,000)

The 2023 budget for the *Replacement Meters* program was based on the five-year historical average. Actual capital expenditures in 2023 were $132,000, or 20%, lower than the budget estimate.

The *2023 Capital Budget Application* was the first capital budget filed under the Provisional Guidelines. The Provisional Guidelines require capital expenditures to be classified based on one of six investment classifications. Previously, budgets and expenditures for meters were pooled as a single capital project. In preparing the *2023 Capital Budget Application*, the Company split capital expenditures for meters into new and replacement to comply with the Provisional Guidelines. Newfoundland Power used a split of 70% replacement and 30% new based on previous experience, forecast customer connections and meter replacements. In 2023, the split for meters was 51% replacement and 49% new. Newfoundland Power will incorporate actual splits in its budgeting methodology going forward.

[2] For example, underground service connections for 400 A and larger require 1/0 copper triplex. The cost for this material is approximately $25 per metre, compared to overhead 2/0 aluminum triplex which costs approximately $7 per metre.

Distribution

13. *Replacement Services:*
Budget: $546,000 Actual: $352,000 Variance: ($194,000)

The 2023 budget for the *Replacement Services* program was based on the five-year historical average. Actual capital expenditures in 2023 were $194,000, or 36%, lower than the budget estimate. The reduction in actual expenditures was largely due to less required work to replace failed service wire than the historical average.

14. *New Meters:*
Budget: $297,000 Actual: $510,000 Variance: $213,000

The 2023 budget for the *New Meters* program was based on the forecast number of new customer connections and the five-year historical average cost. Actual capital expenditures in 2023 were $213,000, or 72%, higher than the budget estimate.

The *2023 Capital Budget Application* was the first capital budget filed under the Provisional Guidelines. The Provisional Guidelines require capital expenditures to be classified based on one of six investment classifications. Previously, budgets and expenditures for meters were pooled as a single capital project. In preparing the *2023 Capital Budget Application*, the Company split capital expenditures for meters into new and replacement to comply with the Provisional Guidelines. Newfoundland Power used a split of 70% replacement and 30% new based on previous experience, forecast customer connections and meter replacements. In 2023, the split for meters was 51% replacement and 49% new. Newfoundland Power will incorporate actual splits in its budgeting methodology going forward.

Transportation

15. Purchase Vehicles and Aerial Devices (2021 Project):

Budget: $4,032,000 Actual: $4,441,000 Variance: $409,000

Actual capital expenditures for the *Purchase Vehicles and Aerial Devices* project were $409,000, or 10%, higher than the budget estimate, primarily due to vendor price increases resulting from supply chain disruptions affecting the price of raw materials and parts and a manufacturer labour shortage.

In 2023 the Company received the heavy fleet vehicles ordered under the *Purchase Vehicles and Aerial Devices* project in 2021. The original pricing remained in place for the cab and chassis units, but, due to the long delivery times, the cost for the five aerial devices increased by 18% per unit.

Unforeseen Allowance

16. *Allowance for Unforeseen Items:*
Budget: $750,000 Actual: $0 Variance: ($750,000)

No expenditures were required in 2023.

General Expenses Capitalized

17. General Expenses Capitalized:

Budget: $4,000,000 Actual: $5,100,000 Variance: $1,100,000

In 2023, actual capital expenditures for *General Expenses Capitalized* were $1,100,000, or 28%, higher than the budget estimate, resulting primarily from inflationary increases and additional labour costs for capital planning.

Multi-Year Projects

18. Transmission Line Rebuild (94L) (2022-2024 Multi-Year Project)
Budget: $8,819,000 Actual: $7,899,000 Variance: ($920,000)

The *Transmission Line Rebuild (94L)* project was a multi-year project that commenced in 2022. Actual capital expenditures to date were $7,899,000. As described in Appendix B, Newfoundland Power is reviewing the remaining scope of work for the *Transmission Line Rebuild (94L)* project as a result of increased contract prices to complete the work.

19. Replace Vehicles and Aerial Devices (2023-2024)
Budget: $2,833,000 Actual: $1,674,000 Variance: ($1,159,000)

The *Replace Vehicles and Aerial Devices (2023-2024)* project is a multi-year project that commenced in 2023. Actual capital expenditures incurred to date are $1,674,000, including $155,000 carried over into 2024. The overall reduction in expenditure of $1,159,000 associated with the *Replace Vehicles and Aerial Devices (2023-2024)* project is largely due to adjustments in the number of passenger vehicles and offroad vehicles ordered by the Company in order to accommodate the purchase of an additional heavy-duty fleet vehicle as described in Note 20 below. Overall, transportation expenditures in 2023 resulted in a variance of $122,000.

20. Replace Vehicles and Aerial Devices (2022-2023)
Budget: $5,224,000 Actual: $6,505,000 Variance: $1,281,000

The *Replace Vehicles and Aerial Devices (2022-2023)* project was a multi-year project that commenced in 2022. Actual capital expenditures were $6,505,000 including $1,356,000 carried over into 2024. In 2023, the Company determined that an additional heavy-duty fleet vehicle from plan was required in the Western Region to maintain appropriate resourcing and deployment capabilities for field crews.[3] Overall, transportation expenditures in 2023 resulted in a variance of $122,000.

[3] In the Corner Brook area, there are 10 Powerline Technicians ("PLTs"). Typically, field crews are deployed in heavy-duty vehicles in groups of two. The Corner Brook area was operating with four heavy-duty vehicles. Scheduled and unscheduled maintenance of heavy-duty fleet vehicles hindered the Company's ability efficiently respond to customer requirements in this operating area.

Multi-Year Projects

21. *Microsoft Enterprise Agreement (2021-2023 Multi-Year Project)*
Budget: $735,000 Actual: $871,000 Variance: $136,000

The *Microsoft Enterprise Agreement* project was a multi-year project that commenced in 2021. Actual capital expenditures were $136,000, or 19% higher than the total budget estimate, largely due to increases in vendor pricing, as well as an increase in the number of licenses required.

22. *St. John's Teleprotection System Replacement (2022-2023 Multi-Year Project)*
Budget: $1,600,000 Actual: $1,058,000 Variance: ($542,000)

The *St. John's Teleprotection System Replacement* project was a multi-year project that commenced in 2022. Actual capital expenditures were $542,000 or 34%, lower than the total budget estimate, largely due to the Company securing favorable contract pricing through the tendering process.

APPENDIX B:

Discussion of Capital Expenditures

Newfoundland Power's Capital Planning Process

Newfoundland Power's annual capital expenditures are the product of a comprehensive capital planning process. The Company's capital planning process applies sound engineering and objective data to determine which expenditures are required annually to provide customers with access to safe and reliable service, in an environmentally responsible manner, at the lowest possible cost.

Newfoundland Power's annual capital expenditures include a combination of recurring programs and specific projects. The capital planning process for programs and projects is described below.

Capital Program Planning

Programs include capital investments related to high-volume, repetitive work that is required on an ongoing basis. Programs include:

(i) Capital work required to connect new customers to the electrical system, such as the installation of services and meters;
(ii) Corrective and preventative maintenance programs necessary to maintain the electrical system, including the replacement of equipment that has failed or deteriorated; and
(iii) Capital expenditures necessary to replace or add specific materials used in providing service to customers, such as personal computers, tools and equipment.

Programs required to connect new customers to the electrical system are generally budgeted on the basis of forecast customer requirements. Each year, Newfoundland Power updates its capital plan to reflect its most recent Customer, Energy and Demand Forecast. The Customer, Energy and Demand Forecast estimates new customer connections that are expected over the next five years based on economic inputs from the Conference Board of Canada, such as forecast housing starts. This data is then used to determine forecast expenditures to connect new customers, including forecast expenditures for meters, services, and extensions to the distribution system.

Programs required to complete corrective and preventative maintenance of the electrical system are generally budgeted on the basis of historical expenditures and forecast inflation.[1] Capital requirements for corrective and preventative maintenance programs tend to be reasonably stable over time. Each year, the Company updates its forecast expenditures for these programs based on the most recent five-year average of expenditures and the latest forecast of inflation. This budgeting methodology helps to ensure forecast expenditures reflect the Company's most recent experience with maintaining the electrical system.

[1] Inflation is calculated on the basis of the GDP Deflator for Canada for non-labour costs and the Company's internal labour inflation rate for labour costs.

Capital expenditures for programs required to replace or add specific materials used in providing service to customers are generally budgeted based on a combination of historical expenditures, forecast inflation, and identified operational requirements. For example, identified operational requirements could include the need to purchase a specific quantity of personal computers.

In forecasting program expenditures, Newfoundland Power reviews any recent variances in actual costs from approved budgets and the reasons for those variances. If significant variances are observed in consecutive years, an analysis is undertaken to determine whether a different budgeting methodology would be more reflective of forecast requirements.[2]

Capital Project Planning

Projects include capital investments for identifiable assets where the required work has a defined schedule, scope and budget based on detailed engineering estimates.

Forecast expenditures related to projects are updated annually to reflect the latest:

(i) Condition assessments of electrical system assets. Information on asset condition is obtained through annual inspection programs, engineering reviews and recent operating experience. This information identifies equipment that is deteriorated, deficient, or has failed and requires replacement or refurbishment to extend its useful service life.

(ii) Forecasts of electrical system load. System load forecasts are produced annually using computer modelling to determine any areas where capital expenditures are required to respond to customers' changing electrical system requirements.

(iii) Changes in economic factors or industry requirements. This may include changes in engineering standards, regulatory requirements, or economic factors, such as marginal system costs, that could affect requirements for capital expenditures.

(iv) Changes in operational requirements. This may include changes affecting Company information systems, such as obsolescence or cybersecurity requirements, as well as opportunities identified to enhance operational efficiency or effectiveness.

2023 Capital Expenditures Overall

As detailed in the *2023 Capital Expenditure Report*, approved capital expenditures in 2023 totalled $122.9 million. Actual expenditures were $124.2 million, including forecast expenditures of $10.8 million carried forward into 2024. Actual expenditures were $1,258,000 or 1% higher than the total approved capital budget of $122.9 million.

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2 For example, Newfoundland Power adjusted its budget for forecasting expenditures under its *Street Lighting* program as part of its *2022 Capital Budget Application* in response to previous variances.

2023 Capital Project Changes

The *Transmission Line Rebuild (94L)* project was a multi-year project that commenced in 2022. The 2022 scope of work was executed in 2023, due in part to environmental assessment and permitting delays.

Newfoundland Power is reviewing the remaining scope of work for the *Transmission Line Rebuild (94L)* project as a result of increased contract prices to complete the work, which will result in a material increase in project expenditures. Consistent with section V.6 of the Provisional Guidelines, the Company will file information associated with the material increase in expenditures, along with any material changes in the remaining scope of work, associate with this project for further review by the Board as part of its *2025 Capital Budget Application.*

APPENDIX C:

Key Performance Indicators

A summary in table and graphical format of variance metrics for capital projects and programs. is provided below in accordance with the Provisional Guidelines.[1]

2023 Capital Projects

In 2023, Newfoundland Power had a total of 37 capital projects, 19 of which were fully completed in 2023.[2] The approved budget of the 19 completed capital projects totaled $26,401,000 and the final cost was $26,520,000.

Table 1 provides the number of capital projects planned compared to the number of capital projects completed, presented by investment classification and materiality threshold.

Table 1
2023 Capital Projects
Planned and Completed

Investment Classification	Materiality Threshold	Planned	Completed
Access	<$1 million	-	-
	$1 million to $5 million	2	2
	>$5 million	-	-
Total Access		2	2
General Plant	<$1 million	6	3
	$1 million to $5 million	5	2
	>$5 million	2	-
Total General Plant[3]		13	5
Mandatory	<$1 million	3	3
	$1 million to $5 million	1	1
	>$5 million	-	-
Total Mandatory		4	4

1 As this is a new requirement, Newfoundland Power is only providing variance metrics for 2023 at this time. In the future, as Newfoundland Power executes its annual capital program, it will report on additional years of variance metrics to provide graphical data in addition to tabular data.

2 Projects not completed included six multi-year capital projects that commenced in 2023 and continued in 2024. An additional 12 capital projects had forecast carryover expenditures into 2024 as outlined above.

3 Of the eight capital projects not completed in 2023, one project is an ongoing multi-year project with expenditures in 2024. Six capital projects are substantially complete, with small carryovers forecasted in 2024. One capital project with carryover forecasted in 2024 is anticipated to be completed by the second quarter of 2024 as a result of the timing of availability of resources.

Table 1 2023 Capital Projects Planned and Completed			
Investment Classification	Materiality Threshold	Planned	Completed
Renewal	<$1 million	5	4
	$1 million to $5 million	6	1
	>$5 million	3	-
Total Renewal[4]		**14**	**5**
Service Enhancement	<$1 million	1	1
	$1 million to $5 million	1	-
	>$5 million	1	1
Total Service Enhancement[5]		**3**	**2**
System Growth	<$1 million	1	1
	$1 million to $5 million	-	-
	>$5 million	-	-
Total System Growth		**1**	**1**
Overall	<$1 million	16	12
	$1 million to $5 million	15	6
	>$5 million	6	1
Total Overall		**37**	**19**

[4] Of the nine capital projects not completed in 2023, five projects are ongoing multi-year projects with expenditures in 2024. The remaining four capital projects are substantially complete with small carryovers forecasted into 2024 to accommodate delivery times of materials or to complete minor site work.

[5] The *Distribution Feeder Automation* project was not completed in 2023, with carryover forecasted into 2024 to accommodate delayed delivery of materials.

Table 2 provides the approved 2023 budget amount of the capital projects that were completed in 2023 compared to the final cost of the project, presented by investment classification and materiality threshold.

Table 2
2023 Capital Projects Completed
Budget and Final Costs
($000s)

Investment Classification	Materiality Threshold	Approved Budget	Final Cost
Access	<$1 million	-	-
	$1 million to $5 million	6,003	5,543
	>$5 million	-	-
Total Access		**6,003**	**5,543**
General Plant	<$1 million	1,703	1,878
	$1 million to $5 million	2,351	1,900
	>$5 million	-	-
Total General Plant		**4,054**	**3,778**
Mandatory	<$1 million	1,422	738
	$1 million to $5 million	4,000	5,100
	>$5 million	-	-
Total Mandatory		**5,422**	**5,838**
Renewal	<$1 million	2,659	2,609
	$1 million to $5 million	1,577	1,556
	>$5 million	-	-
Total Renewal		**4,236**	**4,165**
Service Enhancement	<$1 million	563	511
	$1 million to $5 million	-	-
	>$5 million	5,453	5,953
Total Service Enhancement		**6,016**	**6,464**

Table 2 2023 Capital Projects Completed Budget and Final Costs ($000s)			
Investment Classification	Materiality Threshold	Approved Budget	Final Cost
System Growth	<$1 million	670	732
	$1 million to $5 million	-	-
	>$5 million	-	-
Total System Growth		670	732
Overall	<$1 million	7,017	6,468
	$1 million to $5 million	13,931	14,099
	>$5 million	5,453	5,953
Total Overall		26,401	26,520

2023 Capital Programs

In 2023, Newfoundland Power had four capital programs whose budgets were determined based on forecast customer connections or forecast units to be replaced. These include the *Extensions* program, *New Services* program, *New Meters* program, and *Replacement Meters* program.

Table 3 provides the approved budget and final cost, number of units planned and completed, as well as the estimated average unit cost and actual average unit cost by materiality threshold.

Table 3
2023 Capital Programs

Materiality Threshold	Program	Approved Budget ($000s)	Final Cost ($000s)	Number of Planned Units[6]	Actual Number of Units[7]	Estimated Average Unit Cost ($)	Actual Average Unit Cost ($)
<$1 million	New Meters	297	510	2,185	2,372	136	215
	Replacement Meters	662	530	4,877	2,898	136	183
$1 million to $5 million	New Services	2,916	3,260	2,185	2,372	1,335	1,374
>$5 million	Extensions	12,218	15,145	2,185	2,372	5,592	6,385

[6] For the *New Meters, New Services,* and *Extensions* programs, planned units reflect the forecasted customer connections. For the *Replacement Meters* program, planned units reflect the sum of forecast replacement meters, Compliance Sampling Orders ("CSOs") and Government Retest Orders ("GROs").

[7] For the *New Meters, New Services,* and *Extensions* programs, actual units reflect the actual number of customer connections. For the *Replacement Meters* program, actual units reflect the sum of meters replaced, CSOs, and GROs.

NEWFOUNDLAND POWER
A FORTIS COMPANY

2024 Capital Budget Expenditure Status Report

June 2024

Newfoundland Power Inc.

2024 Capital Budget Expenditure
Status Report

Compliance Matter

The *2024 Capital Budget Expenditure Status Report* is presented in compliance with the directive of the Board of Commissioners of Public Utilities (the "Board") contained on page 4, paragraph 7 of Order No. P.U. 2 (2024):

> *"Unless otherwise directed by the Board, Newfoundland Power shall provide, in conjunction with its 2025 Capital Budget Application, a status report on the 2024 capital budget expenditures showing for each project:*
> *i) the approved budget for 2024;*
> *ii) the expenditures prior to 2024;*
> *iii) the 2024 expenditures to the date of the application;*
> *iv) the remaining projected expenditures for 2024;*
> *v) the variance between the projected total expenditures and the approved budget; and*
> *vi) an explanation of the variance."*

Overview

Page 1 of the *2024 Capital Budget Expenditure Status Report* outlines the forecast variances from budget of the 2024 capital expenditures approved by the Board. The detailed tables on pages 2 to 8 provide additional detail on the capital expenditures for 2024 which were approved in Order No. P.U. 2 (2024) and Order No. P.U. 14 (2023). The additional detail is organized by single-year projects and programs approved for 2024, multi-year projects approved to commence in 2024 and previously approved multi-year projects with expenditures occurring in 2024.

The *Capital Budget Application Guidelines (Provisional)* (the "Provisional Guidelines") require variance explanations to be provided for variances of more than 10% of approved expenditure and $100,000 or greater. For the *2024 Capital Budget Expenditure Status Report*, there are six projects that meet the criteria for variance explanations. These explanations are contained in Appendix A, which immediately follows the conclusion of the *2024 Capital Expenditure Status Report*.

Newfoundland Power will provide updated information to the Board in its regular reporting and upon request of the Board.

Newfoundland Power Inc.
2024 Capital Budget Expenditure Status Report
Capital Expenditure Overview
($000)

	Annual Budget	Expenditures		Annual Forecast	
		Actual	Forecast		
Asset Class and Project Description	**2024 Budget**	**January to April**	**May to December**	**2024 Forecast**	**Variance**
Generation - Hydro	5,329	891	4,438	5,329	0
Generation - Thermal	311	0	311	311	0
Substations	22,171	3,612	18,559	22,171	0
Transmission	15,064	1,100	13,964	15,064	0
Distribution	54,865	22,013	38,802	60,815	5,950
General Property	2,340	341	1,999	2,340	0
Transportation	3,806	88	3,718	3,806	0
Telecommunication	502	10	492	502	0
Information Systems	6,180	1,408	4,772	6,180	0
Unforeseen Items	750	0	750	750	0
General Expenses Capitalized	4,500	1,728	2,772	4,500	0
Total	**115,818**	**31,191**	**90,577**	**121,768**	**5,950**

Expenditure Type					
Single-Year Projects and Programs Over $750,000	83,583	27,747	61,786	89,533	5,950
Single-Year Projects and Programs $750,000 and Under	10,514	1,578	8,936	10,514	0
Multi-Year Projects Commencing in 2024	5,234	238	4,996	5,234	0
Multi-Year Projects Commencing Prior to 2024	16,487	1,628	14,859	16,487	0
Total	**115,818**	**31,191**	**90,577**	**121,768**	**5,950**

Newfoundland Power Inc.
2024 Capital Budget Expenditure Status Report
Single-Year Projects and Programs Over $750,000[1]
($000)

Asset Class and Project Description	Annual Budget	Expenditures		Annual Forecast		
		Actual	Forecast			
	2024 Budget	January to April	May to December	2024 Forecast	Variance	Notes
Generation - Hydro						
Mobile Hydro Plant Surge Tank Refurbishment	977	47	930	977	0	
Hydro Facility Rehabilitation	794	33	761	794	0	
Total Generation - Hydro	**1,771**	**80**	**1,691**	**1,771**	**0**	
Substations						
Gambo Substation Refurbishment and Modernization	5,267	684	4,583	5,267	0	
Memorial Substation Refurbishment and Modernization	4,351	551	3,800	4,351	0	
Old Perlican Substation Refurbishment and Modernization	3,356	288	3,068	3,356	0	
Substation Replacements Due to In-Service Failures	4,797	1,478	3,319	4,797	0	
Total Substations	**17,771**	**3,001**	**14,770**	**17,771**	**0**	
Transmission						
Transmission Line Maintenance	2,651	204	2,447	2,651	0	
Total Transmission	**2,651**	**204**	**2,447**	**2,651**	**0**	

Newfoundland Power Inc.
2024 Capital Budget Expenditure Status Report
Single-Year Projects and Programs Over $750,000[1]
($000)

	Annual Budget	Expenditures		Annual Forecast		
		Actual	Forecast			
Asset Class and Project Description	**2024 Budget**	**January to April**	**May to December**	**2024 Forecast**	**Variance**	**Notes**
Distribution						
LED Street Lighting Replacement	5,541	2,344	3,197	5,541	0	
Feeder Additions for Load Growth	2,811	65	2,746	2,811	0	
Distribution Reliability Initiative	900	417	483	900	0	
Distribution Feeder Automation	888	547	341	888	0	
Distribution Feeder OXP-01 Refurbishment	840	304	536	840	0	
Extensions	11,640	5,040	8,165	13,205	1,565	**1**
Reconstruction	6,953	2,959	3,994	6,953	0	
Rebuild Distribution Lines	4,974	1,242	3,732	4,974	0	
Relocate/Replace Distribution Lines for Third Parties	3,766	1,130	2,636	3,766	0	
Replacement Transformers	3,681	2,996	2,806	5,802	2,121	**2**
New Transformers	3,264	2,458	2,687	5,145	1,881	**3**
New Services	2,847	1,035	2,195	3,230	383	**4**
New Street Lighting	2,429	664	1,765	2,429	0	
Replacement Street Lighting	863	332	531	863	0	
Total Distribution	**51,397**	**21,533**	**35,814**	**57,347**	**5,950**	

Newfoundland Power Inc.
2024 Capital Budget Expenditure Status Report
Single-Year Projects and Programs Over $750,000[1]
($000)

	Annual Budget	Expenditures		Annual Forecast		
		Actual	Forecast			
Asset Class and Project Description	**2024 Budget**	**January to April**	**May to December**	**2024 Forecast**	**Variance**	**Notes**
Information Systems						
Application Enhancements	1,892	433	1,459	1,892	0	
Shared Server Infrastructure	964	275	689	964	0	
System Upgrades	957	244	713	957	0	
Cybersecurity Upgrades	930	249	681	930	0	
Total Information Systems	**4,743**	**1,201**	**3,542**	**4,743**	**0**	
Unforeseen Allowance						
Allowance for Unforeseen Items	750	0	750	750	0	
Total Unforeseen Allowance	**750**	**0**	**750**	**750**	**0**	
General Expenses Capitalized						
General Expenses Capitalized	4,500	1,728	2,772	4,500	0	
Total General Expenses Capitalized	**4,500**	**1,728**	**2,772**	**4,500**	**0**	
Total	**83,583**	**27,747**	**61,786**	**89,533**	**5,950**	

1 Approved in Order No. P.U. 2 (2024).

Newfoundland Power Inc.
2024 Capital Budget Expenditure Status Report
Single-Year Projects and Programs $750,000 and Under[1]
($000)

	Annual Budget	Expenditures		Annual Forecast		
		Actual	Forecast			
Asset Class and Project Description	**2024 Budget**	**January to April**	**May to December**	**2024 Forecast**	**Variance**	**Notes**
Generation - Hydro						
Hydro Plant Replacements Due to In-Service Failures	716	170	546	716	0	
Total Generation - Hydro	**716**	**170**	**546**	**716**	**0**	
Generation - Thermal						
Thermal Plant Replacements Due to In-Service Failures	311	0	311	311	0	
Total Generation - Thermal	**311**	**0**	**311**	**311**	**0**	
Substations						
Substation Ground Grid Upgrades	580	0	580	580	0	
PCB Removal	544	32	512	544	0	
Oxen Pond Substation Bus Upgrade	451	29	422	451	0	
Oxen Pond Substation Switch Replacements	316	17	299	316	0	
Substation Protection and Control Replacements	635	392	243	635	0	
Total Substations	**2,526**	**470**	**2,056**	**2,526**	**0**	
Transmission						
Transmission Line 24L Relocation	701	2	699	701	0	
Total Transmission	**701**	**2**	**699**	**701**	**0**	
Distribution						
Distribution Feeder GDL-02 Refurbishment	667	13	654	667	0	
Allowance for Funds Used During Construction	260	94	166	260	0	
Distribution Feeder BIG-02 Relocation	196	0	196	196	0	
Replacement Meters	571	23	383	406	-165	**5**
Replacement Services	457	111	346	457	0	
New Meters	302	155	312	467	165	**6**
Total Distribution	**2,453**	**396**	**2,057**	**2,453**	**0**	

Newfoundland Power Inc.
2024 Capital Budget Expenditure Status Report
Single-Year Projects and Programs $750,000 and Under[1]
($000)

Asset Class and Project Description	Annual Budget	Expenditures		Annual Forecast		
		Actual	Forecast			
	2024 Budget	January to April	May to December	2024 Forecast	Variance	Notes
General Property						
Energized Conductor Support Tools	539	0	539	539	0	
Additions to Real Property	655	122	533	655	0	
Tools and Equipment	570	88	482	570	0	
Physical Security Upgrades	401	113	288	401	0	
Total General Property	**2,165**	**323**	**1,842**	**2,165**	**0**	
Telecommunications						
Fibre Optic Cable Build	380	7	373	380	0	
Communications Equipment Upgrades	122	3	119	122	0	
Total Telecommunications	**502**	**10**	**492**	**502**	**0**	
Information Systems						
Network Infrastructure	420	81	339	420	0	
Personal Computer Infrastructure	720	126	594	720	0	
Total Information Systems	**1,140**	**207**	**933**	**1,140**	**0**	
Total	**10,514**	**1,578**	**8,936**	**10,514**	**0**	

1 Approved in Order No. P.U. 2 (2024).

Newfoundland Power Inc.
2024 Capital Budget Expenditure Status Report
Multi-Year Projects Commencing in 2024[1]
($000)

	2024 Summary						Overall Project Summary				
	Annual Budget	Expenditures		Annual Forecast	Variance	Notes	Total Project Budget	Total Project Spend to Date	Total Project Forecast	Variance	Notes
		Actual	Forecast								
Asset Class and Project Description	2024 Budget	January to April	May to December	2024 Forecast	2024 Forecast vs Budget		2024 - 2026	YTD April 2024	2024 - 2026	Total Forecast vs Budget	
Generation - Hydro											
Lookout Brook Hydro Plant Refurbishment	362	69	293	362	0		1,935	69	1,935	0	
Total Generation - Hydro	**362**	**69**	**293**	**362**	**0**		**1,935**	**69**	**1,935**	**0**	
Substations											
Islington Substation Refurbishment and Modernization	308	117	191	308	0		5,014	117	5,014		
Total Substations	**308**	**117**	**191**	**308**	**0**		**5,014**	**117**	**5,014**	**0**	
Transmission											
Transmission Line 146L Rebuild	2,152	34	2,118	2,152	0		11,361	34	11,361	0	
Total Transmission	**2,152**	**34**	**2,118**	**2,152**	**0**		**11,361**	**34**	**11,361**	**0**	
General Property											
Gander Building Renovation	175	18	157	175	0		935	18	935	0	
Total General Property	**175**	**18**	**157**	**175**	**0**		**935**	**18**	**935**	**0**	
Transportation											
Replace Vehicles and Aerial Devices 2024-2025	1,940	0	1,940	1,940	0		4,809	0	4,809	0	
Total General Property	**1,940**	**0**	**1,940**	**1,940**	**0**		**4,809**	**0**	**4,809**	**0**	
Information Systems											
Microsoft Enterprise Agreement	297	0	297	297			891	0	891	0	
Total Information Systems	**297**	**0**	**297**	**297**	**0**		**891**	**0**	**891**	**0**	
Total	**5,234**	**238**	**4,996**	**5,234**	**0**		**24,945**	**238**	**24,945**	**0**	

[1] Approved in Order No. P.U. 2 (2024).

Newfoundland Power Inc.
2024 Capital Budget Expenditure
Status Report Multi-Year Projects
Approved in Previous Years
($000)

	2024 Summary						Overall Project Summary				
	Annual Budget	Expenditures		Annual Forecast	Variance	Notes	Total Project Budget	Total Project Spend to Date	Total Project Forecast	Variance	Notes
		Actual	Forecast								
Asset Class and Project Description	**2024 Budget**	**January to April**	**May to December**	**2024 Forecast**	**2024 Forecast vs Budget**		**2022 - 2024**	**2022 - April 2024**	**2022 - 2024**	**Total Forecast vs Budget**	
Generation - Hydro											
Mobile Hydro Plant Refurbishment[1]	2,480	572	1,908	2,480	0		4,146	1,003	4,146	0	
Total Generation - Hydro	**2,480**	**572**	**1,908**	**2,480**	**0**		**4,146**	**1,003**	**4,146**	**0**	
Substations											
MUN-T2 Power Transformer Replacement[2]	1,566	24	1,542	1,566	0		1,614	26	1,614	0	
Total Substations	**1,566**	**24**	**1,542**	**1,566**	**0**		**1,614**	**26**	**1,614**	**0**	
Transmission											
Transmission Line 94L Rebuild[3]	4,276	0	4,276	4,276	0		13,095	7,899	13,095	0	
Transmission Line 55L Rebuild[1]	5,284	860	4,424	5,284	0		10,612	3,966	10,612	0	
Total Transmission	**9,560**	**860**	**8,700**	**9,560**	**0**		**23,707**	**11,865**	**23,707**	**0**	
Distribution											
Distribution Reliability Initiative (SUM-01)[1]	1,015	84	931	1,015	0		1,671	792	1,671	0	
Total Distribution	**1,015**	**84**	**931**	**1,015**	**0**		**1,671**	**792**	**1,671**	**0**	
Transportation											
Replace Vehicles and Aerial Devices 2023-2024[1]	1,866	88	1,778	1,866	0		4,699	1,607	4,699	0	
Total General Property	**1,866**	**88**	**1,778**	**1,866**	**0**		**4,699**	**1,607**	**4,699**	**0**	
Total	**16,487**	**1,628**	**14,859**	**16,487**	**0**		**35,837**	**15,293**	**35,837**	**0**	

1 Approved in Order No. P.U. 38 (2022).
2 Approved in Order No. P.U. 14 (2023).
3 Approved in Order No. P.U. 36 (2021).

APPENDIX A:

Variance Notes

Distribution

1. Extensions:

   Budget: $11,640,000 Forecast: $13,205,000 Variance: $1,565,000

   The forecast expenditure for *Extensions* is expected to be approximately 13% above the budgeted amount. The increase reflects a 13% increase in anticipated new customer connections. In 2024, the forecast number of new customer connections is expected to increase from 2,053 to 2,329.[1]

2. Replacement Transformers:

   Budget: $3,681,000 Forecast: $5,802,000 Variance: $2,121,000

   The forecast expenditure for *Replacement Transformers* is expected to be approximately 58% above the budgeted amount. The increase is largely due to supply chain issues resulting in material cost increases and the requirement to ensure adequate supply of inventory.

3. New Transformers:

   Budget: $3,264,000 Forecast: $5,145,000 Variance: $1,881,000

   The forecast expenditure for *New Transformers* is expected to be approximately 58% above the budgeted amount. The increase is largely due to supply chain issues resulting in material cost increases and the requirement to ensure adequate supply of inventory.

4. New Services:

   Budget: $2,847,000 Forecast: $3,230,000 Variance: $383,000

   The forecast expenditure for *New Services* is expected to be approximately 13% above the budgeted amount. The increase reflects a 13% increase in anticipated new customer connections. In 2024, the forecast number of new customer connections is expected to increase from 2,053 to 2,329.

5. Replacement Meters:

   Budget: $571,000 Forecast: $406,000 Variance: ($165,000)

   The forecast expenditure for *Replacement Meters* is expected to be approximately 29% below the budgeted amount. The *2023 Capital Budget Application* was the first capital budget filed under the Provisional Guidelines. Previously, budgets and expenditures for meters were pooled as a single capital project. The 2024 forecast has been revised to

[1] Based on the Conference Board of Canada's medium-term outlook released on February 14, 2024.

reflect the actual expenditure split between *Replacement Meters* and *New Meters* in 2023.

6. New Meters:

Budget: $302,000 Forecast: $467,000 Variance: $165,000

The forecast expenditure for *New Meters* is expected to be approximately 55% above the budgeted amount. The *2023 Capital Budget Application* was the first capital budget filed under the Provisional Guidelines. Previously, budgets and expenditures for meters were pooled as a single capital project. The 2024 forecast has been revised to reflect the actual expenditure split between *Replacement Meters* and *New Meters* in 2023.

Use of Historical Averages for Budget Estimation

June 2024

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1.0 INTRODUCTION

In Order No. P.U. 2 (2024) the Board of Commissioners of Public Utilities (the "Board") ordered Newfoundland Power Inc. ("Newfoundland Power" or the "Company") to file, as part of its *2025 Capital Budget Application,* a report in relation to the use of historical averages in determining proposed capital expenditures.[1]

This report, which is filed in compliance with Order No. P.U. 2 (2024), provides a review of the methodology used by Newfoundland Power in estimating expenditures using historical averages, including the rationale as to which expenditures are determined using historical averages, the treatment of outliers and trends, the consideration of other related circumstances, and the time period which is used. The report also provides information related to the use of historical averages by other utilities, as well as available alternatives.

2.0 HISTORICAL AVERAGE METHODOLOGY

The *Capital Budget Application Guidelines (Provisional),* effective January 2022 (the "Provisional Guidelines") require that all capital expenditures be categorized as projects or programs. Projects correspond to individual capital investments, typically of a non-repetitive nature. Programs are capital investments comprised of activities that are high volume, repetitive, like-for-like capital replacements, enhancements or additions that are expected to continue into the foreseeable future.

The Provisional Guidelines also require that a budget estimate be filed for all capital expenditures within the application. The estimating methodology is not constrained, other than that variances greater than $100,000 and 10% of the total estimate must be explained in a capital expenditure report to be filed in the following year.[2]

Newfoundland Power currently uses historical averages for its capital programs, which include routine capital expenditures driven by customer requests, equipment failures on the power system or that would otherwise be identified through inspections conducted in the normal course of business.[3] The methodology, which provides a budget estimate using the Company's historical expenditures and inputs from independent third parties, has remained substantially the same since 2000.[4]

In Order No. P.U. 2 (2024) – Reasons for Decision, the Board recognized that Newfoundland Power has been using historical averages to estimate capital budgets for many years and that it can be a useful tool for estimating costs that cannot be determined with precision when the capital budget application is prepared.[5]

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1 Order No. P.U. 2 (2024), page 3, lines 40-41 and page 4, lines 1-2.

2 Pursuant to section 41 of the *Public Utilities Act*, the capital expenditure report must be filed by April 1; however, the Board has on occasion advanced the filing deadline to March 1.

3 In addition, as these programs are driven by needs arising throughout the year the work scopes that would be undertaken in the programs may not be known at the time of filing the budget, restricting the available methods for estimation.

4 The use of historical averages in generating capital budget estimates appears as early as the Company's *2000 Capital Budget Application.* Newfoundland Power uses data from independent third parties such as the Conference Board of Canada's GDP Deflator and Housing Data Forecast.

5 Order No. P.U. 2 (2024) Reasons for Decision, page 16, line 4-5 and lines 9-11.

Table 1 outlines Newfoundland Power's capital programs.

Table 1
Newfoundland Power's Capital Programs

Name	Description
Extensions	Construction of primary and secondary distribution to connect new customers to the power system.
Reconstruction	Replacement of deteriorated or damaged distribution structures and electrical equipment.
Rebuild Distribution Lines	Replacement of deteriorated distribution equipment that has been identified during inspections and engineering reviews.
Relocate/Replace Distribution Lines for Third Party	Relocates or replaces distribution lines at the request of governments, telecommunications companies, or other third parties.
Replacement Transformers	Budget item to purchase replacement transformers to replace those that fail or have deteriorated in a given year.
New Transformers	Purchases new transformers to serve customer growth.
New Services	Installation of service wires to connect new customers to the distribution system.
New Street Lighting	Installation of new street lighting fixtures based upon customer requests, including pole, bracket and wires as needed.
Replacement Street Lighting	Involves the replacement of failed street lighting poles and hardware, including wiring and bracketry.
Substation Replacements Due to In Service Failures	Replacement of substation equipment that has failed in service and provision of spare parts inventory.
Transmission Line Maintenance	Replacement of transmission line infrastructure that has or is at risk of failure.
Replacement Meters	Purchase and installation of meters to replace deteriorated meters in service and to comply with legislative requirements.
New Meters	Purchase and installation of new meters to be used in connecting new customers.
Replacement Services	Installation of service wires to replace service wires that have failed or become undersized due to load growth.
Substation Protection and Control Replacements	This program involves replacing substation protection and control systems, including Supervisory Control and Data Acquisition system equipment and protection relay devices.
Hydro Plant Replacements Due to In-Service Failures	Replacement or refurbishment of hydro plant equipment that has failed or is obsolete.

Table 1 Newfoundland Power's Capital Programs	
Name	Description
Thermal Plant Replacements Due to In Service Failures	Replacement or refurbishment of thermal plant equipment that has failed or is obsolete.
Personal Computer Infrastructure	This program is necessary for the replacement or upgrade of personal computers that have reached the end of their service lives.
Communication Equipment Upgrades	Replacement or upgrade of communication equipment associated with electrical system operation.
Additions to Real Property	Replacement of building components and systems that have failed or are at imminent risk of failure in district and area offices.
Tools and Equipment	Purchase of new or replacement tools, equipment and office furniture to complete Newfoundland Power's normal field and office work.
Physical Security Upgrades	Upgrades to the physical security infrastructure at facilities throughout the Company's service territory.

Newfoundland Power utilizes two historical average methodologies – one for programs related to new customer connections and one for programs with estimates not driven by forecasted customer growth. The primary inputs for the methodology are historical actual spending, inflation rates (including the GDP Deflator and internal labour deflator) and the customer connection forecast.

For expenditures related to new customer connections, an average cost per connection is calculated based on historical data.[6] Historical annual expenditures for these programs over the most recent five-year period are expressed in current-year dollars ("Adjusted Costs"). The Adjusted Costs are divided by the number of new customers in each year to derive a cost per connection. The average of these costs is inflated by the GDP Deflator for Canada for non-labour costs and the Company's internal labour inflation rate for labour costs, and then multiplied by the forecast number of new customers for the budget year.

For programs with estimates not driven by forecast customer growth, the calculation is similar; however, it omits the calculation of unit costs and forecasted customer connections.

[6] This would include programs such as *Extensions, New Services* and *New Meters.*

3.0 REVIEW OF CANADIAN UTILITY PRACTICE

During its *2024 Capital Budget Application,* Newfoundland Power conducted a jurisdictional scan of other Canadian utilities subject to annual capital budget filings.[7]

Table 2 shows the results of this jurisdictional scan:

Table 2
Other Canadian Utilities
Use of Historical Expenditures

Utility	Project/Program Description	Historical Period
Nova Scotia Power	One program related to joint use work and three programs related to upgrading distribution infrastructure to serve new customers.	Both three-year and five-year averages with annual inflation.
Maritime Electric	Programs related to extensions, overhead and underground services, street lighting, replacements due to road alterations, and replacements due to storms, fires and collisions.	Five-year averages normalized for budget year with annual inflation.
Newfoundland and Labrador Hydro ("Hydro")	Programs related to service extensions and in-service failures (thermal generation, hydraulic generation, terminal stations, and distribution systems and street lights).	Three-year averages.

All four Atlantic Canadian utilities utilize historical averages to prepare budget estimates for certain projects and programs. Newfoundland Power and Maritime Electric use five-year averages;[8] Hydro uses three-year averages; and Nova Scotia Power uses a mix of three-and five-year averages.

In addition to a review of Atlantic Canadian utilities, Newfoundland Power reviewed recent decisions from other Canadian regulators, which provided that utilities in those jurisdictions utilize historical averages to prepare budget estimates for certain projects and programs. For example, in British Columbia, FortisBC Energy Inc.'s growth capital is forecasted based on historical spending.[9] In Alberta, when approving a performance-based rate ("PBR") plan PBR3, the Alberta Utilities Commission ("AUC") directed that the PBR3 K-bar should be computed

7 See the response to Request for Information CA-NP-200 filed as part of the Company's *2024 Capital Budget Application.*

8 Newfoundland Power may use a three-year historical average in the event that a program has existed in its current form for five years or less, or when significant changes to costs occur. Once there is sufficient program data or costs level, as the case may be, the Company will begin using a five-year historical average.

9 See section *1.3.3.1 FEI Growth Capital* of FortisBC's *Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024.* As provided in section *1.3.3 Capital Forecast* of the filing, FortisBC Energy Inc.'s growth capital consists of expenditures for the installation of new mains, services, meters, and distribution system improvements to support customer additions.

using a five-year average of 2018-2022 actual capital additions.[10] In Ontario, the Ontario Energy Board used a five-year average in determining the normal capital expenditure for Alectra Utilities Corporation in a 2023 capital module application.[11]

Based on the review, the use of historical averaging for capital programs similar to Newfoundland Power's is accepted utility practice throughout Canada.

4.0 HISTORICAL AVERAGE METHODOLOGY REVIEW AND OTHER INFORMATION

4.1 Historical Average Methodology Review

In preparing this report, Newfoundland Power reviewed its historical cost methodology by comparing its results to scenarios using alternative averaging techniques, described as follows:

- **Scenario 1**: Current methodology, using three years of data rather than five years.
- **Scenario 2**: Current methodology, using one year of data (most recent actual year) rather than five years.
- **Scenario 3**: Current methodology, removing the year with largest absolute variance from the average used to determine the budget estimate.[12]
- **Scenario 4**: Scenario 1, removing the year with largest absolute variance from the average used to determine the budget estimate.[13]

For the current methodology, as well as for each scenario outlined in Table 3, the Company analyzed actual to budget variances for 2023 on both a total and absolute basis.[14]

[10] See AUC decision 27388-D01-2023.
[11] See Decision EB-2023-0004, page 14.
[12] The largest absolute variance is the year with largest variance (either positive or negative) from the five-year average used in the current methodology. The removal is completed by program. The budget estimate in that scenario is then based on the inflation-adjusted average of the remaining four years of data.
[13] The largest absolute variance is the year with largest variance (either positive or negative) from the three-year average used in Scenario 1. The removal is completed by program. The budget estimate in that scenario is then based on the inflation-adjusted average of the remaining two years of data.
[14] The total variance considers the offsetting impact of positive and negative variances of the individual programs. The absolute variance treats each variance (either positive or negative) on the same basis.

Table 3 provides the results of the review.

Table 3 Review Results		
Methodology	Total Variance	Absolute Variance
Current	9%	15%
Scenario 1	13%	16%
Scenario 2	15%	18%
Scenario 3	12%	17%
Scenario 4	14%	19%

The results show that Newfoundland Power's current methodology provided for reasonable budget estimates for 2023, with a total variance of 9%. The scenarios analyzed did not provide for any differences to suggest a change from the Company's current methodology is necessary.

4.2 Outliers and Variances

Newfoundland Power may identify and adjust for outliers in its historical average methodology based on prior expenditure experience. Outliers are costs that are identified to be one-time costs not representative of future work in a particular program. For example, in estimating its *Additions to Real Property* program in 2022, the Company excluded eight work scopes costing approximately $1.1 million over four years.

In the Company's *2025 Capital Budget Application*, the budgets for the *New Transformers* and *Replacement Transformers* programs are based on a three-year historical average rather than the five-year average methodology due to higher than average material costs combined with increases to meet minimum inventory requirements.[15]

Newfoundland Power provides variance explanations of greater than ±10% by program in its annual *Capital Expenditure Report*. This process may identify potential outliers to consider in the following budget year. However, in the Company's experience, program variances are generally the result of higher or lower work requirements or price changes associated with a particular program.

For example, in 2015, the *Extensions* program had a variance of 25%.[16] This variance was due to the construction of approximately 10% more kilometres of distribution extensions than in the years prior to serve customers, despite a reduction in customer connections.[17] Similarly, in 2019, the *Rebuild/Relocate Distribution Lines for Third Parties* program had a variance of 113%.[18] This resulted from joint use partners increasing their capital programs, notably through

15 For additional information on this change, see the Company's *2025 Capital Budget Application, Schedule B,* page 33.
16 See Newfoundland Power's *2015 Capital Expenditure Report, Appendix A,* page 4.
17 Ibid.
18 See Newfoundland Power's *2019 Capital Expenditure Report, Appendix A,* page 6.

the Bell Connecting Canadians project, which in turn caused the amount of distribution assets requiring upgrades to accommodate joint use requirements to exceed the historical average.[19] With respect to price changes, a number of capital program budget variances in 2021 were due to higher than anticipated inflationary cost pressures.[20]

In Newfoundland Power's view, circumstances such as those described above do not require an adjustment to the five-year average methodology to remove its impact in the following budget year. Rather, its inclusion in the five-year average ensures the program budget estimates contemplate that capital expenditure requirements in any one year may vary by a larger amount than a more typical year.

4.3 Alternative Cost Estimation Approaches

This section reviews alternative methodologies that could be used to estimate the Company's capital program budgets. The methodologies reviewed were engineering, extrapolation from actual cost, analogy and parametric.

An engineering estimate is derived from assigning known costs to a well-defined work scope for a project, typically of a non-repetitive nature. Due to the lack of definition in the work scopes for the Company's programs estimated using historical averages, an engineering estimate is viewed as unsuitable for programs driven by work requirements arising within the budget year.

Extrapolation from actual cost utilize known costs from the same work to project costs into the future for the same work. This method is well suited to mature programs where recent data is available.

An analogy-based estimate uses realized costs from a similar program with an adjustment for perceived differences. This methodology is viewed as being suitable for conceptual stage estimates as opposed to mature programs where recent data is available. A parametric estimate is based upon statistical regressions drawn from numerous similar projects that were completed recently. This method is best suited to large entities like government procurement agencies as opposed to mature programs that have similar work scopes year over year.

The Company views its historical average approach as equivalent to the extrapolation from actuals method.

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19 Ibid.

20 For example, the main contributor to the *Street Lighting* project expenditure increases in 2021 was higher material costs. The purchase cost of # 6 duplex used for street lights increased by 10% and the purchase cost of poles increased by 4.3% in 2021, which were higher than expected in determining the estimates for the *2021 Capital Budget Application.*

5.0 CONCLUSION

The work completed under the Company's capital programs is necessary to meet its obligation to provide safe, reliable electricity service to customers. Newfoundland Power's current historical average methodology has provided for reasonable budget estimates for these capital programs. The Company's methodology is consistent with Canadian utility practice.

Consistent with its approach, Newfoundland Power will continue to consider if any adjustments to the budget estimates derived using its methodology is necessary for significant outliers. Variances of greater than ±10% will continue to be reported and explained to the Board as part of the Company's annual *Capital Expenditures Report*.

NEWFOUNDLAND POWER
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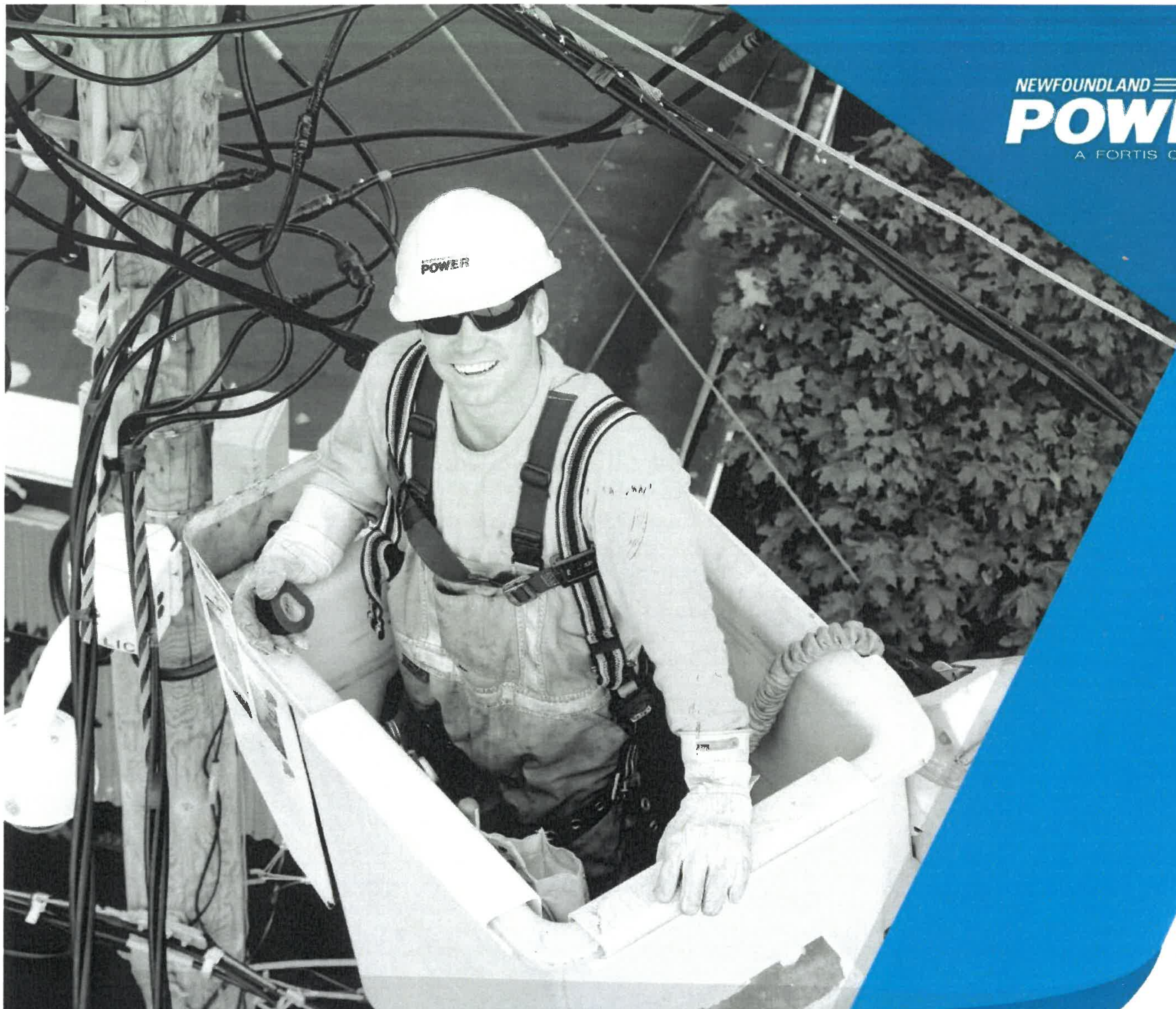

1.1 Feeder Additions for Load Growth

June 2024

Prepared by: Tony Jones, P.Eng

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1.0 INTRODUCTION

As load increases on an electrical system, the components of the system can become overloaded. These overload conditions can occur at the substation level, on equipment, such as transformers, breakers and reclosers, or on specific sections of the distribution system.

When an overload condition has been identified, it can often be mitigated through operating practices, such as feeder balancing or load transfers.[1] Such practices are low-cost solutions and are completed as normal operating procedures. However, in some cases it becomes necessary to complete upgrades to the distribution system to either increase capacity or alter system configuration in order to eliminate overload conditions. Eliminating overload conditions mitigates risks of in-service equipment failures, which can result in significant repair costs and extended customer outages.

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") has identified two overload conditions to be addressed in 2025 by upgrading existing distribution lines. The overload conditions described in this report can each be attributed to residential growth in specific areas of the Company's service territory.

2.0 OVERLOADED CONDUCTOR

2.1 General

An overloaded section of conductor on a distribution line is at risk of failure. Failures are caused by overheating of the conductor as the load exceeds the conductor's capacity ratings. As a result, the conductor will have excessive sag, which may result in the conductor coming into contact with other conductors or the conductor breaking, causing a fault and subsequent customer outage and safety hazard. Overloaded conductor can also have a negative impact on restoration efforts following customer outages due to increased conductor loading associated with cold load pick-up.

Newfoundland Power analyzes its distribution feeders using a distribution feeder computer modelling application to identify sections of feeders that may be overloaded. The results are followed up with field verifications to ensure the accuracy of information.[2]

[1] Feeder balancing involves transferring load from one phase to another on a three-phase distribution feeder in order to balance the amount of load on each phase. Load transfers involve transferring load from one feeder to another adjacent feeder.

[2] Where necessary, load measurements are taken to verify the results of the computer modelling. The analysis uses conductor capacity ratings based on Newfoundland Power's *Distribution Planning Guidelines*. These ratings are shown in Appendix A.

2.2 Alternatives to Address Overloaded Conductor

There are generally five categories of alternatives to address overloaded conductor. The applicability of each category depends on factors such as available tie points to surrounding feeders, the amount of conductor overload, physical limitations of line construction, and the effect of offloading strategies on adjacent feeders. The five categories of alternatives are:

(i) ***Feeder Balancing -*** In some cases, conductor may be overloaded on only one phase of a three-phase line. In this situation, it may be possible to resolve the overload condition by balancing the downstream loads through load transfers from the highly loaded phase to one of the more lightly loaded phases. In some situations, overload conditions on individual phases can be alleviated by extending the three-phase trunk of the feeder. This is only applicable in situations where all three phases are not overloaded.

(ii) ***Load Transfer -*** On a looped system, if a tie point exists downstream of the overload condition, it may be possible to transfer a portion of load to an adjacent feeder. However, consideration must be given to the loading on the adjacent feeder to ensure a new overload condition is not created. In some cases, transferring load to an adjacent feeder may require building new sections of three-phase distribution line.

(iii) ***Feeder Upgrades -*** In some cases, overload conditions can be eliminated by increasing the conductor size on the overloaded section, upgrading overloaded single-phase sections to three phase, or building new sections of distribution feeder.

(iv) ***New Feeder -*** In cases where the feeder conductor leaving a substation is overloaded, and none of the above alternatives can be used to resolve the overload condition, the addition of a new feeder from the substation may be required to transfer a portion of load from the overloaded conductor.

(v) ***Non-Wires Alternatives -*** Non-wires alternatives comprise a broad category that encompasses various innovative alternatives to standard "poles and wires" solutions. These include, but are not limited to, distributed energy resources, microgrids and battery storage.

3.0 PROJECT DESCRIPTION

3.1 Overloaded Single-Phase & Two-Phase Lines

Heavily loaded single-phase and two-phase sections of distribution lines can result in unbalanced loads on the three phases of a feeder. This can result in a subsequent operation of feeder protection mechanisms at the substation, resulting in outages to customers and extended time for restoring service. The unbalanced load condition can occur during peak load, cold load pick-up or when a protection fuse operates. Eliminating unbalanced conditions caused by growth on single-phase and two-phase feeder sections mitigates reliability and safety risks in providing service to customers.

An analysis of Newfoundland Power's distribution feeders was completed using CYME Power Engineering Software to identify single-phase and two-phase lines that may be overloaded.[3] Load measurements were subsequently taken to verify the results of the computer simulation.[4]

The analysis identified two locations where two-phase lines are overloaded. Mitigation of these overload conditions is required, and each are described below.

3.2 Distribution Feeder APT-02 Upgrade

Distribution feeder APT-02 leaves the Airport ("APT") Substation in St. John's and extends west along Portugal Cove Road to supply customers in the St. John's and Portugal Cove – St. Philip's areas. This distribution feeder serves approximately 949 residential and commercial customers.

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3 Overloaded taps typically start out as only a few spans in length, but over time can grow into much larger feeder extensions. The growth most often occurs in new subdivisions where a large number of customers requiring single-phase service are added over time. Further growth on these taps are also expected as a result of electrification in general and increased penetration of electric vehicles over the coming years.

4 Newfoundland Power forecasts load at the substation transformer and distribution feeder levels annually. In the case of distribution feeders, total feeder load is allocated across the feeder to approximate load at each distribution transformer downstream from the substation, based on their individual capacities. As the Company does not currently utilize Advanced Metering Infrastructure meters, loading on individual sections of distribution line can only be approximated by the modelling software, and must be verified in the field when warranted by operational concerns, such as protection device trips or inquiries regarding new developments.

Figure 1 illustrates the route of distribution feeder APT-02.

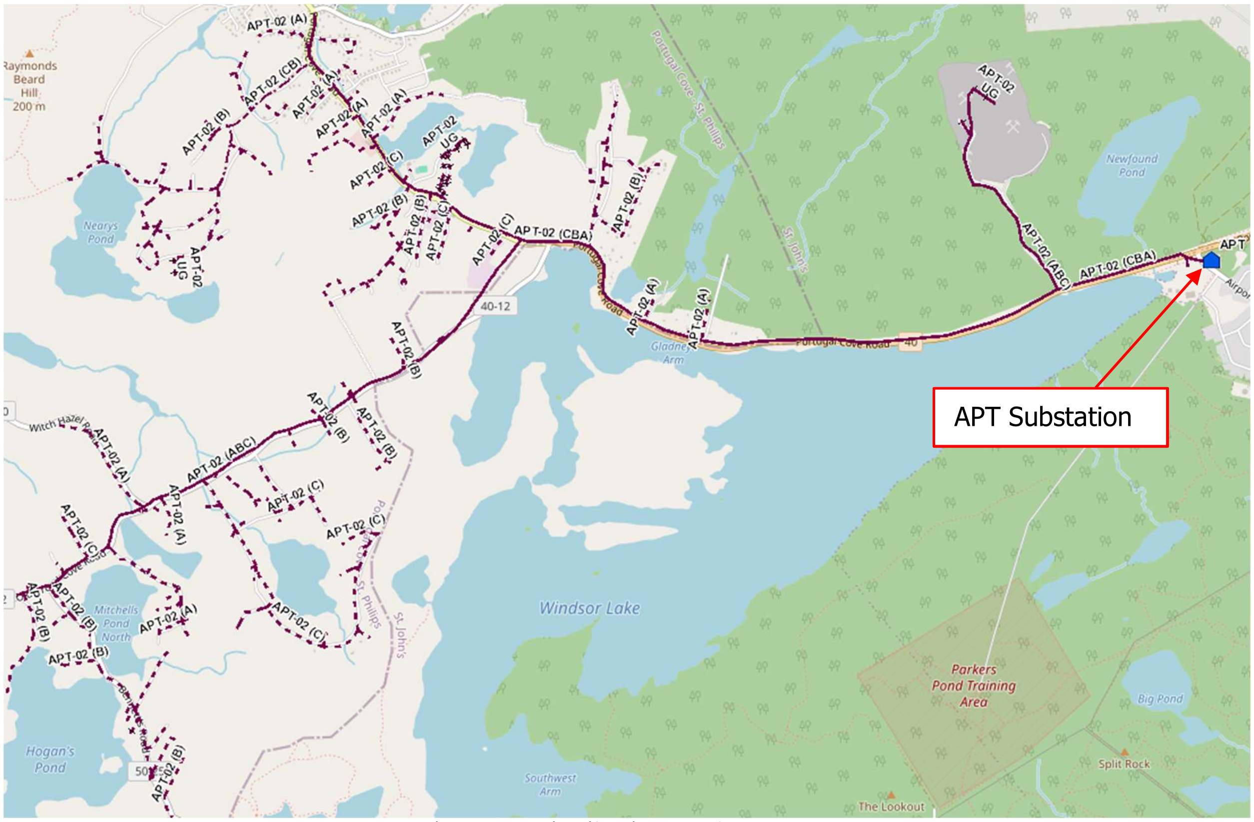

Figure 1 – Distribution Feeder APT-02

A 1.6-kilometre section of two-phase distribution feeder is overloaded. This section of line extends southwest on Nearys Pond Road off Portugal Cove Road to serve customers in the Portugal Cove – St. Philip's area. Load growth on this section of line is mainly attributed to new customer connections and service upgrades in the area. The number of customers supplied by this line has increased by 27% over the last 15 years.[5]

An analysis of distribution feeder APT-02 was completed using CYME Power Engineering software and verified using actual load measurements. The analysis showed that the load on the identified two-phase section of the feeder is approximately 82 amps on Phase B and 109 amps on Phase C, which exceeds the Company's planning criteria for maximum current on a two-phase section of distribution line.[6]

Three categories of alternatives that are generally available to address overloaded conductor are not applicable to APT-02. Feeder balancing is not applicable because transferring load from Phase C onto Phase B would result in both phases being overloaded. A new feeder build is not

5 There were 146 customers supplied by this section of line in 2009 and 185 customers in 2023, an increase of 39 customers (39 / 146 = 0.267, or 27%).

6 Newfoundland Power's planning criteria for maximum current on any phase of a single-phase or two-phase distribution line is 85 amps.

applicable due to the magnitude of the associated costs. A load transfer onto Pulpit Rock ("PUL") Substation distribution feeder PUL-04 was also considered, due to its relative proximity to APT-02. However, there is insufficient capacity on power transformer PUL-T2 to accommodate the additional load from APT-02. As a result, the alternatives evaluated to mitigate the overloaded section of distribution feeder APT-02 include: (i) upgrading from two-phase to three-phase; and (ii) a non-wires alternative.

Alternative 1: Upgrade Two-Phase Section to Three-Phase

This alternative would involve upgrading a 1.6-kilometre section of two-phase distribution line along Nearys Pond Road in Portugal Cove – St. Philip's to three-phase 1/0 AASC conductor to resolve the overload condition. The capital cost associated with this project is estimated to be approximately $375,000.

Figure 2 illustrates the work that would be required under this alternative.

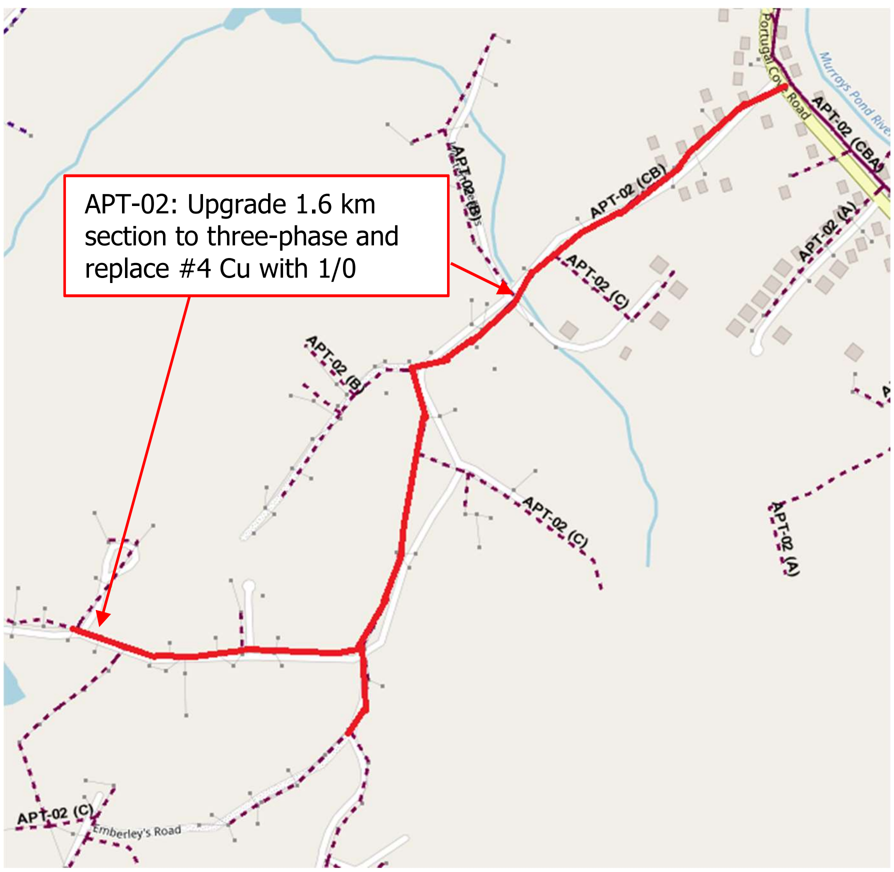

Figure 2 – Distribution Feeder APT-02 Upgrade

Alternative 2: Non-Wires Alternative

This alternative would utilize commercial-grade battery storage technology to provide capacity to alleviate the overload condition during peak load conditions. Based on verified load readings and distribution feeder modelling, approximately 4 hours of capacity would be required to alleviate the overload conditions on this section of line during peak load. A preliminary capital cost estimate for the procurement of a battery storage solution for this application is approximately $397,000 and would have an expected lifetime of 15-years.[7]

Recommended Alternative

Of the technically viable alternatives considered, upgrading the overloaded section of distribution feeder APT-02 from two-phase to three-phase is least cost. This is therefore the recommended alternative to address the identified overload condition.

3.3 Distribution Feeder GOU-03 Upgrade

Distribution feeder GOU-03 leaves Goulds ("GOU") Substation and extends south along the Main Road. The distribution feeder serves approximately 1,713 residential and commercial customers in the Goulds area.

[7] To offload Phase C to be within Newfoundland Power's planning limits of 85 amps, a 691 kWh battery storage system would be required. The preliminary procurement cost of this solution is approximately $397,000 based on 2025 projected battery storage costs of $574/kWh (US$388/kWh converted to Canadian dollars) obtained from *Cost Projections for Utility-Scale Battery Storage: 2023 Update*, June 2023, page 13, prepared for the National Renewable Energy Laboratory by Wesley Cole and Akash Karmakar. According to Cole and Karmakar, the median lifetime of utility scale battery systems is 15 years.

Figure 3 illustrates the route of distribution feeder GOU-03.

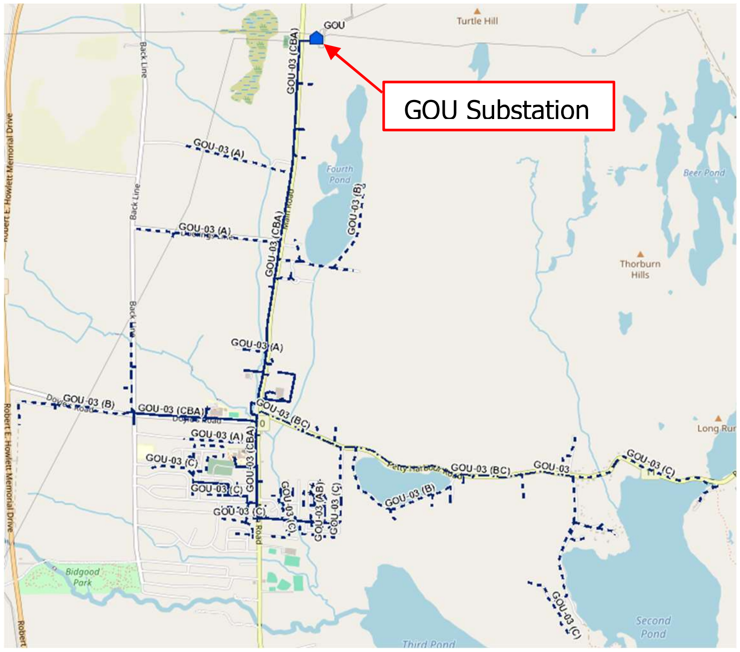

Figure 3 – Distribution Feeder GOU-03

A 2.4-kilometre section of two-phase distribution line is overloaded. This section of distribution line extends east from Main Road in the Goulds along Petty Harbour Road. Load growth on this two-phase line is mainly attributed to customer connection growth, as well as electrical service upgrades in the area. The number of customers supplied by this line has increased by 28% over the last 15 years.[8]

An analysis of distribution feeder GOU-03 was completed using CYME Power Engineering Software and verified using actual load measurements. The analysis showed that the load on the individual phases of the identified section of the feeder are approximately 125 amps, which exceeds the Company's planning criteria for maximum current on a two-phase distribution line.[9]

Two categories of alternatives that are generally available to address overloaded conductor are not applicable to distribtion feeder GOU-03. Feeder balancing is not applicable as the individual phases on the identified section of GOU-03 are already overloaded. A new feeder build is not applicable due to the magnitude of the associated costs. As a result, the alternatives evaluated to mitigate the overloaded section of distribution feeder GOU-03 include: (i) a load transfer; (ii) upgrading from two-phase to three-phase; and (iii) a non-wires alternative.

8 There were 219 customers supplied by this section of line in 2009 and 280 customers in 2023, an increase of 61 customers (61 / 219 = 0.279, or 28%).

9 Newfoundland Power's planning criteria for maximum current on any phase of a single-phase or two-phase distribution line is 85 amps.

Alternative 1: Load Transfer to Distribution Feeder PHR-01

This alternative would involve transferring load from distribution feeder GOU-03 to Petty Harbour ("PHR") Substation distribution feeder PHR-01. This would require upgrading two kilometres of single-phase distribution to three-phase. In addition, a new 1.0-kilometre section of three-phase distribution line would be required to connect the overloaded section of distribution feeder GOU-03 to PHR-01. A 12.5 kV to 4.16 kV step-down transformer would also be required to facilitate the connection of two feeders with varying distribution voltages. Costs associated with the work are estimated to be approximately $875,000.

Figure 4 illustrates the work that would be required under this alternative.

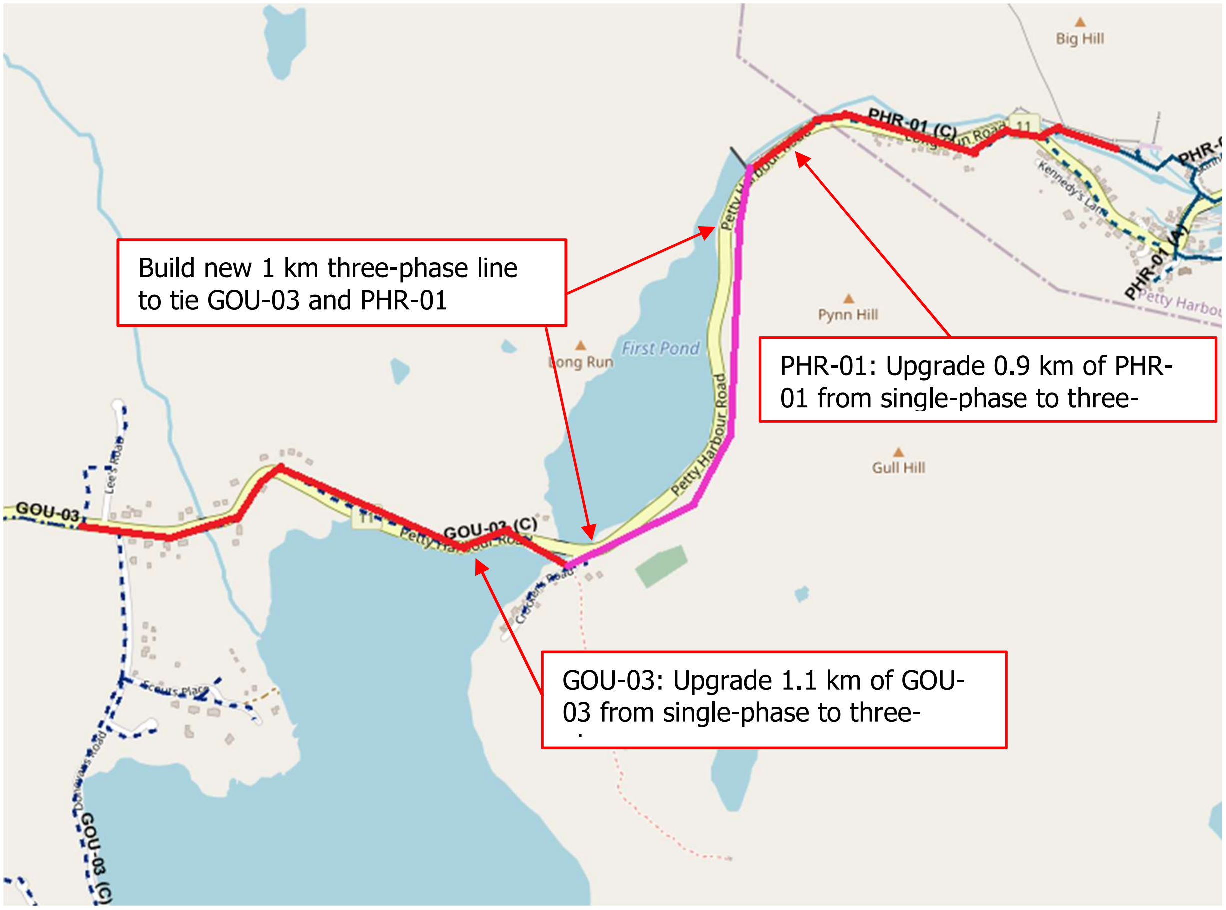

Figure 4– Load Transfer of Distribution Feeder GOU-03 onto PHR-01

Alternative 2: Upgrade Two-Phase Section to Three-Phase

This alternative would involve upgrading the 2.4-kilometre section of single-phase distribution line along Petty Harbour Road to three-phase 1/0 AASC conductor to resolve the overloaded conductor. The capital cost associated with this work is estimated to be approximately $585,000.

Figure 5 illustrates the work that would be required under this alternative.

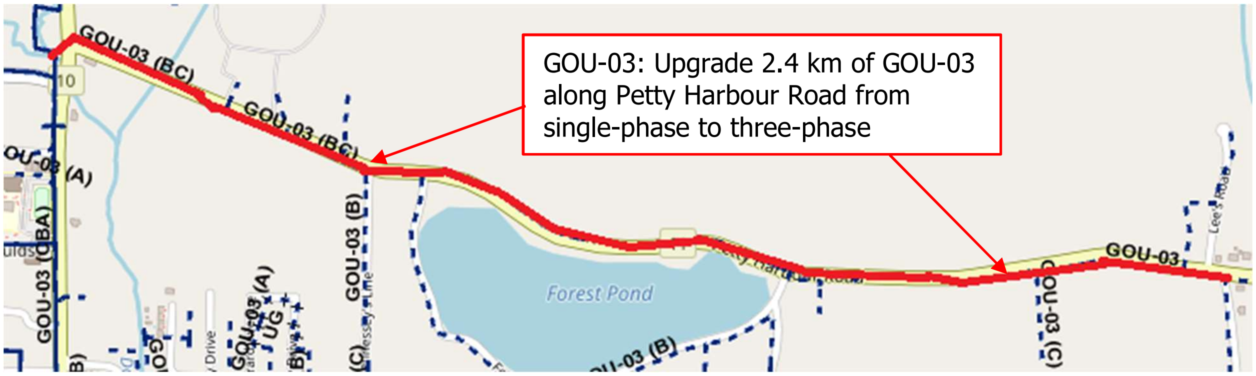

Figure 5 – Distribution Feeder GOU-03 Upgrades Along Petty Harbour Road

Alternative 3: Non-Wires Alternative

This alternative would utilize commercial-grade battery storage technology to provide four hours of on-peak capacity to eliminate the overload condition. Based on verified load readings and distribution feeder modelling, approximately four hours of capacity would be required to alleviate the overload conditions on this section of line during peak load. A preliminary capital cost estimate for the procurement of a battery storage solution for this application is approximately $1,322,000 and would have an expected lifetime of 15 years.[10]

Recommended Alternative

Of the technically viable alternatives considered, upgrading the overloaded section of distribution feeder GOU-03 from two-phase to three-phase is the least-cost alternative. This is therefore the recommended alternative to address the identified overload condition.

[10] To offload the two-phase section of distribution line to be within Newfoundland Power's planning limits of 85 amps, a 2.3 MWh battery storage system would be required. The preliminary procurement cost of this solution is approximately $1,322,000 based on 2025 projected battery storage costs of $574/kWh (US$388/kWh converted to Canadian dollars) obtained from *Cost Projections for Utility-Scale Battery Storage: 2023 Update*, June 2023, page 13, prepared for the National Renewable Energy Laboratory by Wesley Cole and Akash Karmakar. According to Cole and Karmakar, the median lifetime of utility scale battery systems is 15 years.

4.0 PROJECT COST

Table 1 provides the cost of the *Feeder Additions for Load Growth* project to address overload conditions on distribution feeders APT-02 and GOU-03 in 2025.

Table 1
Feeder Additions for Load Growth Project
2025 Project Cost
($000s)

Cost Category	APT-02	GOU-03	Total
Material	117	180	297
Labour – Internal	115	179	294
Labour – Contract	125	197	322
Engineering	18	29	47
Other	-	-	-
Total	375	585	960

The total cost of the *Feeder Additions for Load Growth* project is $960,000 in 2025.

5.0 CONCLUSION

The *Feeder Additions for Load Growth* project for 2025 includes:

(i) Upgrading a 1.6-kilometre two-phase section of distribution feeder APT-02 along Nearys Pond Road in Portugal Cove – St. Philip's to three-phase 1/0 AASC;
(ii) Upgrading a 2.4-kilometre two-phase section of distribution feeder GOU-03 along Petty Harbour Road in the Goulds to three-phase 1/0 AASC.

These upgrades are the least-cost solutions to address overload conditions resulting from customer growth in the St. John's area. Completing this work in 2025 will ensure the continued provision of safe and reliable service to customers in these areas.

APPENDIX A:

Distribution Planning Guidelines
Conductor Ampacity Ratings

Table A-1 Aerial Conductor Ampacity Ratings						
			Planning Ratings[3] CLPU Factor[4] = 2.0 Sectionalizing Factor[5] = 1.33			
	Continuous Winter Rating[1]	Continuous Summer Rating[2]		MVA		
Size and Type	Amps	Amps	Amps	4.16 kV	12.5 kV	25.0 kV
1/0 AASC	303	249	228	1.6	4.9	9.8
4/0 AASC	474	390	356	2.6	7.7	15.4
477 ASC	785	646	590	4.2	12.7	25.5
#2 ACSR	224	184	168	1.2	3.6	7.3
2/0 ACSR	353	290	265	1.9	5.7	11.4
266 ACSR	551	454	414	3.0	8.9	17.9
397 ACSR	712	587	535	3.9	11.6	23.1
#6 Copper	175	125	132	0.95	2.9	5.7
#4 Copper	203	166	153	1.1	3.3	6.6
1/0 Copper	376	309	283	2.0	6.1	12.2
2/0 Copper	437	359	329	2.4	7.1	14.2

1 The winter rating is based on ambient conditions of 0ºC and 2 ft/s wind speed.
2 The summer rating is based on ambient conditions of 25ºC and 2 ft/s wind speed.
3 The planning rating is theoretically 75% of the winter conductor ampacity. In practice, the actual percentage will be something less due to: (i) the age and physical condition of the conductor; (ii) the number of customers on the feeder; (iii) the ability to transfer load to adjacent feeders; and (iv) operational considerations including the geographic layout and the distribution of customers on the feeder.
4 Cold load pick-up ("CLPU") occurs when power is restored after an extended outage. On feeders with electric heat, the load on the feeder can be 2.0 times as high as the normal winter peak load. This is the result of all electric heat coming on at once when power is restored. The duration of CLPU is typically between 20 minutes and one hour.
5 A two-stage sectionalizing factor is used during CLPU conditions to increase the Planning Rating of aerial conductors. Restoring power to one section of the feeder at a time reduces the overall effect of CLPU. The sectionalizing factor is the fraction of the load that is restored in the first stage multiplied by the CLPU factor. The optimal portion of the total load on a feeder that is restored in the first stage is 0.66, resulting in a sectionalizing factor of 0.66 x 2.0 = 1.33.

NEWFOUNDLAND POWER
A FORTIS COMPANY

2.1 2025 Substation Refurbishment and Modernization

June 2024

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1.0 INTRODUCTION

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") operates 131 substations located throughout its service territory. These include: (i) generation substations that connect generating plants to the electrical system; (ii) transmission substations that connect transmission lines of different voltages; and (iii) distribution substations that connect the low-voltage distribution system to the high-voltage transmission system.[1] The equipment in substations ensures the electrical system operates safely and at appropriate voltage levels.

Substation assets are critical to electrical system reliability. A single substation outage can result in a loss of service to thousands of customers. Because of the critical role they play in the electrical system, substations must be designed and maintained to provide a high degree of reliability.

Newfoundland Power introduced its *Substation Refurbishment and Modernization Plan* as part of its *2007 Capital Budget Application.*[2] The plan focuses on the refurbishment and modernization of individual substations based on the condition of core infrastructure and equipment.

In 2025, the Company is proposing to refurbish and modernize Northwest Brook ("NWB") Substation in the town of Northwest Brook-Ivan's Cove at a cost of $4,175,000. In 2025, the Company is also proposing to commence two-year projects to refurbish and modernize: (i) Summerville ("SMV") Substation in the town of Summerville at a total cost of $5,021,000; and (ii) Lockston ("LOK") Substation in the town of Lockston at a total cost of $4,826,000. All three of these substations contain a considerable amount of deteriorated and obsolete equipment that pose a risk to their reliable operation.

Due to supply chain constraints and procurement lead times for electrical equipment, Newfoundland Power is transitioning to multi-year substation refurbishment and modernization projects. This will provide the ability to complete design, procurement and contract approval in year one and construction and commissioning in a subsequent year. This transition is continuing with the SMV Substation and LOK Substation, which will both be two-year projects. LOK Substation requires a new power transformer that has a procurement lead time greater than one year. Over the next few years all refurbishment and modernization projects that require equipment having long procurement lead times will be completed as multi-year projects.[3]

This report provides an update on Newfoundland Power's *Substation Refurbishment and Modernization Plan* and the overall condition of substation assets. The three projects proposed as part of the *2025 Capital Budget Application* are detailed in the appendices that follow.

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1 Newfoundland Power's substations may serve multiple purposes and can be classified as any combination of the generation, transmission and distribution functions.

2 Newfoundland Power's *Substation Refurbishment and Modernization Plan* is an element of the *Substation Strategic Plan* filed with its *2007 Capital Budget Application*.

3 Equipment with long procurement lead times used in refurbishment and modernization projects include power transformers, circuit breakers, reclosers and steel bus structures.

2.0 BACKGROUND

2.1 Substation Refurbishment and Modernization Plan

Good utility practice involves a structured and comprehensive approach to preventative and corrective maintenance for critical substation assets. Maintenance programs are intended to keep critical assets in good working order, prolong their life and protect against in-service failures with significant consequences.

Newfoundland Power's substations are inspected eight times annually. These inspections identify preventative and corrective maintenance necessary to ensure the reliable operation of critical substation assets.

Inspection results are incorporated into the Company's annual update of its *Substation Refurbishment and Modernization Plan*. Under this plan, the maintenance cycle for major substation equipment is coordinated with the individual refurbishment and modernization projects. This coordination provides productivity and service benefits for customers.

Table 1 provides the latest update of the *Substation Refurbishment and Modernization Plan*.

Table 1
Substation Five-Year Forecast
2025 to 2029

Substation Designations	Cost Estimates ($000s)				
	2025	2026	2027	2028	2029
ISL	4,706	-	-	-	-
NWB	4,175	-	-	-	-
LOK	305	4,521	-	-	-
SMV	511	4,510	-	-	-
HAR	-	327	4,230	-	-
GPD			2,829		
PHR	-	-	836	4,636	-
LLK	-	-	576	3,792	-
FRN	-	-	181	2,352	-
RBK	-	-	171	2,210	-
SLA	-	-	-	64	1,170
FER	-	-	-	299	3,879
SBK	-	-	-	206	3,142
BLK					3,293
MOP	-	-	-	-	32†
GOU	-	-	-	-	397†
HWD	-	-	-	-	111†
BCV	-	-	-	-	234†
BIG	-	-	-	-	376†
QTZ	-	-	-	-	34†
TOTAL	9,697	9,358	8,823	13,559	12,668

Note: SUB: See the Electrical System Handbook included with the *2006 Capital Budget Application* for three-letter substation designations.
† Year one of multi-year projects in 2029 and 2030

Newfoundland Power's current plan includes the refurbishment and modernization of 20 substations over the next five years. The refurbishment and modernization plan reflects the age and condition of the Company's substation assets, as described below. Refurbishment and modernization projects will continue to focus on addressing obsolete and deteriorated equipment in individual substations.

2.2 Substation Asset Assessment

Substations include a combination of electrical system equipment, such as power transformers, reclosers and circuit breakers, and civil infrastructure, such as bus structures and buildings. The following section provides an update on the age and condition of substation equipment and infrastructure, including the strategy for addressing these assets during refurbishment and modernization projects.

Overall, the assessment shows that substation asset management practices have improved the age and risk profile of certain assets, such as reclosers and circuit breakers. The continued execution of the *Substation Refurbishment and Modernization Plan* is necessary to continue replacing obsolete and deteriorated substation equipment and infrastructure.

Power Transformers

Power transformers are the most critical assets in a substation and are used to change voltages for different applications. Newfoundland Power has 191 substation power transformers in service. The most common applications for power transformers include: (i) distribution power transformers which are used to change from transmission to distribution voltages, such as 66 kV to 12.5 kV; (ii) system power transformers which are used to change between transmission voltages, such as 138 kV to 66 kV; and (iii) generation transformers which are used to change generation voltages to transmission or distribution voltages.[4] Power transformer failures can lead to extended outages for a large number of customers.

According to industry experience, the expected life of a power transformer is between 30 and 50 years,[5] with a sharp decline for in-service power transformers past 70 years of age.[6] The load profile in Newfoundland and Labrador is favourable for transformer life expectancy, as the highest loads are experienced in the winter when ambient temperatures are the lowest.[7]

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4 Power transformers in hydro plants change from generation voltages from 2,400 volts and 6,900 volts to either distribution or transmission voltages.

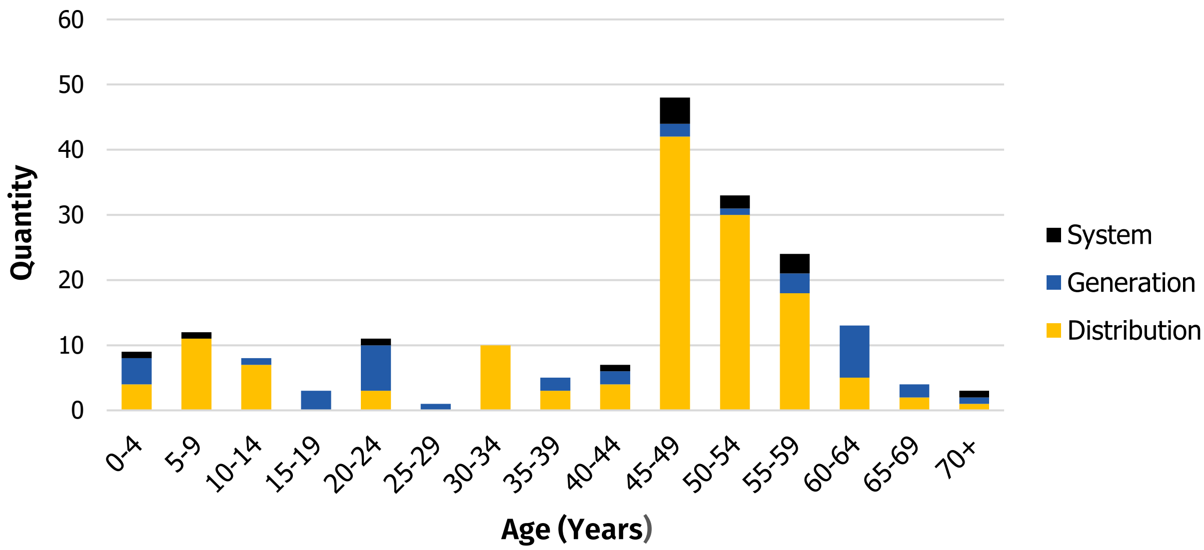
5 Based on information published by the International Council on Large Electric Systems ("CIGRE"). CIGRE is an international association with an objective to develop and facilitate the exchange of engineering knowledge and information in the field of electric power systems. CIGRE published a report on asset management in 2013 titled *Asset Management Decision Making Using Different Risk Assessment Methodologies* (the "CIGRE Report"). Unless otherwise noted, information provided on industry experience regarding substation assets was based on the CIGRE Report.

6 Based on 2021 information available from the Electric Power Research Institute ("EPRI"). EPRI is an energy research and development organization. EPRI has a database of thousands of power transformers from its electric utility members, including Newfoundland Power.

7 The transformer temperature is influenced by the ambient temperature. The transformer temperature is one of the main factors affecting the winding insulation life of a transformer. Many transformer failures are a result of a breakdown of the winding insulation.

Figure 1 shows the age distribution of the Company's power transformers.

Figure 1
Power Transformer Age Distribution



The useful service lives of Newfoundland Power's power transformers have historically exceeded what is typically seen in the industry, with nearly 40% of the Company's transformer fleet at 50 years in service or older.

Given the age profile of the Company's transformer fleet, the probability of transformer failures will continue to increase as their condition degrades with age. The Company has had seven major power transformer failures in the past five years.[8]

As part of the substation asset management practices, Newfoundland Power conducts regular inspections and oil sample analysis to gauge the internal health of power transformers to determine when corrective maintenance is required.[9] All power transformers undergo annual oil sampling.[10] Additionally, power transformers are scheduled for a major overhaul every 12 years. This involves removing the transformer from service to perform electrical testing and to repair deficiencies.

8 A major power transformer failure requires either transformer replacement, transportation off site for repairs, or removal from service for six months or longer. The seven major power transformers failures since 2019 include MUN-T2, BLK-T2, DUN-T1, SLA-T4, GBS-T1, BVA-T1 and PUL-T2.

9 Inspections also check for tank and cooler leaks, cooling fan and pump operation, operation of liquid and winding temperature equipment, oil level, tank pressure, breather operation and controls operation.

10 Oil sampling includes standard oil tests and dissolved gas in oil analysis. Standard oil tests check for contaminants and moisture, which at unacceptable levels can lower the dielectric strength of oil and cause a fault. Dissolved gas analysis is used to monitor and diagnose internal transformer electrical problems, such as the presence of arcing or poor electrical connections. Certain gases naturally increase as a transformer ages, but can be a sign of excessive temperatures and overloading in newer transformers. Oil sampling and analysis is completed annually to gauge the internal health of transformers.

Asset data is gathered for each power transformer through these regular inspections and testing practices. This data can be used to generate an overall view of the condition of the Company's power transformer fleet. The overall view will identify the power transformers that have a higher probability of failure.

Newfoundland Power utilizes EPRI's Power Transformer Expert System ("PTX") to diagnose and assess the condition of its power transformer fleet. This assessment tool yields a set of indices for each transformer, providing insight into the condition of the cellulose insulation system and the potential for any abnormal incipient fault.

The PTX System identifies the Incipient Fault Risk and the Insulation Degradation Risk for each unit in the Company's Power Transformer fleet. The Incipient Fault Risk is used to identify units that may be experiencing a variety of unexpected problems due to manufacturing, operating issues, or defects. The Insulation Degradation Risk is intended to provide an indication of the physical condition of the paper insulating system relative to its initial state. These indices serve as a guide for maintenance efforts on individual units, while also informing overall fleet management decisions.

Additionally, the Company will continue to monitor its spare power transformer inventory to manage risks associated with the increasing age of its transformer fleet and potential impacts on the provision of service to customers.[11] Power transformers will also be assessed and considered for replacement during refurbishment and modernization projects based on the estimated remaining useful life and timing of future replacement.

Circuit Breakers

Circuit breakers are electrical system devices designed to safely protect, control and isolate electrical equipment. Newfoundland Power has 375 high voltage circuit breakers in service.[12] Circuit breakers are critical components of the transmission and distribution system. The failure of a circuit breaker to operate when required increases the risk of damage to other assets, introduces safety concerns and increases the risk of customer outages.

The most common types of circuit breakers currently in service are the SF6 and vacuum types.[13] A majority of the SF6 type breakers were installed to replace older bulk-oil type breakers. There remains a number of older bulk-oil type breakers still in service.

Industry experience indicates the expected life of all types of circuit breakers is between 30 and 50 years. The Company's experience with vacuum and SF6 breakers is that they require replacement earlier than oil-filled breakers. Oil-filled breakers tended to remain in operation closer to 50 years, while it is anticipated that vacuum and SF6 breakers will likely have a useful life closer to 30 years.[14]

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11 See the *2023 Capital Budget Application*, report *2.2 Substation Spare Transformer Inventory*.

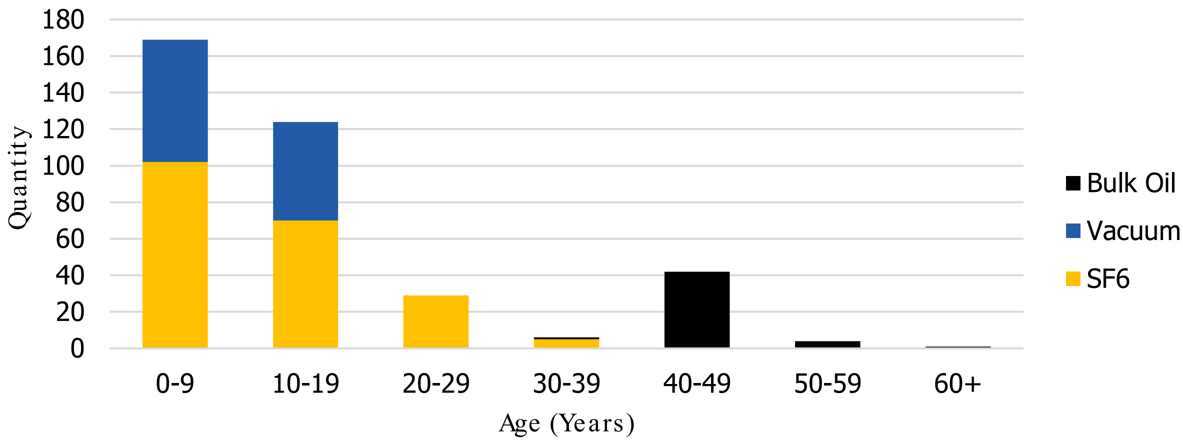
12 There are additional circuit breakers located in switchgear in the Company's substations and generation plants. This quantity of 375 breakers excludes switchgear circuit breakers.

13 Sulfur hexafluoride ("SF6") gas is used in high voltage circuit breaker design to extinguish the electrical arc created when opening energized breaker contacts.

14 The average age of failure for the Company's fleet of SF6 breakers is 27 years. The average age of failure for the Company's fleet of vacuum breakers is 20 years.

Figure 2 shows the age distribution of the Company's circuit breaker fleet.

Figure 2
Circuit Breaker Age Distribution



The age profile of Newfoundland Power's circuit breakers has been improved since 2007 as a result of the *Substation Refurbishment and Modernization*, *PCB Bushing Phase-out*, and *Replacements Due to In-Service Failures* projects and programs.

There are 206 SF6 type breakers in service. The majority of these breakers are less than 20 years old, with an average age of 11 years.

While the age of the Company's SF6 circuit breakers is generally favourable, certain models are experiencing operational issues. There were 44 Hyosung SF6 circuit breakers installed between 2008 and 2016.[15] These breakers have started to experience issues with excessive SF6 leaks, with 12 of these units having gaskets replaced to address this issue.[16] These breakers are being monitored closely for further leakage issues and will be repaired as required.

There are 48 bulk-oil type breakers in service. The majority of bulk-oil type breakers have been in service for 40 years or more, with an average age of 48 years.

The bulk-oil type breakers that remain in service are approaching the end of their useful service life. GE KSO and GE FKP oil-filled breakers comprise 90% of those in service. GE KSO breakers were manufactured from 1976 to 1991, have an average age of 45 years and can no longer be economically maintained.[17] The GE FKP breakers were manufactured from 1970 to 1982 and

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15 There are 18 66 kV breakers and 26 138 kV breakers.

16 SF6 is a potent greenhouse gas with a high global warming potential, and its concentration in the earth's atmosphere is rapidly increasing. Care must be taken to ensure containment of SF6 gas and to avoid its release into the atmosphere.

17 Newfoundland Power does not have adequate spare parts on hand and spare parts are not readily available. These circuit breakers are difficult to troubleshoot and the Company no longer has the expertise to maintain these units.

have an average age of 48 years. The age and condition of these breakers pose environmental risks as they can contain between 250 and 12,500 liters of oil.

Currently, all new breakers being purchased are either SF6 or vacuum type, depending on the required voltage and fault interrupting capability.

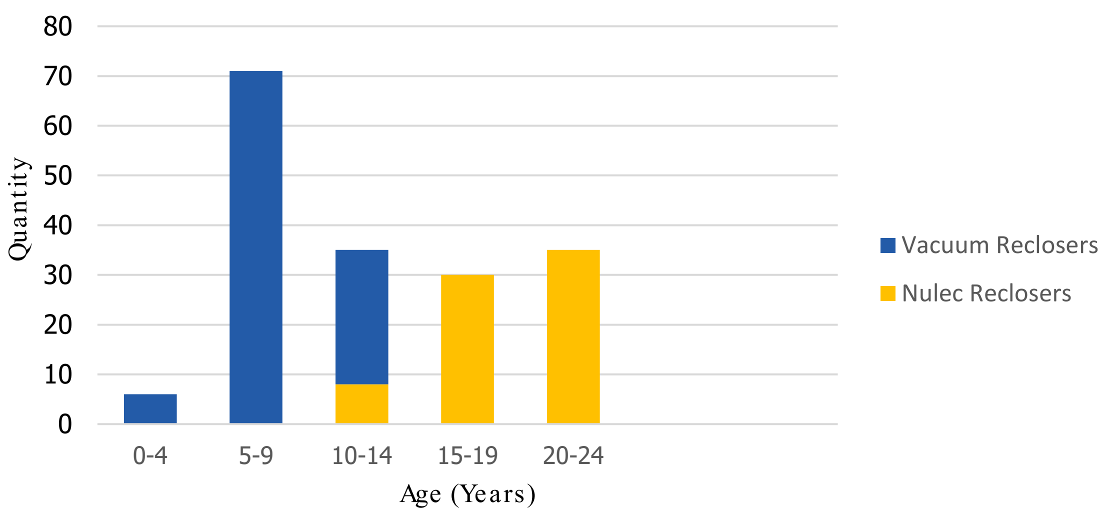
Reclosers

Reclosers are electrical safety devices designed to control, protect and isolate electrical distribution equipment where low short circuit fault levels are present. Newfoundland Power has 177 substation reclosers in service.[18] Following the completion of the *Substation Feeder Automation* project in 2019, all in-service substation reclosers are either vacuum type or vacuum type insulated with SF6 gas manufactured by Nulec.[19]

Industry experience indicates the expected life of reclosers is between 30 and 50 years. This includes vintage hydraulic reclosers which tended to remain in operation in excess of 50 years. Based on the Company's experience, it is expected that the newer vintage reclosers will likely have a useful life more towards the lower end of this range.

Figure 3 shows the age distribution of the Company's substation recloser fleet.

Figure 3
Recloser Age Distribution



[18] There are additional reclosers located on the Company's distribution feeders. This quantity of 177 reclosers excludes the downline reclosers installed on distribution feeders.

[19] In 2015, as part of the *Substation Refurbishment and Modernization* project, the Company initiated a five-year *Substation Feeder Automation* program to modernize its substation reclosers by replacing vintage hydraulics reclosers with reclosers with automation capability.

With the completion of the *Substation Feeder Automation* program in 2019, the age profile of the Company's substation reclosers is favourable.[20] All substation reclosers are currently less than 23 years old.

While the age profile of the Company's reclosers is favourable, some of the oldest reclosers in Newfoundland Power's system are no longer supported by the manufacturer and spare parts are no longer available. This includes 73 Nulec reclosers installed between 2001 to 2012 for distribution feeder protection.[21] Over the last five years, ten of these reclosers have required replacement. The failures experienced and the lack of manufacturer support of the Nulec reclosers indicate that they are reaching the end of their useful service life.[22]

Switchgear

Switchgear is used in indoor applications and encloses circuit breakers which are electrical devices designed to safely control, protect and isolate electrical equipment. Newfoundland Power has six substations with nine distribution switchgear lineups.[23] The majority of this switchgear is operated at 12.5 kV distribution voltage; however, there are two locations with 4.16 kV switchgear.[24] The Company's substation switchgear consists of a total of 54 individual circuit breakers.[25]

Switchgear circuit breakers are critical components of substation equipment. The failure of a circuit breaker to operate properly increases the risk of damage to other assets, introduces safety concerns and increases the risk of customer outages.

Industry experience indicates the expected life of circuit breakers is 30 to 50 years.

The majority of Newfoundland Power's substation switchgear breakers were purchased in the 1960s and 1970s. Approximately 11% of the Company's switchgear breakers have been in service for 50 years or more, which is the upper limit of typical industry experience. There is a high risk that in-service failures will occur as the switchgear breakers continue to age and deteriorate.

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20 Since the early 2000s, Newfoundland Power has been automating its distribution feeders to provide full remote monitoring and control from its Supervisory Control and Data Acquisition ("SCADA") system. In 2015, with approximately 60% of all distribution feeders already automated, the Company instituted a plan to complete the automation of substation reclosers and breakers on the remaining 40% of distribution feeders by the end of 2019.

21 Nulec was one of the first manufacturers of fully automated reclosers offering remote monitoring and control capability through utility SCADA systems. The remainder of the Company's reclosers were purchased since 2012 and were manufactured by either Thomas & Betts, G&W Viper, or Eaton Cooper.

22 The Nulec controller is the only digital relay for which Newfoundland Power cannot remotely access fault records using the Company's relay management system. Access to fault records is only available on site through the Nulec user interface.

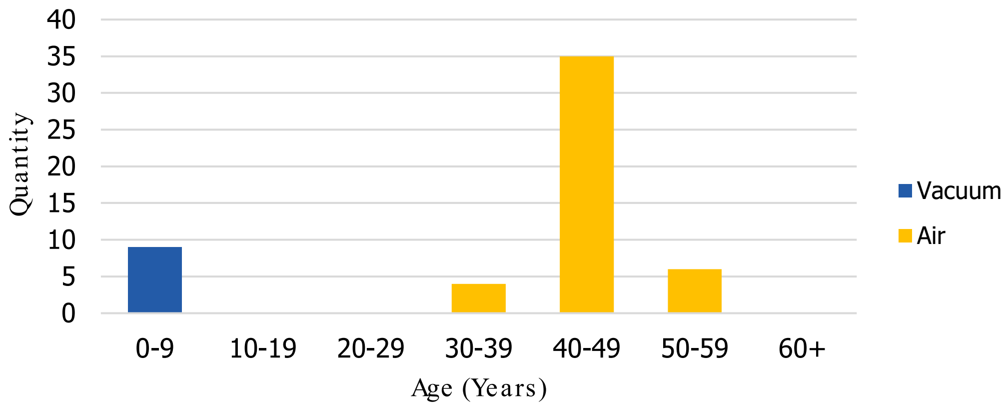
23 There are also 57 switchgear lineups associated with the Company's generation plants.

24 The only 4.16 kV distribution switchgear remaining in service are located at the Company's Grand Falls ("GFS") and Stamps Lane ("SLA") substations.

25 The most common type of switchgear breakers currently in-service are air-blast circuit breakers.

Figure 4 shows the age distribution of the Company's switchgear breakers.

Figure 4
Substation Switchgear Breaker Age Distribution



All of the Company's 1960 and 1970 vintage substation switchgear is approaching the end of its service life. Support from the manufacturers has been discontinued and replacement parts are no longer available. This vintage of switchgear is not built to current standards necessary to mitigate arc flash hazards.[26] Arc flash technologies on newer switchgear mitigate the arc flash hazard to prevent injury to personnel and contain equipment damage.[27] Replacing end of life switchgear mitigates safety risks, equipment damage and supply interruptions impacting reliable service to customers.

Voltage Regulators

Voltage regulators are electrical system devices used to control voltage levels on long feeders. The majority of Newfoundland power's voltage regulators are installed along the distribution network, however, there are 16 sites with voltage regulators inside of the substation.

Industry experience indicates the expected useful service life is 30 to 50 years for voltage regulators.

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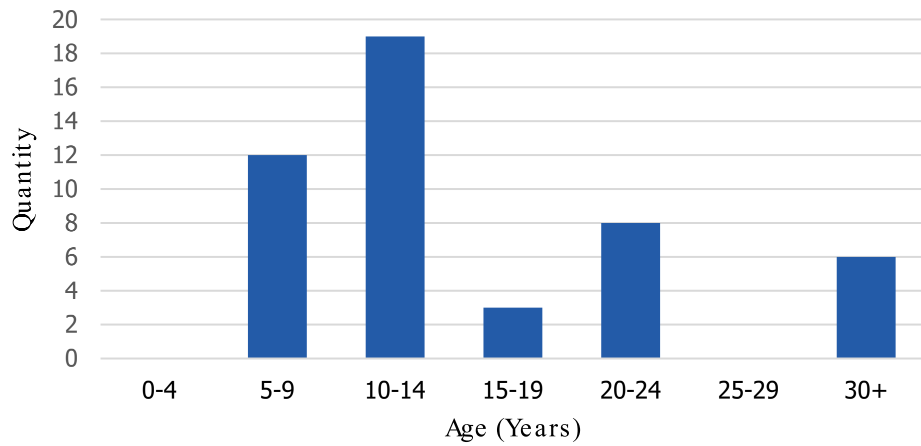
26 Arc resistant switchgear relieves the pressure buildup from severe arcing and exhausts the rapidly expanding air away from operating personnel. Arc flash protective relays can detect the early stage of an arc's development and initiate instantaneous tripping of the associated breakers.

27 The feeder protection and controls are typically installed on the front panel of the switchgear cubicles exposing personnel to potential arc flash hazards. The current standard is to install the protection and controls remote from the switchgear in a separate control room. This reduces the requirement for working in close physical proximity to the switchgear, which enhances safety for personnel in the event of an arc flash or other equipment failure.

Figure 5 provides the age distribution of Newfoundland Power's substation voltage regulators.

Figure 5
Substation Voltage Regulator Age Distribution



Protection Relays

Protective relaying in substations is used to protect transmission lines, substation equipment and distribution feeder circuits. Newfoundland Power currently uses electromechanical relays, digital relays and controllers to protect and control its substation equipment. Failure of protective relaying can result in widespread outages, cause significant equipment damage and jeopardize the safe operation of the electrical system.

Vintage electromechanical relays were the original electrical protection used by Newfoundland Power. Electromechanical relays operate by using torque producing coils energized by current and voltage inputs, which open or close contacts based on mechanically calibrated thresholds. Electromechanical relays have moving parts that can fail as they age, wear, and accumulate dirt and dust. Electromechanical relays have become obsolete as digital relays have now become industry standard.

Starting in the early 2000s, Newfoundland Power began modernizing its protection devices by replacing electromechanical relays with digital relays and controllers.[28] Multiple electromechanical relays can be replaced by one digital relay as they can offer several protection elements in one device. This approach minimizes the number of active devices used to provide protection to substation assets. In addition, digital relays incorporate communications functionality to allow for remote interaction with the relay.[29]

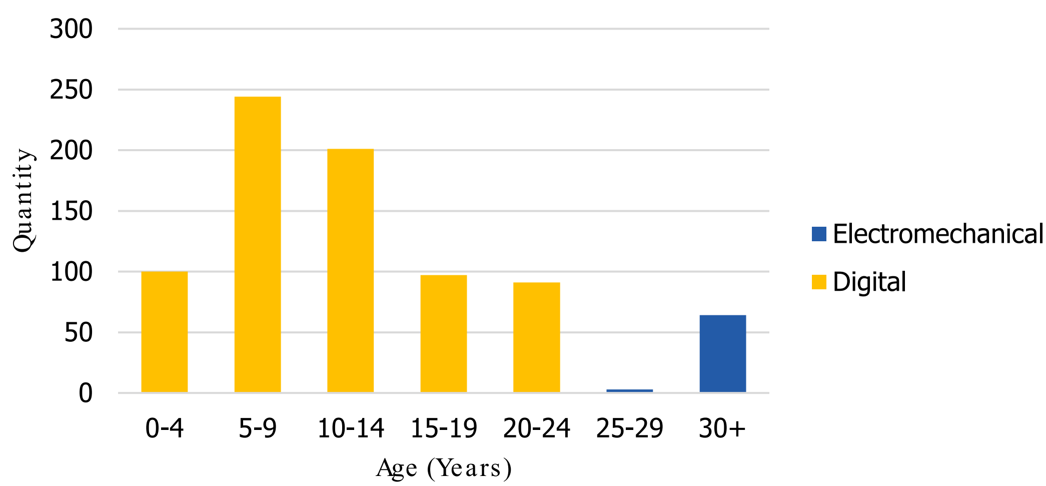
Over the past 20 years, Newfoundland Power has upgraded most of the electromechanical protection devices. However, approximately 9% of the protection devices currently in service are still electromechanical.

Industry experience indicates the expected useful service life is 20 to 30 years for electromechanical relays and ten to 25 years for digital relays.

A majority of Newfoundland Power's electromechanical relays are over 30 years old, which is the upper limit of typical industry experience. The Company plans to continue replacing the remaining electromechanical relays with digital devices.

Figure 6 provides the age distribution of Newfoundland Power's electromechanical and digital relays.

Figure 6
Electromechancal and Digital Relay Age Distribution



[28] In its *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power,* December 17, 2014, The Liberty Consulting Group, examined Newfoundland Power's practice of replacing multiple obsolete electromechanical relays with a single modern microprocessor-controlled relay and concluded that the Company uses reasonable practices that conform to industry practice.

[29] Remote administration of upgraded devices allows protection relays to be interrogated and reconfigured remotely. This allows engineers to interrogate protection relays remotely, providing quicker diagnosis of system problems. Without this capability, engineers would have to travel to the substation to interrogate the relay on site, thereby increasing the time necessary to diagnose fault data and restore service to customers.

Operating issues with the Company's older in-service digital relays have highlighted the need for asset replacement. For example, since 2015, 11 Micom P142 digital relays have failed in-service and required replacement.[30] There are a number of other in-service relays that will soon reach the end of the expected life for digital relays.[31]

High Voltage Switches

Substation high voltage switches provide isolation for equipment such as power transformers, circuit breakers and reclosers.[32] Newfoundland Power has approximately 2,800 high voltage switches in service.

Switches that are operated infrequently tend to seize due to deterioration of bushings, corrosion in operating mechanisms or misalignment of blades. Substation switches such as transformer isolating and bus tie switches are operated infrequently. Consequently, they are susceptible to this form of failure.[33]

Over the life of a switch, its operation contributes to mechanical wear and tear experienced by items such as hinge bushings, Teflon bushing liners and springs used to assist movement. The result is typically misalignment of switch blades and contact surfaces, which causes heating, arcing and eventually switch failure. The Company's strategy for high voltage switches is to replace switches when they are more than 30 years old. Switches will also be assessed and considered for replacement during refurbishment and modernization projects if substation bus structure replacements or expansions are required.

30 There are currently 94 Micom P142 relays in service. Micom P142 relays were installed from 2002 until 2016 primarily for distribution feeder protection. These Micom relays have exhibited operational issues in recent years. The version of this relay installed between 2002 and 2009 is no longer supported by the manufacturer, and spare parts are no longer available. This accounts for 61% of the in-service Micom P142 devices.

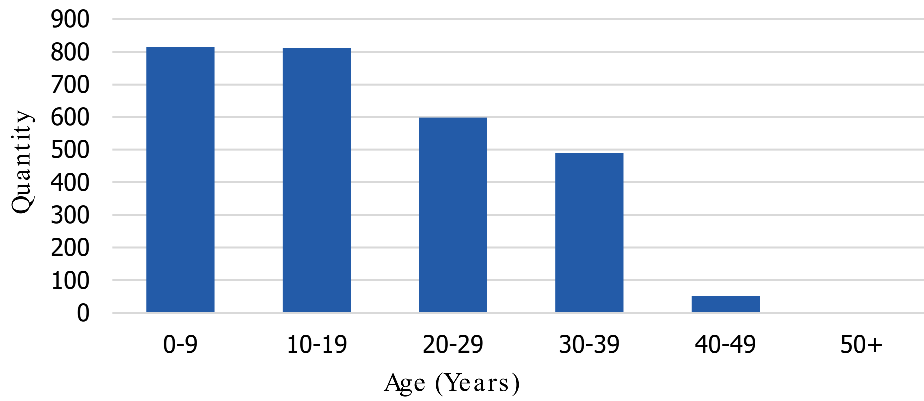
31 These include Micom P632, P442, P543, P941 and Schweitzer SEL-487B type relays.

32 This includes switches of all high voltage classes including 12.5 kV, 25 kV, 66 kV and 138 kV.

33 To help avoid switch issues resulting from infrequent use, the Company will operate and maintain these high voltage switches whenever opportunities and substation work permit.

Figure 7 provides the age distribution of Newfoundland Power's high voltage switches.

Figure 7
Switch Age Distribution



High Voltage Fused Switches and High-Speed Ground Switches

While digital protection relays are generally installed as today's industry standard for transformer protection, fuses are also used for transformer protection up to 10 MVA.[34] Fuses can economically protect small power transformers against primary and secondary faults; however, they provide limited protection against faults internal to the transformer. Generally, for transformers rated 10 MVA or higher, protection relays provide a higher degree of precision in the detection of internal faults.

Another method of providing transformer protection is to incorporate a high-speed ground switch for transformers up to 10 MVA.[35] The high-speed ground switch operates by providing a deliberate single-phase ground fault on the high voltage side of the power transformer.[36] This single-phase ground fault, in turn, is detected by the transmission line protection at the upstream substation. Relying on protection equipment at the upstream substation to detect faults at the downstream substation exposes the power transformer and low-voltage bus to increased fault levels for longer periods of time, which effectively reduces the life of the assets exposed to the fault.[37]

34 The IEEE Guide for Protecting Power Transformers ("IEEE C37.91") indicates that fuses can be used for protection on transformers rated less than 10 MVA. They, however, provide limited protection for internal faults.

35 IEEE C37.91 also indicates that high-speed ground switches are generally used for protection on transformers operating at voltages less than 100 kV and on transformers rated less than 10 MVA.

36 The operation of the switch is initiated by the transformer protection for a fault in the power transformer, on the low voltage bus, or on a distribution feeder where the fault is not cleared by the feeder recloser.

37 The time for a high-speed ground switch to operate and the upstream circuit breaker to trip is slower than a standard circuit breaker operation.

Newfoundland Power has 18 fuses installed for transformer protection on power transformers rated 10 MVA or higher, which is not industry standard. There are currently 11 high-speed ground switches in service being utilized for power transformer protection.[38]

Proper transformer protection that conforms to current standards is required to safely and reliably operate the electrical system. Replacing fuses and high-speed ground switches with circuit breakers provides a standard form of transformer protection that conforms to current standards.[39] As part of *Substation Refurbishment and Modernization* projects, Newfoundland Power will replace fuses and high-speed ground switches with standard forms of protection for power transformers rated 10 MVA or higher.

Bus Structures and Foundations

Bus structures are galvanized steel or wood pole structures that support the switches, insulators and conductors in a substation.[40]

Approximately 30% of the existing wooden bus structures are over 50 years of age. Wooden structures over 50 years of age show signs of deterioration such as decay, shell separation, splitting, checking and cracking.[41] This deterioration compromises the strength of the wooden structures affecting their ability to support the weight of critical substation equipment and increasing the probability of failure. In addition, the deterioration leads to bending and movement in the wooden components affecting the alignment of equipment mounted on the bus structure. Depending on the degree of deterioration, the replacement of the bus structure may be required. Bus structures will also be assessed and considered for replacement during refurbishment and modernization projects based on the requirement to add additional equipment to the bus structure or substation reconfiguration requirements.

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38 Eight of the 11 high-speed ground switches installed on the Company's transformers are operating at 138 kV or on transformers rated 10 MVA or higher, which does not conform with the recommendations of IEEE C37.91.

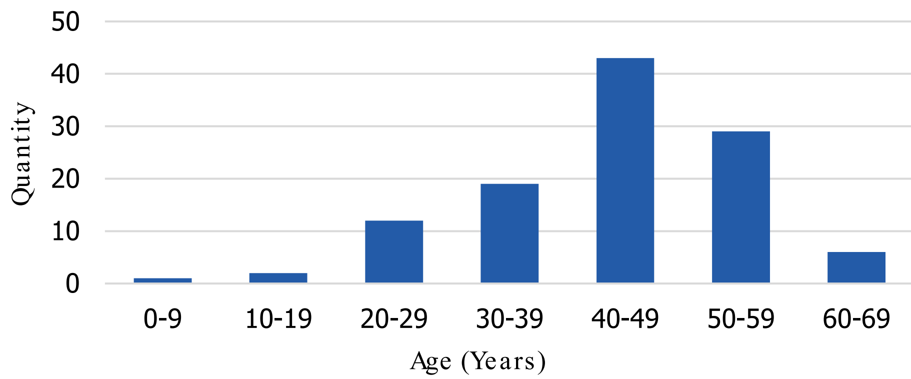
39 Circuit breakers also provide the ability to remotely control the energization of the transformer through the Company's SCADA system.

40 Newfoundland Power has 112 wooden and 148 steel bus structures.

41 Deep splits and checks allow moisture and fungus to enter the pole past the treated outer layer and into the untreated center of the pole. Repeated freeze and thaw cycles exacerbate this problem by widening the split and checks, which can result in failure of the poles.

Figure 8 shows the age distribution of Newfoundland Power's Substation wooden bus structures.

Figure 8
Wooden Bus Structure Age Distribution



Steel structures are more physically stable than wood structures which move and twist over time. This makes steel structures better suited for mounting high voltage switches as they stay properly aligned, reducing maintenance, repair and replacement of switches. Steel structures do not require guying. This decreases the overall dimensions of the substation compared to designs employing guyed wooden structures. The Company uses galvanized steel when replacing or installing new bus structures.[42]

Concrete foundations are used to support steel bus structures, breakers and reclosers. Concrete foundations deteriorate over time. If left unchecked, the deterioration of concrete foundations and footings can jeopardize the structural stability of substation equipment. The Company repairs or replaces concrete foundations as required.

[42] See Newfoundland Power's *2007 Capital Budget Application* report *2.1 Substation Strategic Plan*, page 7.

Spill Containments

Spill containment structures are used to protect the environment from oil leaks and spills from oil field substation equipment. IEEE Standard 980-2021 *Guide for Containment and Control of Oil Spills in Substations* recommends spill containment to prevent or mitigate the environmental impacts of an oil release or spill.[43] These impacts can range from the clean-up costs incidental to a spill, to the contamination of water supplies. Additionally, IEEE Standard 979-2012 *Guide for Substation Fire Protection* recommends spill containment to minimize the surface area of a spill, which provides fire protection benefits.[44]

Currently, 84 of the 191 in-service power transformers have spill containment installed. Newfoundland Power has 14 substations that contain voltage regulators and two of these currently have spill containment installed.

As part of *Substation Refurbishment and Modernization* projects, Newfoundland Power installs concrete containment foundations for power transformers and voltage regulators inside substations to manage the environmental risk from oil spills.[45]

Ground Grids

A ground grid is a network of conductor and grounding electrodes embedded into the earth that connects to all major pieces of substation equipment. In accordance with *ANSI/IEEE Standard 80-2013 Guide for Safety in AC Substation Grounding*, the Company's substation ground grids are designed to:

(i) Provide a means to carry electric currents into the earth under normal and fault conditions without exceeding any operating and equipment limits or adversely affecting continuity of service.
(ii) Reduce the risk of a person in the vicinity of grounded facilities being exposed to the danger of electric shock or electrocution through step and touch potential.

Ground grid upgrades are completed in conjunction with *Substation Refurbishment and Modernization* projects and through the *Substation Ground Grid Upgrades* project.

Modifications include the addition of equipment bonding, grounding mats, below-grade copper wire and ground wells as required to improve ground grid impedance. Grounding studies are necessary for each substation to design a proper ground grid that accounts for local site conditions. These studies include field testing and computer modeling to complete a step and touch potential analysis to identify the upgrades required.

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43 See IEEE. Standard 980-2021, *Guide for Containment and Control of Oil Spills in Substations*. Retrieved June 19, 2024, from https://standards.ieee.org/ieee/980/7038/.
44 See IEEE. Standard 979-2012, *IEEE Guide for Substation Fire Protection*. Retrieved June 19, 2024, from https://standards.ieee.org/ieee/979/3665/.
45 In February 2023, there was an incident where approximately 500 litres of oil was captured in a transformer spill containment, which prevented environmental contamination related to oil releasing from a power transformer.

Control Buildings

Control buildings provide a weatherproof and temperature-controlled environment for auxiliary equipment such as protection relays, meters, battery systems, communication and control equipment and AC and DC distribution panels for power substation equipment.

Small distribution substations with minimal auxiliary equipment may house the required auxiliary equipment in outdoor weatherproof cabinets.[46] Other substations that contain digital protection relays for circuit breakers and transformers require a control building to house the associated auxiliary equipment.[47]

Many of Newfoundland Power's existing control buildings are vintage pre-fabricated buildings which include metal roofs and exterior steel cladding. Maintenance and refurbishment of these pre-fabricated buildings is limited and would require adapting available construction materials to the pre-fabricated design. Newfoundland Power has standardized its control building design to wood frame construction on a concrete slab using standard construction materials such as metal siding and asphalt shingles. This design allows the control buildings to be easily built and maintained with materials readily available from local suppliers. Control buildings are assessed during refurbishment and modernization projects. Depending on the condition of the existing building and requirements to add additional auxiliary substation equipment, control buildings will be refurbished or replaced as required.

Physical Security

The unauthorized entry of personnel within Company facilities, including substations, can result in property damage and exposure to energized equipment or hazardous materials. This can create safety hazards for individuals entering the facilities, including employees, which can result in serious injuries occurring.

Theft and vandalism at substations continue to be a particular concern. From 2019 to 2023 there were 31 substation break-ins. A significant increase in substation break-ins has been observed recently, with 18 break-ins occurring so far in 2024. Given previous experience with substation break-ins, the probability of a security breach that poses a major security risk is likely.

To address these concerns, the Company has begun performing security upgrades at its substations as part of the *Physical Security Upgrades* program and *Substation Refurbishment and Modernization* projects. To date, 37 substations have been equipped with surveillance and alarm systems to deter theft and vandalism.

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[46] Small distribution substations may have a transformer protected by fuses, and feeder reclosers that have integrated protection cabinets. These substations would have minimal auxiliary equipment which could be housed in weatherproof cabinets.

[47] Circuit breakers and power transformers will typically use digital protection relays to provide electric equipment protection at a substation. These substations would typically require a 125 VDC battery system, network and communication functionality, control switches, blocking switches, AC and DC distribution panels and other auxiliary equipment. This amount of equipment is not feasible to be contained in outdoor enclosures. It is also difficult to operate and maintain devices in outdoor enclosures due to limited equipment accessibility and lack of protection from adverse weather conditions.

Battery Banks and Chargers

Battery banks and chargers provide direct current ("DC") supply to protection and control devices inside substations. Battery banks are capacity tested every three years as part of a regular maintenance cycle. Battery banks that fail the capacity test are replaced the following year. Battery chargers are remotely monitored and trigger alarms when not operating properly. When an alarm investigation determines the charger has failed it is replaced immediately using a spare charger from inventory.

Batteries have a typical service life of between ten and 20 years, and battery chargers have a typical service life of 20 years.

3.0 ASSESSMENT OF ALTERNATIVES

The age and condition of Newfoundland Power's substations shows that certain critical substation equipment and infrastructure is reaching the end of its useful service life and is prone to deterioration or obsolescence. Preventative and corrective maintenance continues to be required to address substation equipment and infrastructure that is deteriorated, obsolete and at imminent risk of failure.

There are generally two alternative approaches to addressing maintenance in substations:

(i) *Alternative 1 – Component Replacement*

Alternative 1 focuses on the replacement of specific components at various substations throughout Newfoundland Power's service territory. This can include components that are identified as obsolete, failed or prone to failure based on operating experience. Under this alternative, work is prioritized based on the condition and criticality of a specific piece of equipment.

(ii) *Alternative 2 – Refurbishment and Modernization*

Alternative 2 involves undertaking refurbishment and modernization projects at individual substations. This approach focuses on addressing a large number of deficiencies at individual substations that are identified as being in poor condition. Under this alternative, projects are prioritized based on the condition of individual substations where a large volume of work is required.

Both the component replacement and refurbishment and modernization approaches are viable alternatives to address maintenance requirements in substations.

In Newfoundland Power's experience, implementing a combination of these alternatives allows the Company to maintain the overall condition of its 131 substations.

For 2025, the Company has proposed five programs and projects that address component replacements at various substations. The *Pulpit Rock Substation Power Transformer Replacement* project addresses the deteriorated PUL-T2 power transformer. This project will mitigate risks to the delivery of reliable service to customers in the communities of Torbay, Portugal Cove – St. Philip's, Pouch Cove and Logy Bay – Middle Cove – Outer Cove. The *Gander Substation Power Transformer Replacement* project addresses the deteriorated GAN-T2 power transformer. This project will mitigate risks to the delivery of reliable service to customers from the Gander area. The *Substation Replacements Due to In-Service Failures* program addresses equipment at various substations that has failed or is at imminent risk of failure. This program allows Newfoundland Power to respond to equipment failures that occur during normal operations, which are generally not predictable. The *Substation Protection and Control Replacements* program replaces obsolete protection relays with industry standard digital relays. This program allows the Company to focus on replacing a specific piece of equipment that is obsolete and poses a risk to the safe and reliable operation of the electrical system. The *Substation Ground Grid Upgrades* project ensures substation ground grids are compliant with industry standards.

The *Substation Refurbishment and Modernization Plan* allows Newfoundland Power to focus on the condition of individual substations. Refurbishment and modernization projects are proposed when an individual substation contains a material amount of aged, deteriorated and obsolete equipment.

The continued implementation of the *Substation Refurbishment and Modernization Plan* provides productivity and service benefits for customers. Under this plan, individual refurbishment and modernization projects are coordinated with the maintenance cycle for major substation equipment. Coordinating a large volume of work required at a specific substation increases efficiency by reducing supervisory requirements, travel time, accommodation expenses and overhead expenses associated with job safety planning and environmental management planning. In addition, conducting work on critical equipment generally requires a substation to be removed from service. The approach outlined in this plan reduces requirements for customer outages and optimizes the deployment of portable substations required to maintain service to customers.

Newfoundland Power's substation asset management practices were reviewed by the Board of Commissioners of Public Utilities' (the "Board") consultant, The Liberty Consulting Group, in 2014 and were found to be consistent with good utility practice.[48]

4.0 PROJECT SCOPE AND COST

4.1 Summerville Substation Refurbishment and Modernization

Summerville ("SMV") Substation was constructed in 1969 as a distribution substation. The substation is supplied by Newfoundland Power 66 kV Transmission Line 113L from Princeton Pond ("PRC") Substation and Lethbridge ("LET") Substation. One 4 MVA power transformer SMV-T1 supplies one 25 kV distribution feeder, serving approximately 1,130 customers in the Charleston, Princeton, Summerville, Plate Cove and King's Cove area.

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[48] Conclusion 3.6 of The Liberty Consulting Group's *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power,* December 17, 2014, stated that: *"Newfoundland Power's substation inspection, corrective maintenance, and preventive maintenance practices are consistent with good utility practices."*

An engineering assessment of the substation shows that it contains a significant amount of deteriorated and obsolete equipment.
Appendix A provides the detailed engineering assessment and scope for the *Summerville Substation Refurbishment and Modernization* multi-year project.

Table 2 provides a detailed breakdown of the *Summerville Substation Refurbishment and Modernization* multi-year project.

Table 2
Summerville Substation Refurbishment and Modernization Project
Project Cost Estimate
($000s)

Cost Category	2025	2026	Total
Material	213	3,452	3,665
Labour - Internal	34	330	364
Labour - Contract	-	-	-
Engineering	261	396	657
Other	3	332	335
Total	**511**	**4,510**	**5,021**

The project to refurbish and modernize SMV Substation is estimated to cost $511,000 in 2025 and $4,510,000 in 2026 for a total project cost of $5,021,000.

4.2 Northwest Brook Substation Refurbishment and Modernization

Northwest Brook ("NWB") Substation was constructed in 1992 as a transmission and distribution substation. The substation is supplied by Newfoundland Power 138 kV Transmission Line 109L from Sunnyside ("SUN") Substation and Clarenville ("CLV") Substation. One 11.2 MVA distribution power transformer, NWB-T1, supplies two 25 kV distribution feeders, serving approximately 1,790 customers in the North West Brook – Ivany's Cove area.

An engineering assessment of the substation shows that it contains a significant amount of deteriorated and obsolete equipment.

Appendix B provides the detailed engineering assessment and scope for the *Northwest Brook Substation Refurbishment and Modernization* project.

Table 3 provides a detailed breakdown of the *Northwest Brook Substation Refurbishment and Modernization* project for 2025.

Table 3
Northwest Brook Substation
Refurbishment and Modernization Project
2025 Project Cost
($000s)

Cost Category	($000s)
Material	3,033
Labour – Internal	257
Labour – Contract	0
Engineering	643
Other	242
Total	4,175

The project to refurbish and modernize NWB Substation is estimated to cost $4,175,000 in 2025.

4.3 Lockston Substation Refurbishment and Modernization

Lockston ("LOK") Substation was built in 1956 as part of the Lockston Hydro Plant (the "Plant") development. In 1955, in anticipation of the new hydro plant at Lockston, a 46 kV transmission line was constructed connecting the Plant to the electricity system at Port Union. Ten years later, the transmission voltage was increased to 66 kV to establish transmission links to Port Blandford and Clarenville.[49] An arrangement of three power transformers LOK-T1, LOK-T2 and LOK-T4 convert 6.9 kV to 66 kV for the 4.275 MVA Plant. One 4 MVA power transformer LOK-T3 supplies a single 12.5 kV distribution feeder, serving approximately 1,100 customers in the Lockston area.

An engineering assessment of the substation shows that it contains a significant amount of deteriorated and obsolete equipment.

Appendix C provides the detailed condition assessment and scope for the *Lockston Substation Refurbishment and Modernization* multi-year project.

[49] The *Illustrated History of Newfoundland Light & Power*, Creative Publishers, 1990, Chapter XI describes the history of Union Electric Light and Power Company which served electricity customers on the Bonavista Peninsula prior to amalgamation in 1967.

Table 4 provides a detailed breakdown of the *Lockston Substation Refurbishment and Modernization* multi-year project.

Table 4 Lockston Substation Refurbishment and Modernization Project Project Cost Estimate ($000s)			
Cost Category	2025	2026	Total
Material	8	3,636	3,644
Labour - Internal	34	188	222
Labour - Contract	-	-	-
Engineering	260	397	657
Other	3	300	303
Total	305	4,521	4,826

The project to refurbish and modernize LOK Substation is estimated to cost $305,000 in 2025 and $4,521,000 in 2026 for a total project cost of $4,826,000.

5.0 CONCLUSION

The implementation of Newfoundland Power's *Substation Refurbishment and Modernization Plan* continues to be appropriate given the age and condition of the Company's substation assets. Implementing this plan allows the Company to maintain the overall condition of its substation assets in a manner that provides efficiency and service benefits for customers.

For 2025, Newfoundland Power is proposing to refurbish and modernize NWB, SMV and LOK.[50] These substations contain a significant amount of deteriorated and obsolete equipment. Refurbishing and modernizing these substations will ensure the continued provision of safe and reliable service to approximately 4,000 customers supplied by NWB, SMV and LOK substations.

[50] The refurbishment of SMV and LOK Substations are two-year projects commencing in 2025.

APPENDIX A:

Summerville Substation Refurbishment and Modernization

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1.0 SUMMERVILLE SUBSTATION

Summerville ("SMV") Substation was constructed in 1969 as a distribution substation. The substation is supplied by Newfoundland Power 66 kV Transmission Line 113L from Princeton Pond ("PRC") Substation and Lethbridge ("LET") Substation. One 4 MVA power transformer SMV-T1 supplies one 25 kV distribution feeder, serving approximately 1,130 customers in the Charleston, Princeton, Summerville, Plate Cove and King's Cove area.

Figure A-1 shows SMV Substation.

Figure A-1: SMV Substation

2.0 ENGINEERING ASSESSMENT

2.1 66 kV Infrastructure

The 66 kV wooden pole structures were installed in 1969 when the substation was first constructed. An inspection and engineering assessment was completed in 2022. The wood poles were found to have deep splits and crowning, and many of them are beginning to twist and bend causing the structure to tip. The deteriorated condition of the wood structures compromises their ability to support the weight of critical substation equipment such as switches and bus support, increasing the probability of failure. The wood pole structure is deteriorated to the point where replacement is required.

Figure A-2 shows examples of the deterioration exhibited on the 66 kV wood bus structure.

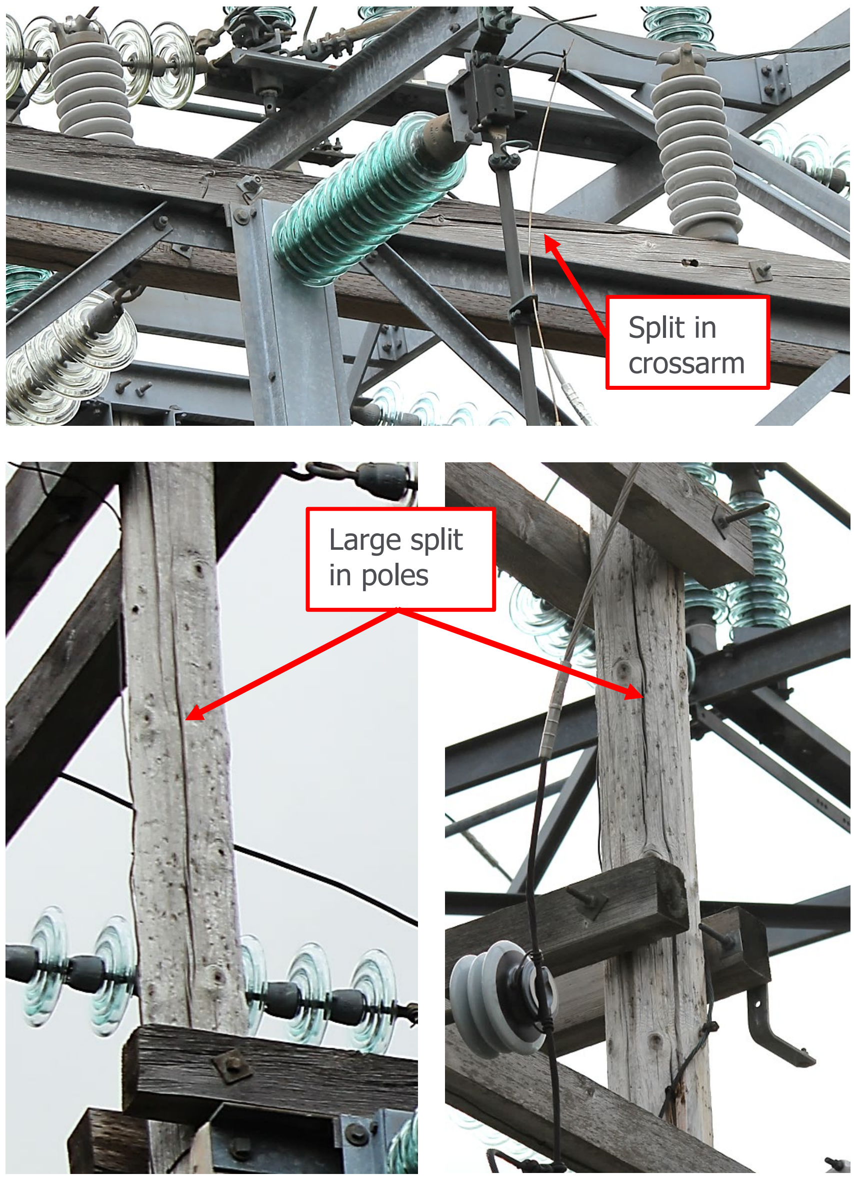

Figure A-2: Deteriorated SMV 66 kV Wood Structure

The switches on the 66 kV wooden structure were installed in 1969 and 1974 and are deteriorated. During planned work in 2023, one of the switches failed to operate resulting in field crews having to remove electrical connections to the switch to establish an isolation point. The switches now require replacement as a result of their mechanical operating condition and corrosion.

SMV Substation is designed such that, if a fault occurs on Transmission Line 113L, there will be an outage to approximately 1,130 customers served by SMV Substation. The current protection scheme does not include circuit breakers in SMV and relies on circuit breakers at LET Substation and Lockston Substation for transmission line protection. Figure A-3 below shows Transmission Line 113L.

Figure A-3: Transmission Line 113L

Two new 66 kV circuit breakers with two side break switches are recommended to divide Transmission Line 113L into two sections.[1] These breakers would be controlled by new transmission and transformer protection relays. Installing breakers would improve automation and reduce substation and transmission outages for customers served by SMV Substation.

Newfoundland Power Inc. proposes to install a new 66 kV steel structure to accommodate new equipment and replace the deteriorated poles. The installation of a new 66kV steel structure requires the installation of new switches designed to mount properly on the new structure. The existing switches on the 66 kV bus structure are original to the substation and were designed specifically to mount to wood pole structures.

[1] The installation of these two breakers, along with the existing normally open breaker at LET substation, allows SMV substation to be re-energized remotely in the event of a fault on Transmission Line 113L between Summerville and Princeton Pond or Transmission Line 113L between Summerville and Lethbridge. It also allows PRC Substation to be re-energized remotely in the event of a fault on Transmission Line 113L between Summerville and Lethbridge.

2.2 25 kV Infrastructure

The 25kV wood pole structures were installed in 1969 when the substation was first constructed. An inspection and engineering assessment was completed in 2022. The wood poles have deep splits, shell separation, decay and woodpecker holes. Many of the wood poles are beginning to twist and bend causing the structure to tip. The deteriorated condition of the wood pole structure compromises its ability to support the weight of critical substation equipment such as switches and bus support, increasing the probability of failure. The wood pole structure is deteriorated to the point where replacement is required.

Figure A-4 shows examples of the deteriorated wood pole structures.

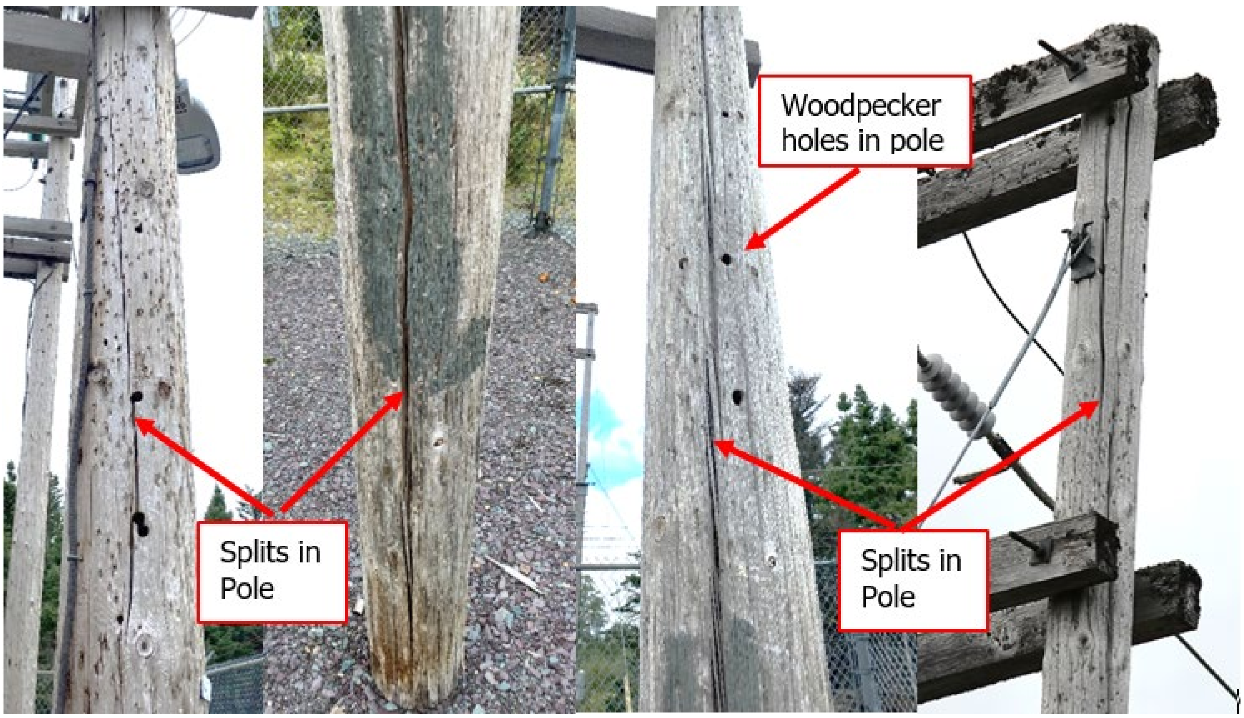

Figure A-4: Splitting of Wood Poles

The wood pole structure will be removed and replaced with a new galvanized steel structure.

The switches on the 25 kV wooden structure were installed in 1969 and 1974 and are deteriorated. One of the hook stick switches had a phase replaced due to failure in 2013, and both switches required repairs in 2017. The switches now require replacement as a result of their mechanical operating condition and corrosion.

Two of the SMV Substation voltage regulators were manufactured by Allis-Chalmers in 1973 and one of the voltage regulators was manufactured by Cooper in 2020. The Cooper regulator replaced a 1973 Allis-Chalmers voltage regulator in 2021 as a result of an in-service failure. The voltage regulators will not be replaced at this time and will be reconnected to the new steel structure. The oil-filled voltage regulators currently lack spill containment.[2] A spill containment foundation is required to protect against environmental damage in the event of an oil spill from the units.

The 25 kV feeder recloser SMV-01-R was manufactured by G&W in 2016. It is in good condition and will be reconnected to the new bus structure. The concrete foundation on for the recloser is deteriorated as shown in Figure A-5.

Figure A-5: Recloser Deteriorated Foundation

2.3 Power Transformer

SMV-T1 is a 53-year-old distribution power transformer that was manufactured by Canadian General Electric in 1971. SMV-T1 is a 66 kV to 25 kV, 4 MVA power transformer. The power transformer is in working order and oil test results show no signs of abnormal internal conditions. Annual inspections of the transformers physical condition are good in all categories.

Newfoundland Power uses Electric Power Research Institute's ("EPRI") PTX software to monitor the health of its power transformer assets. For SMV-T1, the Abnormal Condition Index indicates low short-term risk, and the Normal Degradation Index indicates low long-term risk.

Given the Company's aging power transformer fleet, SMV-T1 is expected to be replaced within the next ten years.

The transformer lacks a spill containment foundation. A new spill containment foundation is required for the transformer to protect against environmental damage in the event of an oil spill from the unit.[3]

2 The SMV Substation voltage regulator bank contains a total oil volume of approximately 1,500 liters.
3 Power transformer SMV-T1 contains approximately 7,500 liters of oil.

Figures A-6 shows power transformer SMV-T1.

Figure A-6: SMV-T1 Power Transformer

2.4 Protection and Control

Power transformer SMV-T1 is currently protected by a set of fuses. Fuses can economically protect small power transformers against primary and secondary faults; however, they provide limited protection against faults internal to the transformer. The feeder protection is provided by a microprocessor-based digital relay which will remain in service. The two new proposed 66 kV transmission line breakers with associated microprocessor-based digital relays, along with a new transformer microprocessor-based digital relay, will provide improved protection, automation and outage response times for SMV substation.

Modernization of the protection requires upgrading the existing substation communication functionality, which currently only includes a cellular modem inside the recloser cabinet. A communications gateway would provide remote control and monitoring of the new substations protection equipment from the Supervisory Control and Data Acquisition ("SCADA") system.[4] The communications gateway will provide a network connection to the SCADA system for all the substation devices that provide monitoring, protection and control of the transmission lines,

[4] The enhanced capabilities provided by the microprocessor-based digital relays provide greater options for remote control and monitoring through the Company's SCADA system.

distribution feeder and substation transformer. The modernization will also allow for remote administration of upgraded devices.[5]
The installation of a new 25 kV combined potential and current transformer is required for metering. The installation of new 66 kV PTs is required for protection and control.

Substation security cameras will be installed to deter unauthorized entry and to provide company personnel with access to video streaming to view remote facilities in the event of a security or fire alarm. There have been no break-ins at SMV Substation in the last five years.

2.5 Building

The SMV Substation does not have an existing control building as the limited number of protection and control devices in service are able to fit in small outdoor control cabinets. A new control building is required to permit the installation of a 125 VDC battery system, full network and communication functionality, multiple protection relays, control switches, blocking switches and other miscellaneous equipment.[6]

2.6 Site Condition

The SMV Substation site requires an extension to accommodate the increased footprint required for the spill containment foundations, the 66 kV breakers, the new 66 kV and 25 kV steel structures and a portable substation. Minor improvements to the site such as addressing drainage requirements, removing unsuitable soils and vegetation, and laying structural fill will be completed during the proposed project.

The existing ground grid at SMV Substation has deficiencies that pose a safety hazard. The substation has sections where there is no ground grid, and the fence grounding is insufficient. A grounding study is necessary and the ground grid for the substation would require upgrading to align with current standards and to cover the expanded substation yard and new equipment.

3.0 RISK ASSESSMENT

The *Summerville Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to approximately 1,130 customers in the Charleston, Princeton, Summerville, Plate Cove and King’s Cove area.

Equipment failure in the substation would expose all customers supplied by SMV Substation to the risk of outages. The time to restore service to customers would depend on the nature of the failure and could range from several hours up to 36 hours.

SMV Substation contains equipment that is deteriorated and at end of life, which increases the probability of outages to customers. The wood pole structures in the substation are deteriorated

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[5] Remote administration of upgraded devices allows protection relays to be interrogated and reconfigured remotely. This allows engineers to interrogate protection relays from their office, providing quicker diagnosis of system problems and improved outage response times. Without this capability, engineers have to travel to the substation to interrogate the relay on site, thereby greatly increasing the time necessary to diagnose fault data.

[6] Protection and communication devices housed in panels are required to be kept in a dry environment with temperature control.

and require replacement. The majority of the substation switches have deteriorated and require replacement due to their mechanical condition. The power transformer is protected by fuses which provide limited protection.
The existing power transformer and voltage regulators in SMV Substation contain large amounts of insulating oil and lack standard spill containment. Proper spill containment is required to mitigate the risk of an environmental incident if an oil spill were to occur. Remediation costs associated with oil spills can be significant. In addition, spill containment will minimize the surface area of an oil spill and thus provides fire protection benefits.

There are deficiencies identified with the ground grid at SMV Substation that pose a risk to safety and reliability. The substation has sections where there is no ground grid, and the fence grounding is insufficient. The purpose of ground grid upgrades is to reduce the risk exposure to electric shock or electrocution through step and touch potential. An insufficient ground grid can also affect continuity of service if there is an inadequate ground path which is required for proper equipment operation.

Overall, refurbishment and modernization of SMV Substation is necessary to ensure the continued delivery of reliable, safe and environmentally responsible service to customers in the Charleston, Princeton, Summerville, Plate Cove and King's Cove area.

4.0 ASSESSMENT OF ALTERNATIVES

In the case of SMV Substation, the number of components requiring preventative and corrective maintenance at this time justifies the refurbishment and modernization of the substation in 2025 and 2026. The 66 kV and 25 kV wood pole structures are deteriorated and require replacement. The 66 kV and 25 kV switches are deteriorated and have reached the end of their useful life. The power transformer and voltage regulators do not have a spill containment foundation.

Deferral of the *Summerville Substation Refurbishment and Modernization* project would increase the risk that some components will be run to failure. Run to failure is not a viable alternative as it would increase risks to the delivery of safe and reliable service to approximately 1,130 customers in the Charleston, Princeton, Summerville, Plate Cove and King's Cove area.

5.0 PROJECT SCOPE

The 2025 and 2026 scope of work at SMV Substation includes the following:

(i) Expand the existing yard;
(ii) Construct a new control building;
(iii) Construct new 66 kV and 25 kV steel structures to replace deteriorated wood structures;
(iv) Construct new spill containment foundations for existing transformer and voltage regulators;
(v) Install two new 66 kV breakers;
(vi) Replace deteriorated 66 kV and 25 kV switches;
(vii) Install 66 kV potential transformer;
(viii) Install new 25 kV combined current and potential transformer;

(ix) Install new digital relays and the associated communications equipment;
(x) Upgrade and extend the ground grid;
(xi) Install new security cameras; and
(xii) Install varmint protection on all 25 kV equipment.

Table A-1 summarizes the age and condition of the primary equipment planned to be replaced.

Table A-1
2025/2026 Planned Equipment Replacements
Summerville Substation

Equipment	Age (Years)	Condition
66 kV Wood Pole Structure	55	Deteriorated
66 kV Air Break Switches	55	Deteriorated/End of Life
25 kV Wood Pole Structure	55	Deteriorated
25 kV Hook-Stick Operated Switches	55	Deteriorated/End of Life

Engineering design and procurement of long lead equipment will be completed in 2025. Construction will begin in the second quarter of 2026 and will be completed in the fourth quarter of 2026. Commissioning of the substation will be completed during the fourth quarter of 2026.

6.0 PROJECT COST

Table A-2 provides the cost breakdown for the *Summerville Substation Refurbishment and Modernization* multi-year project.

Table A-2
Summerville Substation Refurbishment and Modernization Project
Project Cost
($000s)

Cost Category	2025	2026	Total
Material	213	3,452	3,665
Labour - Internal	34	330	364
Labour - Contract	-	-	-
Engineering	261	396	657
Other	3	332	335
Total	$511	$4,510	$5,021

The project to refurbish and modernize SMV Substation is estimated to cost $511,000 in 2025 and $4,510,000 in 2026 for a total project cost of $5,021,000.

7.0 CONCLUSION

The *Summerville Substation Refurbishment and Modernization* project is required to provide reliable service to customers at the lowest possible cost. The project will address the deteriorated and obsolete equipment identified through an engineering assessment of SMV Substation. New 66 kV and 25 kV steel structures will replace the deteriorated wood structures, deteriorated switches will be replaced, and two new breakers and new digital relays will provide improved automation and protection. New transformer and voltage regulator spill containment foundations will be constructed to protect against environmental hazards. The total project cost to complete the *Summerville Substation Refurbishment and Modernization* project is estimated to be $5,021,000.

APPENDIX B:

Northwest Brook Substation Refurbishment and Modernization

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1.0 NORTHWEST BROOK SUBSTATION

Northwest Brook ("NWB") Substation was constructed in 1992 as a transmission and distribution substation. The substation is supplied by Newfoundland Power 138 kV Transmission Line 109L between Sunnyside ("SUN") and Clarenville ("CLV") Substations. One 11.2 MVA distribution power transformer, NWB-T1, supplies two 25 kV distribution feeders, serving approximately 1,790 customers in the North West Brook – Ivany's Cove area.

Figure B-1 shows NWB Substation.

Figure B-1: NWB Substation

2.0 ENGINEERING ASSESSMENT

2.1 138 kV Infrastructure

The 138 kV infrastructure was constructed using steel in 1992. The engineering assessment determined that the 138 kV steel structure and insulators are in good condition.

Two of the three 138 kV switches are in excess of 32 years in service and are deteriorated. One of these switches failed to operate in 2024. These switches require replacement as a result of their mechanical operating condition. The 138 kV transformer air break switch was replaced in 2015 and will remain in service.

NWB Substation is designed such that, if a fault occurs on Transmission Line 109L, there will be an outage to approximately 1,790 customers served by NWB Substation. The current protection scheme does not include circuit breakers in NWB and relies on circuit breakers at Clarenville Substation and Sunnyside Substation for transmission line protection.

Figure B-2 below shows Transmission Line 109L.

Figure B-2: Transmission Line 109L

Two new 66 kV circuit breakers with two side break switches are recommended to divide Transmission Line 109L into two sections.[1] These breakers will be controlled by new transmission line and transformer protection relays. Installing breakers will improve automation and reduce substation and transmission outages for customers served by NWB substation.

2.2 25 kV Infrastructure

The 25 kV wood pole structures were installed in 1992 when the substation was first constructed. An inspection and engineering assessment was completed in 2022. The inspection determined that the wood poles and insulators are in good condition. Three of the seventeen cross arms will be replaced due to their poor condition.

Figure B-3 shows an example of the deteriorated wood crossarms.

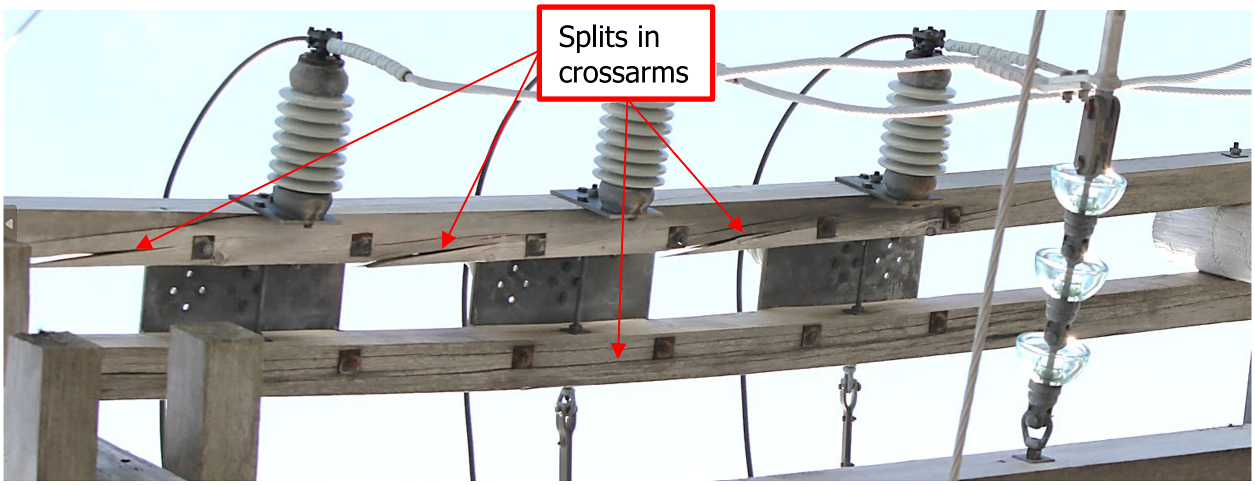

Figure B-3 Deteriorated Wood Crossarms

The 25 kV switches are in excess of 32 years in service and are deteriorated. These switches require replacement as a result of their mechanical operating condition and corrosion. This includes one air break switch, one side break switch, one voltage regulator bypass switch and four sets of hook stick operated switches. The air break switch failed to close during switching in 2023. A hot spot was detected on the voltage regulator bypass switch in 2022.

The NWB Substation voltage regulators manufactured by Cooper Power Systems in 2015 are in good condition and will remain in service. The oil-filled voltage regulators currently lack spill containment. [2] A spill containment foundation is required to protect against environmental damage in the event of an oil spill from either of the three units.

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1 The installation of these two breakers allows NWB Substation to remain energized in the event of a fault on transmission line 109L between North West Brook and Sunnyside. It also allows NWB Substation to remain energized in the event of a fault on transmission 109L between North West Brook and Clarenville, including on the CLV high voltage bus.

2 The NWB Substation voltage regulator bank contains a total oil volume of approximately 2,500 liters.

The oil-filled metering tank is currently 32 years old and is at the end of its service life. This will be replaced with three 25kV potential transformers for metering purposes.

The two 25 kV reclosers protecting distribution feeders NWB-01 and NWB-02 are in good condition and will remain in service.

2.3 Power Transformer

NWB-T1 is a 59-year old distribution power transformer that was manufactured by Westinghouse in 1965. NWB-T1 is a 138 kV to 25 kV, 11.2 MVA power transformer. The power transformer is in working order and oil test results show no indication of abnormal internal conditions. Annual inspections of the transformers physical condition are good in all categories.

Newfoundland Power uses EPRI's PTX software to monitor the health of its power transformer assets. For NWB-T1, the Abnormal Condition Index indicates low short-term risk, and the Normal Degradation Index indicates moderate long-term risk.

Given the Company's aging power transformer fleet, NWB-T1 is expected to be replaced within the next ten years.

The NWB-T1 transformer lacks standard spill containment. A new spill containment foundation is required for the transformer to protect against environmental damage in the event of an oil spill from the unit.[3]

Figure B-4 shows power transformer NWB-T1.

Figure B-4 - NWB-T1

[3] Power transformer NWB-T1 contains approximately 19,000 liters of oil.

2.4 Protection and Control

Protection of power transformer NWB-T1 consists of a high-speed ground switch NWB-T1-HGS. The high-speed ground switch relies on SUN-109L-B and CLV-109L-B to clear faults on NWB-T1. The time for a high-speed ground switch to operate and the upstream circuit breaker to trip is slower than a standard circuit breaker operation. This exposes equipment to fault currents for longer periods of time, which effectively reduces the life of the assets exposed to the fault. Replacing high-speed ground switches with circuit breakers provides standard protection, reduces equipment exposure to fault currents, and allows the system control center to remotely operate the transmission lines.[4]

The bus and transformer protection relays for NWB-T1 are vintage electromechanical type relays that were installed in 1993. The protection system for the 138 kV bus and transformers is comprised of electromechanical relays installed in an outdoor, pole mounted protection panel. These electromechanical relays are no longer industry standard and are at end of life.

Figure B-5 shows the protection panel for the 138 kV bus and transformer NWB-T1.

Figure B-5 - 138 kV Bus, NWB-T1 Protection Panel

The protection and control of the substation assets require modernization by replacing the obsolete electromechanical relays with microprocessor-based digital relays.

[4] With the circuit breaker additions at NWB, a fault on 109L will no longer cause an outage at the NWB Substation.

A new communications gateway will be installed to provide remote control and additional monitoring of the substation equipment from the Supervisory Control and Data Acquisition ("SCADA") system. The existing communications gateway lacks the ports to facilitate the additional transmission line and power transformer protection. The communication gateway will provide a network connection to the SCADA system for all the substation devices that provide monitoring, protection and control of the transmission lines, distribution feeders and substation power transformers. The modernization will also allow for remote administration of upgraded devices.[5]

Substation security cameras will be installed to deter unauthorized entry and to provide company personnel with access to video streaming to view remote facilities in the event of a security or fire alarm. There was a break-in at NWB Substation in August, 2021.

2.5 Control Building

The NWB Substation does not have an existing control building as the limited number of protection and control devices in service are able to fit in small outdoor control cabinets. A new control building is required to permit the installation of a 125 VDC battery system, full network and communication functionality, multiple protection relays, control switches, blocking switches, and other miscellaneous equipment.[6]

2.6 Site Condition

Minor improvements to the site such as addressing drainage requirements, removing unsuitable soils and vegetation, and laying structural fill will be completed.

The existing ground grid at NWB Substation has deficiencies that pose a risk to the safe and reliable operation of the electric equipment in the substation. There are sections of the yard with insufficient grounding and there are also missing connections between the main ground grid and the substation fence. A grounding study is necessary and the ground grid for the substation requires an upgrade to align with current standards and to cover the expanded substation yard and new equipment.

3.0 RISK ASSESSMENT

The *Northwest Brook Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to customers from the area of North West Brook – Ivany's Cove area.

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5 Remote administration of upgraded devices allows protection relays to be interrogated and reconfigured remotely. This allows staff to interrogate protection relays from their office, providing quicker diagnosis of system problems and improved outage response times for customers. Without this capability, staff have to travel to the substation to interrogate the relay on site, thereby greatly increasing the time necessary to assess fault data.

6 Protection and communication devices housed in panels are required to be kept in a dry environment with temperature control.

NWB Substation provides service to approximately 1,790 customers in the North West Brook – Ivany's Cove area. Equipment failure in the substation exposes all customers supplied by NWB Substation to the risk of outages. The time to restore service to customers depends on the nature of the failure and could range from several hours up to 36 hours.[7]

NWB Substation contains equipment that is deteriorated, obsolete, and at end of life which increases the probability of outages to customers. A significant quantity of switches require replacement based on their age and mechanical condition. Replacing the existing high-speed ground switch with a circuit breaker and protective relaying, will reduce the exposure of transformer NWB-T1 and other substation equipment to fault currents. The electromechanical protection relays are obsolete and are no longer industry standard. The wood pole crossarms in the substation are deteriorated and require replacement.

The power transformer and the voltage regulators in NWB Substation contain large amounts of insulating oil and lack standard spill containment. Proper spill containment is required to mitigate the risk of an environment incident if an oil spill were to occur. Remediation costs associated with oil spills can be significant. In addition, spill containment will minimize the surface area of an oil spill and thus provides fire protection benefits.

There are deficiencies identified with the ground grid at NWB Substation that pose a risk to safe and reliable operation of the electrical equipment. There are sections of the yard with insufficient grounding and there are also missing connections between the main ground grid and substation fence. The purpose of ground grid upgrades is to reduce the risk associated with step and touch potential hazards. An insufficient ground grid can also affect continuity of service if there is an inadequate ground path, which is required for proper equipment operation.

Overall, refurbishment and modernization of NWB Substation is necessary to ensure the continued delivery of reliable, safe and environmentally responsible service to customers in the area of North West Brook – Ivany's Cove area.

4.0 ASSESSMENT OF ALTERNATIVES

In the case of NWB Substation, the number of components requiring preventative and corrective maintenance at this time justifies the refurbishment and modernization of the substation in 2025. The existing electromechanical protection relays are obsolete and require replacement. The 25 kV wood crossarms are deteriorated and requires replacement. The majority of the substation switches are deteriorated and have reached the end of their useful service life. The power transformers and voltage regulators do not have spill containment foundations. The ground grid requires upgrades and the metering tank is at the end of its service life.

Deferral of the *Northwest Brook Substation Refurbishment and Modernization* project increases the risk that some components will be run to failure. Run to failure is not a viable alternative as it increases the risk to the delivery of safe and reliable service to approximately 1,790 customers in the area of North West Brook – Ivany's Cove.

[7] In the event that NWB-T1 fails, a portable substation installation is required to restore service to customers. Typically, a portable substation can be installed within 24 to 36 hours, assuming one is available.

5.0 PROJECT SCOPE

The 2025 scope of work at NWB Substation includes the following:

(i) Construct a new control building;
(ii) Replace 25kV wooden cross arms in poor condition;
(iii) Construct new concrete spill containment foundations for existing transformer and existing voltage regulators;
(iv) Install two new 138 kV breakers and one 25 kV breaker to replace the existing high-speed ground switch;
(v) Replace deteriorated 138 kV and 25 kV switches;
(vi) Install new 138 kV and 25 kV potential transformers;
(vii) Replace obsolete electromechanical relays with new digital relays and associated communications equipment;
(viii) Upgrade and extend the ground grid;
(ix) Install new security cameras; and
(x) Install varmint protection on all 25 kV equipment.

Engineering design and procurement of long lead equipment will be completed in the first quarter of 2025. Construction will begin in the second quarter and will be completed early in the fourth quarter of 2025. Commissioning of the substation will be completed by the end of 2025.

Table B-1 summarizes the age and condition of the primary equipment planned to be replaced.

Table B-1
2025 Planned Equipment Replacements
Northwest Brook Substation

Equipment	Age (Years)	Condition
138 kV Air Break Switches	32	Deteriorated/End of Life
25 kV Wood Pole Structure	32	Deteriorated
25 kV Metering Tank	32	End of Life
25 kV Air Break Switch	32	Deteriorated/End of Life
25 kV Hook-Stick Operated Switches	32	Deteriorated/End of Life
Electromechanical Protection Relays	32	Obsolete

6.0 PROJECT COST

Table B-2 provides the cost breakdown for the *Northwest Brook Substation Refurbishment and Modernization* project.

Table B-2
Northwest Brook Substation
Refurbishment and Modernization Project
2025 Project Cost
($000s)

Cost Category	Total
Material	3,033
Labour - Internal	257
Labour - Contract	0
Engineering	643
Other	242
Total	**$4,175**

The total project cost for the *Northwest Brook Substation Refurbishment and Modernization* project is $4,175,000 in 2025.

7.0 CONCLUSION

The *Northwest Brook Substation Refurbishment and Modernization* project is required to provide reliable service to customers at the lowest possible cost. It will address the deteriorated and obsolete equipment identified through an engineering assessment in the NWB Substation. Deteriorated 138 kV and 25 kV switches will be replaced, obsolete electromechanical protection relays will be replaced with digital relays, and deteriorated wood structure crossarms will be replaced. New transformer and voltage regulator spill containment foundations will be constructed to protect against environmental hazards. The total project cost for the *North West Brook Substation Refurbishment and Modernization* project is $4,175,000 in 2025.

APPENDIX C:

Lockston Substation Refurbishment and Modernization

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1.0 LOCKSTON SUBSTATION

Lockston ("LOK") Substation was constructed in 1956 as part of the Lockston Hydro Plant (the "Plant") development. In 1955, in anticipation of the new hydro plant at Lockston, a 46 kV transmission line was constructed connecting the Plant to the electricity system at Port Union. Ten years later, the transmission voltage was increased to 66 kV to establish transmission links to Port Blandford and Clarenville.[1] An arrangement of three power transformers LOK-T1, LOK-T2 and LOK-T4 convert 6.9 kV to 66 kV for the 4.275 MVA Hydro Plant. One 4 MVA power transformer LOK-T3 supplies a single 12.5 kV distribution feeder, serving approximately 1,100 customers in the Lockston area.

Figure C-1 shows LOK Substation.

Figure C-1: LOK Substation

2.0 ENGINEERING ASSESSMENT

2.1 66 kV Infrastructure

The 66 kV wood pole structure was installed in 1973. An inspection and engineering assessment was completed in 2022. The inspection determined that the poles are showing signs of deterioration. The wood poles have splits and decay. The deteriorated condition of the wood pole structure compromises its ability to support the weight of critical substation equipment

1 The *Illustrated History of Newfoundland Light & Power*, Creative Publishers, 1990, Chapter XI describes the history of Union Electric Light and Power Company which served electricity customers on the Bonavista Peninsula prior to amalgamation in 1967.

such as switches and potential transformers, increasing the probability of failure. The wood pole structure is deteriorated to the point where replacement is required.

The wood pole structure will be removed and replaced with a new galvanized steel structure.

Figure C-2 shows the deteriorated wood structures.

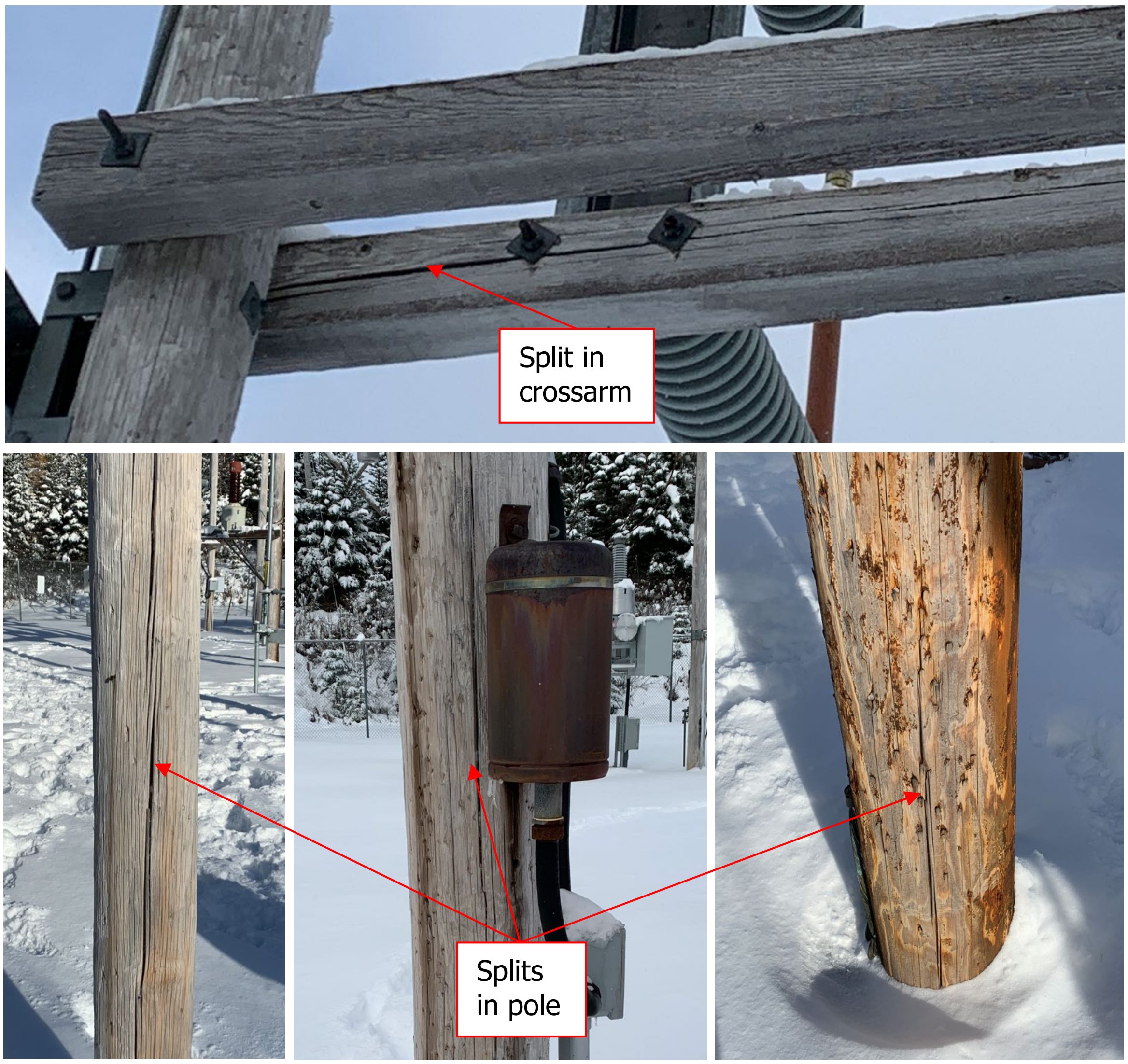

Figure C-2: 66 kV Wood Structure Condition

Three of the six 66 kV switches are 51 years in service and are deteriorated. These switches, including two side break switches and one air break switch, require replacement as a result of their mechanical operation condition and corrosion. Two air break switches are ten years old and will be returned to stores for future use. One high speed ground switch is 27 years old and will be replaced to improve power transformer protection.

LOK is designed such that, if a fault occurs on Transmission Line 111L there will be an outage to approximately 1,100 customers served by LOK substation. The current protection scheme at LOK includes one breaker on Transmission Line 113L to Princeton Pond Substation, but no breaker on 111L to Port Union Substation. LOK relies on a circuit breaker at Catalina Substation for transmission line protection. Figure C-3 below shows Transmission Line 111L.

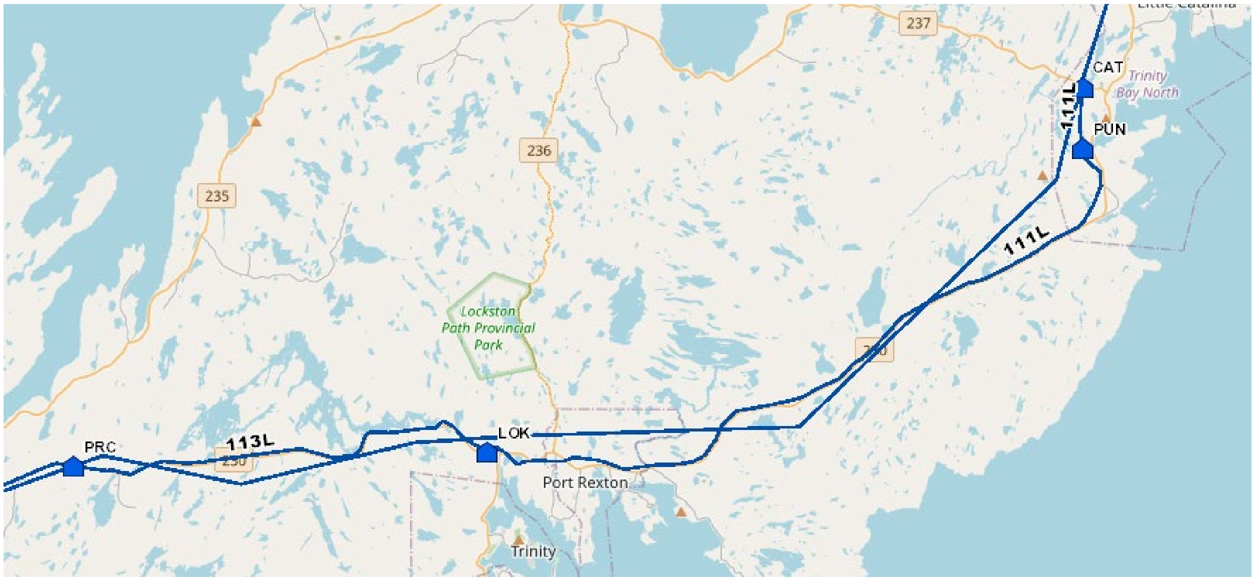

Figure C-3: Transmission Line 111L

One new 66 kV circuit breaker with two side break switches is recommended to divide Transmission Line 111L into two sections. This breaker will be controlled by new transmission line and transformer protection relays. Installing a breaker will improve automation and reduce substation and transmission outages for customers served by LOK substation.

Three oil filled 66 kV potential transformers installed in 1974 are at the end of life. They will be replaced with three dry type potential transformers.

2.2 46 kV Infrastructure

The 46 kV infrastructure only includes a wood pole structure that was installed in 1956. LOK is the only substation with 46 kV infrastructure. This infrastructure will be removed from the system at the end of this project as detailed in section *2.5 Power Transformers*.

2.3 12.5 kV Infrastructure

The 12.5 kV wood pole structures were installed in 1977. An inspection and engineering assessment was completed in 2022. The inspection determined that the wood poles are showing signs of deterioration. The poles have splits and decay. The deteriorated condition of the wood pole structure compromises its ability to support the weight of critical substation equipment such as switches and instrument transformers, increasing the probability of failure. The wood pole structure is deteriorated to the point where replacement is required.

Figure C-4 shows the deteriorated wood structures.

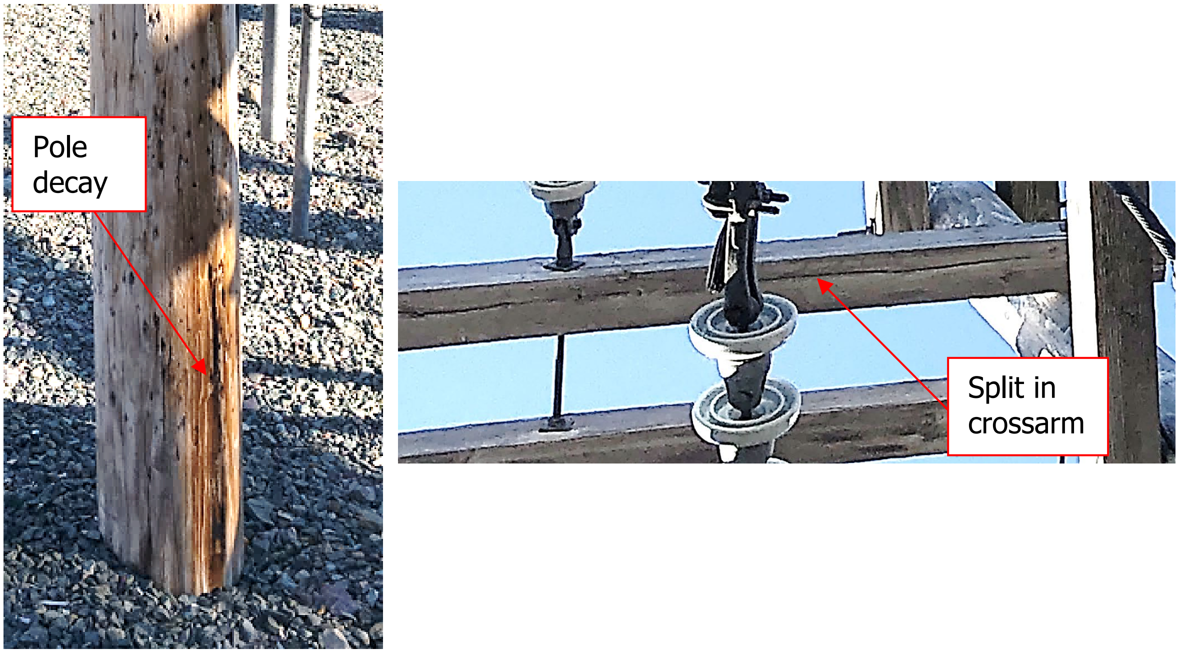

Figure C-4: 12.5 kV Wood Pole Condition

The wood pole structure will be removed and replaced with a new galvanized steel structure.

The 12.5 kV switches are in excess of 47 years old and are deteriorated. These switches require replacement as a result of their mechanical operating condition and corrosion. This includes one air break switch, one side break switch and two sets of hook operated switches.

The combined current transformer/potential transformer was replaced in 2013 and will be returned to the Electrical Maintenance Centre for future use.

The one 12.5 kV recloser protecting distribution feeder LOK-01 is in good condition and will remain in service.

2.4 6.9 kV Infrastructure

The 6.9 kV wood pole structure was installed in 1956. An inspection and engineering assessment was completed in 2022. The inspection determined that the wood poles are showing signs of deterioration. The poles and cross arms have splits. The deteriorated condition of the wood pole structure compromises its ability to support the weight of critical substation equipment such as switches and power cables, increasing the probability of failure.

Figure C-5 shows the deteriorated wood structures.

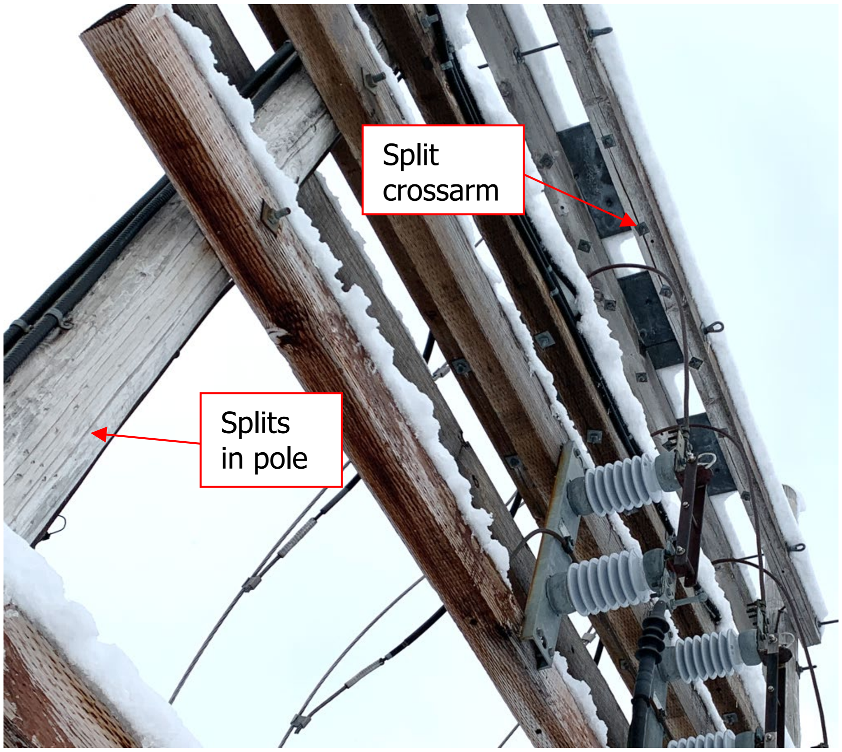

Figure C-5: 6.9 kV Crossarm Condition

The wood pole structure will be removed and replaced with a new galvanized steel structure.

2.5 Power Transformers

LOK Substation has three power transformers connecting the Hydro Plant generators LOK-G1 and LOK-G2 to Transmission Line 111L and Transmission Line 113L. A single power transformer steps down the 66 kV transmission voltage to 12.5 kV for the single distribution feeder supplied by the substation. The details for these power transformers are included in Table C-1.

Table C-1
LOK Substation Power Transformer Details

Field Name	Manufacturer	Year Built	HV Rating (kV)	LV Rating (kV)	Capacity (MVA)	PCB Concentration (ppm)	Purpose
LOK-T1	General Electric	1955	46	6.9	2.5	82	Generation
LOK-T2	General Electric	1967	66	46	4	31	Generation
LOK-T3	General Electric	1970	66	12.5	4	<1	Distribution
LOK-T4	General Electric	1955	46	6.9	2.5	6	Generation

Generation Power Transformers

The three generation transformers are arranged in a non-standard configuration as shown in Figure C-6. The intermediate 46 kV voltage arrangement is not standard. This is a legacy voltage that existed prior to the electricity system on the island being interconnected. LOK is the only substation on the Newfoundland Power system with equipment operating at 46 kV. As a result, if any one of the power transformers failed, a portable substation would be required to bypass all three transformers in order to maintain the existing electrical capacity.

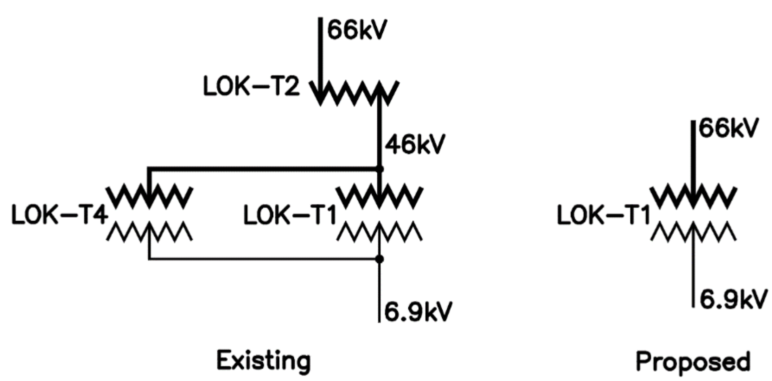

Figure C-6: Existing and Proposed LOK Hydro Plant Power Transformer Arrangements

Figure C-7 shows power transformers LOK-T1, LOK-T2 and LOK-T4.

Figure C-7: LOK Hydro Plant Transformers (LOK-T1, LOK-T2 and LOK-T4)

Transformer oil analysis of LOK-T1 indicated the presence of PCBs in the main tank oil and bushings above permissible levels. LOK-T1 has a main tank PCB contamination of 82 ppm and bushings that range between 78 and 85 ppm based on oil analysis performed in 2021.[2]

Although the concentration of PCBs in the main tank oil of LOK-T2 and LOK-T4 is below the government mandated 50 ppm, they are considered hazardous waste as they have PCB concentrations above 2 ppm. Oil with PCB concentrations above 2 ppm have environmental regulations regarding handling and disposal. This poses an environmental hazard should a leak occur in either of these transformers that is not captured by their spill pans.

Based on industry average expected power transformer life, the 68 year old LOK-T1 and LOK-T4 units are approaching the end of life.[3] The risk of these power transformers failing is expected to increase as they continue to age.[4] LOK-T1, LOK-T2 and LOK-T4 are in close proximity to one another; the failure of one unit could cause damage to either of the other two units, as they are not protected by firewalls. These power transformers are also protected by a high-speed ground switch which exposes them to fault currents further increasing their likelihood of failure.

Newfoundland Power uses EPRI's PTX software to monitor the health of its power transformer assets. The Abnormal Condition Index indicates low short-term risk for LOK-T1, LOK-T2 and

2 The phase-out of PCBs is mandated by Government of Canada PCB Regulation (SOR/2008-273), and requires that substation equipment must have PCB concentrations lower than 50 ppm, otherwise they must be removed from service by the end of 2025.

3 According to industry experience, the expected life of a power transformer is between 30 and 50 years, with a sharp decline for in-service power transformers past 70 years of age based on industry wide asset data.

4 Insulation deterioration of the power transformer internal windings naturally occurs over time and is accelerated by exposure to high temperatures. Insulation that is found to be degraded is a major indicator that a power transformer has reached end of life.

LOK-T4. The Normal Degradation Index indicates moderate long-term risk for LOK-T1, LOK-T2 and LOK-T4.

Due to the age and condition of LOK-T1, LOK-T2 and LOK-T4, the site-specific factors, and the government regulations on PCBs it is recommended that all three of these transformers be removed. A single 66 kV to 6.9 kV, 5 MVA power transformer can replace all three of these transformers, eliminate the non-standard 46 kV voltage, reduce electrical losses on the system and reduce the amount of equipment maintenance required at the substation.

Distribution Power Transformer

Power transformer LOK-T3 is in working order and oil test results show no indication of abnormal internal conditions. Annual inspections of the transformer's physical condition discovered minor signs of rust on the main tank, as well as minor deterioration and condensation on the transformer's protective devices.

Newfoundland Power uses EPRI's PTX software to monitor the health of its power transformer assets. For LOK-T3, the Abnormal Condition Index indicates minimal short-term risk, and the Normal Degradation Index indicates moderate long-term risk.

Given the Company's aging power transformer fleet, LOK-T3 is expected to be replaced within the next ten years.

2.6 Protection and Control

Protection of power transformers LOK-T1, LOK-T2, LOK-T3 and LOK-T4 consists of power fuses and a high-speed ground switch LOK-T2-HGS. The high-speed ground switch relies on LOK-113L-B and CAT-111L-B to clear faults for all LOK power transformers. The time for a high-speed ground switch to operate and the upstream circuit breaker to trip is slower than a standard circuit breaker operation. This exposes equipment to fault currents for longer periods of time, which effectively reduces the life of the assets exposed to the fault. Replacing high-speed ground switches with circuit breakers provides standard protection, reduces equipment exposure to fault currents, and allows the system control center to remotely operate the transmission lines.[5]

The transformer protection for LOK-T1, LOK-T2, LOK-T3 and LOK-T4 relies on contact-based protection to operate for mechanical transformer protection. This is no longer industry standard and will be replaced with digital transformer protection.

5 With the circuit breaker addition at LOK, a fault in LOK substation would no longer cause an outage at the Port Union ("PUN") Substation and Summerville ("SMV") Substation depending on system configuration.

Figure C-8 shows the protection panel for the LOK-T1, LOK-T2, LOK-T3 and LOK-T4 transformer protection.

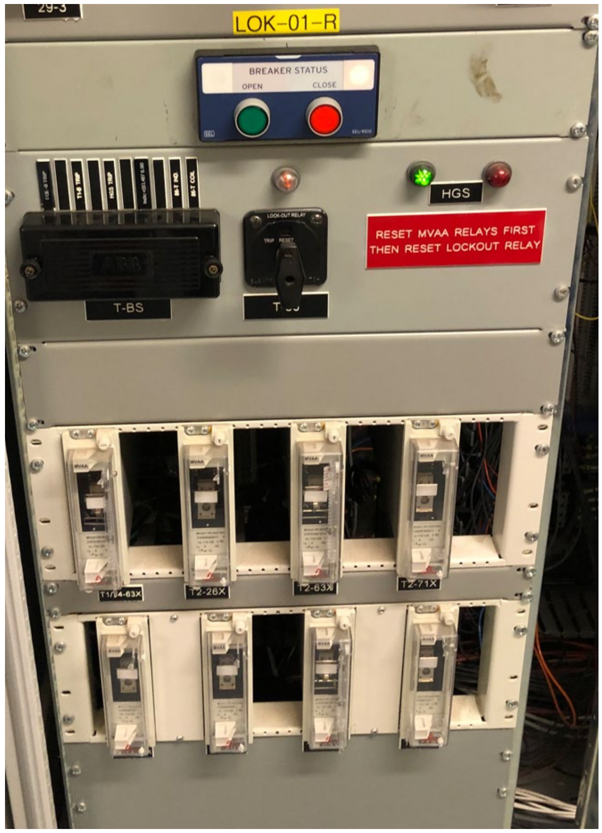

Figure C-8: LOK-T1, LOK-T2, LOK-T3 and LOK-T4 Protection Panel

The microprocessor-based digital relays associated with LOK Substation protection include a transmission protection Micom P543 relay installed in 2012 for Transmission Line 113L which will remain.

Substation security cameras will be installed to deter unauthorized entry and to provide company personnel with access to video streaming to view remote facilities in the event of a security or fire alarm. There have been no break-ins at LOK Substation in the last five years.

2.7 Site Condition

The LOK Substation site is in fair condition, with minor upgrades required at this time. The protection and control equipment for the substation is located inside the Plant control room. The yard would require an extension to accommodate the increased footprint required for the portable substation install during the project to serve the distribution customers and also allow for other future installations.

The existing ground grid at LOK has deficiencies that pose a safety hazard. There are sections of the yard with insufficient grounding and there are also missing connections between the main ground grid and the substation fence. A grounding study is necessary and the ground grid for the substation would require upgrading to align with current standards and to cover the expanded substation yard and new equipment.

3.0 RISK ASSESSMENT

The *LOK Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to customers in the Trinity and Port Rexton area.

LOK Substation provides service to approximately 1,100 customers in the Trinity and Port Rexton area and connects the 4.275 MVA Hydro Plant to the transmission system. Equipment failure in the substation would expose all 1,100 customers and the generation capacity of the LOK Hydro Plant to the risk of outages. The time to restore service to customers would depend on the nature of the failure and could range from several hours up to 36 hours.

LOK Substation contains equipment that is deteriorated, obsolete and approaching end of life. LOK-T1 has a PCB concentration above 50 ppm that must be addressed by the end of 2025. LOK-T1, LOK-T2 and LOK-T4 are in close proximity to one another without the protection of a firewall. A failure of any of these transformers could result in damage to either of the other transformers. A condition assessment determined that the majority of the substation switches have deteriorated and are now at end of life. Replacing the existing high-speed ground switch with a circuit breaker and protective relaying, will reduce the exposure of transformer LOK-T1, LOK-T2, LOK-T3, LOK-T4 and other substation and plant equipment to fault currents. The wood pole structures are deteriorated. The low voltage equipment also lacks standard varmint protection.

There are deficiencies identified with the ground grid at LOK Substation that pose a risk to safety and reliability. A proper ground grid is required to reduce the risk of a person in the vicinity of the substation being exposed to electric shock or electrocution through step and touch potential. An insufficient ground grid can affect continuity of service if there is an inadequate ground path for proper equipment operation.

Overall, refurbishment and modernization of LOK Substation is necessary to ensure the continued delivery of reliable, safe, and environmentally responsible service to customers in the Lockston area.

4.0 ASSESSMENT OF ALTERNATIVES

In the case of LOK Substation, the number of components requiring preventative and corrective maintenance at this time justifies the refurbishment and modernization of the substation in 2025 and 2026. LOK-T1 exceeds the PCB concentration 50 ppm regulation and requires action to remediate this by the end of 2025. The 66 kV and 12.5 kV switches are deteriorated and require replacement. A high-speed ground switch provides the transformer protection, but does so by exposing equipment to fault currents effectively reducing the life of the assets. Replacing the high-speed ground switch with a circuit breaker will provide a standard form of transformer protection that is more in line with today's industry standards. The new breaker will allow the substation energization to be controlled remotely through the Company's SCADA system. The 66 kV and 25 kV wood pole structures are deteriorated and require replacement.

Deferral of the LOK Substation refurbishment and modernization project increases the risk that some components will be run to failure. Run to failure is not a viable alternative as it increases the risk to the delivery of safe and reliable service to approximately 1,100 customers in the Trinity and Port Rexton area.

5.0 PROJECT SCOPE

The 2025 and 2026 scope of work at LOK Substation includes the following:

(i) Remove LOK-T1, LOK-T2, LOK-T4, 46 kV equipment;
(ii) Install new 66 kV to 6.9 kV, 5 MVA power transformer including new concrete spill containment foundation;
(iii) Complete a yard extension;
(iv) Construct new 66kV, 12.5 kV and 6.9 kV steel structures to replace deteriorated wood structures;
(v) Install new 66 kV circuit breaker to replace the existing high speed ground switch;
(vi) Replace deteriorated 66 kV, 12.5 kV and 6.9 kV switches;
(vii) Install new digital relays and the associated communications equipment;
(viii) Upgrade and extend the ground grid;
(ix) Install new security cameras; and
(x) Install varmint protection on all 12.5 kV and 6.9 kV equipment.

Engineering design and procurement of long lead equipment will be completed in 2025. Construction will begin in the second quarter of 2026 and will be completed early in the fourth quarter of 2026. Commissioning of the substation will be completed during the fourth quarter of 2026.

Table C-2 provides a list of planned equipment replacements, including age and condition for LOK Substation.

Table C-2
2025/2026 Planned Equipment Replacements
Lockston Substation

Equipment	Age (Years)	Condition
66 kV Wood Pole Structure	51	Deteriorated
12.5 kV Wood Pole Structure	47	Deteriorated
6.9 kV Wood Pole Structure	68	Deteriorated
Transformer LOK-T1	69	PCB Phase-Out/End of Life
Transformer LOK-T2	57	Remove as Part of PCB Phase-Out
Transformer LOK-T4	69	End of Life/ Remove as Part of PCB Phase-Out
66 kV Potential Transformers	51	Deteriorated
66 kV Air Break Switch	51	Deteriorated/End of Life
66 kV Air Break/High Speed Ground Switch	27	Replacing with Breaker
66 kV Side Break Switches	50	Deteriorated/End of Life
12.5 kV Air Break Switch	47	Deteriorated/End of Life
12.5 kV Hook-Stick Operated Switches	47	Deteriorated/End of Life

6.0 PROJECT COST

Table C-3 provides the cost breakdown for the *Lockston Substation Refurbishment and Modernization* project.

Table C-3
Lockston Substation Refurbishment and Modernization Project
Project Cost
($000s)

Cost Category	2025	2026	Total
Material	8	3,636	3,644
Labour – Internal	34	188	222
Labour - Contract	-	-	-
Engineering	260	397	657
Other	3	300	303
Total	$305	$4,521	$4,826

The total project cost for the *Lockston Substation Refurbishment and Modernization* project is $305,000 in 2025 and $4,521,000 in 2026 for a total project cost of $4,826,000.

7.0 LIFECYCLE COST ANALYSIS

The LOK Substation serves the Plant by stepping the 6.9 kV plant generation voltage up to the 66 kV transmission voltage. Newfoundland Power's hydro plants provide economic benefit for customers and must remain profitable over the longer term. Therefore, any capital investments related to the operation of these plants must be analyzed to ensure they remain economically viable. In the case of LOK Substation, the replacement of the generation power transformers LOK-T1, LOK-T2, and LOK-T4 as well as the 6.9 kV infrastructure are only required to serve LOK Hydro Plant. If the Plant was decommissioned and removed this equipment would no longer be needed. This requires a lifecycle cost analysis of the Plant including the necessary capital investment required for equipment in LOK Substation related to the Plant. The results of this analysis will determine if the operation of the Plant will continue to provide economic benefit for customers over the longer term and ensure that new assets do not become stranded.

7.1 Summary of Results

A lifecycle cost analysis has been completed and confirms that continued operation of the Lockston Hydro Plant will provide economic benefit for Newfoundland Power's customers over the longer term and that the risk of the Plant becoming stranded is low.

Table C-4 summarizes the results of the lifecycle cost analysis of the Lockston Hydro Plant.

Table C-4
Lockston Hydro Plant Lifecycle Cost Analysis Results[6]

	50 Year Levelized Value	Net benefit
Lifecycle Cost of the Plant	5.38 ¢/kWh	-
Cost of Replacement Production (Run-of-River)	10.00 ¢/kWh	4.41 ¢/kWh
Cost of Replacement Production (Fully Dispatchable)	16.06 ¢/kWh	10.57 ¢/kWh

The analysis shows the Plant's production provides a net benefit for customers of between 4.41 ¢/kWh and 10.57 ¢/kWh. The cost of replacement production would need to be reduced by between 44% and 65% to be less than the cost of operating the Plant. The differences between costs and benefits suggest any reasonable variance in the estimates will support the continued operation of the Plant. Various sensitivity analyses have confirmed the economic benefit of the Plant's production.

8.0 CONCLUSION

The *Lockston Substation Refurbishment and Modernization* project is required to provide reliable service to customers at the lowest possible cost. The project will address the deteriorated and obsolete equipment identified through an engineering assessment of LOK Substation. The existing power transformer containing PCB's will be replaced, deteriorated 66 kV and 12.5 kV switches will be replaced, a high-speed ground switch will be replaced with a circuit breaker and associated digital relays, and deteriorated wood structures will be replaced. The total project cost to complete the *Lockston Substation Refurbishment and Modernization* project is estimated to be $4,826,000

[6] The detailed lifecycle cost analysis can be found in attachment A.

Attachment A:

Lifecycle Cost Analysis of the Lockston Hydroelectric Development

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1.0 INTRODUCTION

This lifecycle evaluation examines the future viability of generation at Newfoundland Power's Lockston hydroelectric development (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2025, 2026 and beyond.

This evaluation compares the cost of continued operation of the Plant to the cost of replacement production. The analysis includes a study period of 50 years and expresses the results in terms of the levelized cost of energy. It also provides sensitivity analyses that examine the sensitivity of the results to changes in assumptions.

2.0 LIFECYCLE COSTS

2.1 Capital Costs

Table A-1 provides all significant capital expenditures for the Plant over the next 50 years.

Table A-1
Lockston Hydroelectric Development
Capital Expenditures
($000s)

Year	Expenditure
2025	28
2026	1,170
2033	1,050
2042	2,050
2060	75
2062	2,250
2063	750
2072	575
2073	300
2074	600
Total	$8,848

The estimated capital expenditure for the Plant is $8,848,000 over the next 50 years. These capital expenditures include the expenditures proposed for 2025, 2026, and future capital expenditures.

Attachment A-1 provides a comprehensive breakdown of capital costs.

2.2 Operating Costs

Annual operating costs for the Plant, including water rental fees, are estimated to be approximately $147,900 per year. The operating cost represents both direct charges for operations and maintenance at the Plant, as well as indirect costs such as those related to managing the environment, safety, dam safety inspections, and staff training. The annual water rental fee is forecasted to be approximately $26,600 for 2025. This fee, adjusted for inflation, will be paid annually to the Provincial Government based on the Plant's production.

Attachment A-2 provides a summary of operating costs.

2.3 Cost of Spill During Construction

Included in the lifecycle cost is the cost of reduced production from the Plant during the refurbishment project. During construction, the Plant will be out of service for a period of time. This will result in the spillage of water from its reservoirs and reduced Plant production. In 2026, it is expected that approximately 3.4 GWh of reduced production will occur, which will result in additional costs to replace lost production of approximately $92,000.

3.0 COST OF PLANT DOWNTIME

3.1 General

If the refurbishment project does not proceed as proposed, there is risk that the Plant will be out of service for a prolonged period due to equipment failure and potential safety hazards. Taking the Plant out of service will result in replacing its production with additional power from Newfoundland and Labrador Hydro ("Hydro"). The cost to replace the production from the Plant consists primarily of: (i) marginal energy costs; and (ii) the potential need to add generation capacity.

Table A-2 provides a breakdown of the normal production of the Plant.

Table A-2 Normal Production from the Lockston Plant		
Marginal Cost Period	Normal Production (GWh)	Production (%)
Non-Winter Period (All hours)	4.84	58
Winter Period		
On-Peak	1.76	21
Off-Peak	1.76	21
Annual Production	8.36	100

3.2 Marginal Energy Cost

The Island Interconnected System is connected to the North American power grid through the Labrador Island Link ("LIL") and the Maritime Link. An updated marginal cost study (the "Marginal Cost Update") completed by Hydro in 2023 provides estimates of the marginal energy cost as the opportunity cost of selling energy to other jurisdictions.[1] The marginal energy cost estimates vary by time of day and by season. To recognize these time-varying characteristics, the costs are summarized by winter on-peak, winter off-peak and non-winter peak periods.

Attachment A-3 to this report provides the forecast marginal energy costs for the period 2024 to 2042.

3.3 Cost of Replacement Capacity

The Island Interconnected System's need for new capacity additions is being reviewed by the Board of Commissioners of Public Utilities. Removing the Plant from service would reduce the capacity available to supply customers and increase the need for new generation sources.[2]

The Marginal Cost Update provides estimates of the marginal cost of generation capacity for the Island Interconnected System in terms of cost per MWh and cost per kW of peak demand.

The Plant can provide 3.00 MW of capacity during the winter. The cost of replacement capacity is dependent on the extent to which this capacity is available to meet peak load conditions. This

[1] The most recent marginal cost study results are found in Hydro's Marginal Cost Update, dated October 2023. The marginal cost study covers the period from 2024 to 2042.

[2] In its *Reliability and Resource Adequacy Study – 2022 Update* Hydro stated that "Regardless of the assumptions made for the Island Interconnected System load growth, the LIL capacity and bipole forced outage rate, the Island Interconnected System will be significantly capacity constrained once the Holyrood Thermal Generating Station ("TGS") and the Hardwoods Gas Turbine are retired." See *Reliability and Resource Adequacy Study – 2022 Update, Volume III, Long Term Resource Plan*, Page 51, lines 25-27.

is impacted by the amount of storage, the timing of rainfall, how the plants are dispatched, the volume of requests by Hydro to maximize generation and the potential that the plants are out of service when required to meet increased customer demand.

To assess the cost of replacement capacity, Newfoundland Power completed an evaluation under two assumptions: (i) assuming the Plant's production reflects a run-of-river hydro plant; and (ii) evaluating the Plant as a fully dispatchable plant.

A run-of-river plant has little storage and provides minimum flexibility for the Company to schedule production for periods of greatest value.[3] The capacity from a run-of-river plant is dependent on the extent to which timing of the river flow will correspond to periods when the cost of capacity is the greatest. Evaluation of a run-of-river plant is completed by applying the production for each marginal cost time period to the appropriate marginal generation capacity cost.

Fully dispatchable generation, on the other hand, has sufficient storage to allow it to produce at its full rated capacity for all potential periods of need. This would be similar to a gas turbine, which can be dispatched at any time to provide its rated capacity to support customer demand. The capacity of a fully dispatchable plant is primarily reflective of its rated capacity and the likelihood it is not available for service.

Newfoundland Power's hydro generation facilities operate between being run-of-river and fully dispatchable generation plants. The Plant has total available storage of approximately 2.7 GWh. This level of storage represents approximately 37 days of production at a production rate of 3.00 MW. However, storage levels are often not full, and there are practical limitations to managing the flow of water from storage to the forebay. These practical considerations limit the Company's ability to maintain continuous production at rated capacity for extended periods of time.[4]

4.0 LIFECYCLE ANALYSIS RESULTS

4.1 Base Case Analysis

An analysis has been completed comparing the lifecycle costs of the Plant to the cost of replacement production over a 50-year study period. The Marginal Cost Update covers the period from 2024 to 2042. As a result, there is no forecast of marginal costs beyond this period. For the purposes of the 50-year study period, the Company has used the GDP Deflator to escalate marginal cost for the remaining years of the 50-year study period. To deal with the uncertainty of future marginal costs, the Company has prepared five sensitivity analyses with different approaches to estimate future marginal cost to confirm the robustness of the lifecycle cost analysis.

[3] As examples, periods of greatest value for production include during generation shortages and peak demand periods.

[4] During periods of low water availability, such as during the summer months, generation capacity from the Plant will be limited and reflect a run-of-river system. During periods with greater water availability, such as during the spring and fall, generation capacity from the Plant will be high and reflect a fully dispatchable system. Since, at certain times of the year, the Plant operates as either a run-of-river system or a fully dispatchable system, the lifecycle analysis includes the value of capacity under both scenarios to assess the lowest and highest value of capacity from the Plant.

The costs are presented on a levelized cost of energy approach. The levelized cost of energy expresses the costs and benefits in terms of a ¢/kWh of production.

Table A-3 compares the estimated levelized costs of the Plant's production and the cost of replacement production.

Table A-3
Lifecycle Analysis Results

	50 Year Levelized Value[5]	Net benefit
Lifecycle Cost of the Development	**5.38 ¢/kWh**	
Cost of Replacement Production (Run-of-River)		
Energy Costs	4.00 ¢/kWh	
Capacity Costs	6.00 ¢/kWh	
Total	**10.00 ¢/kWh**	4.41 ¢/kWh
Cost of Replacement Production (Fully Dispatchable)		
Energy Cost	4.00 ¢/kWh	
Capacity Cost	12.05 ¢/kWh	
Total	**16.06 ¢/kWh**	10.57 ¢/kWh

The cost to replace Plant's production will exceed the Plant's cost by between 4.41 ¢/kWh and 10.57 ¢/kWh. In order for the replacement production costs to be less than the Plant Development's costs, the production replacement costs would need to be reduced by between 44% and 65% based on the run-of-river and fully dispatchable assumptions, respectively. The large differences between costs and benefits suggest any reasonable variance in the estimates of the costs and benefits will support the continued operation of the Plant.

This evaluation compares the cost of continued operation of the Plant to the cost of replacing the Plant's production. If the life extension of the Plant was determined to be costlier than the cost of replacement production, then further analysis would be required to assess the cost of decommissioning through mothballing or dismantling the Plant. The present value of these costs would be incremental to the cost of replacement production.

Attachment A-4 provides the detailed results of the calculated levelized costs and benefits.[6]

5 See Attachment A-4.
6 The financial assumptions used in the economic evaluation are provided in Attachment A-5.

4.2 Sensitivity Analysis

To illustrate the robustness of the conclusion that continued operation is in the economic best interest of customers, the following scenarios were included in a sensitivity analysis:

(i) *Scenario 1A: Uncertainty with marginal costs beyond 2040*
Assumes the Plant ceases production in 2041 in consideration of the expiration of the Churchill Falls contract in 2041.[7]

(ii) *Scenario 1B: Uncertainty with marginal costs beyond 2042*
Assumes the marginal energy and capacity costs for the years after 2042 will remain at the same amount as the 2042 forecast with no escalation.

(iii) *Scenario 1C: Uncertainty with marginal costs beyond 2042*
Assumes the marginal energy for the years after 2042 will remain at the same amount as the 2042 forecast with no escalation, and capacity costs for the years after 2042 escalated using the GDP Deflator.

(iv) *Scenario 2: Uncertain accuracy of Hydro's marginal capacity cost*
Assumes Hydro's marginal capacity costs decrease by 25%.

(v) *Scenario 3: Uncertain accuracy of Hydro's marginal energy cost*
Assumes Hydro's marginal energy costs decrease by 25%.

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[7] This scenario tests whether the operation of the Plant's Development remains economic if the Development ceases production in 2041.

Table A-4 shows comparison of the present value of the Plant's operations to the present value of replacement production for the base case and each scenario.

Table A-4 Present Value Sensitivity Analysis Results ($2025)`				
Scenario	Cost of Continued Operation ($M)	Cost of Replacement Production		Net Savings ($M)
		Run-of-River ($M)	Fully Dispatchable ($M)	
Base Case[8]	6.8	12.1	19.6	5.3 – 12.8
Scenario 1A	3.3	6.9	11.0	3.6 – 7.7
Scenario 1B	6.8	11.2	18.0	4.4 – 11.2
Scenario 1C	6.8	11.8	19.2	5.0 – 12.4
Scenario 2	6.8	10.3	15.9	3.5 – 9.1
Scenario 3	6.8	10.9	18.4	4.1 – 11.6

The sensitivity analysis shows that the cost of continuing to operate the Plant will provide an economic benefit under all scenarios.

5.0 CONCLUSION

The results indicate that continued operation of the Lockston hydroelectric development is economically justified under current forecast capital, operating, marginal energy and capacity costs. Continued operation is also justified within reasonable variations in costs, including uncertainty of marginal costs.

8 The base case provides the results of the levelized costs provided in Table A-3 expressed as present value of costs as opposed to the levelized cost per kWh.

Attachment A-1:

Summary of Capital Costs

Lockston Hydroelectric Development Economic Analysis Summary of Capital Costs (2025-2074) ($000s)										
Description	2025	2026	2033	2042	2060	2062	2063	2072	2073	2074
Civil										
Dam, Spillways and Gates										400
Penstock and Surge Tank			750				750			
Access Road and Bridges										
Powerhouse			300						300	200
Mechanical										
Turbine				1,100		1,100				
Powerhouse Systems										
Electrical										
Generator Refurbishment				300		300				
Switchgear						850				
Protection and Control Systems				650	75			575		
Other										
Substation Refurbishment	28	1,170								
Transmission Line Refurbishment										
Total ($2025)	$28	$1,170	$1,050	$2,050	$75	$2,250	$750	$575	$300	$600

Attachment A-2:

Summary of Operating Costs

Lockston Hydroelectric Development Economic Evaluation Summary of Operating Costs ($2025)	
	Amount
2019	108,087
2020	109,212
2021	103,886
2022	143,914
2023	141,525
Average[1]	$121,325
Water Power Rental[2]	26,585
Total Average Operating Cost	$147,910

1 Cost excludes the water power rental rate.
2 Calculated using the Provincial Government's current water rental rate ($3.00/MWh in 2023 escalated using CPI All Items for Canada) multiplied by the normal annual output of the plant.

Attachment A-3:

Marginal Costs Estimates

Marginal Cost Projections 2024-2042[1]
Island Interconnected System
At Hydro's Delivery Point to Newfoundland Power

	Energy Supply Costs			Generation and Transmission Capacity Costs			
	Winter		Non-Winter	Winter		Non-Winter	
Year	On-Peak $/MWh	Off-Peak $/MWh	All-Hours $/MWh	On-Peak $/MWh	Off-Peak $/MWh	All-Hours $/MWh	Annual $/kW·yr
2025	122.40	103.38	29.95	152.86	59.46	2.63	309.94
2026	84.71	69.40	27.05	155.48	60.48	2.67	315.26
2027	62.51	48.76	25.44	158.15	61.52	2.72	320.67
2028	61.38	49.95	28.39	160.87	62.58	2.76	326.17
2029	58.98	50.29	26.72	163.64	63.65	2.81	331.78
2030	54.00	45.47	24.56	166.46	64.75	2.86	337.49
2031	50.59	42.25	22.02	169.33	65.86	2.91	343.30
2032	50.15	41.23	24.48	172.25	66.99	2.96	349.22
2033	54.66	45.96	23.64	175.23	68.15	3.01	355.24
2034	56.49	48.31	25.09	178.26	69.32	3.06	361.38
2035	51.38	45.86	24.66	181.34	70.52	3.11	367.62
2036	48.29	44.00	24.46	184.48	71.74	3.16	373.98
2037	48.29	44.37	22.08	187.68	72.98	3.22	380.46
2038	46.48	43.57	23.88	190.93	74.24	3.27	387.05
2039	49.04	46.26	21.40	194.25	75.53	3.33	393.76
2040	47.51	47.53	21.41	197.62	76.84	3.39	400.60
2041	56.70	57.20	25.62	201.06	78.18	3.44	407.56
2042	55.23	55.45	26.18	204.56	79.53	3.50	414.65

[1] 2024-2042 based on the marginal cost projections provided by Hydro in the summary report Marginal Cost Update, dated October 2023.

Attachment A-4:

Calculation of Levelized Costs and Benefits

Calculation of Levelized Costs				
	PV Costs[1] ($000)	Levelized Annual Cost ($000)	Annual Production (GWh)	Levelized Unit Cost (¢/kWh)
Lifecycle Cost of Plant	6,823	473	8.36	5.65
Cost of Replacement Production (Run-of-River)				
Energy Cost	4,780	331	8.36	3.96
Capacity Cost	7,361	510	8.36	6.10
Total	**$12,141**	**841**		**10.06**
Cost of Replacement Production (Fully Dispatchable)				
Energy Cost	4,780	331	8.36	3.96
Capacity Cost	14,795	1,025	8.36	12.26
Total	**$19,575**	**$1,356**		**16.22**

[1] See Cumulative Present Value at 50-year life on pages A-4-2 to A-4-7.

Present Worth Analysis of the Lifecycle Cost of the LOK Development

Production Year	Year	Generation Hydro 65.7 yrs 8% CCA	Generation Hydro 65.7 yrs 100% CCA	Transmission 51.9 yrs 8% CCA	Substation 48.5 yrs 8% CCA	Capital Revenue Requirement	Operating Costs	Spillage Cost	Net Benefit	Present Worth Benefit	Cumulative Present Value Benefit
-1	2025	0	0	0	28,000	2,630	0	0	-2,630	-2,805	-2,805
0	2026	0	0	0	1,170,000	112,807	0	91,967	-204,774	-204,774	-207,580
1	2027	0	0	0	0	123,696	152,967	0	-276,663	-259,412	-466,992
2	2028	0	0	0	0	119,874	155,610	0	-275,484	242,200	-709,192
3	2029	0	0	0	0	116,219	158,405	0	-274,624	226,389	-935,581
4	2030	0	0	0	0	112,720	161,295	0	-274,015	-211,802	-1,147,384
5	2031	0	0	0	0	109,362	164,224	0	-273,586	-198,285	-1,345,669
6	2032	0	0	0	0	106,136	167,206	0	-273,342	-185,755	-1,531,424
7	2033	1,208,237	0	0	0	214,167	170,200	0	-384,367	-244,918	-1,776,342
8	2034	0	0	0	0	220,270	173,203	0	-393,473	-235,087	-2,011,429
9	2035	0	0	0	0	213,781	176,280	0	-390,060	-218,516	-2,229,945
10	2036	0	0	0	0	207,562	179,428	0	-386,990	-203,278	-2,433,224
11	2037	0	0	0	0	201,593	182,609	0	-384,202	-189,230	-2,622,454
12	2038	0	0	0	0	195,854	185,842	0	-381,695	-176,273	-2,798,727
13	2039	0	0	0	0	190,325	189,133	0	-379,458	-164,313	-2,963,040
14	2040	0	0	0	0	184,991	192,502	0	-377,492	-153,270	-3,116,310
15	2041	0	0	0	0	179,835	195,924	0	-375,759	-143,053	-3,259,363
16	2042	2,763,716	0	0	0	429,059	199,405	0	-628,464	224,340	-3,483,703
17	2043	0	0	0	0	445,030	202,955	0	-647,985	-216,885	-3,700,588
18	2044	0	0	0	0	432,102	206,581	0	-638,683	200,443	-3,901,031
19	2045	0	0	0	0	419,709	210,274	0	-629,982	-185,384	-4,086,415
20	2046	0	0	0	0	407,806	214,020	0	-621,826	-171,574	-4,257,989
21	2047	0	0	0	0	396,355	217,834	0	-614,189	158,900	-4,416,889
22	2048	0	0	0	0	385,319	221,715	0	-607,034	-147,256	-4,564,146
23	2049	0	0	0	0	374,665	225,666	0	-600,331	-136,550	-4,700,695
24	2050	0	0	0	0	364,364	229,687	0	-594,050	-126,696	-4,827,391
25	2051	0	0	0	0	354,385	233,779	0	-588,164	-117,619	-4,945,010
26	2052	0	0	0	0	344,704	237,945	0	-582,649	-109,251	-5,054,261
27	2053	0	0	0	0	335,297	242,184	0	-577,482	-101,530	-5,155,791
28	2054	0	0	0	0	326,142	246,500	0	-572,642	-94,402	-5,250,193
29	2055	0	0	0	0	317,219	250,892	0	-568,111	-87,815	-5,338,007
30	2056	0	0	0	0	308,509	255,362	0	-563,871	-81,725	-5,419,732
31	2057	0	0	0	0	299,995	259,912	0	-559,907	-76,090	-5,495,823
32	2058	0	0	0	0	291,662	264,543	0	-556,205	-70,874	-5,566,697
33	2059	0	0	0	0	283,495	269,257	0	-552,751	-66,042	-5,632,739
34	2060	138,964	0	0	0	288,262	274,054	0	-562,317	-62,996	-5,695,735
35	2061	0	0	0	0	281,435	278,938	0	-560,372	-58,864	-5,754,598
36	2062	4,318,794	0	0	0	670,532	283,908	0	-954,440	-94,006	-5,848,605
37	2063	1,465,249	0	0	0	829,811	288,966	0	-1,118,778	-103,322	-5,951,927
38	2064	0	0	0	0	820,099	294,115	0	-1,114,214	-96,484	-6,048,411
39	2065	0	0	0	0	795,743	299,356	0	-1,095,099	-88,916	-6,137,327
40	2066	0	0	0	0	772,294	304,690	0	-1,076,983	-81,993	-6,219,319
41	2067	0	0	0	0	749,678	310,119	0	-1,059,797	-75,653	-6,294,972
42	2068	0	0	0	0	727,831	315,644	0	-1,043,475	-69,843	-6,364,816
43	2069	0	0	0	0	706,689	321,268	0	-1,027,957	-64,515	-6,429,330
44	2070	0	0	0	0	686,196	326,993	0	-1,013,189	-59,623	-6,488,953
45	2071	0	0	0	0	666,301	332,819	0	-999,120	-55,129	-6,544,082
46	2072	1,316,889	0	0	0	768,087	338,749	0	-1,106,836	-57,264	-6,601,346
47	2073	699,315	0	0	0	824,631	344,785	0	-1,169,416	-56,729	-6,658,076
48	2074	1,423,550	0	0	0	984,792	350,928	0	-1,335,720	-60,757	-6,718,833
49	2075	0	0	0	0	909,055	357,181	0	-1,266,236	-54,005	-6,772,837
50	2076	0	0	0	0	883,496	363,546	0	-1,247,042	-49,870	-6,822,707

Present Value of the Cost of Replacement Energy (Reduced Exports)					
Productio n Year	Year	Marginal Energy Costs ($)	Total Present Worth ($)	Cumulative Present Worth ($)	Export Sales (¢/kWh)
-1	2025	0	0	0	0.00
0	2026	0	0	0	0.00
1	2027	318,705	298,832	298,832	3.81
2	2028	333,131	292,882	591,715	3.98
3	2029	321,399	264,949	856,664	3.84
4	2030	293,693	227,013	1,083,677	3.51
5	2031	269,766	195,516	1,279,193	3.23
6	2032	279,153	189,704	1,468,897	3.34
7	2033	291,242	185,579	1,654,476	3.48
8	2034	305,648	182,615	1,837,090	3.66
9	2035	290,281	162,619	1,999,709	3.47
10	2036	280,616	147,402	2,147,112	3.36
11	2037	269,730	132,850	2,279,961	3.23
12	2038	273,844	126,466	2,406,427	3.28
13	2039	271,072	117,380	2,523,807	3.24
14	2040	270,680	109,902	2,633,709	3.24
15	2041	324,196	123,423	2,757,131	3.88
16	2042	321,271	114,683	2,871,814	3.84
17	2043	326,991	109,446	2,981,260	3.91
18	2044	332,832	104,455	3,085,715	3.98
19	2045	338,782	99,693	3,185,408	4.05
20	2046	344,818	95,142	3,280,550	4.12
21	2047	350,962	90,799	3,371,350	4.20
22	2048	357,216	86,655	3,458,004	4.27
23	2049	363,581	82,699	3,540,703	4.35
24	2050	370,059	78,924	3,619,628	4.43
25	2051	376,653	75,322	3,694,949	4.51
26	2052	383,364	71,883	3,766,833	4.59
27	2053	390,195	68,602	3,835,435	4.67
28	2054	397,147	65,471	3,900,906	4.75
29	2055	404,223	62,482	3,963,388	4.84
30	2056	411,426	59,630	4,023,018	4.92
31	2057	418,757	56,908	4,079,926	5.01
32	2058	426,218	54,311	4,134,237	5.10
33	2059	433,812	51,831	4,186,068	5.19
34	2060	441,542	49,466	4,235,534	5.28
35	2061	449,409	47,208	4,282,741	5.38
36	2062	457,417	45,053	4,327,794	5.47
37	2063	465,567	42,996	4,370,790	5.57

Present Value of the Cost of Replacement Energy (Reduced Exports)					
Production Year	Year	Marginal Energy Costs ($)	Total Present Worth ($)	Cumulative Present Worth ($)	Export Sales (¢/kWh)
38	2064	473,863	41,034	4,411,824	5.67
39	2065	482,306	39,161	4,450,984	5.77
40	2066	490,900	37,373	4,488,358	5.87
41	2067	499,647	35,667	4,524,025	5.98
42	2068	508,549	34,039	4,558,064	6.08
43	2069	517,611	32,485	4,590,549	6.19
44	2070	526,833	31,002	4,621,551	6.30
45	2071	536,221	29,587	4,651,139	6.41
46	2072	545,775	28,237	4,679,375	6.53
47	2073	555,500	26,948	4,706,323	6.64
48	2074	565,397	25,718	4,732,041	6.76
49	2075	575,472	24,544	4,756,585	6.88
50	2076	585,725	23,423	4,780,008	7.01

Present Value of the Cost of Replacement Capacity (Run-of-River Assumption)					
Production Year	Year	Marginal Capacity Costs ($)	Total Present Worth ($)	Cumulative Present Worth ($)	Avoided Generation Capacity (¢/kWh)
-1	2025	0	0	0	0.00
0	2026	0	0	0	0.00
1	2027	398,828	373,960	373,960	4.77
2	2028	405,680	356,666	730,626	4.85
3	2029	412,655	340,177	1,070,803	4.94
4	2030	419,757	324,455	1,395,258	5.02
5	2031	426,988	309,465	1,704,723	5.11
6	2032	434,349	295,171	1,999,894	5.20
7	2033	441,844	281,542	2,281,436	5.29
8	2034	449,475	268,546	2,549,982	5.38
9	2035	457,245	256,154	2,806,136	5.47
10	2036	465,156	244,338	3,050,473	5.56
11	2037	473,212	233,070	3,283,543	5.66
12	2038	481,414	222,325	3,505,868	5.76
13	2039	489,766	212,079	3,717,947	5.86
14	2040	498,271	202,308	3,920,255	5.96
15	2041	506,931	192,990	4,113,246	6.06
16	2042	515,749	184,105	4,297,350	6.17
17	2043	524,932	175,699	4,473,049	6.28
18	2044	534,308	167,686	4,640,735	6.39
19	2045	543,860	160,041	4,800,776	6.51
20	2046	553,550	152,735	4,953,511	6.62
21	2047	563,413	145,764	5,099,275	6.74
22	2048	573,452	139,110	5,238,385	6.86
23	2049	583,670	132,760	5,371,145	6.98
24	2050	594,070	126,700	5,497,845	7.11
25	2051	604,655	120,917	5,618,762	7.23
26	2052	615,429	115,397	5,734,159	7.36
27	2053	626,395	110,130	5,844,289	7.49
28	2054	637,556	105,103	5,949,391	7.63
29	2055	648,916	100,305	6,049,697	7.76
30	2056	660,478	95,727	6,145,423	7.90
31	2057	672,246	91,357	6,236,780	8.04
32	2058	684,224	87,187	6,323,967	8.18
33	2059	696,416	83,207	6,407,174	8.33
34	2060	708,825	79,409	6,486,583	8.48
35	2061	721,455	75,784	6,562,367	8.63
36	2062	734,309	72,325	6,634,692	8.78
37	2063	747,393	69,024	6,703,716	8.94

Present Value of the Cost of Replacement Capacity (Run-of-River Assumption)					
Production Year	Year	Marginal Capacity Costs ($)	Total Present Worth ($)	Cumulative Present Worth ($)	Avoided Generation Capacity (¢/kWh)
38	2064	760,710	65,873	6,769,589	9.10
39	2065	774,265	62,866	6,832,455	9.26
40	2066	788,061	59,996	6,892,451	9.43
41	2067	802,102	57,258	6,949,709	9.59
42	2068	816,394	54,644	7,004,353	9.77
43	2069	830,941	52,150	7,056,503	9.94
44	2070	845,746	49,769	7,106,272	10.12
45	2071	860,816	47,498	7,153,770	10.30
46	2072	876,154	45,329	7,199,099	10.48
47	2073	891,765	43,260	7,242,360	10.67
48	2074	907,655	41,286	7,283,645	10.86
49	2075	923,827	39,401	7,323,047	11.05
50	2076	940,288	37,603	7,360,649	11.25

Present Value of the Cost of Replacement Capacity (Fully Dispatchable Assumption)						
Production Year	Year	Effective Capacity (MW)[1]	Marginal Capacity Costs ($)	Total Present Worth ($)	Cumulative Present Worth ($)	Avoided Generation Capacity (¢/kWh)
-1	2025	0.00	0	0	0	0.00
0	2026	0.00	0	0	0	0.00
1	2027	2.50	801,663	751,676	751,676	9.59
2	2028	2.50	815,432	716,912	1,468,588	9.75
3	2029	2.50	829,449	683,766	2,152,354	9.92
4	2030	2.50	843,721	652,162	2,804,516	10.09
5	2031	2.50	858,251	622,028	3,426,543	10.27
6	2032	2.50	873,044	593,295	4,019,838	10.44
7	2033	2.50	888,105	565,898	4,585,737	10.62
8	2034	2.50	903,440	539,775	5,125,511	10.81
9	2035	2.50	919,054	514,865	5,640,376	10.99
10	2036	2.50	934,952	491,112	6,131,489	11.18
11	2037	2.50	951,139	468,462	6,599,951	11.38
12	2038	2.50	967,622	446,864	7,046,815	11.57
13	2039	2.50	984,405	426,268	7,473,083	11.78
14	2040	2.50	1,001,495	406,628	7,879,711	11.98
15	2041	2.50	1,018,897	387,898	8,267,609	12.19
16	2042	2.50	1,036,618	370,037	8,637,646	12.40
17	2043	2.50	1,055,074	353,141	8,990,787	12.62
18	2044	2.50	1,073,920	337,036	9,327,823	12.85
19	2045	2.50	1,093,118	321,670	9,649,493	13.08
20	2046	2.50	1,112,595	306,987	9,956,480	13.31
21	2047	2.50	1,132,420	292,974	10,249,454	13.55
22	2048	2.50	1,152,597	279,601	10,529,055	13.79
23	2049	2.50	1,173,134	266,838	10,795,893	14.03
24	2050	2.50	1,194,037	254,658	11,050,551	14.28
25	2051	2.50	1,215,312	243,034	11,293,585	14.54
26	2052	2.50	1,236,967	231,940	11,525,525	14.80
27	2053	2.50	1,259,007	221,353	11,746,878	15.06
28	2054	2.50	1,281,440	211,249	11,958,126	15.33
29	2055	2.50	1,304,273	201,606	12,159,732	15.60
30	2056	2.50	1,327,512	192,403	12,352,136	15.88
31	2057	2.50	1,351,166	183,621	12,535,757	16.16
32	2058	2.50	1,375,241	175,239	12,710,996	16.45
33	2059	2.50	1,399,745	167,240	12,878,236	16.74
34	2060	2.50	1,424,686	159,606	13,037,842	17.04
35	2061	2.50	1,450,071	152,321	13,190,163	17.35

[1] Effective Capacity reflects winter capacity and an allowance for a 5% forced outage rate and a 16% reserve margin.

Present Value of the Cost of Replacement Capacity (Fully Dispatchable Assumption)						
Production Year	Year	Effective Capacity (MW)[1]	Marginal Capacity Costs ($)	Total Present Worth ($)	Cumulative Present Worth ($)	Avoided Generation Capacity (¢/kWh)
36	2062	2.50	1,475,908	145,368	13,335,531	17.65
37	2063	2.50	1,502,206	138,732	13,474,263	17.97
38	2064	2.50	1,528,972	132,400	13,606,663	18.29
39	2065	2.50	1,556,215	126,356	13,733,019	18.62
40	2066	2.50	1,583,944	120,588	13,853,607	18.95
41	2067	2.50	1,612,167	115,084	13,968,691	19.28
42	2068	2.50	1,640,892	109,831	14,078,522	19.63
43	2069	2.50	1,670,130	104,817	14,183,339	19.98
44	2070	2.50	1,699,888	100,033	14,283,372	20.33
45	2071	2.50	1,730,177	95,467	14,378,839	20.70
46	2072	2.50	1,761,005	91,109	14,469,948	21.06
47	2073	2.50	1,792,382	86,950	14,556,898	21.44
48	2074	2.50	1,824,319	82,981	14,639,879	21.82
49	2075	2.50	1,856,825	79,193	14,719,072	22.21
50	2076	2.50	1,889,910	75,578	14,794,651	22.61

Attachment A-5:

Economic Analysis Financial Assumptions

Economic Evaluation
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects a statutory income tax rate of 30%.

Operating Costs: Operating costs were assumed to be in 2025 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:		Capital Structure	Return	Weighted Cost
	Debt	55.00%	5.122%	2.82%
	Common Equity	45.00%	8.500%	3.83%
	Total	100.00%		6.65%

CCA Rates:	Class	Rate	Details
	17.1 & 47	8.00%	All generating, transmission, substation and distribution equipment not otherwise noted.
	43.2	75.00%	Expenditures related primarily to new generation or additions/alterations that increase the capacity of generating facilities.

Escalation Factors: Conference Board of Canada GDP deflator, medium term forecast dated February 14, 2024, and long term forecast dated December 18, 2023.

Supporting Documents: Newfoundland and Labrador Hydro's Marginal Cost Update, dated October 2023.

2.2 Substation Power Transformer Replacements

June 2024

Prepared by: Michael Power, P.Eng

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1.0 INTRODUCTION

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") operates 131 substations located throughout its service territory. These include: (i) generation substations that connect generating plants to the electrical system; (ii) transmission substations that connect transmission lines of different voltages; and (iii) distribution substations that connect the low-voltage distribution system to the high-voltage transmission system.[1] The equipment in substations ensures the electrical system operates safely and at appropriate voltage levels.

The largest, most expensive and most critical pieces of equipment located in substations are the power transformers. The in-service failure of a power transformer can result in extended outages to thousands of customers.

A significant number of Newfoundland Power's substation power transformers have aged beyond the service life typically observed in the industry. In order to manage this risk, Newfoundland Power monitors the health of its transformer fleet. As part of this process, two power transformers have been identified for replacement.

In 2025, the Company is proposing the replacement of: (i) Pulpit Rock Distribution Power Transformer, PUL-T2 ("200331"), in the Town of Torbay at a cost of $2,922,000; and (ii) Gander System Power Transformer, GAN-T2 ("200175"), in the Town of Gander at a cost of $4,185,000. These power transformers are deteriorated and pose a risk to reliable operation.

Due to supply chain constraints and procurement lead times for power transformers, Newfoundland Power is proposing multi-year projects for substation power transformer replacements. This will provide the ability to complete design, procurement, and contract approval in year one and installation and commissioning in a subsequent year.

2.0 BACKGROUND

2.1 Power Transformer Fleet

Power transformers are the most critical assets in a substation and are used to change voltages for different applications. Newfoundland Power has 191 substation power transformers in service. The most common applications for power transformers include: (i) distribution power transformers which are used to change from transmission to distribution voltages, such as 66 kV to 12.5 kV; (ii) system power transformers which are used to change between transmission voltages, such as 138 kV to 66 kV; and (iii) generation transformers which are used to change generation voltages to transmission or distribution voltages.[2] Power transformer failures can lead to extended outages for a large number of customers.

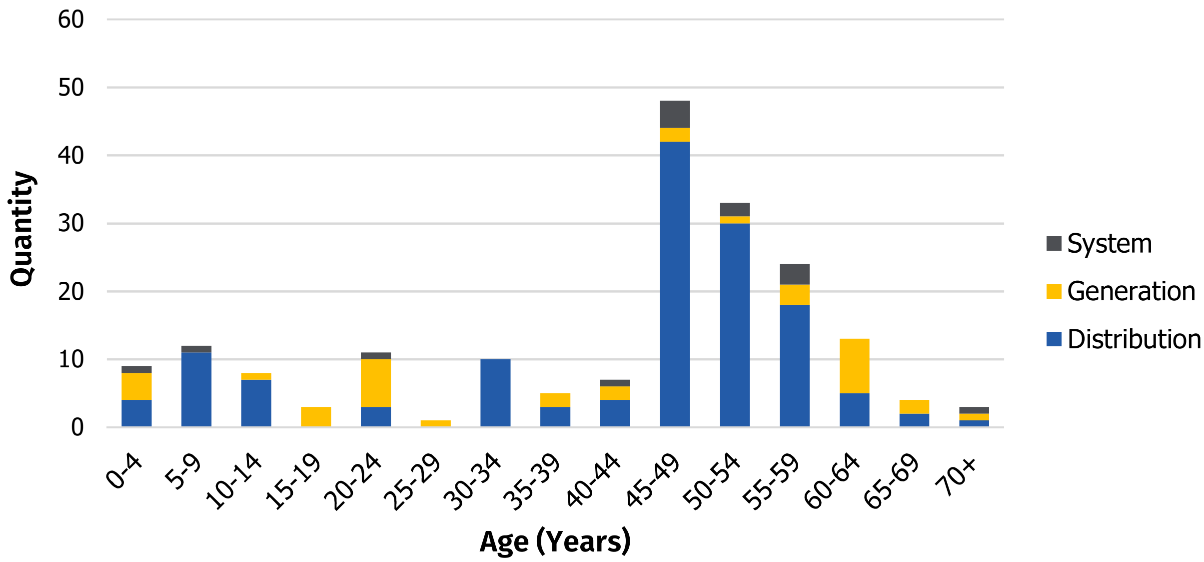
[1] Newfoundland Power's substations may serve multiple purposes and can be classified as any combination of the generation, transmission and distribution functions.

[2] Power transformers in hydro plants change generation voltages from 2,400 volts and 6,900 volts to either distribution or transmission voltages.

According to industry experience, the expected life of a power transformer is between 30 and 50 years,[3] with a sharp decline for in-service power transformers past 70 years of age.[4] The load profile in Newfoundland and Labrador is favourable for transformer life expectancy, as the highest loads are experienced in the winter when ambient temperatures are the lowest.[5]

Figure 1 shows the age distribution of the Company's power transformers.

Figure 1
Power Transformer Age Distribution



The useful service lives of Newfoundland Power's power transformers have historically exceeded what is typically seen in the industry, with nearly 40% of the Company's transformer fleet at 50 years in service or older.

3 Based on information published by the International Council on Large Electric Systems ("CIGRE"). CIGRE is an international association with an objective to develop and facilitate the exchange of engineering knowledge and information in the field of electric power systems. CIGRE published a report on asset management in 2013 titled *Asset Management Decision Making Using Different Risk Assessment Methodologies* (the "CIGRE Report"). Unless otherwise noted, information provided on industry experience regarding substation assets is based on the CIGRE Report.

4 Based on 2021 information available from the Electric Power Research Institute ("EPRI"). EPRI is an energy research and development organization. EPRI has a database of thousands of power transformers from its electric utility members, including Newfoundland Power.

5 The transformer temperature is influenced by the ambient temperature. The transformer temperature is one of the main factors affecting the winding insulation life of a transformer. Many transformer failures are a result of a breakdown of the winding insulation.

Given the age profile of the Company's transformer fleet, the probability of transformer failures will continue to increase as their condition degrades with age. The Company has had seven major power transformer failures in the past five years.[6]

2.2 Power Transformer Asset Management and Condition Assessment

As part of the substation asset management practices, Newfoundland Power conducts regular inspections and oil sample analysis to gauge the internal health of power transformers to determine when corrective maintenance is required.[7] All power transformers undergo annual oil sampling.[8] Additionally, power transformers are scheduled for a preventative maintenance every 12 years. This involves removing the transformer from service to perform electrical testing and to repair deficiencies.

Asset data is gathered for each power transformer through these regular inspections and testing practices. This data can be used to generate an overall view of the condition of the Company's power transformer fleet. The overall view will identify the power transformers that have a higher probability of failure.

Newfoundland Power utilizes EPRI's Power Transformer Expert System ("PTX") to diagnose and assess the condition of its power transformer fleet.[9] This assessment tool yields a set of indices for each transformer, providing insight into the condition of the cellulose insulation system and the potential for any abnormal incipient fault.

The PTX System identifies the Incipient Fault Risk and the Insulation Degradation Risk for each unit in the Company's power transformer fleet. The Incipient Fault Risk is used to identify units that may be experiencing a variety of unexpected problems due to manufacturing or operating issues, or defects. The Insulation Degradation Risk is intended to provide an indication of the physical condition of the paper insulating system relative to its initial state. These indices serve as a guide for maintenance efforts on individual units, while also informing overall fleet management decisions.

6 A major power transformer failure requires either transformer replacement, transportation off site for repairs, or removal from service for six months or longer. The seven major power transformers failures since 2018 include MUN-T2, BLK-T2, DUN-T1, SLA-T4, GBS-T1, BVA-T1 and PUL-T2.

7 Inspections also check for tank and cooler leaks, cooling fan and pump operation, operation of liquid and winding temperature equipment, oil level, tank pressure, breather operation and controls operation.

8 Oil sampling includes standard oil tests and dissolved gas in oil analysis. Standard oil tests check for contaminants and moisture, which at unacceptable levels can lower the dielectric strength of oil and cause a fault. Dissolved gas analysis is used to monitor and diagnose internal transformer electrical problems, such as the presence of arcing or poor electrical connections. Certain gases naturally increase as a transformer ages, but can be a sign of excessive temperatures and overloading in newer transformers. Oil sampling and analysis is completed annually to gauge the internal health of transformers.

9 The EPRI PTX software is also used by other utilities as a tool to aid in the development of transformer condition assessments.

3.0 PROJECT SCOPE AND COST

In 2025-2027 the Company plans to replace two power transformers that require proactive replacement. These replacements will mitigate the risk of in-service failures based on the detailed condition assessments outlined in Appendix A and Appendix B.

3.1 Pulpit Rock Substation Power Transformer Replacement

Pulpit Rock ("PUL") Substation was constructed in 1974 as a distribution substation. This substation is supplied by Newfoundland Power 66 kV Transmission Line 59L from Virginia Waters ("VIR") Substation. Two 25 MVA distribution power transformers, PUL-T1 ("200345") and PUL-T2 ("200331"), supply five 12.5 kV distribution feeders, serving approximately 6,744 customers in the communities of Torbay, Portugal Cove–St. Philip's, Pouch Cove and Logy Bay-Middle Cove-Outer Cove.

PUL-T2 is a 39-year-old, 15/20/25 MVA, 66-12.5 kV power transformer manufactured by Ferranti Packard. A condition assessment of the transformer shows that it is deteriorating and requires replacement.

Appendix A provides the detailed condition assessment and scope for the *Pulpit Rock Substation Power Transformer Replacement*.

Table 1 below provides the cost breakdown for the *Pulpit Rock Substation Power Transformer Replacement* multi-year project.

Table 1
Pulpit Rock Substation Power Transformer Replacement Project
Project Cost
($000s)

Cost Category	2025	2026	Total
Material	-	2,645	2,645
Labour - Internal	-	13	13
Labour - Contract	-	-	-
Engineering	14	91	105
Other	3	156	159
Total	$17	$2,905	$2,922

The project to replace PUL-T2 is estimated to cost $17,000 in 2025 and $2,905,000 in 2026 for a total project cost of $2,922,000.

3.2 Gander Substation Power Transformer Replacement

Gander Substation ("GAN") was constructed in 1959 as both a transmission and distribution substation. This substation is supplied by Newfoundland Power 138 kV Transmission Line 144L from Cobbs Pond ("COB") Substation and Transmission Line 146L from Gambo ("GAM") Substation. One 26.67 MVA system power transformer, GAN-T2 ("200175"), converts 138 kV to 66 kV for Transmission Line 108L which feeds two substations including Jonathan's Pond ("JON") Substation and Gander Bay ("GBY") Substation and Transmission Line 102L which feeds Roycefield Substation ("RFD"). There are approximately 2,323 customers fed from these substations.

GAN-T2 also serves as the emergency alternate system transformer for COB-T2 ("200313") which converts 138 kV to 66 kV for Transmission Line 142L which feeds Boyd's Cove ("BOY") Substation, Summerford ("SUM") Substation, Twillingate ("TWG") Substation and Newfoundland and Labrador Hydro's Farewell Head ("FHD") Terminal Station. There are approximately 4,205 customers fed from these substations.[10]

GAN-T2 is a 57-year-old, 16/21.3/26.67 MVA, 138-66 kV power transformer manufactured by Federal Pioneer. A condition assessment of the transformer shows that it is deteriorating and requires replacement.

Appendix B provides the detailed condition assessment and scope for the *Gander Substation Power Transformer Replacement*.

The replacement of GAN-T2 is also being aligned with the construction of the proposed new transmission line between Lewisporte ("LEW") substation and BOY substation, this allows for the timely removal of GAN-T2 and the installation of the new power transformer in BOY substation as outlined in report *3.1 Gander – Twillingate Transmission System Planning Study*.

Table 2 below provides a cost breakdown of the *Gander Substation Power Transformer Replacement* multi-year project.

Table 2
Gander Substation Power Transformer Replacement Project
Project Costs
($000s)

Cost Category	2025	2026	2027	Total
Material	-	3,797	81	3,878
Labour - Internal	-	2	11	13
Labour - Contract	-	-	-	-
Engineering	14	18	73	105
Other	3	88	98	189
Total	$17	$3,905	$263	$4,185

[10] Newfoundland and Labrador Hydro services roughly 1,800 additional customers from FHD Terminal Station.

The project to replace GAN-T2 is estimated to cost $17,000 in 2025, $3,905,000 in 2026, and $263,000 in 2027 for a total project cost of $4,185,000.

4.0 CONCLUSION

Newfoundland Power's customers are exposed to increasing risk of extended outages due to the failure of aging and deteriorated power transformers. An assessment of alternatives determined that proactively replacing deteriorated power transformers has become necessary to mitigate risks of extended customer outages and is necessary to continue delivering reliable service to customers at the lowest possible cost.

APPENDIX A

Pulpit Rock Substation Power Transformer - Replacement Report

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1.0 BACKGROUND

1.1 Pulpit Rock Substation

Pulpit Rock ("PUL") Substation was constructed in 1974 as a distribution substation. This substation is supplied by Newfoundland Power Inc. ("Newfoundland Power" or the "Company") 66 kV Transmission Line 59L from Virginia Waters ("VIR") Substation as shown in Figure A-1. Two 25 MVA distribution power transformers, PUL-T1 ("200345") and PUL-T2 ("200331"), supply five 12.5 kV distribution feeders, serving approximately 6,724 customers in the communities of Torbay, Portugal Cove– St. Philip's, Pouch Cove and Logy Bay–Middle Cove–Outer Cove.

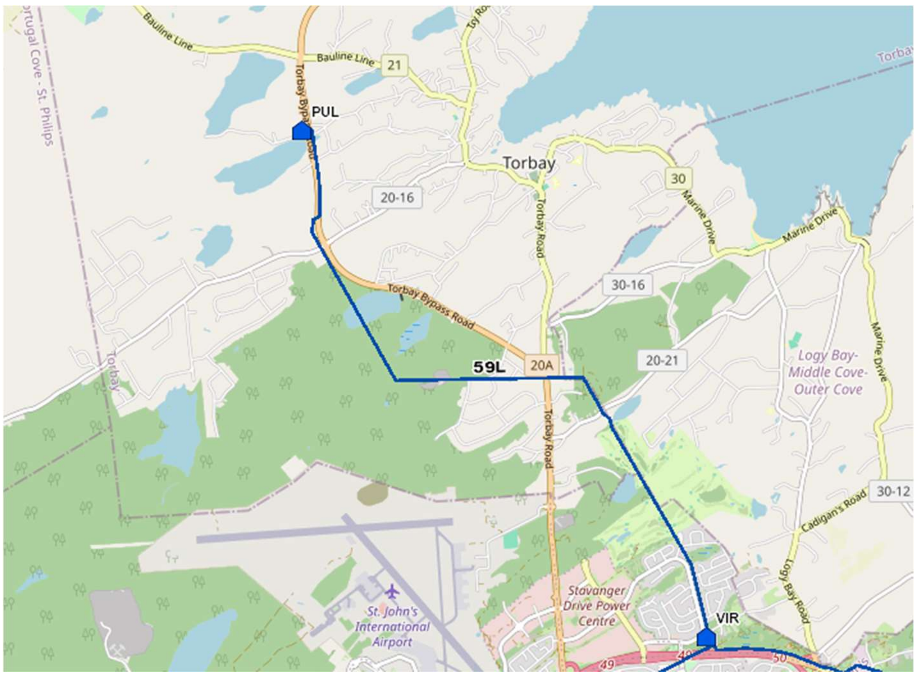

Figure A-1: 59L 66 kV Radial Transmission System Map

1.2 PUL-T2 Power Transformer

PUL-T2 is a 39-year-old, 15/20/25 MVA, 66-12.5/25 kV power transformer manufactured by Ferranti Packard. This transformer was originally installed in the Chamberlains ("CHA") substation as CHA-T1 when it was purchased in 1985 to provide service to 25 kV distribution feeders. In 2017 it was replaced by a larger 50 MVA power transformer as part of an *Additions Due to Load Growth* project at CHA Substation. At that time, it became a spare power transformer.

It was moved to Catalina ("CAT") Substation to be used as a temporary transformer as part of the *2017 Substation and Refurbishment and Modernization* project. It was used to provide service to 12.5 kV distribution feeders and eliminated the need to use a portable substation to support the project. Following its temporary use as part of a *Substation and Refurbishment Modernization* project, the transformer was returned to the spare power transformer fleet. In early 2019 the previous PUL-T2 ("200360") power transformer failed in service and PUL-T2 ("200331") was removed from the spare power transformer fleet and installed at PUL as its replacement. Not long after its installation in PUL, test results started indicating deterioration of the internal components of the transformer.

PUL-T2 is deteriorating and an assessment of alternatives determined that it should be replaced.

Figure A-2 shows power transformer PUL-T2.

Figure A-2: Power Transformer PUL-T2

Newfoundland Power is proposing to replace PUL-T2 over two years commencing in 2025 at an estimated cost of $2,922,000.

2.0 Engineering Assessment

2.1 Oil Analysis and Electrical Testing

PUL-T2 has undergone regular maintenance and last underwent full maintenance in July 2022.[1] It has also undergone routine oil sampling to monitor its condition.[2] Oil samples were taken in 2023 in accordance with standard maintenance practices.

In 2019, oil samples were taken from power transformer PUL-T2 when it was relocated from the spare inventory at the Electrical Maintenance Centre to PUL. The Transformer Condition Assessments™ ("TCA") completed by TJ/H2b Analytic Services Incorporated ("TJ/H2b")[3] at this time showed that PUL-T2 was a Code 1 and in good health. [4]

In March 2021, Newfoundland Power received a TCA from TJ/H2b during a routine oil sample which noted that PUL-T2 had escalated from a Code 1 to a Code 3. A summary of TJ/H2b's TCA reports completed between February 2019 to April 2024 are included in Attachment A.

The TCA's completed on PUL-T2 have consistently indicated arcing and heating at high temperatures inside the transformer since May 2022. These are signs of the deteriorating health of the power transformer.

In July 2022, the transformer was de-energized and electrical testing was completed on the unit. Testing continued to show signs of deterioration. An internal inspection was completed in September 2022. This inspection found signs of carbon present in the oil, dark/discoloured oil, and small particles of carbon on level surfaces.[5] After the inspection, PUL-T2 was placed back in service and continues to be monitored.

---

1 Full transformer maintenance includes an insulation resistance test, dissipation/power factor test, turns ratio test, winding resistance test, tap changer operation testing and bushing condition inspection. Inspections also check for tank and cooler leaks, cooling fan and pump operation, operation of liquid and winding temperature equipment, oil level, tank pressure, breather operation and controls operation.

2 Oil sampling includes standard oil tests and dissolved gas in oil analysis. Standard oil tests check for contaminants and moisture, which at unacceptable levels can lower the dielectric strength of oil and cause a fault. Dissolved gas analysis is used to monitor and diagnose internal transformer electrical problems, such as the presence of arcing or poor electrical connections. Certain gases naturally increase as a transformer ages, but can be a sign of excessive temperatures and overloading in newer transformers. Oil sampling and analysis is completed annually to gauge the internal health of transformers.

3 TJ/H2b's laboratory is located in Calgary, Alberta. T2/H2b specializes in diagnostic testing of oil, gas and other insulating materials used in transformers, power circuit breakers and load tap changers.

4 TJ/H2b's Condition Assessment Diagnostic Evaluation ranges from Code 1 to a Code 4*. The code evaluation system is a measure of a transformer's health with Code 1 representing a transformer in a state of good health, while a rise in coding values signifies a progressive deterioration in the transformer's health.

5 Active arcing in mineral oil can lead to oil carbonization which will degrade and contaminate the oil. Transformer oil should ideally be light coloured and clear. The colour changing over time is an indication of oxidation, deterioration, or contamination of the oil.

2.2 PTX Condition Assessment

Newfoundland Power utilizes Electric Power Research Institute ("EPRI") Power Transformer Expert System ("PTX") to diagnose and assess the condition of its power transformer fleet.

The indices produced by PTX are meant to provide a measure of the likelihood that normal degradation or abnormal conditions exist within the transformer. A summary of the EPRI PTX results for PUL-T2 based on information received as of December 31st, 2023 is shown in Figure A-3 below.

Company:	NP	**Region:**	St. John's
Station:	PUL	**Designation:**	T2
Equipment ID:	200331	**Serial Number:**	46311
Manufacturer:	Ferranti Packard	**Manufacture Date:**	3/1/1985
Energize Date:		**Repair Date:**	
Retire Date:		**Voltage Rating:**	66/25/12.5
Top MVA:	25	**Cooling Type:**	ONAF/ONAF
Number of Phases:	3	**Core Type:**	Core
Is Autotransformer:	False	**Failure Consequence Index:**	0.83

PTX Result Summary

Normal Degradation Index:	0.34	**Oil Quality Index:**	0.34
Abnormal Thermal Index:	0.46	**Bushing Index:**	0.00
Abnormal Electrical Index:	0.63	**LTC Index:**	0.60
Abnormal Core Index:	0.54	**Throughfault Failure Index:**	

Diagnosis Summary:
Abnormal Electrical is High (0.63) possibly due to:
Winding Dielectric Failure - Minor Insulation (0.63)
Ungrounded or Improperly Insulated Metallic Part (0.48)
Abnormal Core is High (0.54) possibly due to:
Loose Core Laminations (0.54)

Figure A-3: EPRI PUL-T2 Summary

The Normal Degradation Index is intended to provide an indication of the physical condition of the paper insulating system relative to its initial state. Transformers undergo normal aging or degradation due to operation of the transformer under conditions that do not exceed the design criteria of the transformer. This normal degradation is generally due to aging of the paper insulation system, in which the paper insulation experiences decreasing mechanical strength as a function of time and temperature.

A Normal Degradation Index of greater than 0.25 indicates a unit that warrants further scrutiny. Normal Degradation Index values above 0.60 highly correlate with units that have insulating paper that is no longer capable of providing reliable service.

As indicated in Figure A-3, the Normal Degradation Index of PUL-T2 exceeds the 0.25 threshold.

The Abnormal Condition Indices are used to identify units that may be experiencing a variety of unexpected problems due to manufacturing or operating issues or defects. Transformers in these categories show the existence of some condition that would not be present or expected in normal operations. These indices are not a function of service age.

Abnormal Condition Indices are divided into three categories: (i) Abnormal Thermal Index; (ii) Abnormal Electrical Index; and (iii) Abnormal Core Index. Any Abnormal Condition Index value above 0.5 warrants further review. High abnormal index values indicate the need to take immediate action which could come in the form of additional testing and monitoring, inspection, or corrective action.

As indicated in Figure A-3, both the Abnormal Electrical Index and Abnormal Core Index of PUL-T2 exceed the 0.5 threshold.

2.3 Physical Condition Assessment

The Company's power transformers are inspected annually to record any exterior physical defects that need to be addressed. The 2023 inspection report of PUL-T2 indicated minor rust and corrosion on the main tank, radiators and load tap changer, as well as moderate rust and corrosion on the conservator tank and piping. There were no visible leaks, and the bushings and protection devices were in good condition.

Previous corrective maintenance of PUL-T2 includes: (i) multiple gas detector gauge replacements between 1995 and 2019; (ii) H2 bushing replacement in 1997; (iii) fan repaired in 2007; (iv) leak repaired in 2017; (v) exterior of transformer repainted, grounding to lightning arrestors replaced in 2019; and (vi) exterior of transformer repainted in 2022.

3.0 RISK ASSESSMENT

The *Pulpit Rock Substation Power Transformer Replacement* project will mitigate risks to the delivery of reliable service to 6,724 customers in the Torbay, Portugal Cove–St. Philip's, Pouch Cove and Logy Bay–Middle Cove–Outer Cove area.

In the case of a PUL-T2 failure, PUL-T1 is unable to supply the existing peak load of the PUL Substation. System load forecasts indicate that up to 18.9 MVA of load would need to be transferred in order to avoid overload of PUL-T1 under these conditions.[6] Transfer capabilities to adjacent substations do not exist for the entire 18.9 MVA of load which means a portable substation or a spare transformer would need to be installed in the event of a PUL-T2 failure.

Newfoundland Power has three portable substations and one spare power transformer that can be used for the emergency response of PUL-T2.[7] Failure of PUL-T2 would result in an unplanned short-term installation of a portable substation followed by a long-term installation of

[6] A max peak load of 43.9 MVA is being forecasted over the next five years at PUL Substation.
[7] The compatible spare transformer was procured through the *2023 Substation Spare Transformer Inventory Application* and is expected to arrive in the fourth quarter of 2024.

a spare power transformer when available.[8] Present power transformer delivery times are estimated between 24 and 36 months.

Overall, an increased probability of power transformer failure, combined with a limited inventory of spare units, has the potential to place considerable pressure on the availability of portable substations. Extended delivery times for replacements have the potential to exacerbate this risk. Reduced availability of portable substations exposes the Company's customers to an increased risk of extended outages and negatively impacts the execution of the substation capital maintenance program.

Based on this assessment, PUL-T2 should be replaced.

4.0 ASSESSMENT OF ALTERNATIVES

Newfoundland Power identified and assessed three alternatives to address the deteriorating condition of PUL-T2 power transformer. These are: (i) Condition Based Maintenance of PUL-T2; (ii) Repair PUL-T2; or (ii) Proactive Replacement of PUL-T2. These alternatives are discussed below.

4.1 Alternative 1 – Condition Based Maintenance of PUL-T2

Increasing delivery lead times of power transformers, limited emergency response capabilities, and the increased possibility of transformer failure of the aging fleet all result in increased risks to customer reliability. Newfoundland Power has four portable substations and seven spare power transformers which can be used for the emergency response of power transformer replacements.

Among these resources, there are three portable substations that can be installed as a short-term emergency response to offload PUL-T2. Following this offload, there is one spare transformer available that can then be installed for the long-term replacement of PUL-T2.[9] With power transformer delivery times between 24 to 60 months, there are limited resources available to respond to future power transformer failures in the short and medium term.

Run to failure is not a viable alternative as it would increase risks to the delivery of safe and reliable service to 6,724 customers in the communities of Torbay, Portugal Cove–St. Philip's, Pouch Cove and Logy Bay–Middle Cove–Outer Cove. Deferral of the *Pulpit Rock Substation Power Transformer Replacement* multi-year project would increase the risk that PUL-T2 will fail in service.

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[8] Another spare power transformer would need to be procured if the new spare power transformer is utilized to respond to a failure. Present power transformer delivery times are estimated between 24 and 36 months, and upwards of 60 months for some manufacturers.

[9] The compatible spare transformer was procured through the *2023 Substation Spare Transformer Inventory* project approved in the company's *2023 Capital Budget Application* and is expected to arrive in the fourth quarter of 2024.

4.2 Alternative 2 – Repair PUL-T2

Repair of a power transformer requires the unit to be removed from service and shipped to a third-party facility outside of the province for an internal assessment to first determine its viability for repair, followed by the repair if applicable. Repairing PUL-T2 would require it to be removed from service for 18-24 months requiring the long-term installation of a portable substation or spare power transformer. This would put additional pressure on the Company's portable and spare transformer fleet creating an unacceptable risk to customers.

There are numerous additional disadvantages to repair. There are limited facilities that can repair power transformers, resulting in high costs and long lead times. The quality of work and testing undertaken by a repair facility is also generally of a lower standard compared to that of an original equipment manufacturer. Repaired units might not perform as consistently or predictably as new units, as there can be defects that are not fully addressed during refurbishment. Repaired transformers still have some original components, which can lead to reduced reliability and shorter lifespan compared to new transformers.

Following a repair, the power transformer tank would remain and is susceptible to rust over time. Rust is addressed through routine maintenance by sandblasting and painting the tank, which leads to thinning of the metal over time, creating a further risk of oil leaks and environmental damage. This results in a service life substantially less that than of a new transformer.

Repair of a power transformer may sometimes be a valid option. However, the repair of PUL-T2 is not a viable alternative given that a repair would require the unit to be removed from service for 18-24 months requiring the long-term installation of a portable substation or spare power transformer. This would put additional pressure on the Company's portable and spare transformer fleet. These risks to customer reliability are amplified by the increasing delivery lead times of power transformers, the Company's limited emergency response capabilities, and the increased possibility of transformer failure due to the Company's aging fleet.

4.3 Alternative 3 – Proactive Replacement of PUL-T2

To address the risks outlined above, Newfoundland Power proposes to proactively replace the deteriorated power transformer based on the condition assessment outlined in this report.

The deteriorated condition of the power transformer justifies replacing it in 2025-2026. The TCA Code from oil samples has been high since 2021 which indicates arcing, heating and partial discharge taking place within the transformer windings. The PTX System software indicates a high probability that there are deficiencies within the core of the transformer and a high probability that the winding paper insulation is starting to break down. An internal inspection of the transformer in 2022 identified that the oil was dark and discoloured with small particles of carbon found on level surfaces.

The proactive replacement of PUL-T2 will manage the risk to an acceptable level by replacing the deteriorated transformer with a newer more reliable transformer. Strategically replacing the power transformer in a planned manner avoids the additional cost and outages associated with unplanned failures. This will ensure the continued delivery of safe and reliable service to customers served from PUL Substation.

5.0 PROJECT SCOPE AND COST

This project involves purchasing a new 15/20/25 MVA, 66-12.5/25 kV power transformer to replace PUL-T2 while the existing unit remains in service. The project is proposed to be completed over two years. This would include design and procurement in 2025, followed by delivery, installation, testing and commissioning in 2026.

Table A-1 below provides a cost breakdown of the *Pulpit Rock Substation Transformer Replacement* multi-year project.

Table A-1
Pulpit Rock Substation Power Transformer Replacement Project
Project Costs
($000s)

Cost Category	2025	2026	Total
Material	-	2,645	2,645
Labour - Internal	-	13	13
Labour - Contract	-	-	-
Engineering	14	91	105
Other	3	156	159
Total	$17	$2,905	$2,922

The project to replace PUL-T2 is estimated to cost $17,000 in 2025 and $2,905,000 in 2026 for a total project cost of $2,922,000.

6.0 CONCLUSION

Power transformer PUL-T2 is deteriorated and requires replacement. It is essential to the safe and reliable operation of the PUL Substation.

Completing the replacement of PUL-T2 over two years commencing in 2025 is necessary to address the unit's deteriorated condition, and to ensure the continued delivery of safe and reliable service to PUL Substation. The Company will monitor the condition of PUL-T2 while the project is ongoing to mitigate any further risks to the delivery of safe and reliable service.

Attachment A:

TJ/H2b Transformer Condition Assessment History - Power Transformer PUL-T2

Table A-1 TJ/H2b Transformer Condition Assessment History Power Transformer PUL-T2				
Date	Condition Assessment Code	Sampling Interval	Operating Procedure	Comments
2019-02-03	1	1 year	Continue normal operation	No abnormal gas generation is indicated
2019-02-28	1	1 year	Continue normal operation	No abnormal gas generation is indicated
2020-03-19	1	1 year	Continue normal operation	No abnormal gas generation is indicated
2021-03-16	3	5 month	Monitor for increased arcing. Evaluate for worn or damaged components.	A slightly abnormal dissipation of energy is noted[1]. Partial discharge is indicated. Abnormal arcing is indicated. Follow guidelines for oils with highly flammable gas content.
2021-04-14	2	6 month	Continue normal operation. Paper mechanical condition is normal.	Arcing is indicated.
2022-05-26	4	Retest Immediately	Plan to remove from service for additional testing, investigation and analysis.	Arcing and heating at higher temperatures are indicated. Paper condition is normal.
2022-06-07	4	14 Days	Plan to remove from service for additional testing, investigation and analysis.	Heating at higher temperatures and arcing are indicated. Cellulose may be involved.[2] Paper condition is normal.

1 This is an early indication of fault or wear activity.

2 The transformer insulation system is typically made up of a cellulose material which is the main constituent of paper and wood. The combination of moisture, heat, and oxygen is the key factor that affects the rate of cellulose degradation. Carbon monoxide and carbon dioxide in specific ratios are typically found in transformer insulating liquid in fault conditions. The dissolved gas analysis can help to identify that the predominant source of the of the carbon monoxide and carbon dioxide is due to overheated cellulose.

2022-06-20	4	14 Days	Plan to remove from service for additional testing, investigation and analysis.	Heating at higher temperatures and arcing are indicated.
2022-07-19	4	14 Days	Plan to remove from service for additional testing, investigation and analysis.	Heating at higher temperatures and arcing are indicated. Paper condition is normal.
2022-08-18	4	14 Days	Plan to remove from service for additional testing, investigation and analysis.	Heating at higher temperatures and arcing are indicated. Paper condition is normal.
2022-11-16	4	30 Days	Plan to remove from service for additional testing, investigation and analysis.	Arcing is indicated. Paper condition is normal.
2023-02-08	3	90 Days	Continue normal operation.	Heating and arcing are indicated. Paper condition is normal.
2023-03-20	3	3 Months	Monitor for increased arcing. Evaluate for worn or damaged components.	Arcing is indicated. Partial discharge is indicated. Paper condition is normal.
2023-05-08	3	3 Months	Monitor for increased arcing. Evaluate for worn or damaged components.	Arcing is indicated. Partial discharge is indicated. Paper condition is normal.
2023-07-13	3	3 Months	Monitor for increased arcing. Evaluate for worn or damaged components.	Arcing and heating at higher temperatures are indicated. Paper condition is normal.
2023-11-01	3	3 Months	Monitor for increased arcing. Evaluate for worn or damaged components.	Arcing is indicated. Partial discharge is indicated. Paper condition is normal.

2023-11-15	3	3 Months	Monitor for increased arcing. Evaluate for worn or damaged components.	Arcing is indicated. Partial discharge is indicated. Paper condition is normal.
2024-02-28	3	3 Months	Monitor for increased arcing. Evaluate for worn or damaged components.	Arcing and heating at higher temperatures are indicated. Cellulose may be involved.
2024-04-16	3	3 Months	Monitor for increased arcing. Evaluate for worn or damaged components.	Arcing and heating at higher temperatures are indicated. Cellulose may be involved. Paper condition is normal.

APPENDIX B:

Gander Substation Power Transformer Replacement Report

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1.0 BACKGROUND

1.1 Gander Substation

Gander Substation ("GAN") was constructed in 1959 as both a transmission and distribution substation. This substation is supplied by Newfoundland Power Inc. ("Newfoundland Power" or the "Company") 138 kV Transmission Line 144L from Cobbs Pond ("COB") Substation and Transmission Line 146L from Gambo ("GAM") Substation as shown in Figure B-1. One 20 MVA distribution power transformer, GAN-T1 ("200249"), supplies four 12.5 kV distribution feeders, serving approximately 1,697 customers in the Gander area. One 26.67 MVA system power transformer, GAN-T2 ("200175"), converts 138 kV to 66 kV for Transmission Line 108L which provides service to 2,323 customers at Jonathan's Pond ("JON") and Gander Bay ("GBY") Substations and also Transmission Line 102L which feeds Roycefield ("RFD") Substation.

Figure B-1: 144L/146L 138 kV Looped Transmission System Map

1.2 Gander Bay 66 kV Transmission System

The Gander - Twillingate area is supplied electricity via two radial 66 kV transmission line systems as shown in Figure B-2.

Figure B-2: Gander Bay 66 kV Transmission System

Radial transmission line 108L is supplied by GAN-T2 and runs north between GAN and GBY substations. JON substation is supplied by a two phase tap off of 108L approximately 19 kilometers north of GAN substation. Radial transmission line 114L exits GBY substation heading north-west and passes through Boyd's Cove ("BOY") substation before terminating at Summerford ("SUM") substation. Radial transmission line 140L runs north between SUM and

Twillingate ("TWG") substations while radial transmission line TL254 runs north between BOY substation and Newfoundland and Labrador Hydro's Farewell Head ("FHD") terminal station. Radial transmission line 142L is supplied by COB-T2 ("200313") and runs north between COB substation and 114L in Clarke's Head. 142L and 114L are connected in a T-tap configuration through a tie point located approximately 1.7 kilometers west of GBY substation.

The normal configuration of the 66 kV transmission system in the Gander – Twillingate area has 114L open on the GBY end and has the tie point with 142L closed. In this configuration COB-T2 provides service to BOY, SUM, TWG and FHD.

GAN-T2 and COB-T2 are required to provide service to the Gander Bay 66 kV transmission system. Both transformers act as the backup for each other in emergency situations and also for short durations during off peak season to perform planned maintenance.

As described in the *3.1 Gander – Twillingate Transmission System Planning Study*, as a result of the relatively weak 66 kV transmission network in the Gander – Twillingate area and the deteriorating condition of 108L, the Company is recommending the construction of a new 138 kV transmission line from Lewisporte ("LEW") Substation to BOY Substation.

This would improve system voltages in the Gander - Twillingate area and permit the retirement of 108L. This also eliminates the need for a 138-66 kV system transformer at GAN Substation. As a result, GAN-T2 can be relocated to BOY Substation creating a fully redundant transmission system loop.

Due to the aforementioned power transformer supply chain constraints, the Company expects to receive the proposed GAN-T2 system power transformer replacement towards the end of 2026. This would align with the construction of the proposed new transmission line between LEW and BOY substations, and allow for the new system power transformer to be installed at BOY substation in 2027.

1.3 GAN-T2 Power Transformer

GAN-T2 is a 57-year-old, 16/21.3/26.67 MVA, 138-66 kV power transformer manufactured by Federal Pioneer. This transformer was originally installed in Gander ("GAN") substation as GAN-T2 when it was purchased in 1967 to provide service to 66 kV transmission lines.

In 1981 an internal inspection was conducted on this unit following reports of high gas levels detected through routine oil sampling and analysis. The inspection found substantial physical damage to the internal components of the transformer which was suspected to be due to a system fault that this transformer experienced two years prior. The transformer was removed from service and sent out of province for repairs in 1981. It was successfully repaired and returned to service as GAN-T2 in 1982. Routine inspections and maintenance have been performed on this transformer since that time. High gas levels from oil sampling were observed in 2013. Results have fluctuated between high and normal levels since that time but have been high since 2022. These results indicate deterioration of the internal components of the transformer.

In 2014 the high voltage bushings and low voltage bushings were replaced as part of the *PCB Bushing Phase-out* project.

Figure B-3 shows power transformer GAN-T2.

Figure B-3: Power Transformer GAN-T2

Power transformer GAN-T2 is deteriorating and an assessment of alternatives determined that it should be replaced.

Newfoundland Power is proposing to replace GAN-T2 over three years commencing in 2025 at an estimated cost of $4,185,000.

2.0 ENGINEERING ASSESSMENT

2.1 Oil Analysis and Electrical Testing

GAN-T2 has undergone regular maintenance and last underwent full maintenance in September 2022.[1] It has also undergone routine oil sampling to monitor its condition.[2] Oil samples were taken in 2023 in accordance with standard maintenance practices.

In February of 2013, Newfoundland Power received a Transformer Condition Assessment™ ("TCA") from TJ/H2B Analytic Services Incorporated ("TJ/H2B")[3] during a routine oil sample which noted that GAN-T2 had escalated from a Code 1 to a Code 2. This escalation triggered a follow-up sample three months later and those test results indicated that the TCA had returned to a Code 1.

In June of 2014, the TCA results from a routine oil sample indicated that GAN-T2 had escalated from a Code 1 to a Code 4. More frequent oil sampling occurred as a result of these results. The TCA Code reduced to a Code 3 in January 2015 and eventually returned to a normal Code 1 in June of 2015.

In June of 2022, the TCA results from a routine oil sample indicated that GAN-T2 had escalated from a Code 1 to a Code 3. A summary of TJ/H2B's TCA reports completed between December of 2021 to December 2023 are included Attachment A.

The TCA's completed on GAN-T2 have consistently indicated arcing and partial discharge inside the transformer since June of 2022. These are signs of the deteriorating health of the power transformer.

GAN-T2 continues to be monitored.

2.2 PTX Condition Assessment

Newfoundland Power utilizes Electric Power Research Institute ("EPRI") Power Transformer Expert System ("PTX") to diagnose and assess the condition of its power transformer fleet.

The indices produced by PTX are meant to provide a measure of the likelihood that normal degradation or abnormal conditions exist within the transformer.

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1 Full transformer maintenance includes an insulation resistance test, dissipation/power factor test, turns ratio test, winding resistance test, tap changer operation testing and bushing condition inspection. Inspections also check for tank and cooler leaks, cooling fan and pump operation, operation of liquid and winding temperature equipment, oil level, tank pressure, breather operation and controls operation.

2 Oil sampling includes standard oil tests and dissolved gas in oil analysis. Standard oil tests check for contaminants and moisture, which at unacceptable levels can lower the dielectric strength of oil and cause a fault. Dissolved gas analysis is used to monitor and diagnose internal transformer electrical problems, such as the presence of arcing or poor electrical connections. Certain gases naturally increase as a transformer ages, but can be a sign of excessive temperatures and overloading in newer transformers. Oil sampling and analysis is completed annually to gauge the internal health of transformers.

3 TJ/H2b's laboratory is located in Calgary, Alberta. T2/H2b specializes in diagnostic testing of oil, gas and other insulating materials used in transformers, power circuit breakers and load tap changers.

A summary of the EPRI PTX results for GAN-T2 based on information received as of December 31st, 2023 is included in Figure B-4 Below.

Company:	NP	**Region:**	Gander
Station:	GAN	**Designation:**	T2
Equipment ID:	200175	**Serial Number:**	W 1010-1
Manufacturer:	Federal Pioneer	**Manufacture Date:**	3/1/1967
Energize Date:		**Repair Date:**	3/1/1982
Retire Date:		**Voltage Rating:**	138/66
Top MVA:	21.3	**Cooling Type:**	ONAF/ONAF
Number of Phases:	3	**Core Type:**	Core
Is Autotransformer:	False	**Failure Consequence Index:**	0.65

PTX Result Summary

Normal Degradation Index:	0.43	**Oil Quality Index:**	0.71
Abnormal Thermal Index:	0.55	**Bushing Index:**	0.00
Abnormal Electrical Index:	0.71	**LTC Index:**	0.00
Abnormal Core Index:	0.62	**Throughfault Failure Index:**	

Diagnosis Summary:
Abnormal Thermal is High (0.55) possibly due to:
Winding/Lead - Bad Joint (0.55)
Abnormal Electrical is High (0.71) possibly due to:
Winding Dielectric Failure - Minor Insulation (0.71)
Winding - Poor Shield Connection or Construction (0.67)
Ungrounded or Improperly Insulated Metallic Part (0.52)
Abnormal Core is High (0.62) possibly due to:
Loose Core Laminations (0.62)

Figure B-4: EPRI GAN-T2 Summary

The Normal Degradation Index is intended to provide an indication of the physical condition of the paper insulating system relative to its initial state. Transformers undergo normal aging or degradation due to operation of the transformer under conditions that do not exceed the design criteria of the transformer. This normal degradation is generally due to aging of the paper insulation system, in which the paper insulation experiences decreasing mechanical strength as a function of time and temperature.

A Normal Degradation Index of greater than 0.25 indicates a unit that warrants further scrutiny. Normal Degradation Index values above 0.60 highly correlate with units that have insulating paper that is no longer capable of providing reliable service.

As indicated in Figure B-4, the Normal Degradation Index of GAN-T2 exceeds the 0.25 threshold.

The Abnormal Condition Indices are used to identify units that may be experiencing a variety of unexpected problems due to manufacturing or operating issues or defects. Transformers in these categories show the existence of some condition that would not be present or expected in normal operations. This index is not a function of service age.

Abnormal Condition indices are divided into three categories: (i) Abnormal Thermal Index; (ii) Abnormal Electrical Index; and (iii) Abnormal Core Index. Any Abnormal Condition Index value above 0.5 warrants further review. High abnormal index values indicate the need to take immediate action which could come in the form of additional testing and monitoring, inspection, or corrective action.

As indicated in Figure B-4, all Abnormal Condition Indices of GAN-T2 exceed the 0.5 threshold.

2.3 Physical Condition Assessment

The Company's power transformers are inspected annually to record any exterior physical defects that need to be addressed. The 2023 inspection report of GAN-T2 indicated minor rust and corrosion on the main tank, radiators and conservator tank and piping. There were no visible leaks, and the bushings and protection devices were in good condition.

Previous corrective maintenance of GAN-T2 includes: (i) leak repaired in 1999; (ii) block tower coil replaced in 2008; (iii) gas detector relay replaced, oil level gauge replaced, repaired leak on tap changer, fans replaced, exterior painted due to rust in 2014; and (iv) piping to conservator tank replaced due to rust in 2014.

3.0 RISK ASSESSMENT

The *Gander Substation Power Transformer Replacement* project will mitigate risks to the delivery of reliable service to 6,513 customers in the Gander - Twillingate areas.

In the case of a GAN-T2 failure, load can be transferred to COB-T2. However, COB-T2 is unable to independently supply the 66 kV transmission system in the area during peak conditions. Electric modelling shows that undervoltage scenarios are expected to occur at multiple substations. This means that a portable substation or a spare transformer would need to be installed in the event of a GAN-T2 failure.

Newfoundland Power has two portable substations and one spare power transformer that can be used for the emergency response of GAN-T2. Depending on the time of year, the installation of a portable substation may not be required while planning to install the spare power transformer. The spare transformer that is capable of replacing GAN-T2 is presently installed in the Salt Pond ("SPO") substation with the designation SPO-T5, and is currently serving as an in-service backup to SPO-T4. This unit must be reinstalled on the Burin Peninsula once it is no longer needed for emergency use.[4] The spare transformer would need to remain installed until

[4] SPO-T5 works in tandem with power transformer SPO-T4 serving approximately 8,313 customers on the Burin Peninsula. These two power transformers provide N-1 redundancy for supplying the 66 kV transmission system. Good utility practice indicates system transformers should have N-1 redundancy. An N – 1, or N minus one, criterion requires that a system be capable of continued operation with the loss of any single component of that system.

a replacement power transformer could be procured. Present power transformer delivery times are estimated between 24 and 36 months.[5]

Overall, an increased probability of power transformer failure, combined with a limited inventory of spare units, has the potential to place considerable pressure on the availability of portable substations. Extended delivery times for replacements have the potential to exacerbate this risk. Reduced availability of portable substations exposes the Company's customers to an increased risk of extended outages and negatively impacts the execution of the substation capital maintenance program.

Based on this assessment, GAN-T2 should be replaced.

4.0 ASSESSMENT OF ALTERNATIVES

Newfoundland Power identified and assessed three alternatives to address the deteriorating condition of GAN-T2 power transformer. These are: (i) condition Based Maintenance of GAN-T2; (ii) repair GAN-T2; and (iii) proactive Replacement of GAN-T2. These alternatives are discussed below.

4.1 Alternative 1 – Condition Based Maintenance of GAN-T2

Increasing delivery lead times of power transformers, limited emergency response capabilities, and the increased possibility of transformer failure of the aging fleet all result in increased risks to customer reliability. Newfoundland Power has four portable substations and seven spare power transformers which can be used for the emergency response of power transformer replacements.

Among these resources, there are two portable substations that can be installed as a short-term emergency response to offload GAN-T2. Following this offload, there is one spare transformer available that can then be installed for the replacement of GAN-T2.[6] With power transformer delivery times between 24 to 60 months, there are limited resources available to respond to future power transformer failures in the short and medium term.

Run to failure is not a viable alternative as it would increase risks to the delivery of safe and reliable service to 6,513 customers in the Gander - Twillingate area. Deferral of the *Gander Substation Power Transformer Replacement* project would increase the risk that GAN-T2 will fail in service.

4.2 Alternative 2 – Repair GAN-T2

Repair of a power transformer requires the unit to be removed from service and shipped to a third-party facility outside of the province for an internal assessment to first determine its

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5 Power transformer delivery times have increased significantly in recent years. The manufacturers typically being utilized by Newfoundland Power have recently offered lead times of 24 to 36 months. However, other manufacturers in the market are stating lead times up to 60 months.

6 The spare transformer that is capable of replacing GAN-T2 is presently installed in the SPO substation with the designation SPO-T5, and is currently serving as an in-service backup to SPO-T4. This unit must be reinstalled on the Burin Peninsula once it is no longer needed for emergency use.

viability for repair, followed by the repair if applicable. Repairing GAN-T2 would require it to be removed from service for 18-24 months requiring the long-term installation of a portable substation or spare power transformer. This would put additional pressure on the Company's portable and spare transformer fleet creating an unacceptable risk to customers.

There are numerous additional disadvantages to repair. There are limited facilities that can repair power transformers, resulting in high costs and long lead times. The quality of work and testing undertaken by a repair facility is also generally of a lower standard compared to that of an original equipment manufacturer. Repaired units might not perform as consistently or predictably as new units, as there can be defects that are not fully addressed during repair. Repaired transformers still have some original components, which can lead to reduced reliability and shorter lifespan compared to new transformers.

Following a repair, the power transformer tank would still remain and is susceptible to rust over time. Rust is addressed through routine maintenance by sandblasting and painting the tank, which leads to thinning of the metal over time, creating a further risk of oil leaks and environmental damage. This results in a service life substantially less that than of a new transformer.

Repair of a power transformer may sometimes be a valid option. However, the repair of GAN-T2 is not a viable alternative given that a repair would require the unit to be removed from service for 18-24 months, requiring the long-term installation of a portable substation or spare power transformer. This would put additional pressure on the Company's portable and spare transformer fleet. These risks to customer reliability are amplified by the increasing delivery lead times of power transformers, the Company's limited emergency response capabilities, and the increased possibility of transformer failure due to the Company's aging fleet.

4.3 Alternative 3 – Proactive Replacement of GAN-T2

To address the risks outlined above, Newfoundland Power proposes to proactively replace the deteriorated power transformer based on the condition assessment outlined in this report.

The deteriorated condition of the power transformer justifies replacing it in 2025-2026. The TCA Code from oil samples has been high since 2022 which indicates arcing and partial discharge taking place within the transformer windings. The PTX System software indicates a high probability that there are deficiencies within the core of the transformer, a high probability that the winding paper insulation is starting to break down and a high probability that there are deteriorating electrical connections within the transformer windings.

The proactive replacement of GAN-T2 will manage the risk to an acceptable level by replacing the deteriorated transformer with a newer more reliable transformer. Strategically replacing the power transformer in a planned manner avoids the additional cost and outages associated with unplanned failures. This will ensure the continued delivery of safe and reliable service to customers in the Gander – Twillingate area.

5.0 PROJECT SCOPE AND COST

This project involves purchasing a new 25/33.3/41.6 MVA, 138-66 kV power transformer to replace GAN-T2 while the existing unit remains in service. The project is proposed to be completed over three years. Year one would include design and procurement, followed by delivery, installation, testing and commissioning in years two and three. The transformer capacity has increased from the existing size to provide backup to COB-T2 all year long without causing undervoltage scenarios.

Table B-1 below provides a cost breakdown of the *Gander Substation Power Transformer Replacement* multi-year project.

Table B-1
Gander Substation Power Transformer Replacement Project
Project Costs
($000s)

Cost Category	2025	2026	2027	Total
Material	-	3,797	81	3,878
Labour - Internal	-	2	11	13
Labour - Contract	-	-	-	-
Engineering	14	18	73	105
Other	3	88	98	189
Total	$17	$3,905	$263	$4,185

The project to replace GAN-T2 is estimated to cost $17,000 in 2025, $3,905,000 in 2026, and $263,000 in 2027 for a total project cost of $4,185,000.

6.0 CONCLUSION

Power transformer GAN-T2 is deteriorated and requires replacement. It is essential to the safe and reliable operation in the Gander - Twillingate area.

Completing the replacement of GAN-T2 over three years commencing in 2025 is necessary to address the unit's deteriorated condition, to ensure the continued delivery of safe and reliable service to the Gander - Twillingate area. The Company will monitor the condition of GAN-T2 while the project is ongoing to mitigate any further risks to the delivery of safe and reliable service.

Attachment A:

TJ/H2b Transformer Condition Assessment History - Power Transformer GAN-T2

Table A-1 TJ/H2B Transformer Condition Assessment History GAN-T2				
Date	Condition Assessment Code	Sampling Interval	Operating Procedure	Comments
2021-12-14	1	6 months	Continue normal operation. Paper condition is normal.	Arcing is indicated.
2022-06-06	3	30 days	Monitor for increased arcing. Evaluate for worn or damaged components.	Arcing is indicated. Partial discharge is indicated. Paper condition is normal.
2022-07-06	3	3 months	Monitor for increased arcing. Evaluate for worn or damaged components.	Arcing is indicated. Partial discharge is indicated. Paper condition is normal.
2022-08-18	3	3 months	Monitor for increased arcing. Evaluate for worn or damaged components.	Arcing is indicated. Partial discharge is indicated. Paper condition is normal.
2022-09-15	3	3 months	Monitor for increased arcing. Evaluate for worn or damaged components.	Arcing is indicated. Partial discharge is indicated. Paper condition is normal.
2022-12-09	3	3 months	Monitor for increased arcing. Evaluate for worn or damaged components.	Arcing is indicated. Cellulose may be involved. Partial discharge is indicated. Paper condition is normal.
2023-06-05	3	3 months	Monitor for increased arcing. Evaluate for worn or damaged components.	Arcing is indicated. Cellulose may be involved. Partial discharge is indicated. Paper condition is normal.
2023-12-12	3	3 months	Plan for maintenance.	Arcing is indicated. Cellulose may be involved. Paper mechanical condition is reduced to approximately 70 % tensile strength.

NEWFOUNDLAND POWER
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3.1 Gander - Twillingate Transmission System Planning Study

June 2024

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1.0 INTRODUCTION

This system planning study was initiated as a result of three critical issues that have been identified on the 66 kV transmission network that supplies customers in the Gander - Twillingate area: (i) a transmission-level undervoltage condition; (ii) Transmission Line 108L requiring replacement; and (iii) Gander ("GAN") Substation system power transformer GAN-T2 requiring replacement.

Transmission Line 108L is 59 years old and is among the oldest in Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") service territory. Recent inspections have indicated that a significant number of structures on Transmission Line 108L have deteriorated to the point where they require replacement. Similarly, GAN-T2 is 57 years old, and a condition assessment of the transformer shows that it is deteriorating and requires replacement.

Due to the high capital costs associated with rebuilding Transmission Line 108L and replacing GAN-T2, other transmission reconfiguration alternatives were examined to address their replacement and determine a solution that could mitigate the undervoltage condition. This study identifies the capital projects required to provide safe, reliable, least-cost electrical service to the Gander - Twillingate area (the "Study Area").

2.0 BACKGROUND

The 66 kV transmission network supplying the Study Area is supplied from 138/66 kV system power transformers at Cobb's Pond ("COB") and GAN substations. Both COB and GAN substations are part of the Central Newfoundland 138 kV network, which receives supply from Newfoundland and Labrador Hydro's ("Hydro") Stony Brook ("STY") and Sunnyside ("SUN") terminal stations. The 138 kV network spanning Central Newfoundland was built throughout the 1970's and 1980's following the construction of the Bay D'Espoir hydroelectrical development in 1967.

Prior to the development of the 138 kV transmission network in Central Newfoundland, Newfoundland Power operated several 66 kV transmission lines in the area that provided power to customers, including transmission lines 101L and 102L, which were largely retired as part of Newfoundland Power's *2019 Capital Budget Application, Central Newfoundland System Planning Study.* [1]

The 66 kV transmission network supplying the Study Area serves 6,513 Newfoundland Power customers through the following substations: Gander Bay ("GBY"); Summerford ("SUM"); Twillingate ("TWG"); Jonathan's Pond ("JON"); and Roycefield ("RFD"). In addition, the 66 kV transmission network supplies approximately 1,800 Hydro customers on Fogo Island and Change Islands, through Hydro's Farewell Head ("FHD") Terminal Station. Supply to FHD Terminal Station is through Hydro's 66 kV Transmission Line TL-254 and is wheeled through Newfoundland Power's 66 kV transmission network at Boyd's Cove ("BOY") Substation.

[1] The retirement of Transmission Line 102L excluded a 23-kilometre section of the original line, which remains in-service today.

Table 1 provides customer counts for each of the substations within the Study Area.

Table 1
Gander – Twillingate Area
Customer Counts

Substation	Customer Count
GBY	2,317
SUM	2,421
TWG	1,769
FHD (Hydro)	1,800
JON	5
RFD	1
Total	8,313

2.1 Gander - Twillingate 66 kV Transmission Configuration

The Gander - Twillingate 66 kV transmission network is supplied by two radial transmission lines during normal conditions: (i) Transmission Line 142L, which originates from COB Substation; and (ii) Transmission Line 108L, which originates from GAN Substation.

Transmission Line 142L was built in 1978 and is supplied from COB Substation system power transformer COB-T2 and connects to Transmission Line 114L in back country approximately 1.7 kilometres from GBY Substation, in an area known as Clarke's Head. Transmission Line 114L was built in 1972 and extends from Clarke's Head and travels north to BOY Substation. From there, Transmission Line 114L continues on to SUM Substation, and Transmission Line 140L connects TWG Substation to SUM Substation.

Together, transmission lines 142L and 114L form the primary source of supply to all customers downstream of BOY Substation, including SUM and TWG substations and FHD Terminal Station.[2]

Transmission Line 108L is supplied from GAN Substation system power transformer GAN-T2 and travels north, providing the primary source of supply to JON and GBY substations.

2 There are no customers supplied directly from BOY Substation; rather, BOY Substation serves as a 66 kV switching yard.

A normally-open switch at GBY Substation permits Transmission Line 108L to connect to transmission lines 142L and 114L for emergency backup purposes.[3]

An area map is provided in Figure 1 and a simplified single-line diagram of the existing 66 kV configuration is provided in Figure 2.

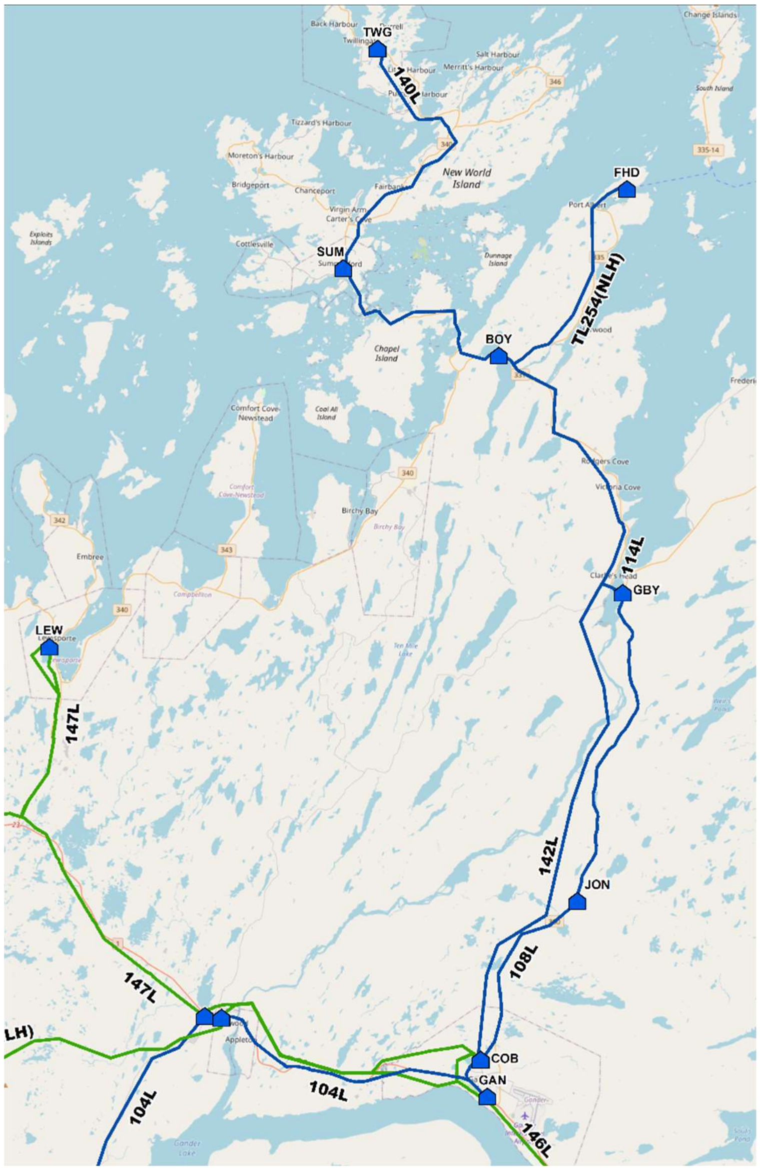

Figure 1: Map of Existing Gander – Twillingate Area Transmission Configuration

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3 The primary function of the normally-open switch is to reduce the risk of customer outages, while also avoiding a voltage collapse and potential overloads under contingency scenarios. When closed, a fault on the 66 kV system at JON or GBY substations would result in an outage to approximately 6,000 customers supplied by SUM, TWG and FHD. Furthermore, if closed, a fault on the transmission lines 142L and 114L network would result in a widespread undervoltage condition to the remaining section, as well as an overload to GAN-T2 under peak conditions.

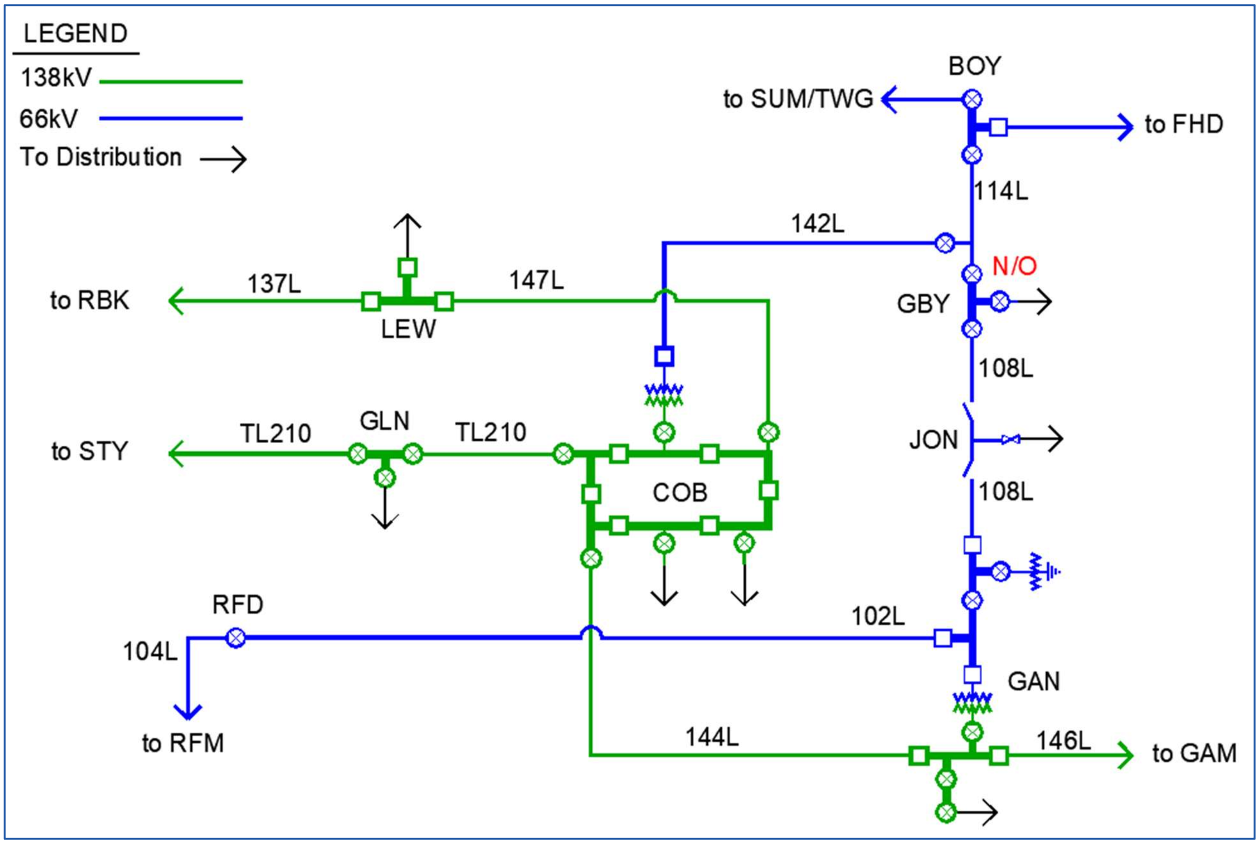

Figure 2: Single Line Drawing of Existing Gander – Twillingate Area Transmission Configuration

To facilitate maintenance and emergency outages, the normally-open switch at GBY Substation can be closed. With Transmission Line 108L out of service, transmission lines 142L and 114L can supply approximately 90% of the peak demand at GBY, SUM and TWG substations as well as FHD Terminal Station. Conversely, with Transmission Line 142L out of service, Transmission Line 108L can supply approximately 65% of the peak demand observed at JON, GBY, SUM, TWG substations and FHD Terminal Station.

2.2 Risk Assessment of Existing 66 kV Transmission System

Four areas of risk have been identified pertaining to the existing 66 kV transmission network serving the Study Area: (i) a system planning voltage violation; (ii) Transmission Line 108L requiring replacement; (iii) system power transformer GAN-T2 requiring replacement; and (iv) the results of a system power transformer contingency assessment, which indicates the potential for substantial customer outages following the loss of system power transformer COB-T2. Each area of risk is described further in this section.

Due to the severity of each of the risks identified, up to 8,313 Newfoundland Power and Hydro customers are at significant risk of extended outages unless transmission system upgrades are pursued.

System Planning Voltage Violation

Table 2 provides Newfoundland Power's system planning criteria with respect to permissible transmission line voltages in per-unit ("pu").

Table 2
Newfoundland Power's
Transmission Voltage Criteria

Operating Condition	Minimum Voltage (pu)	Maximum Voltage (pu)
Normal	0.95	1.05
Emergency	0.90	1.06

Due to the relatively large area supplied by the 138 kV transmission network in Central Newfoundland, the transmission network is relatively weak compared to other transmission networks on the island.[4] In particular, areas furthest from the infeed supply points at SUN and STY terminal stations, which include the Study Area, are prone to relatively lower voltage conditions under high load.

During the 2022 to 2023 and 2023 to 2024 winter seasons, the average per-unit 138 kV voltage at GAN Substation was 0.98 pu, and voltages were below 0.95 pu for roughly 140 hours. Due to on-load tap changers ("OLTC") on distribution power transformers in the area, Newfoundland Power's distribution feeders at GAN Substation and nearby distribution feeders at COB Substation were able to operate within normal voltage limits.

System power transformers at GAN and COB substations supply the downstream 66 kV networks that serve the Study Area. Specifically, GAN-T2 supplies Transmission Line 108L, which serves GBY and JON substations, while COB-T2 supplies transmission lines 142L and 114L, which serve SUM and TWG substations and FHD Terminal Station through BOY Substation.

The 66 kV transmission voltages downstream of BOY Substation are the lowest in the Company's service territory. This is partly due to the relatively low 138 kV infeed voltages at COB and GAN substations, but primarily a result of the combined length and overall load served through the 66 kV Gander - Twillingate area network.[5]

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[4] The "strength" of a power system can be quantified by short-circuit levels. Short-circuit levels at the GAN 138 kV bus are 680 MVA. In comparison, short circuit levels at the SUN 138 kV bus are approximately 1,500 MVA. In the St. John's 66 kV network, short-circuit levels are as high as 2,200 MVA.

[5] Large loads supplied by longer transmission lines will result in larger voltage drops across the line in comparison to large loads supplied by shorter transmission lines.

Table 3 shows a summary of various 66 kV transmission networks with respect to their five-year forecast peak demand versus total length of the supplying transmission lines.

Table 3 Overview of Radial 66 kV Transmission Supply Networks		
Transmission Network	Peak Demand (MVA)	Length (Kilometres)
Gander - Twillingate Area	31.7	167.7
142L/114L[6]	24.1	123.8
108L	7.6	43.9
Other Areas		
59L	43.9	8.8
50L/55L	20.6	43.3
94L/95L	8.1	87.0
353L	5.7	24.6
358L	7.1	22.9

As shown in Table 3, the total length of the Gander - Twillingate 66 kV transmission network is substantially longer than other 66 kV networks, and the relatively high load served by this network contributes to the poor voltages observed. Other larger 66 kV networks in the Company's service territory either have additional sources of generation that provide material voltage support, such as in the Wesleyville and Port-Aux-Basques areas, or are sufficiently interconnected through looped configurations near infeed points, such as the St. John's 66 kV network.

The 66 kV transmission voltages at and downstream of BOY Substation are consistently lower than Newfoundland Power's planning criteria for transmission voltages.

6 Includes lengths of transmission lines 140L and TL254.

Figures 3 and 4 show the most recently available transmission voltage profiles for BOY and TWG substations, respectively.[7]

Figure 3
BOY Substation 66 kV Voltages
(per-unit)

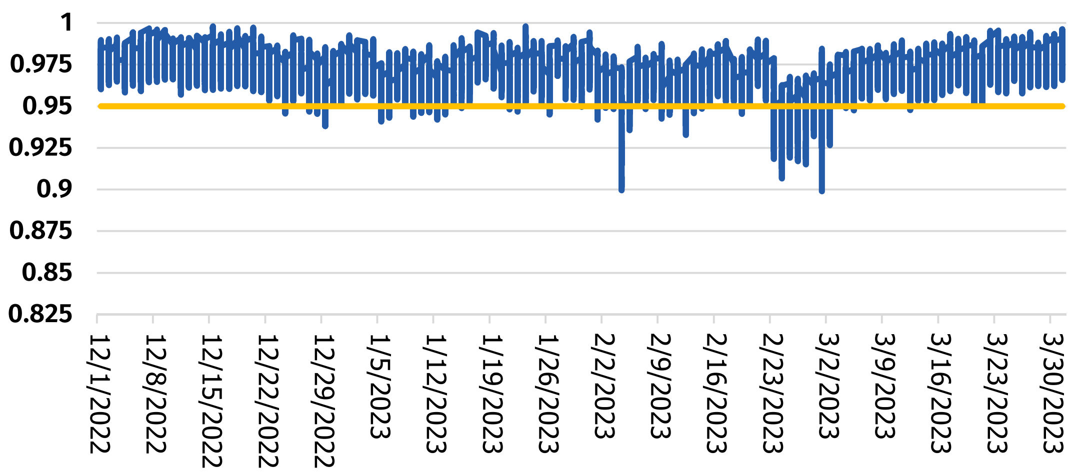
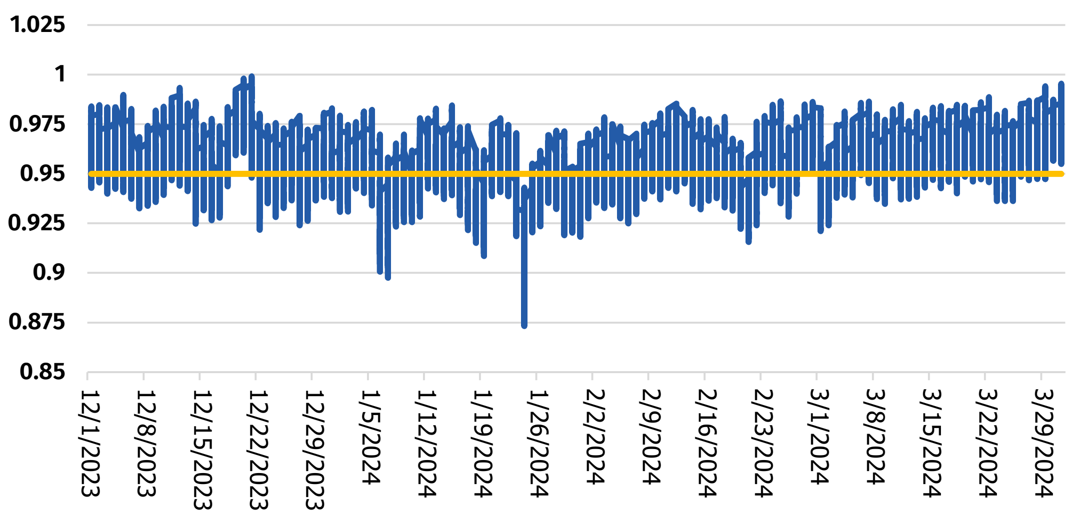


Figure 4
TWG Substation 66 kV Voltages
(per-unit)



[7] Due to metering issues, per-unit voltage data from BOY Substation for the 2023 to 2024 winter season are unavailable. As a result, the most recent available data for BOY Substation is from the 2022 to 2023 period. Power system modeling indicates that BOY substation voltages for the 2023 to 2024 winter season are lower than those observed during the 2022 to 2023 winter season.

Over the course of the most recent 2023 to 2024 winter season, the incoming 66 kV transmission voltage at TWG Substation has been below 0.95 pu for approximately 31% of the entire period. Furthermore, this voltage was below the emergency limit of 0.90 pu for 6.5 hours during the winter period, with a record low of 0.873 pu observed on the most recent seasonal peak day of January 24th, 2024.[8]

In addition to the observed voltage violations, the Company uses power system modeling software to model the transmission network under forecast load conditions. The latest transmission models indicate that any additional load growth associated with electrification will further result in unacceptable transmission voltages at and downstream of BOY Substation. As a result, a voltage mitigation project is recommended to ensure the provision of reliable electricity to the Gander - Twillingate area.

Transmission Line 108L Condition and Reliability Assessment

Transmission Line 108L was constructed in 1965 and is approximately 44 kilometres in length. The line consists of 396 Single Wood Pole structures with 2/0 ACSR which is no longer standard conductor for the Company's transmission lines.[9] The conductor is roughly 60 years old and is approaching the end of the typical useful service life for transmission line conductor.[10]

Transmission Line 108L was not designed to meet current standards for the design of overhead lines. The Canadian Standards Association ("CSA") establishes standards for the construction of overhead systems based on local climatic conditions. At the time of construction in 1965, Transmission Line 108L was designed to withstand sustained winds of 90 km/hour. Current CSA standards require that overhead lines be constructed based on actual historical climate data.[11] Based on this parameter and the actual historical wind speed data which is provided in the standard, Transmission Line 108L should be designed to withstand winds of upwards of 120 km/hour. The substandard design of Transmission Line 108L means it is not built to withstand local climatic conditions, which increases the probability of failure.

Transmission Line 108L has been inspected annually over the last decade. Annual inspections are conducted by experienced Planners that follow the Company's *Transmission Line Inspection and Maintenance Practices*. In conducting annual inspections, Planners create work requests to correct identified deficiencies. Work requests are categorized as Emergency, TD1, TD2 or TD4.[12]

TD4 work requests represent deficiencies to be addressed as part of Newfoundland Power's longer-term capital planning process. The Company monitors these work requests to inform its future capital investment priorities.

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8 A per unit value of 0.873 on a 66 kV system is 57.6 kV; on a 120 V system, it is 104.8 V.

9 ACSR is a bare overhead conductor with aluminum outer strands and a steel core.

10 The typical useful service life of transmission overhead conductor is 63 years.

11 CSA Standard C22.3 - Overhead Systems states: "*it is mandatory in the standard to consider a maximum wind-only weather load case in the design of overhead lines. The magnitude of this wind is required, as a minimum value, to be that which can be predicted to occur at least once in every 50-year period.*"

12 The highest priority for Planners inspecting transmission lines is to identify deficiencies categorized as Emergencies, TD1 or TD2. These deficiencies require action over the near term to address or avoid failure of transmission assets. Work requests for Emergency deficiencies must be addressed immediately. Work requests for TD1 deficiencies must be addressed within seven days and those for TD2 deficiencies must be addressed within one month.

Since 2009, 515 TD4 deficiencies have been identified by Planners completing inspections across Transmission Line 108L. Due to the large number of known deficiencies on the line, Newfoundland Power initiated an engineering assessment of Transmission Line 108L in 2024.

The engineering assessment included a detailed ground inspection. The inspection determined that 238 of the structures across the line contain wood poles which are deteriorated to the point where they require replacement. On a single pole transmission line, the wood pole is the main component of each structure. It provides the primary support for the structure; all other components are inherently dependent upon the wood pole for support. Having a large percentage of wood poles across the line in deteriorated condition increases the risk of a failure to the line.

Many of the poles on Transmission Line 108L have significant shell separation. Shell separation occurs when the pole shrinks over time and the outer shell separates from the core of the pole. This creates a safety risk for employees climbing the poles to perform maintenance as the deteriorated shell is unable to support the weight of the climber and the climber's spikes can tear out of the pole. It also leaves the core of a pole exposed to moisture and fungus, which accelerates wood rot, compromising its strength over time and increasing the probability of failure.

The original poles installed on the line are Class 4 and 5, which are no longer used by Newfoundland Power to construct transmission lines. Additionally, considerable narrowing has occurred at the top of many poles along the line. This level of deterioration makes it susceptible for hardware to disconnect from the pole.

The poles comprising Transmission Line 108L are also experiencing severe splits and woodpecker holes. Similar to shell separation, deep splits and woodpecker holes can undermine the strength of a pole and introduce avenues for internal decay. Sounding tests also determined that many of these poles are exhibiting hollowness, meaning their strength has already been compromised.[13]

Additionally, the assessment determined that other structure components across the line were deteriorated. A total of 108 structures were identified as having other deficiencies such as damaged or deteriorated crossarms, missing timber cribs, cracked insulators, missing or damaged hardware and damaged conductor.

Appendix A provides additional photos of the deterioration present on Transmission Line 108L.

[13] A sounding test is conducted using a flat faced hammer to sound the pole surface at regular intervals. If a hollow sound is detected, it indicates that decay is present. Poles that have been in service more than 35 years require a sounding test during each inspection. If a sounding test indicates a potential problem, a core sampling test can be completed by drilling through the centerline of the pole to observe the decay.

Insulators

Transmission Line 108L has a number of structures containing porcelain insulators manufactured by Canadian Ohio Brass, which were installed when the line was originally constructed. Failure of these porcelain insulators due to cement growth and radial cracking is a known problem. The presence of these Canadian Ohio Brass insulators on the line increases the risk of a failure occurring due to their known deterioration issues.

Conductor

The 2/0 ACSR conductor used in the original construction of Transmission Line 108L is particularly susceptible to corrosion between the inner steel core and the outer aluminum strands. In October 2023, a failure of this conductor resulted in an extended outage to customers in the Study Area, and a subsequent de-rating of the ampacity of the line was recommended based on its condition.

Timber Cribs

Timber cribs are installed in areas where structures are located in bog or other areas with unsuitable soil conditions to adequately support the wood pole. Timber Cribs along Transmission Line 108L have been identified as being rotted, missing, or without sufficient rock fill to support the pole. This compromises the overall strength of the cribbed structures, as they were designed to have adequate rock fill to support the loads imposed on the structure.

Reliability

Due to their criticality in serving customers, Newfoundland Power's transmission lines must be maintained to operate to a high standard of reliability. All transmission lines, including Transmission Line 108L, are maintained in accordance with the Company's *Transmission Inspection and Maintenance Practices*.[14]

The historical reliability performance of Transmission Line 108L has been poor, and the line has experienced a number of outages in recent years due to a variety of factors.

[14] Over the last 10 years, approximately $262,000 has been spent on completing corrective and preventative maintenance of Transmission Line 108L.

Table 4 provides planned and unplanned outage statistics for Transmission Line 108L from 2017 to 2023.

Table 4
Transmission Line 108L Outage Events and Durations
(2017-2023)

Date	Planned/ Unplanned	Outage Cause	Duration (Hours)
June 2017	Unplanned	Equipment Damage	21.0
April 2018	Unplanned	Equipment Damage	1.4
August 2018	Planned	Preventative Maintenance	48.9
November 2018	Unplanned	Unknown	0.1
November 2018	Unplanned	Severe Weather	2.1
March 2019	Planned	Preventative Maintenance	4.8
June 2019	Unplanned	Equipment Damage	358.7
November 2019	Unplanned	Unknown	0.1
May 2020	Planned	Preventative Maintenance	8.5
November 2020	Unplanned	Severe Weather	17.0
July 2021	Planned	Preventative Maintenance	3.2
October – December 2021	Planned	Preventative Maintenance	1,015.4
November 2022	Planned	Preventative Maintenance	1.9
May 2023	Unplanned	Unknown	0.1
October 2023	Unplanned	Equipment Damage	9.4

Due to the deteriorated condition of the transmission line, the number of known deficiencies, the age of its components, and sub-standard original design when compared to today's design standards, it is anticipated that unplanned outages due to failures on the line will continue and become more frequent in the future. This will contribute to further reliability detriments to customers served by Transmission Line 108L, who already experience high levels of transmission-related supply interruptions.

GAN-T2 Condition Assessment

System power transformer GAN-T2 was installed in 1967 and is 57 years old. Recent inspections have indicated that GAN-T2 is deteriorating and requires replacement.

A detailed condition assessment of system power transformer GAN-T2, along with an overview of outage impacts, is provided in Newfoundland Power's *2025 Capital Budget Application*, report *2.2 Substation Power Transformer Replacements,* Appendix B.

System Transformer Contingency Assessment

Newfoundland Power operates twelve 138/66 kV system power transformers. These transformers typically serve as sources of supply for numerous distribution transformers, and can provide power to substantial amounts of customers. As a result, customer impacts associated with unexpected outages to system power transformers was considered, and an unexpected loss of COB-T2 would result in substantially more customer outages than any other system power transformer within the Company's service territory.[15]

Each of the alternatives presented in section 3.0 would result in decreases to the customer impacts associated with an outage of COB-T2, which are further quantified in section 4.3.

3.0 DEVELOPMENT OF ALTERNATIVES

This section provides an overview of the development of alternatives that satisfy the following criteria:

1. Transmission supply voltages at BOY, SUM, TWG Substations must operate between 0.95-1.05 during normal operating conditions.
2. Transmission Line 108L must either be retired or replaced, while ensuring reliable supply to customers in the Study Area.
3. System power transformer GAN-T2 must either be replaced or relocated, while ensuring reliable supply to customers in the Study Area.
4. Customer risks associated with an outage of COB-T2 cannot increase.
5. Existing levels of transmission backup capabilities within the Study Area cannot be reduced.

3.1 Viable Alternatives

Three alternatives were deemed technically viable and were assessed further:

1. Alternative 1 involves rebuilding Transmission Line 108L, replacing GAN-T2, and relocating COB-T2 to BOY Substation.
2. Alternative 2 involves building a new 138 kV Transmission Line from LEW Substation to BOY Substation, retiring 41.5 kilometres of Transmission Line 108L, and installing the GAN-T2 replacement at BOY Substation.
3. Alternative 3 involves rebuilding Transmission Line 108L, replacing GAN-T2, and installing a utility-scale battery system at SUM Substation for on-peak voltage support.

[15] A loss of COB-T2 during peak conditions would result in a loss of supply to approximately 4,190 customers.

Alternative 1

Alternative 1 would involve the rebuild of 66 kV Transmission Line 108L to address the deteriorated conditions described in section 2.2 of this report. To mitigate the observed voltage violation in the Study Area, COB-T2 would be relocated to BOY Substation. This would also require the conversion of Transmission Line 142L to 138 kV, as well as the construction of a new 138 kV transmission line extension from Clarke's Head to BOY Substation.

A simplified single line diagram illustrating the proposed final transmission configuration of Alternative 1 is provided in Figure 5.

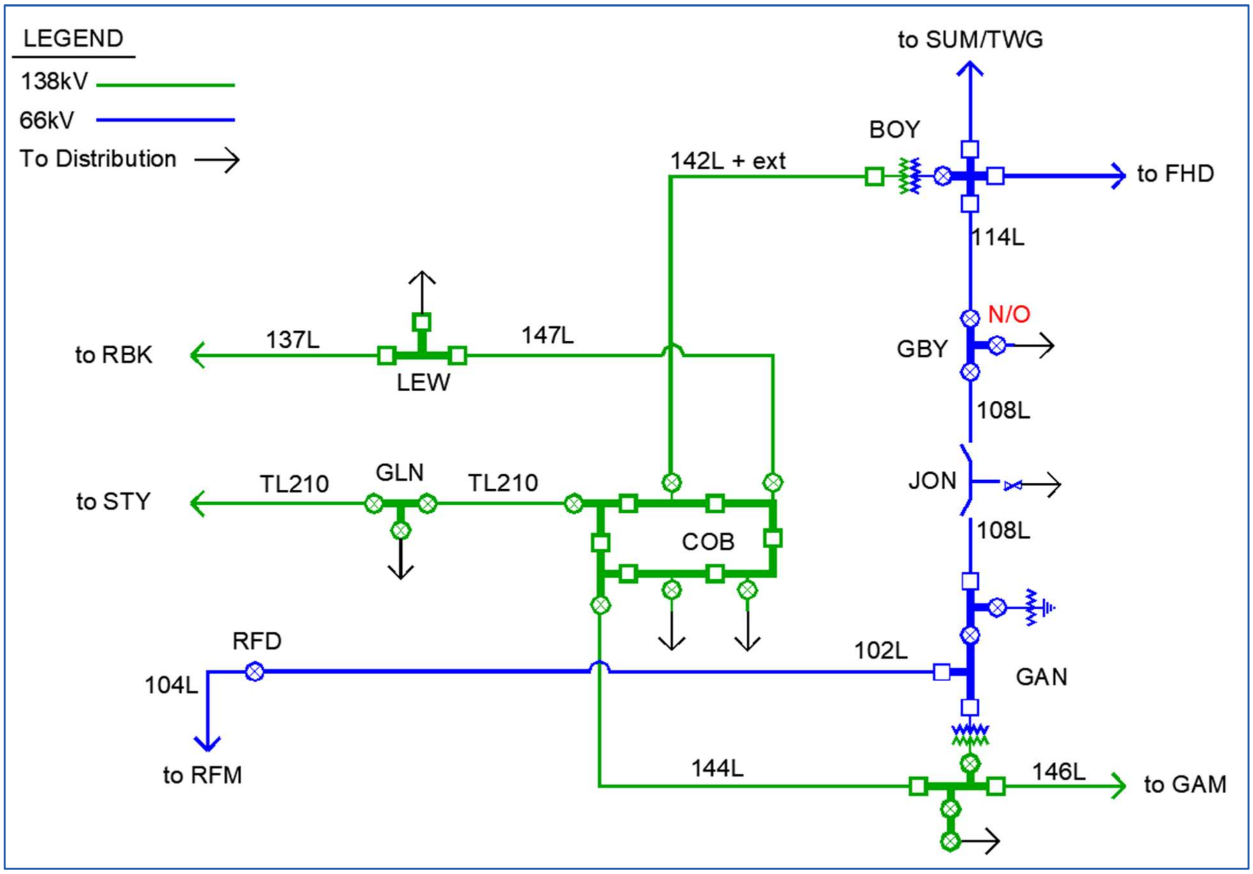

Figure 5: Proposed Single Line Diagram for Alternative 1

Table 5 shows capital costs associated with Alternative 1.

Table 5 Alternative 1 2025–2027 Capital Costs ($ Millions)					
Activity	2025	2026	2027	2030-2036	Total
Rebuild Transmission Line 108L	2.2	8.2	8.1	-	18.5
Replace GAN-T2	0.02	3.9	0.3	-	4.2
Convert Transmission Line 142L to 138 kV and Extend to BOY	-	-	8.8	-	8.8
Relocate COB-T2 to BOY and Upgrade BOY to 138 kV	-	0.5	4.5	-	5.0
Project Total (2025-2027)	2.2	12.6	21.7	-	36.5
Future Rebuilds (2030-2036)	-	-	-	25.4[16]	25.4

It is recognized that transmission lines 142L and 114L are aging assets and will be considered for rebuild in the 2030 to 2036 timeframe under Alternative 1. Similarly, Alternative 1 would involve the continued operation of JON Substation. JON-T1 is 61 years old, and is also expected to be replaced in the 2030 to 2036 timeframe. The impact of these future capital costs is considered further in net-present value ("NPV") analyses of customer revenue requirements, which are provided in section 4.2 of this report.

Following completion of Alternative 1 activities, Newfoundland Power customers in the Study Area would be supplied by combination of 66 kV and 138 kV transmission lines. The impact of the marginal energy and capacity costs associated with modeled losses of this configuration is also considered within the NPV analyses of customer revenue requirements in section 4.2 of this report.

In terms of backup capability, Alternative 1 would involve rebuilding Transmission Line 108L to 559.5 AASC conductor. This would permit Transmission Line 108L to supply approximately 75% of winter demand to the system downstream of GBY, in comparison to approximately 65% of winter peak demand that it can supply today.

[16] Includes costs to rebuild Transmission Line 142L ($16.6M) and 22 kilometres of Transmission Line 114L between GBY and BOY substations ($7.2M), as well as refurbishing JON Substation ($1.6M).

Alternative 2

Alternative 2 would involve the construction of a new 138 kV transmission line from Lewisporte ("LEW") Substation to BOY Substation to resolve the observed voltage violation. This would also permit the primary supply to GBY Substation to be transferred from GAN Substation to BOY Substation through Transmission Line 114L, thereby permitting the majority of Transmission Line 108L to be retired, with approximately 2.5-kilometres remaining in-service to supply Transmission Line 102L, RFD Substation, and Transmission Line 104L.[17] This would facilitate future optimizations of transmission line rebuilds in the 2030 to 2036 timeframe when Transmission Line 142L is expected to reach end-of-life. Presently, Transmission Line 142L runs primarily through back-country, whereas Transmission Line 108L runs primarily roadside.[18] Following the retirement of Transmission Line 108L, Transmission Line 142L could be rebuilt between COB and GBY substations while utilizing the existing Transmission Line 108L right-of-way.

Alternative 2 would effectively result in a 138/66 kV system power transformer no longer being required at GAN Substation. As a result, the newly proposed GAN-T2 transformer replacement outlined in report *2.2 Substation Power Transformer Replacement* would be purchased and installed directly at BOY Substation.

After the installation of the new transformer at BOY Substation, GBY Substation would be supplied by Transmission Line 114L from BOY Substation with a backup supply from Transmission Line 142L from COB Substation. As part of this alternative, a 1.7-kilometre double-circuit extension of transmission lines 142L and 114L would be built from Clarke's Head to GBY Substation. Similarly, a 0.6-kilometre extension between Transmission Line 142L and the remaining section of Transmission Line 108L could be constructed to maintain supply to RFD Substation, if required.

To maintain a ground source at GAN Substation following the relocation of GAN-T2, a 138 kV grounding transformer would be installed at GAN Substation.

Following the eventual retirement of Transmission Line 108L, customers currently supplied by JON Substation would be supplied by a single-phase extension of distribution feeder COB-02. This would also effectively result in the retirement of JON Substation and a reduction of substation assets to be maintained and refurbished in the future.

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[17] See Newfoundland Power's *2019 Capital Budget Application, Central Newfoundland System Planning Study* which recommended the deferral of reconfiguring a 23-kilometre section of Transmission Line 102L to a future year, due to uncertainties surrounding the continued operation of the mine served by RFD Substation.

[18] Transmission lines that run along the roadside typically have lower maintenance costs due to improved access. They also tend to have reduced outage times as patrols and outage maintenance can be performed in a timelier manner.

The proposed configuration is presented in Figure 6.

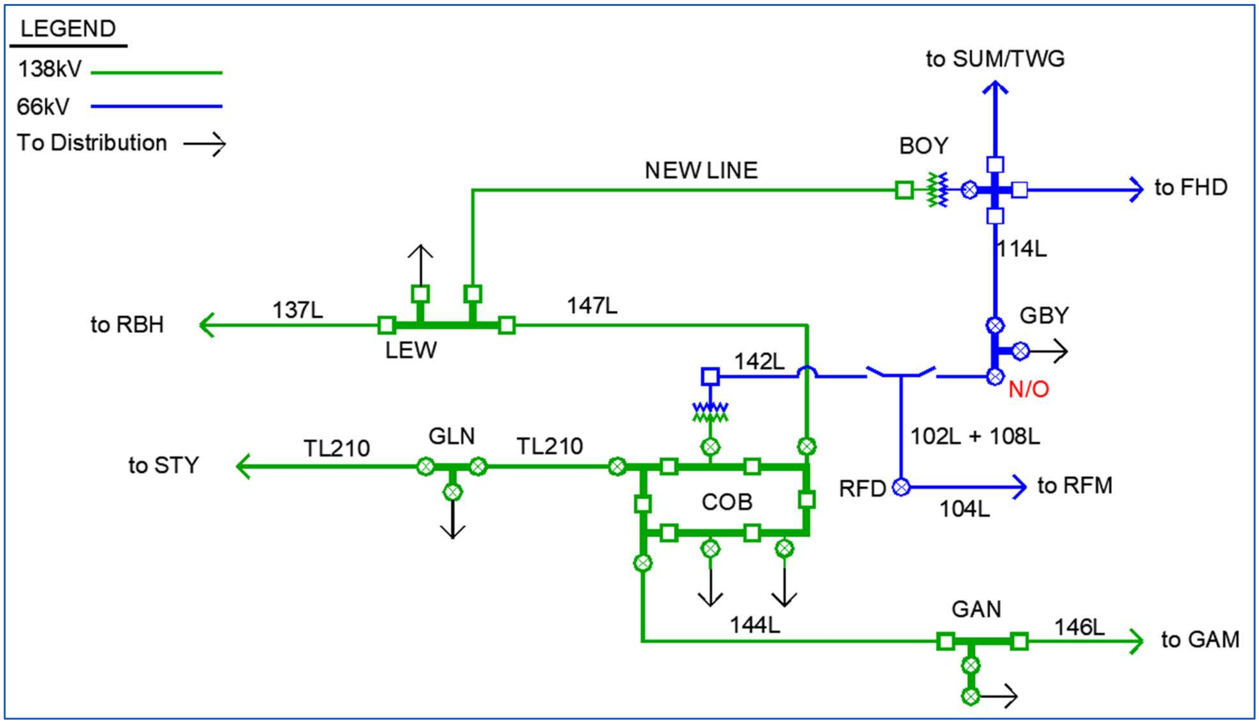

Figure 6: Proposed Single Line Diagram for Alternative 2 (2025-2027)

Table 6 provides capital costs associated with Alternative 2.

Table 6 Alternative 2 2025–2027 Capital Costs ($ Millions)					
Activity	2025	2026	2027	2030-2036	Total
Build new transmission line from LEW to BOY substations	1.9	9.3	9.6	-	20.8
Purchase GAN-T2 Replacement for BOY Substation	0.02	3.9	0.3	-	4.2
Convert BOY Substation to 138 kV	-	0.4	4.1	-	4.5
LEW Substation Upgrades (138 kV termination)	-	0.1	1.5	-	1.6
Extension of COB-02 for JON Substation	-	-	1.2	-	1.2
Extension of Transmission Line 142L for GBY and Transmission Line 104L	-	-	1.5	-	1.5
New 138 kV Grounding Transformer for GAN Substation	-	0.02	2.0	-	2.0
Project Total (2025-2027)	1.9	13.7	20.2	-	35.8
Future Rebuilds	-	-	-	23.3[19]	23.3

Under Alternative 2, JON Substation would be retired, and the proposed configuration would also permit Transmission Line 142L to be relocated and rebuilt utilizing the old Transmission Line 108L right-of-way in the 2030 to 2036 timeframe. The impact of these future capital costs is considered further in NPV analyses of customer revenue requirements, which are provided in section 4.2 of this report.

Following completion of Alternative 2 activities, customers in the Study Area would be supplied by a combination of 66 kV and 138 kV transmission lines. The impact of the marginal energy and capacity costs associated with modeled losses of this configuration is also considered within the NPV analyses of customer revenue requirements in section 4.2 of this report.

Following the retirement of the majority of Transmission Line 108L in the 2025 to 2027 timeframe, and the proposed rebuild of Transmission Line 142L in the 2030 to 2036 timeframe, supply to GBY Substation would be from Transmission Line 114L from BOY Substation and backup supply from Transmission Line 142L from COB Substation. The new transmission line from COB Substation would be shorter in length than Transmission Line 108L, and would permit emergency voltage limits to be maintained at 100% peak demand even with the new

19 Includes costs associated with rebuilding Transmission Line 142L ($16.6M), and rebuilding 20 kilometres of 114L between Clarke's Head and BOY Substation ($6.7M).

transmission line from LEW to BOY substations out of service. As a result, Alternative 2 would facilitate full backup supply of the system.

Furthermore, as Transmission Line 142L is primarily through back country and would be permitted to be rebuilt in the 2030 to 2036 timeframe under Alternative 2, transmission line routes associated with this alternative would consist of more road-side routes in comparison to Alternative 1. This is expected to provide increased operational efficiencies associated with transmission line maintenance as well as improved outage response times.

Alternative 3

A non-wires alternative ("NWA") was also considered as a means to resolve the voltage violation. Power system modeling results indicate that a load reduction downstream of BOY Substation on the order of 10 MW can effectively reduce the voltage drop on transmission lines 142L and 114L such that normal voltage limits can be maintained. To accomplish this, a 40 MWh battery system was considered. Latest utility-scale battery bank cost projections by Cole et al. project capital costs of approximately $23.0 million for such a battery system.

This alternative would also involve maintaining the existing 66 kV network in the Gander area, through the replacement of Transmission Line 108L.

Capital costs associated with this alternative are presented in Table 7.

Table 7
Alternative 3
2025–2027 Capital Costs ($ Millions)

Activity	2025	2026	2027	2030-2036	Total
Rebuild Transmission Line 108L	2.2	8.2	8.1	-	18.5
Replace GAN-T2	0.02	3.9	0.3	-	4.2
New 40 MWh Battery System at SUM Substation	-	-	23.0	-	23.0
Project Total (2025-2027)	2.2	12.1	31.4	-	45.7
Future Rebuilds	-	-	-	25.4[20]	25.4

20 Includes costs to rebuild Transmission Line 142L ($16.6M) and 22 kilometres of Transmission Line 114L between GBY and BOY substations ($7.2M), as well as refurbishing JON Substation ($1.6M).

Following completion of Alternative 3 activities, Newfoundland Power customers in the Study Area would be supplied by solely by 66 kV transmission lines. The impact of the marginal energy and capacity costs associated with modeled losses of this configuration is also considered within the NPV analyses of customer revenue requirements in section 4.2 of this report.

In terms of backup capability, Alternative 3 would involve rebuilding Transmission Line 108L to 559.5 AASC conductor. This would permit Transmission Line 108L to be able to supply approximately 75% of winter demand of the entire Gander - Twillingate 66 kV transmission network. Considering an additional 10 MW on-peak load reduction provided by the battery system, Transmission Line 108L could potentially supply up to 100% of the winter peak demand for up to 4 hours, compared to approximately 65% of winter peak demand that it can supply today.

3.2 Excluded Alternatives

As part of the development of alternatives, several alternatives were considered but were excluded from further consideration due to them not being technically viable, or due to them being cost prohibitive.

Transmission-level capacitor banks were considered as a method to improve system voltages in the Study Area. However, these were deemed to be non-viable, in part, due to the large number of step-sizes required resulting from the low short-circuit levels in the area.[21] Aside from capacitors, the installation of continuous reactive power support devices, such as synchronous condensers, was also considered. However, regardless of their higher costs in comparison to capacitors, such solutions would still require additional transmission line construction or rebuilds to ensure reliability to the area. For this reason, these devices were also excluded from further consideration.

Retiring Transmission Line 108L and GBY Substation was also considered, which would involve supplying GBY Substation customers from other distribution feeders. This was found to be non-viable due to the inability to maintain normal distribution feeder voltages resulting from the long feeder extensions that would be required from SUM and Wesleyville ("WES") substations.

Similarly, retiring Transmission Line 108L and supplying GBY Substation customers directly from BOY Substation through Transmission Line 114L was also considered. This would require COB-T2 to be relocated to BOY Substation to maintain transmission voltages, and would result in all customers from GBY, SUM, and TWG Substations and FHD Terminal Station to be supplied radially from BOY Substation, with no backup capabilities. As per the system power transformer contingency assessment, an outage to COB-T2 results in the greatest risk to customer outages across all system power transformers. This alternative would result in even more customers being supplied by this transformer, thereby resulting in an unacceptable increase in customer risk. Therefore, this option was not considered further.

[21] According to the Institute of Electrical and Electronics Engineers ("IEEE") standard 1543-2022, switching on a capacitor bank on buses greater than 35 kV should be limited to be no more than 2.5% of the short-circuit levels at that particular bus.

Due to the "partial loop" configuration resulting from the normally-open point between Transmission Line 108L and transmission lines 142L and 114L, in conjunction with the observed undervoltage condition, numerous full 138 kV loops were also considered, which would involve the conversion of GBY Substation to 138 kV. However, due to physical limitations at the GBY Substation, the installation of 138 kV infrastructure is not viable. To facilitate the conversion, GBY Substation would have to be relocated, which would incur substantial costs. Therefore, full 138 kV loop alternatives were excluded from further consideration at this time.

4.0 EVALUATION OF ALTERNATIVES

4.1 Evaluation of Transmission Voltages

Power system modeling software was used to simulate transmission voltages over a range of acceptable 138 kV infeed voltages. The Study Area, which includes GBY, BOY, SUM, and TWG substations and FHD Terminal Station, receives its infeed transmission supply from either COB or GAN substations in each alternative described in section 3.1 of this report. Since both Newfoundland Power and Hydro's system planning criteria permit transmission lines to operate as low as 0.95 pu under normal conditions, transmission voltages within the Study Area were modeled with COB and GAN voltages between 0.95 and 1.0 pu.

As shown in Table 8, normal transmission voltages are unable to be maintained during peak conditions within the existing configuration. However, each of the technically viable alternatives described in the previous section result in acceptable transmission voltages, with Alternative 2 having the highest voltage levels.

Table 8
Evaluation of Transmission Voltages
(pu)

COB & GAN Infeed	BOY	SUM	TWG
Existing System			
0.950	0.900	0.876	0.863
0.975	0.914	0.891	0.879
1.000	0.924	0.901	0.889
Alternative 1			
0.950	1.035	1.016	1.006
0.975	1.038	1.019	1.010
1.000	1.040	1.021	1.011
Alternative 2			
0.950	1.037	1.018	1.009
0.975	1.039	1.020	1.010
1.000	1.042	1.023	1.014
Alternative 3			
0.950	0.972	0.960	0.960
0.975	0.977	0.965	0.964
1.000	0.984	0.972	0.972

4.2 Economic Analyses of Alternatives

An NPV analysis of the viable alternatives presented in section 3.1 was completed to determine customer revenue requirements associated with each alternative over the life cycle of the required capital assets. The NPV analysis includes consideration of the value of losses with respect to the latest projection of marginal energy and capacity costs, as well as the potential rebuilds of transmission lines 142L and 114L in the 2030 to 2036 timeframe. Where applicable, JON Substation refurbishment costs were also considered.

Table 9 provides the results of the NPV analysis.

Table 9 NPV Analyses of Viable Alternatives (2025–2036 Expenditures) ($ Millions)	
Alternative #	NPV
1	63.4
2	60.7
3	90.6

Sensitivity Analyses

Three sensitivity analyses were completed that considered impacts to the NPV of customer revenue requirements: (i) the impact of the value of transmission line losses associated with varying marginal energy and capacity costs; (ii) varying estimates by asset class; and (iii) the timing of the transmission lines 142L and 114L rebuild.

For the varying marginal cost analysis, high- and low-marginal cost scenarios were considered. Specifically, under the high-marginal cost scenario, projected marginal energy and capacity costs have been increased by 50%; under the low-marginal cost scenario, projected marginal energy and capacity costs have been decreased by 50%.

Table 10 shows the NPV customer revenue requirement across alternatives with the value of transmission line losses included, based on varying marginal cost scenarios.

Table 10 NPV Sensitivity Analyses Varying Marginal Costs ($ Millions)		
Alternative #	Low Marginal Costs	High Marginal Costs
1	61.0	65.8
2	58.5	62.9
3	88.2	93.0

To analyze the impact of varying estimates by asset class, transmission and distribution-related estimates were increased by 10%, and substation-related estimates were decreased by 10%. Conversely, transmission and distribution-related estimates were decreased by 10%, while substation-related estimates were increased by 10%.

Table 11 shows the impact of varying estimates by asset class on the NPV of customer revenue requirement across alternatives.

Table 11 NPV Sensitivity Analyses Varying Estimates by Asset Class ($ Millions)		
Alternative #	T&D +10% Sub -10%	T&D -10% Sub +10%
1	67.1	59.7
2	63.7	57.6
3	89.8	91.4

Finally, the impact of the timing of the transmission lines 142L and 114L rebuild were also considered. For the base case presented in Table 9 it was assumed that transmission lines 142L and 114L would be rebuilt in 2033.

Table 12 shows the impact of rebuilding transmission lines 142L and 114L in 2030 or 2036 on the NPV of customer revenue requirement across alternatives.

Table 12 NPV Sensitivity Analyses Timing of 142/114L Rebuild ($ Millions)		
Alternative #	2030	2036
1	66.5	60.8
2	63.5	58.2
3	93.7	87.9

Across each of the sensitivities considered, Alternative 2 is the least-cost solution.

4.3 Risk and Reliability Assessment of Alternatives

The system power transformer contingency assessment referenced in section 2.2 illustrated that an unplanned outage to COB-T2 posed the greatest risk to Newfoundland Power across all system power transformer outages in terms of the number of customer outages.

In the current transmission configuration that supplies the study area, a loss of COB-T2 would result in an outage to 4,190 customers. The system power transformer contingency assessment has been expanded to consider the impacts following a loss of COB-T2 for each of the viable alternatives.

Table 13 shows Alternative 2 results in the lowest risk of customer outages following an unexpected loss of COB-T2.

Table 13 Customer Outages Following Unplanned Loss of COB-T2	
Alternative #	Customer Outages
Existing	4,190
1	766
2	0
3	766[22]

[22] The battery bank solution proposed in Alternative 3 could supply approximately 2,700 customers for four hours following the loss of COB-T2 during peak conditions. After this time, there would be 766 customer outages.

Furthermore, the alternatives examined in section 3.1 each consist of varying combinations of transmission lines that run primarily through back-country or roadside. For each of the viable alternatives in section 3.1, the right-of-way for Transmission Line 114L between GBY and BOY substations, as well as the right-of-way between COB and GBY substations are anticipated to remain largely unchanged in the long-term. Across alternatives, the primary difference in the proposed transmission reconfigurations involve either maintaining the existing Transmission Line 142L right-of-way, or constructing a new line between LEW and BOY substations.

A comparison of the average distance to the nearest road, as well as the number of off-road vehicle access points per kilometre of transmission line, for each of the supply alternatives to BOY Substation, is provided in Table 14.

Table 14
Overview of Transmission Line Accessibility

Alternative #	Supply to BOY	Average Distance to Road (m)	Access Points per kilometre
Existing	142L	1,126	0.3
1	142L	1,126	0.3
2	New Line from LEW to BOY	378	0.8
3	142L	1,126	0.3

As shown in Table 14, Transmission Line 142L is predominately in back-country, with few access points for off-road vehicles. Conversely, the newly proposed line between LEW and BOY substations would be closer to the road in general, and would also benefit from additional roads that serve as access points for Newfoundland Power field personnel. Therefore, Alternative 2 results in a more accessible transmission right-of-way overall.

Due to Alternative 2 being associated with both a decreased risk resulting from an outage to COB-T2, as well as a more easily accessible transmission line for maintenance and outage response purposes, Alternative 2 is expected to provide the most reliable configuration.

5.0 RECOMMENDATION

The economic evaluation performed in section 4.2 indicates that Alternative 2 is the least cost alternative that meets all of the required technical criteria. An analysis of modeled transmission level voltages in the Study Area demonstrates that Alternative 2 is associated with the greatest level of voltage improvement over the existing configuration. Alternative 2 is also associated with the lowest risk of customer outages, and will also maximize operational efficiencies by having the transmission system in the Gander - Twillingate area closer to the road.

As a result, Alternative 2 is recommended as the best alternative to meet the long-term electrical transmission system requirements of the Gander - Twillingate area at the lowest possible cost consistent with safe and reliable service.

Table 15 shows the multi-year project description and estimated costs for the recommended alternative.

Table 15
Recommended Capital Project Costs
($ Millions)

Activity	2025	2026	2027	2030-2036	Total
Build new 138 kV TL from LEW to BOY	1.9	9.3	9.6	-	20.8
Purchase GAN-T2 Replacement for BOY	0.02	3.9	0.3	-	4.2
Convert BOY to 138 kV	-	0.4	4.1	-	4.5
LEW Upgrades (138 kV termination)	-	0.1	1.5	-	1.6
Extension of COB-02 for JON	-	-	1.2		1.2
Extension of 142L for GBY and 104L	-	-	1.5	-	1.5
New 138 kV Grounding Transformer for GAN	-	0.02	2.0		2.0
Project Total (2025-2027)	1.9	13.7	20.2	-	35.8
Future Rebuilds	-	-	-	23.3[23]	23.3

23 Includes costs associated with rebuilding Transmission Line 142L ($16.6M), and rebuilding 20 kilometres of Transmission Line 114L between Clarke's Head and BOY Substation ($6.7M).

Figure 7 shows the proposed route for the new 138 kV transmission line between LEW and BOY substations to be completed from 2025 to 2027.

Figure 7: New 138 kV Transmission Line from LEW – BOY Substations

Appendix A:

Photographs of Transmission Line 108L

Figure A-1: Deep Splits Through Hollow Pole

Figure A-2: Hollow Pole, Large Splits

Figure A-3: Deep Splits, Hollow Pole

Figure A-4: Large Split Through Cross-arm Hardware

Figure A-5: Large Split, Hollow Pole (Shared Transmission/Distribution Structure)

Figure A-6: Pole Top Splits Through Hardware; Narrowing of Pole Top

Figure A-7: Deep Splits Through Pole

Figure A-8: Deteriorated and Narrowed Pole Top

Figure A-9: Missing Timber Crib and Splits in Pole

Figure A-10: Leaning Structure (Double Circuit Structure)

Figure A-11: Twisted Cross Arm Supporting Insulator

Figure A-12: Twisted Cross Arms (Double Circuit Structure)

Figure A-13: Conductor bird-caging

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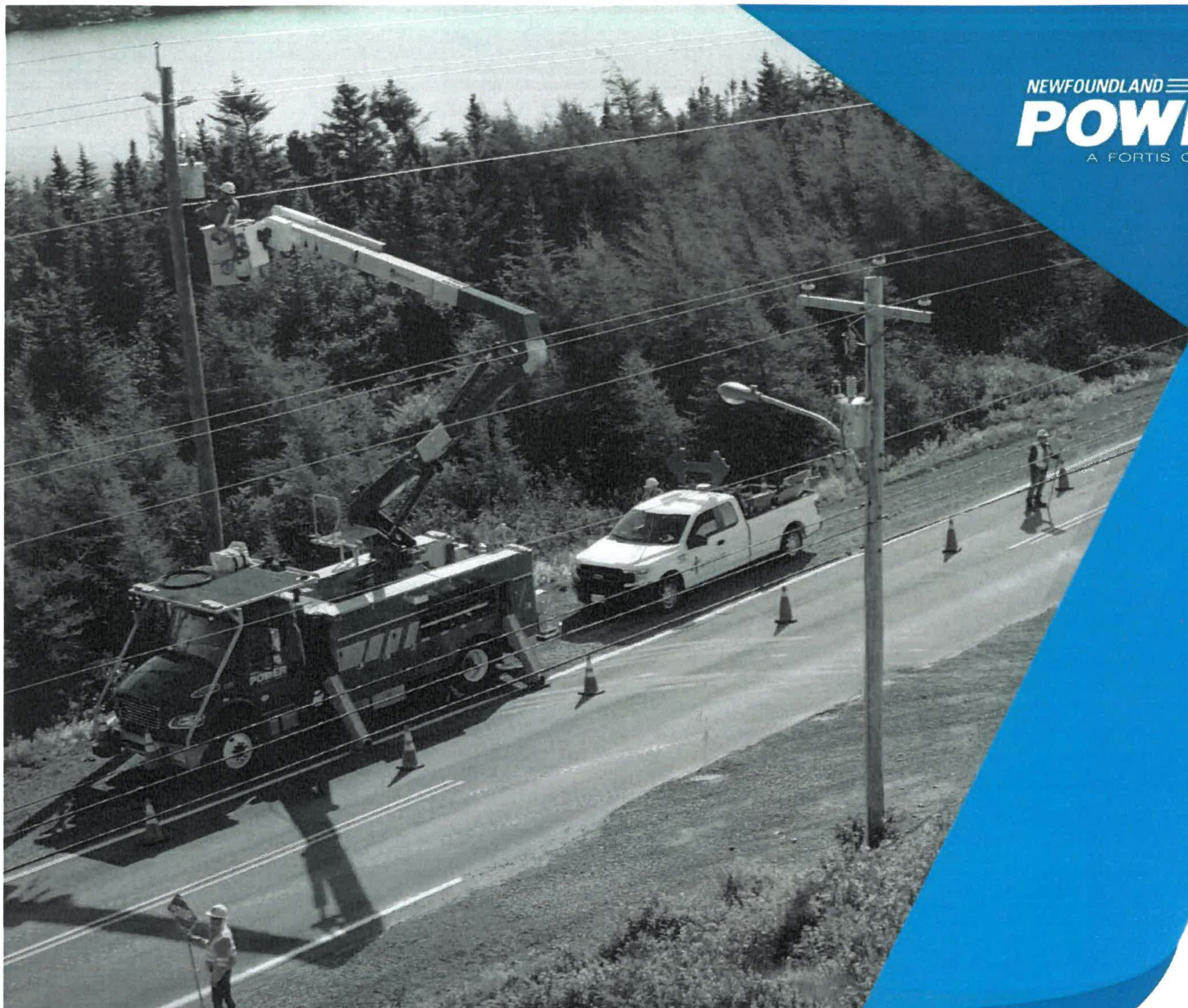

3.2 Transmission Line 94L Rebuild

June 2024

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1.0 INTRODUCTION

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") transmission lines are the backbone of the electricity system providing service to customers. The Company maintains approximately 2,100 kilometres of transmission lines that operate at 66 kV or 138 kV.

Transmission line failures typically result in outages to a significant number of customers at once. Maintaining transmission lines is therefore critical to the delivery of reliable service to customers.

In 2021, Newfoundland Power received approval for the *Transmission Line 94L Rebuild* project (the "Project") as a part of its *2022 Capital Budget Application*.[1] The Project was intended to be completed over the course of three years to address the deteriorated condition of the existing Transmission Line 94L.

During the execution of the phase 1 section of the Project, the Company experienced higher contractor costs related to site access and construction due to geotechnical challenges. This has resulted in an increase in the estimated cost to complete the overall project. As a result, Newfoundland Power completed an engineering review to determine whether a change in project scope would minimize the increase in project execution costs experienced to date.[2]

2.0 BACKGROUND

2.1 General

Newfoundland Power filed a *Transmission Line Rebuild Strategy* (the "Strategy") as part of its *2006 Capital Budget Application*. The Strategy outlined a long-term plan to rebuild the Company's aging transmission lines. Rebuild projects are prioritized based on physical condition, risk of failures, and the potential impact on customers in the event of a failure. This Strategy is updated annually to ensure it reflects the latest condition assessments, inspection information and operating experience.

Transmission Line 94L was one of the 37 transmission lines that were originally included in the Strategy. In accordance with the execution of the Strategy, and due to the deteriorated condition of the line, Newfoundland Power proposed the Project as a part of its *2022 Capital Budget Application.*

2.2 Transmission Line 94L

Transmission Line 94L is a 66 kV H-Frame radial line running between Blaketown ("BLK") Substation on the Trans-Canada Highway near Whitbourne and Riverhead ("RVH") Substation located in Riverhead, St. Mary's Bay. This line provides the only source of supply for St. Catherine's ("SCT") Substation, RVH Substation, and Trepassey Substation via Transmission Line 95L. In total, the three substations serve approximately 2,500 customers.

1 See Order No. P.U. 36 (2021).

2 See the Provisional Guidelines, page 5, which states, *"If there is a material change in a subsequent year the expenditures will be subjected to further review. A change will be considered material if the nature or scope of the project change such that original rationale provided is no longer applicable or where the revised forecast expenditure exceeds the approved amount by 10% or more".*

Figure 1 provides a diagram illustrating how Transmission Line 94L anchors this radial section of the Company's electrical system.

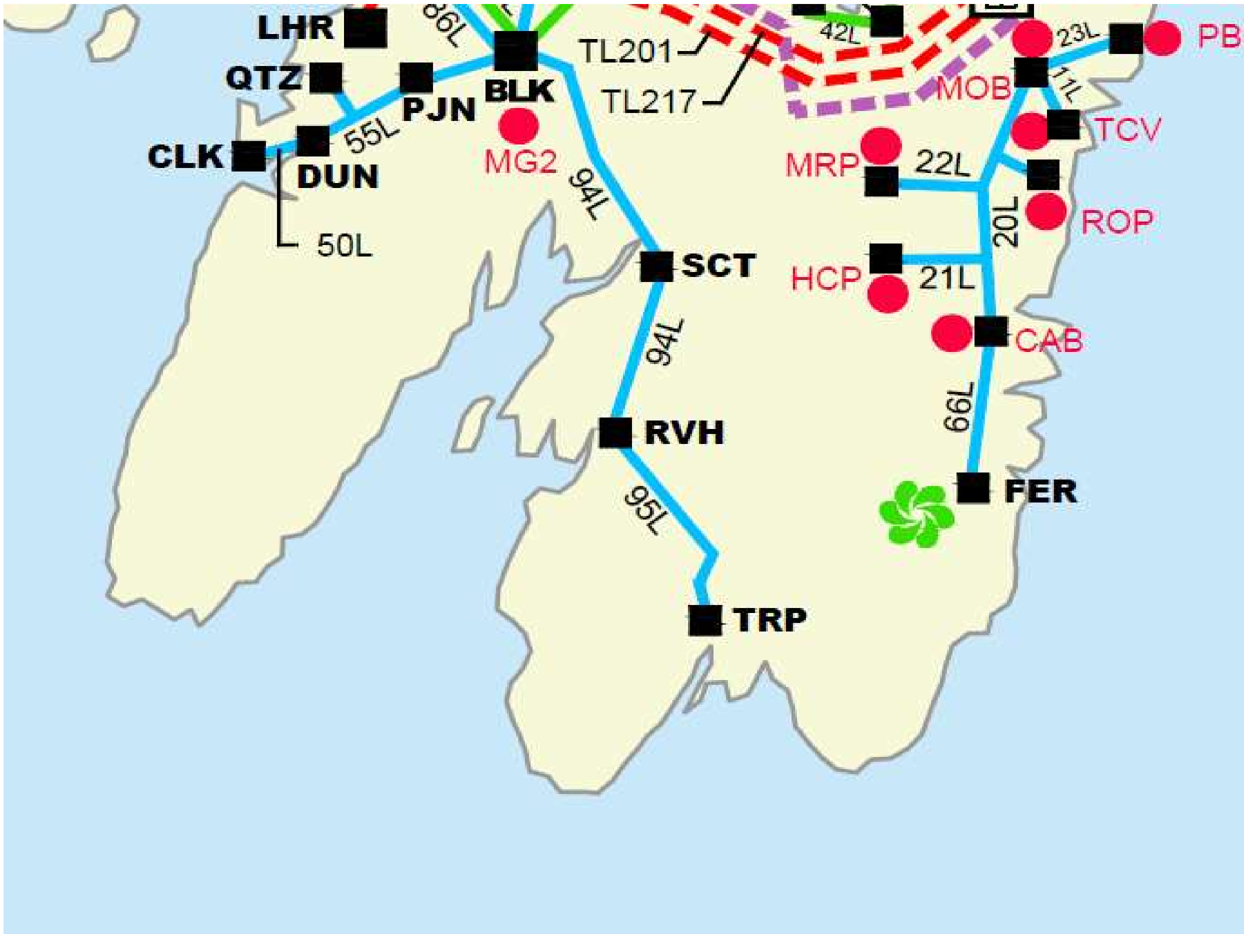

Figure 1 – Transmission Line 94L

2.3 2022 Capital Budget Application Filing – Original Project Details

The Project was approved by the Board as a part of the Company's *2022 Capital Budget Application* as a multi-year project. The Project was to be completed over the span of three years, beginning in 2022 and ending in 2024. The Project was divided into three scopes of work, approximately 20 kilometres in length, with Newfoundland Power planning to complete one of the scopes in each year of the Project. These scopes included the design and construction of the new line, as well as decommissioning the existing Transmission Line 94L.

Table 1 below shows the three individual scopes of work that comprised the approved Project.

Table 1
Transmission Line 94L Rebuild Project
Original Schedule

Scope	Year	Kilometres	Cost ($000s)
1 - RVH-SCT	2022	21.5	4,473
2 - SCT-Markland Road	2023	20.0	4,346
3 - Markland Road-BLK	2024	19.5	4,276

In total, the approved Project includes 61 kilometres of new transmission line constructed over three years at an estimated cost of $13,095,000. Figure 2 below shows the three scopes of work for the approved Project.

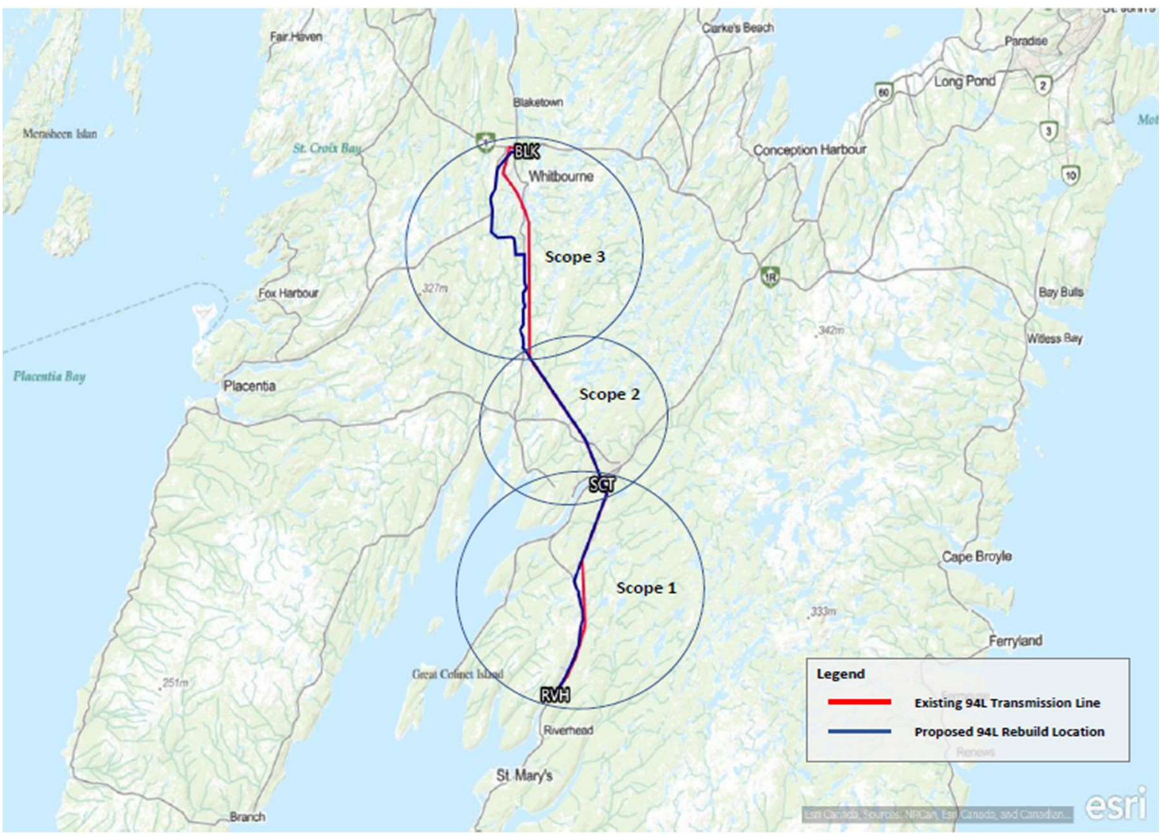

Figure 2 – Transmission Line 94L Rebuild Location

2.4 Project Execution to Date

In early 2022, Newfoundland Power began the execution of Scope 1 of the Project.

Necessary property and environmental permits were required before construction could proceed. As a part of applying for the required permits and crown land easements, the Project had to undergo an Environmental Assessment ("EA") by the Provincial Government's Environmental Assessment Division.[3]

Due to the Provincial Government's plans to designate land in the immediate vicinity of the Project as "environmental reserve" lands, the timeline related to the release of the Project from the EA was delayed. The process ultimately spanned months longer than anticipated, and final release of the Project by the Environmental Assessment Division was not received until September 2022.

This delay in approval prevented the Company from being able to complete Scope 1 of the Project in 2022. Newfoundland Power began brush clearing, survey and design activities upon release of the Project in September 2022 and rescheduled the construction of Scope 1 to 2023. Due to the reduction in planned construction activities, the Company spent $552,000 of the $4,473,000 approved 2022 project budget, with the remainder carried over into 2023.[4]

In early 2023, Newfoundland Power issued a tender for the construction of the 21.5 kilometres of transmission line between RVH Substation and SCT Substation included in Scope 1 of the Project. When the contractor pricing was reviewed upon closing of the tender, the Company found the price received from the lowest bidder was significantly higher than anticipated. This was primarily due to the depths of the bogs found along the right-of-way. As a result, more access trails would need to be built and a large number of bog mats would be required to access structure locations, therefore resulting in additional costs.

After receiving the higher than anticipated contractor pricing, Newfoundland Power re-evaluated the available options and potential routing for Scope 1 of the Project to ensure it was still the least-cost alternative. It was determined that the originally approved scope remained the least-cost option consistent with prior approval.[5] As a result, the Company proceeded with the construction of Scope 1. This scope of the Project was completed and put into service in 2023 at a cost of $7,899,000.

While construction activities for Scope 1 were ongoing, Newfoundland Power issued the tender for the construction of Scope 2. In reviewing the submitted bids, it was determined that contractor pricing had again come in higher than anticipated, resulting in a significant increase in the overall

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3 The purpose of an EA is to protect the environment and quality of life of the people of the province of Newfoundland and Labrador, facilitating the wise management of the natural resources of the province. It requires any person or company who plans a project that could have a significant effect on the natural, social or economic environment to present the project for examination. The EA helps to ensure that projects proceed in an environmentally acceptable manner by having relevant provincial and federal agencies and groups review the proposed work and issue conditions that those planning to execute the project must follow.

4 See Newfoundland Power's *2022 Capital Expenditure Report*.

5 Another potentially viable option was construction of the 21.5 kilometre section of Transmission Line 94L roadside between RVH Substation and SCT Substation, was reviewed. This route increased the total length of the new line and required a significant portion to be constructed in an under-build configuration with distribution feeder SCT-02, both of which increased the cost of the alternative above that of the originally proposed route.

forecasted cost of the Project. As a result, Newfoundland Power completed a further assessment of alternatives to determine whether the Scope 2 and Scope 3 routes remained the least-cost alternative for customers.

3.0 ASSESSMENT OF ALTERNATIVES

3.1 General

Newfoundland Power evaluated two possible alternatives to ensure it was proceeding with the least-cost option for customers. These alternatives were: (i) rebuild Transmission Line 94L as approved in Newfoundland Power's *2022 Capital Budget Application*; and (ii) rebuild Transmission Line 94L between SCT Substation and BLK Substation in a revised right-of-way.[6]

Figure 3 below shows the location of the existing Transmission Line 94L as well as the proposed right-of-way for both of the alternatives that were considered.

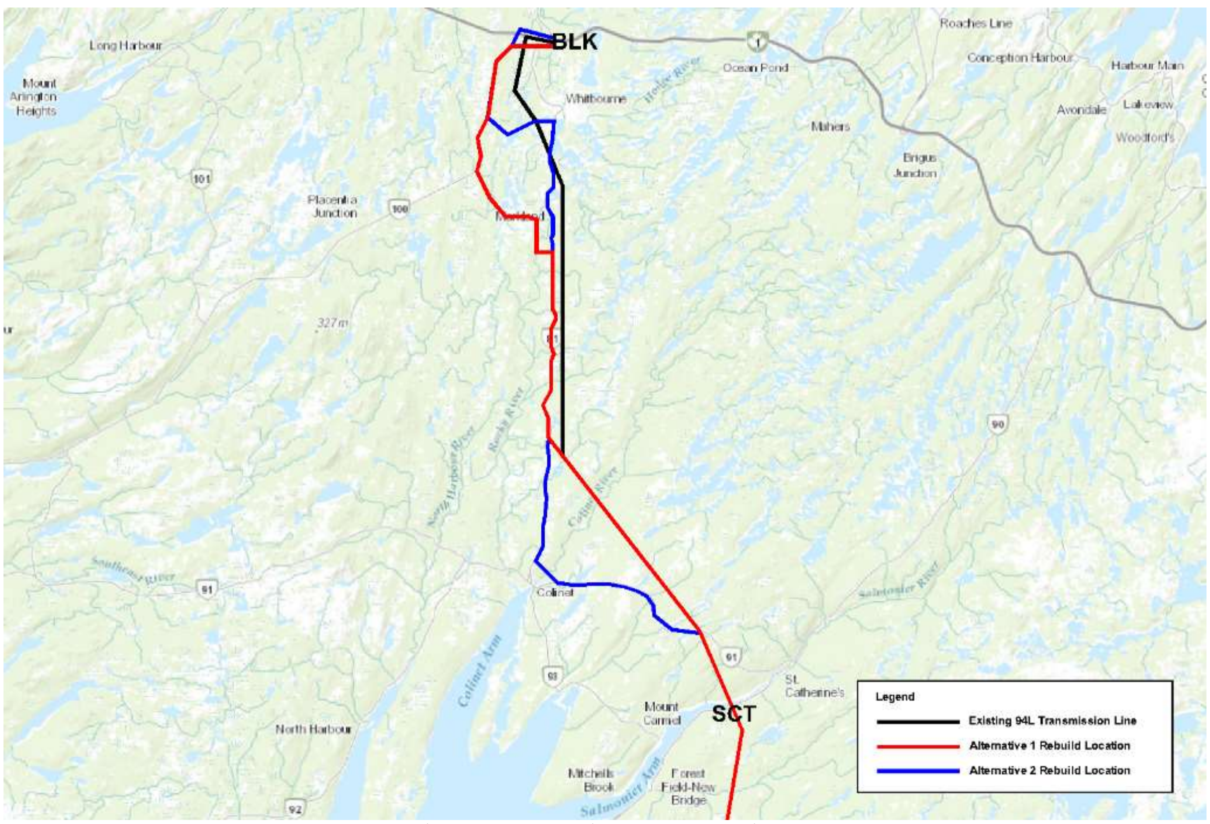

Figure 3 – Overview of Alternatives

[6] A third alternative was also evaluated, which involved re-routing Transmission Line 94L along Salmonier Line and terminating the line at Holyrood Substation instead of Blaketown Substation. This alternative provided for a shorter overall transmission route, however, it also required a significant upgrade at Holyrood Substation and a high amount of distribution underbuild construction along Salmonier Line. This alternative was determined to be cost prohibitive and not considered in the final analysis.

3.2 Alternative 1 – Rebuild as Approved in the 2022 Capital Budget Application

Alternative 1 involves rebuilding Transmission Line 94L as it was originally filed and approved as a part of Newfoundland Power's *2022 Capital Budget Application*. This would include continuing with the execution of Scope 2 and 3 as approved.

Under this alternative, the rebuild of Transmission Line 94L would be completed over two years with 10 kilometres being rebuilt in 2025 and an additional 25 kilometres being rebuilt in 2026.

Figures 4 and 5 show the planned routes for Scope 2 and 3 of Alternative 1.

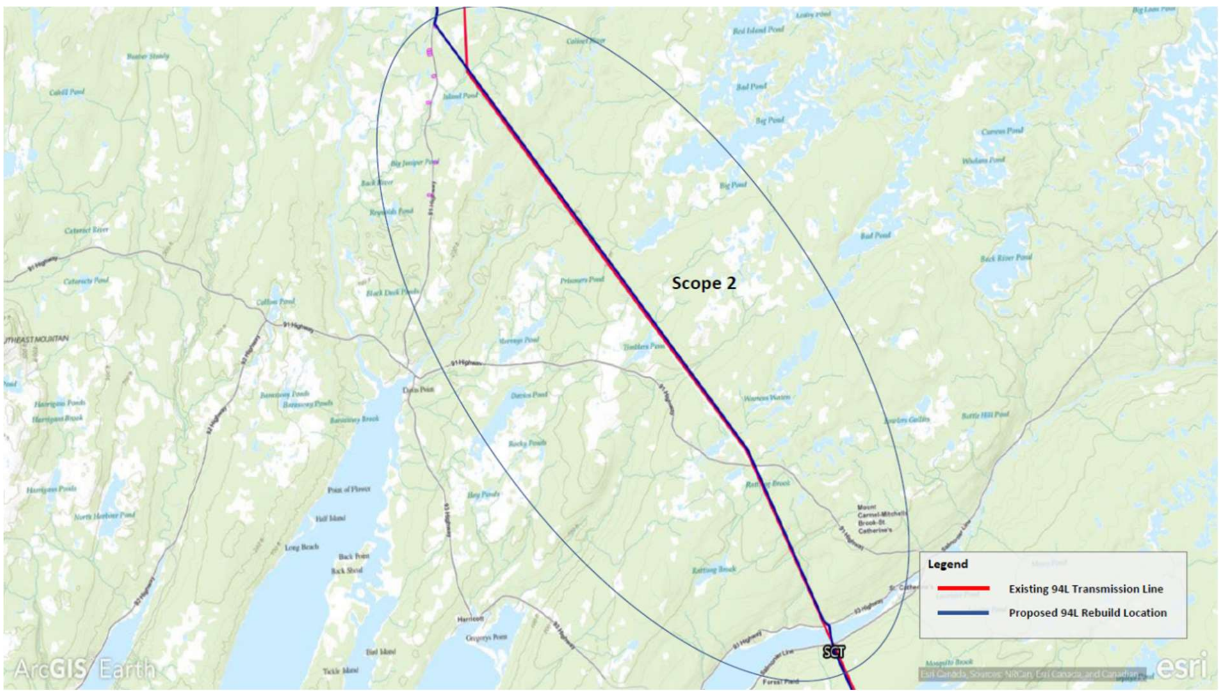

Figure 4 – Scope 2 of Alternative 1 (2025)

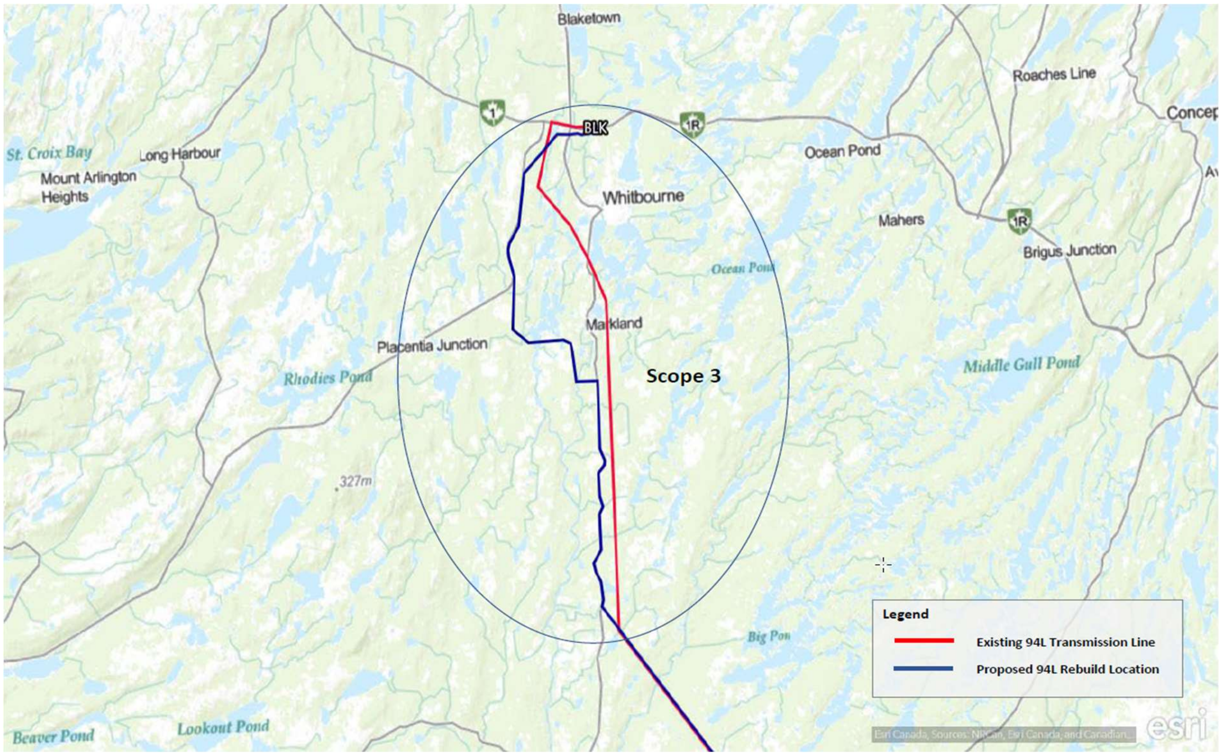

Figure 5 – Scope 3 of Alternative 1 (2026)

This alternative has been re-estimated based on the contractor pricing received in 2023 and a revised number of projected bog structures.

Table 2 shows the estimated capital costs associated with Alternative 1.

Table 2
Alternative 1 Capital Costs
($000s)

Year	Item	Cost
2025	Scope 2 (Remaining Scope)	4,383
2026	Scope 3	12,279
Total		16,662

As outlined above, Alternative 1 presents several issues that have caused the cost to increase significantly when compared to the budget originally approved in the *2022 Capital Budget Application*. The routing planned for this alternative follows the existing Transmission Line 94L, which is located primarily across back-country. The depth of the bogs in the area makes traversing the right-of-way difficult and requires the use of a large number of bog mats. The costs associated with the bog mats and the limited access options account for a significant portion of the overall cost of Alternative 1. Proceeding with this option would also result in issues for future access on the line when completing inspections and required maintenance. These access constraints and the remote location of this route could result in lengthy restoration times for any outages on this line.[7]

3.3 Alternative 2 – Rebuild in a Revised Right-of-Way

Alternative 2 maintains the same system configuration as Alternative 1 by rebuilding Transmission Line 94L between BLK Substation and SCT Substation. However, it is constructed primarily roadside in a different right-of-way than was originally approved in the *2022 Capital Budget Application*.

In this alternative, Transmission Line 94L would be constructed parallel to the existing line for the first 3.5 kilometres outside of the SCT Substation until it intersects with Route 91, following the same routing as the originally approved alternative. At this location, it would then deviate from the previously approved route and be constructed roadside along Route 91. The line would then be constructed behind the Town of Colinet and connect to Route 81 (also known as Markland Road). The line would be built roadside within the Route 81 road right-of-way, until reaching the intersection with the T'Railway, which it would follow west and connect with Route 100. The line would then follow Route 100 North to the Trans-Canada Highway and connect into BLK Substation.

When compared to Alternative 1, this alternative requires more total kilometers of line construction. However, this alternative would remove the costs related to access trail and bog mat installation by eliminating a large portion of the back-country transmission construction and moving it roadside.

Property constraints along both Route 91 and Route 81 require sections of the new line to be constructed in the same location as other existing Newfoundland Power feeders. In these areas, sections of SCT-01 and BLK-01 feeders will be attached to the transmission structures in an under-build configuration.

Under this alternative, most of the revised Scope 2 would be completed in 2025, except for the first 3.5 kilometres, which will be constructed in 2024. Revised Scope 3 would be completed in 2026.

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[7] For example, an unplanned outage on Transmission Line 94L on December 19, 2023 resulted in a 12-hour restoration time for customers. Restoration time for this outage was delayed due to challenges in accessing the location of damage to complete repairs.

Figure 6 shows the proposed route for Alternative 2.

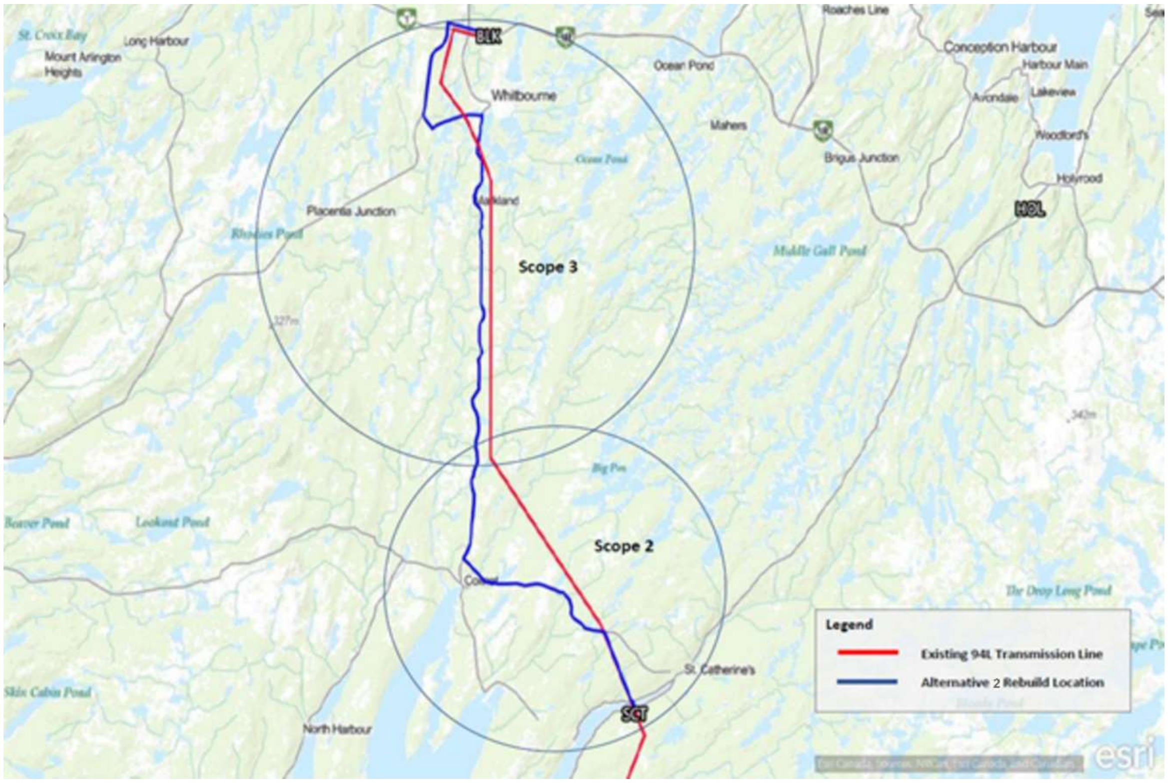

Figure 6 – Proposed Route for Alternative 2

Table 3 shows the estimated capital costs associated with Alternative 2.

Table 3 Alternative 2 Capital Costs ($000s)		
Year	Item	Cost
2025	Revised Scope 2	3,485
2025	SCT-01 Under-build	649
2026	Revised Scope 3	9,075
2026	BLK-01 Under-build	1,140
Total		14,349

The route selected for Alternative 2 optimizes the amount of roadside construction, significantly reduces the need for access trails, the use of bog mats and lowers the forecasted cost of the Project when compared to the other alternatives. This alternative also provides easier access for future line inspections and maintenance.

3.4 Net Present Value Analysis of Alternatives

A net present value ("NPV") calculation of customer revenue requirement was completed for the three alternatives. Capital costs from all years were converted to the customer revenue requirement and an NPV was calculated using the Company's weighted average incremental cost of capital.

Table 4 provides the results of the NPV analysis for the two alternatives.

Table 4
Net Present Value Analysis
($000s)

Alternative	NPV
1 – Rebuild as Approved in 2022	18,415
2 - Rebuild in a Revised Right-of-Way	15,879

The NPV analysis determined that Alternative 2, which involves rebuilding Transmission Line 94L from SCT Substation to BLK Substation in a revised right-of-way is the least-cost alternative.

Based on the NPV analysis, it is recommended to proceed with Alternative 2 to complete the Project, as it is the least-cost alternative for customers, while also providing additional benefits in the form of easier access for inspection and maintenance activities in the future.

4.0 REVISED PROJECT SCOPE AND COST

Based on the results of the NPV analysis above, Newfoundland Power proposes to revise the scope of the Project and proceed with the execution of Alternative 2.

The revised project scope for the Project involves rebuilding the new 66 kV transmission line in a new right-of-way. The new line will primarily be located roadside along Route 91, Route 81 and Route 100, with the majority of the line being constructed in a single-pole configuration.

Due to property constraints along Route 91 and Route 81, some structures on distribution feeders SCT-01 and BLK-01 will be replaced with new shared transmission and distribution structures. A project titled *Distribution Feeders SCT-01 and BLK-01 Relocation* has been included in Schedule B of the *2025 Capital Budget Application* detailing the cost and justification for this scope.

Once the new line has been constructed and energized, the existing Transmission Line 94L between BLK Substation and SCT Substation will be decommissioned.

The revised project scope for the Project is proposed to be completed as a multi-year project. In 2024, the 3.5 kilometre section of line leaving SCT Substation will be constructed as originally approved as a part of Newfoundland Power's *2022 Capital Budget Application*. In 2025, work will involve constructing approximately 12.5 kilometres of new line from SCT Substation to a point approximately 5 kilometres north of the Town of Colinet on Route 81. This will consist of engineering and construction activities, including securing environmental and development permits and approvals, acquiring property rights, completing brush clearing of the new right-of-way, collecting topographic data, finalizing the engineering design, and the construction of the new line. In 2026, the final 27.5 kilometres of line will be constructed along Route 81, Route 100, and the Trans-Canada Highway, connecting back into BLK Substation.

Table 5 provides a breakdown of the transmission cost to rebuild Transmission Line 94L.[8]

Table 5
Transmission Line 94L Rebuild Project Cost (2025-2026)
($000s)

Description	2025	2026	Total
Engineering	52	53	105
Labour - Contract	2,094	5,306	7,400
Labour - Internal	24	164	188
Material	903	2,321	3,224
Other	412	1,231	1,643
Total	3,485	9,075	12,560

The new cost of the revised transmission scope for the Project is estimated to be $12,560,000, including $3,485,000 in 2025 and $9,075,000 in 2026.

5.0 CONCLUSION

Recent increases in contractor pricing have significantly increased costs associated with completing the approved Project. To ensure that the scope of the Project remains the least-cost alternative for customers, Newfoundland Power completed a project review and analysis of alternatives to investigate other available options for this project. Following the completion of this alternative analysis, the Company determined that changing the routing of Transmission Line 94L to be constructed primarily roadside between SCT Substation and BLK Substation would be the least-cost alternative for customers.

8 Costs related to the under-build component of the Project are not included in Table 5. They can be found in Schedule B under the *Distribution Feeders SCT-01 and BLK-01 Relocation* project.

4.1 Mount Carmel Pond Dam Refurbishment

June 2024

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TABLE OF CONTENTS

1.0 INTRODUCTION

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") Mount Carmel Pond spillway and outlet gate are part of the Cape Broyle – Horse Chops hydroelectric development (the "CBHC Development") and are located on the Avalon Peninsula in the town of Cape Broyle and surrounding area. The CBHC Development consists of two (2) generating plants: the Cape Broyle hydroelectric generating plant (the "Cape Broyle Plant"); and the Horse Chops hydroelectric generating plant (the "Horse Chops Plant").[1]

The Cape Broyle Plant was commissioned in 1954 with a capacity of 7.0 MVA under a net head of approximately 54.8 metres. The Cape Broyle Plant contains a single vertical 7,500 hp Francis turbine manufactured by Canadian Vickers which is coupled to a Westinghouse generator.[2] The Cape Broyle Plant is connected to the Island Interconnected System at Cape Broyle Substation and has provided 70 years of reliable energy production.

The Horse Chops Plant was commissioned in 1954 with a capacity of 9.0 MVA under a net head of approximately 85.3 metres. The Horse Chops Plant contains a single vertical 10,000 hp Francis turbine manufactured by Dominion Engineering which is coupled to a Canadian General Electric generator. The Horse Chops Plant is connected to the Island Interconnected System at Horse Chops Substation and has provided 70 years of reliable energy production.

The Mount Carmel Pond spillway and outlet gate were installed in 1954 and are original to the CBHC Development. The outlet gate requires manual operation by hydro plant operations staff, as no electricity for controls equipment is present at the site. The spillway and outlet gate have been in service for 70 years. The spillway structure became damaged by ice loading during the 2022/2023 winter season and can no longer operate at the designed operating level.

In 2025, the Company is proposing to replace the deteriorated spillway structure and automate the outlet gate at Mount Carmel Pond. By replacing the spillway structure and automating the outlet gate, Newfoundland Power will ensure reliable winter capacity and energy availability into the future. The project includes: (i) replacement of the overflow spillway structure; (ii) enhancements to the public safety infrastructure; and (iii) automation of the outlet gate including gate replacement.

The *Mount Carmel Pond Dam Refurbishment* project is estimated to cost $3,608,000 in 2025 and $1,008,000 in 2026.[3]

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1 The Cape Broyle Plant and the Horse Chops Plant operate in series. Water is first utilized for electricity generation at the Horse Chops Plant before flowing downstream to the Cape Broyle Plant.

2 A turbine converts potential energy from pressurized water into rotational mechanical energy. A generator converts rotational mechanical energy into electrical energy.

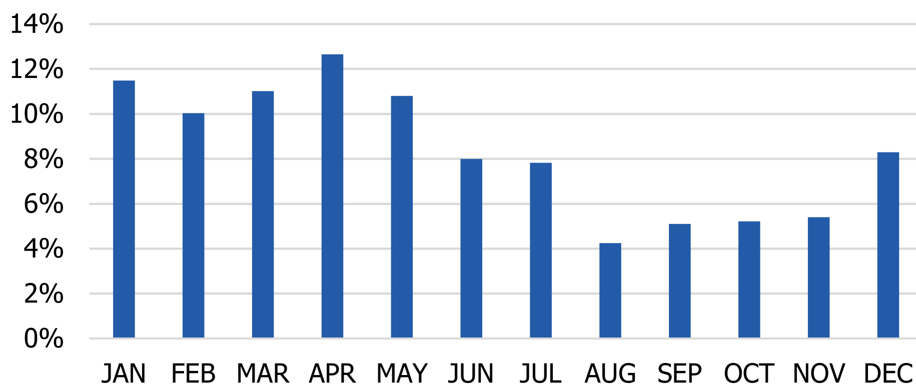
3 Newfoundland Power will also submit distribution and telecommunications capital projects in its *2026 Capital Budget Application* valued at approximately $1,500,000 and $125,000 respectively to allow for full automation of the outlet gate at Mount Carmel Pond.

2.0 BACKGROUND

The normal production of the Cape Broyle Plant is approximately 34.94 GWh, or 8.0% of the total normal hydroelectric production of Newfoundland Power. The normal production of the Horse Chops Plant is approximately 46.70 GWh, or 10.7% of the total normal hydroelectric production of Newfoundland Power.[4] Combined, the CBHC Development accounts for approximately 81.64 GWh, or 18.7% of the total normal hydroelectric production of Newfoundland Power. Both the Cape Broyle Plant and the Horse Chops Plant are typically operated during all twelve (12) months of the year.

Figure 1 shows the average production of the CBHC Development by month based on the most recent five-year average.[5]

Figure 1
Cape Broyle and Horse Chops Average Annual Production
(Percentage by Month)



The Cape Broyle Plant and the Horse Chops Plant are operated throughout the year as a source of low-cost energy for Newfoundland Power's customers. They are also routinely placed into service at the request of Newfoundland and Labrador Hydro ("Hydro").[6] These requests are most often received during the winter peak period, although non-peak operation is also requested.

Production from the CBHC Development has typically been highest from the months of December through May. This corresponds to when customer load and capacity constraints are greatest on the Island Interconnected System.

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4 Newfoundland Power retained Hatch in 2020 to conduct an updated *Hydro Normal Production Review*. The review was completed in April 2021, setting the annual production for the Cape Broyle Plant at 34.94 GWh and the Horse Chops Plant at 46.70 GWh.

5 Figure 1 is comprised of the summation of the average monthly production from both the Cape Broyle Plant and the Horse Chops Plant from 2019 through year end 2023.

6 From 2019 through 2023, Hydro requested generation 104 times for the Avalon Peninsula hydro plants, and 406 times for all Island hydro plants.

The Mount Carmel Pond Dam, along with the associated spillway and gate structure, was placed into service in 1954 and is original to the CBHC Development. Mount Carmel Pond Dam is the furthest upstream water control structure in the CBHC Development watershed and controls the flow of water to both the Horse Chops Plant and the Cape Broyle Plant. Mount Carmel Pond also provides approximately 86% of the energy storage available in the development.[7]

The spillway structure consists of a concrete foundation, steel rock anchors, vertical steel stop log supports, timber stop logs, steel walkway complete with steel handrail and timber decking, and concrete abutments complete with chain link fencing. The downstream side of the spillway is lined with riprap for erosion protection.[8] The outlet gate was installed in 1954 and is original to the CBHC Development. The outlet gate requires manual operation by hydro plant operations staff as no electricity for controls equipment is present at the site. The spillway and outlet gate have been in service for 70 years.

3.0 CONDITION ASSESSMENT

3.1 General

Newfoundland Power became aware of damage to the spillway structure in the spring of 2023. During the 2022/2023 winter operating season, ice loading occurred on the structure's timber stop logs and vertical steel stoplog supports which exceeded the design capacity of the structure. The vertical supports yielded to the stress and deformed in the downstream direction. The condition assessment summarizes information collected by Newfoundland Power personnel at the site since the damage occurred.

3.2 Spillway Civil Works

Riprap

When flood waters flow over the spillway, turbulent water occurs downstream. Riprap is placed downstream in the flood channel as well as on the abutments to mitigate erosion of the downstream toe of the spillway structure or abutments, which could compromise the stability of the spillway. The riprap at Mount Carmel Pond spillway is comprised of blasted rock and is in good condition with little to no displacement.

7 Mount Carmel Pond storage is approximately 17.0 GWh of the total 19.8 GWh storage in the CBHC Development.

8 Riprap is a form of stone armoring applied to structures intended to protect the structures from erosion or scouring by water flow or wave action.

Figure 2 shows the condition of abutment riprap at Mount Carmel Pond spillway.

Figure 2 – Abutment Riprap

Abutments

Abutments are a transition zone between the spillway and the embankment dam. The abutments direct water back into the spillway structure such that erosion of the embankment does not occur. The spillway abutments are constructed of steel reinforced cast in place concrete. The abutments are in good condition with no spalling or chipping of the concrete.

The abutments are also equipped with chain link fencing to restrict access to the spillway structure, protecting the public from danger when high flow rates are occurring over the spillway. The chain link fencing is in good condition with no visible signs of damage or deterioration.

Figures 3 and 4 show the condition of the abutments.

Figure 3 – Left Abutment

Figure 4 – Right Abutment

Timber Stop Logs

The spillway design utilizes wooden stop logs to control the release of water. The stop logs are six (6) inch high by three (3) inch thick rectangular horizontal timber logs. The stop logs bays are approximately 2.5 metres in length, with the bays adjacent to the abutments being shorter. Timber stop logs are routinely replaced when their condition deteriorates to ensure that they are maintained in working condition. The timber stop logs are in good condition.

Figure 5 shows a detailed view of stoplog condition at Mount Carmel Pond spillway.

Figure 5 – Stoplogs at Mount Carmel Pond spillway

Stop Log Supports

The stop log supports are steel I-shaped structural members embedded into the concrete foundation. They are the primary method of load transfer from the timber stop logs to the concrete foundation. Loading on the spillway structure from water, ice and wind is transferred from the wooden stop logs onto the stop log supports.

The stop log supports also function as structural support for the walkway above. The stop log supports have yielded and bent in the downstream direction from excessive ice loading along the entire length of the spillway structure. The stop log supports can no longer resist the applied loading required for safe operation of the spillway structure. The stop log supports are in poor condition and have failed in service.

Figure 6 shows a damaged stop log support observed at Mount Carmel Pond spillway.

Figure 6 – Damaged Stoplog Support

Walkway

The design of the Mount Carmel Pond spillway stop logs requires manual removal by operations staff. To accomplish this, a walkway has been provided to traverse the spillway structure and remove the timber stop logs installed between the vertical stop log supports. The walkway is supported on the vertical stop log supports.

Due to the yielding of the stop log supports, the walkway has tilted in the downstream direction. The walkway is in poor condition and is no longer safe for staff to perform stop log removal activities.

Figure 7 shows deflection of the walkway.

Figure 7 – Walkway deflection

Foundation

The spillway foundation structure transfers the loading applied to the stop log supports into the underlying bedrock. The spillway foundation consists of steel reinforced cast in place concrete with steel rock anchors. The cast in place concrete uses mass to counteract the applied forces on the structure, while the steel rock anchors add to this stability. The steel rock anchors are embedded in the concrete foundation and penetrate the underlying bedrock through a series of grouted boreholes. The concrete foundation is in poor condition near the embedded stop log supports where large portions of the concrete have cracked and fallen off due to the deformation of the supports in the downstream direction.

Figure 8 shows an example of foundation damage in the vicinity of the stop log supports.

Figure 8 – Foundation Damage

3.3 Outlet Gate Structure

Gatehouse

The gatehouse structure protects the gate hoist mechanism from the elements (wind, rain and ice). The gatehouse consists of a concrete foundation, timber framed walls, roof truss, vinyl siding, asphalt shingles and entrance door. The gatehouse is in good condition and was replaced in 2020.

Figure 9 shows the exterior of the gatehouse.

Figure 9 – Exterior of Gatehouse

Outlet Gate

The outlet gate allows for the water stored in Mount Carmel Pond to be discharged downstream to feed both the Horse Chop Plant and the Cape Broyle Plant. The outlet gate consists of the gate itself and the gate operating mechanism. Both the gate and gate operator are original to the CBHC Development having been installed in 1954. The gate operator is manually operated and has been modified to allow for operation utilizing a gas-powered drill. The outlet gate system is in poor condition and is not suitable for future automation.

Figure 10 shows the outlet gate operating mechanism.

Figure 10 – Outlet Gate Operator

4.0 RISK ASSESSMENT

The Mount Carmel Pond spillway is in poor condition. The stop log supports can no longer resist the applied loading from water and ice on the structure, removal of the timber stop logs is necessary to prevent further damage to the spillway structure. Removing the stop logs will result in the loss of 1.2 metres of storage in the Mount Carmel Pond reservoir. The storage in the Mount Carmel Pond reservoir provided by 1.2 metres of spillway stop logs equates to 3.49 GWh.

Traditionally, Newfoundland Power has managed water in the CBHC Development such that energy production has been optimized over the calendar year. By producing energy year-round when water is available, limited usage of this 1.2 metres has been required. Due to the current and future capacity restrictions on the Island Interconnected System, Newfoundland Power is in the process of modifying its hydro plant operations to prioritize system capacity support. To provide increased capacity support, Newfoundland Power has begun to optimize storage in its largest reservoirs entering into the winter season, including Mount Carmel Pond. Due to the changing climatic conditions experienced in Newfoundland and Labrador, mid-winter rainfall events have provided Newfoundland Power with the ability to recharge reservoirs throughout the winter season.

Recharging of the reservoir mid-winter provides additional capacity benefits. If a winter season rainfall event allows for recharge of the reservoir, an additional 3.49 GWh would be achieved, increasing the available capacity assistance to 6.98 GWh to be used during winter on-peak events. Using the marginal cost methodology, the value of this storage varies between $770,000 and $1,920,000 annually over a 10-year period depending upon the year and the availability of winter reservoir recharges as described above.

To enable precise discharge of water from the Mount Carmel Pond reservoir and maximize winter on-peak generation, automation of the outlet gate is necessary. Twice daily operation of the outlet gate will be required to operate the Mount Carmel Pond reservoir to maximize winter on-peak generation which is not practical via manual operation. The Mount Carmel Pond reservoir is remotely located, and requires staff members to travel to the site via off-road vehicles during the winter season.[9]

5.0 LIFECYCLE COST ANALYSIS

A condition assessment and corresponding risk assessment determined that the Mount Carmel Pond dam requires refurbishment. A lifecycle cost analysis has been completed and confirms that continued operation of the CBHC Development will provide economic benefit for Newfoundland Power's customers over the longer term.

Table 1 summarizes the results of the updated lifecycle cost analysis of the CBHC Development.

Table 1
CBHC Development Lifecycle Cost Analysis Results

	50 Year Levelized Value	Net benefit
Lifecycle Cost of the Development	2.65 ¢/kWh	-
Cost of Replacement Production (Run-of-River)	9.77 ¢/kWh	7.12 ¢/kWh
Cost of Replacement Production (Fully Dispatchable)	9.93 ¢/kWh	7.28 ¢/kWh

The analysis shows the CBHC Development's production provides a net benefit for customers of between 7.12 ¢/kWh and 7.28 ¢/kWh. The cost of replacement production would need to be reduced by approximately 73% in both cases to be less than the cost of operating the CBHC Development. The differences between costs and benefits suggest any reasonable variance in

[9] A return trip to Mount Carmel Pond from the Mobile District Building takes approximately two (2) hours. The Mobile District Building is the operations centre for the seven (7) hydro plants on the Southern Shore of the Avalon Penninsula.

the estimates will support continued operation of the CBHC Development. Various sensitivity analyses have confirmed the economic benefit of the CBHC Development's production.[10]

6.0 ASSESSMENT OF ALTERNATIVES

6.1 General

A condition assessment and corresponding risk assessment determined that the Mount Carmel Pond dam contains deteriorated and failed equipment that needs to be replaced to ensure safe and reliable operation of the CBHC Development. A lifecycle cost analysis confirmed that continued operation of the CBHC Development will provide an economic benefit for Newfoundland Power's customers over the longer term.

Newfoundland Power identified and assessed two alternatives to address the deteriorated condition of the Mount Carmel Pond spillway: (i) replace the spillway and automate the outlet gate in 2025 and 2026; and (ii) reduce full supply level by 1.2 metres. The assessment of each alternative is detailed below.

6.2 Alternative 1: Replace Spillway and Automate Outlet Gate in 2025 and 2026

Alternative 1 involves replacing the Mount Carmel Pond spillway structure and automating the outlet gate in 2025 and 2026 for an estimated capital cost of $4,616,000.[11]

6.3 Alternative 2: Reduce Full Supply Level by 1.2 Metres

Alternative 2 involves removing the timber stop logs, steel stop log supports and steel walkway and refurbishing the concrete foundation. This option will decrease available annual winter on-peak generation between 3.49 GWh and 6.98 GWh resulting in lost generation capabilities valued at between $770,000 and $1,920,000 annually as described in section 4.0 above. Since the water impounded by the top 1.2 metres of the spillway structure is primarily used for winter on-peak generation, the marginal cost data for winter on-peak energy and capacity are used to value this storage. Using marginal cost methodology, the return period whereby the value of the storage surpasses the capital investment proposed in Alternative 1 is between three (3) and seven (7) years.

Since the design life of Alternative 1 is greater than 50 years, proceeding with Alternative 2 is not recommended.

7.0 PROJECT SCOPE

The assessment of alternatives determined that replacing the Mount Carmel Pond spillway and automation of the outlet gate in 2025 is necessary to address the deteriorated condition of the spillway structure and to maximize winter on-peak generation available to customers.

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10 See *Newfoundland Power's 2025 Capital Budget Application,* report 4.1 *Mount Carmel Pond Dam Refurbishment, Appendix A: Lifecycle Cost Analysis of the Cape Broyle – Horsechops Hydroelectric Development, Table A-4.*

11 Newfoundland Power will submit distribution and telecommunications capital projects in its *2026 Capital Budget Application* valued at approximately $1,500,000 and $125,000 respectively to allow for full automation of the outlet gate at Mount Carmel Pond.

The *Mount Carmel Pond Dam Refurbishment* project includes the replacement of the stop log spillway structure with a concrete overflow spillway complete with abutments and public safety features. As well, replacement of the outlet gate and installation of an electronic gate operator will be completed concurrently.

Design and procurement for the new spillway structure will be completed in the first quarter of 2025. Construction of the new spillway structure will be completed between the second and last quarter of 2025 prior to the winter season. Design and procurement to automate the outlet gate will be completed by the end of 2026. There will be no required generation unit outages associated with this project.

8.0 PROJECT COST

Table 2 provides a breakdown by category of the cost of the *Mount Carmel Pond Dam Refurbishment* project.

Table 2
Mount Carmel Pond Dam Refurbishment Project Budget
($000s)

Cost Category	2025	2026	Total Cost
Material	3,370	842	4,212
Labour – Internal	4	6	10
Labour – Contract	-	-	-
Engineering	162	54	216
Other	72	106	178
Total	$3,608	$1,008	$4,616

The *Mount Carmel Pond Dam Refurbishment* project is estimated to cost $4,616,000 including $3,608,000 in 2025 and $1,008,000 in 2026. Newfoundland Power will also submit distribution and telecommunications capital projects in its *2026 Capital Budget Application* valued at approximately $1,500,000 and $125,000 respectively to allow for full automation of the outlet gate at Mount Carmel Pond. These estimated costs are in addition to the budget provided in Table 2 above. The additional $1,625,000 required to complete this project in 2026 has been included in the life cycle cost analysis as well as the assessment of alternatives.

9.0 CONCLUSION

Condition assessments have determined that the Mount Carmel Pond spillway has components that have failed in service and are impeding normal operation of the reservoir. The assessment of alternatives confirms that replacing the spillway structure and automating the outlet gate provides significant benefit to customers.

The Mount Carmel Pond reservoir is a critical asset to the operation of the CBHC Development and its ability to support winter on-peak capacity requests. A lifecycle cost analysis confirms that continued operation of the CBHC Development, including the cost of the replacement spillway and outlet gate automation, will provide an economic benefit for customers over the longer term.

APPENDIX A:

Lifecycle Cost Analysis of the Cape Broyle – Horse Chops Hydroelectric Development

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1.0 INTRODUCTION

This lifecycle evaluation examines the future viability of generation at Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") Cape Broyle – Horse Chops hydroelectric development (the "CBHC Development"). The continued long-term operation of the CBHC Development is reliant on the completion of capital improvements in 2025, 2026, and beyond.

This evaluation compares the cost of continued operation of the CBHC Development to the cost of replacement production. The analysis includes a study period of 50 years, the expected service life of the generator, and expresses the results in terms of the levelized cost of energy. It also provides sensitivity analyses that examine the sensitivity of the results to changes in assumptions.

2.0 LIFECYCLE COSTS

2.1 Capital Costs

Table A-1 provides all significant capital expenditures for the CBHC Development over the next 50 years.

Table A-1
CBHC Development
Capital Expenditures
($000s)

Year	Expenditure
2025	3,608
2026	2,633
2027	2,025
2028	3,900
2029	3,100
2030	1,950
2031	400
2036	1,500
2058	2,150
2062	4,450
2070	4,600
Total	$30,316

The estimated capital expenditure for the CBHC Development is $30,316,000 over the next 50 years. These capital expenditures include the expenditures proposed for 2025, 2026, and future capital expenditures.

Attachment A provides a comprehensive breakdown of capital costs.

2.2 Operating Costs

Annual operating costs for the CBHC Development, including water rental fees, are estimated to be approximately $579,000 per year. The operating cost represents both direct charges for operations and maintenance at the CBHC Development, as well as indirect costs such as those related to managing the environment, safety, dam safety inspections, and staff training. The annual water rental fee is forecasted to be approximately $260,000 for 2025. This fee, adjusted for inflation, will be paid annually to the Provincial Government based on the Plant's production.

Attachment B provides a summary of operating costs.

2.3 Cost of Spill During Construction

Spill is not anticipated to occur as part of the work proposed in the application.

3.0 COST OF PLANT DOWNTIME

3.1 General

If the refurbishment project does not proceed as proposed, there is risk that the CBHC Development will be out of service for a prolonged period due to equipment failure and potential safety hazards. Taking the CBHC Development out of service will result in replacing its production with additional power from Newfoundland and Labrador Hydro ("Hydro"). The cost to replace the production from the CBHC Development consists primarily of: (i) marginal energy costs; and (ii) the potential need to add generation capacity.

Table A-2 provides a breakdown of the normal production of the CBHC Development.

Table A-2
Normal Production from the CBHC Development

Marginal Cost Period	Normal Production (GWh)	Production (%)
Non-Winter Period (All hours)	48.17	59
Winter Period		
On-Peak	16.33	20
Off-Peak	17.14	21
Annual Production	81.64	100

3.2 Marginal Energy Cost

The Island Interconnected System is connected to the North American power grid through the Labrador Island Link ("LIL") and the Maritime Link. An updated marginal cost study (the "Marginal Cost Update") completed by Hydro in 2023 provides estimates of the marginal energy cost as the opportunity cost of selling energy to other jurisdictions.[1] The marginal energy cost estimates vary by time of day and by season. To recognize these time-varying characteristics, the costs are summarized by winter on-peak, winter off-peak and non-winter peak periods.

Attachment C provides the forecast marginal energy costs for the period 2024 to 2042.

3.3 Cost of Replacement Capacity

The Island Interconnected System's need for new capacity additions is being reviewed by the Board of Commissioners of Public Utilities. Removing the Plant from service would reduce the capacity available to supply customers and increase the need for new generation sources.[2]

The Marginal Cost Update provides estimates of the marginal cost of generation capacity for the Island Interconnected System in terms of cost per MWh and cost per kW of peak demand.

The CBHC Development can provide 14.5 MW of capacity during the winter. The cost of replacement capacity is dependent on the extent to which this capacity is available to meet peak load conditions. This is impacted by the amount of storage, the timing of rainfall, how the plants are dispatched, the volume of requests by Hydro to maximize generation and the potential that the plants are out of service when required to meet increased customer demand.

To assess the cost of replacement capacity, Newfoundland Power completed an evaluation under two assumptions: (i) assuming the CBHC Development's production reflects a run-of-river hydro plant; and (ii) evaluating the CBHC Development as a fully dispatchable plant.

A run-of-river plant has little storage and provides minimum flexibility for the Company to schedule production for periods of greatest value.[3] The capacity from a run-of-river plant is dependent on the extent to which timing of the river flow will correspond to periods when the cost of capacity is the greatest. Evaluation of a run-of-river plant is completed by applying the production for each marginal cost time period to the appropriate marginal generation capacity cost.

Fully dispatchable generation, on the other hand, has sufficient storage to allow it to produce at its full rated capacity for all potential periods of need. This would be similar to a gas turbine, which can be dispatched at any time to provide its rated capacity to support customer demand.

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[1] The most recent marginal cost study results are found in Hydro's Marginal Cost Update, dated October 2023. The marginal cost study covers the period from 2024 to 2042.

[2] In its *Reliability and Resource Adequacy Study – 2022 Update* Hydro stated that "Regardless of the assumptions made for the Island Interconnected System load growth, the LIL capacity and bipole forced outage rate, the Island Interconnected System will be significantly capacity constrained once the Holyrood TGS and the Hardwoods Gas Turbine are retired." See *Reliability and Resource Adequacy Study – 2022 Update, Volume III, Long Term Resource Plan*, page 51, lines 25-27.

[3] As examples, periods of greatest value for production include during generation shortages and peak demand periods.

The capacity of a fully dispatchable plant is primarily reflective of its rated capacity and the likelihood it is not available for service.

Newfoundland Power's hydro generation facilities operate between being run-of-river and fully dispatchable generation plants. The Plant has total available storage of approximately 19.8 GWh. This level of storage represents approximately 56 days of production at a production rate of 14.5 MW. However, storage levels are often not full, and there are practical limitations to managing the flow of water from storage to the forebay. These practical considerations limit the Company's ability to maintain continuous production at rated capacity for extended periods of time.[4]

4.0 LIFECYCLE ANALYSIS RESULTS

4.1 Base Case Analysis

An analysis has been completed comparing the lifecycle costs of the CBHC Development to the cost of replacement production over a 50-year study period. The Marginal Cost Update covers the period from 2024 to 2042. As a result, there is no forecast of marginal costs beyond this period. For the purposes of the 50-year study period, the Company has used the GDP Deflator to escalate marginal cost for the remaining years of the 50-year study period. To deal with the uncertainty of future marginal costs, the Company has prepared five sensitivity analyses with different approaches to estimate future marginal cost to confirm the robustness of the lifecycle cost analysis.

The costs are presented on a levelized cost of energy approach. The levelized cost of energy expresses the costs and benefits in terms of a ¢/kWh of production.

[4] During periods of low water availability, such as during the summer months, generation capacity from the Plant will be limited and reflect a run-of-river system. During periods with greater water availability, such as during the spring and fall, generation capacity from the Plant will be high and reflect a fully dispatchable system. Since, at certain times of the year, the Plant operates as either a run-of-river system or a fully dispatchable system, the lifecycle analysis includes the value of capacity under both scenarios to assess the lowest and highest value of capacity from the Plant.

Table A-3 compares the estimated levelized costs of the Plant's production and the cost of replacement production.

Table A-3
Lifecycle Analysis Results

	50 Year Levelized Value[5]	Net benefit
Lifecycle Cost of the Development	2.65 ¢/kWh	
Cost of Replacement Production (Run-of-River)		
Energy Costs	3.97 ¢/kWh	
Capacity Costs	5.80 ¢/kWh	
Total	9.77 ¢/kWh	7.12 ¢/kWh
Cost of Replacement Production (Fully Dispatchable)		
Energy Cost	3.97 ¢/kWh	
Capacity Cost	5.96 ¢/kWh	
Total	9.93 ¢/kWh	7.28 ¢/kWh

The cost to replace CBHC Development's production will exceed the CBHC Development's cost by between 7.12 ¢/kWh and 7.28 ¢/kWh. In order for the replacement production costs to be less than the CBHC Development's costs, the production replacement costs would need to be reduced by approximately 73% in both the run-of-river and fully dispatchable assumptions. The large differences between costs and benefits suggest any reasonable variance in the estimates of the costs and benefits will support the continued operation of the CBHC Development.

This evaluation compares the cost of continued operation of the CBHC Development to the cost of replacing CBHC Development's production. If the life extension of the CBHC Development was determined to be costlier than the cost of replacement production, then further analysis would be required to assess the cost of decommissioning through mothballing or dismantling the CBHC Development. The present value of these costs would be incremental to the cost of replacement production.

Attachment D provides the detailed results of the calculated levelized costs and benefits.[6]

[5] See *Newfoundland Power's 2025 Capital Budget Application,* report *4.1 Mount Carmel Pond Dam Refurbishment, Appendix A: Lifecycle Cost Analysis of the Cape Broyle – Horse Chops Hydroelectric Development, Attachment D: Calculation of Levelized Costs and Benefits,* pages D1-D6.

[6] The financial assumptions used in the economic evaluation are provided in Attachment E.

4.2 Sensitivity Analysis

To illustrate the robustness of the conclusion that continued operation is in the economic best interest of customers, the following scenarios were included in a sensitivity analysis:

(i) *Scenario 1A: Uncertainty with marginal costs beyond 2040*
Assumes the Plant ceases production in 2041 in consideration of the expiration of the Churchill Falls contract in 2041.[7]

(ii) *Scenario 1B: Uncertainty with marginal costs beyond 2042*
Assumes the marginal energy and capacity costs for the years after 2042 will remain at the same amount as the 2042 forecast with no escalation.

(iii) *Scenario 1C: Uncertainty with marginal costs beyond 2042*
Assumes the marginal energy for the years after 2042 will remain at the same amount as the 2042 forecast with no escalation, and capacity costs for the years after 2042 escalated using the GDP Deflator.

(iv) *Scenario 2: Uncertain accuracy of Hydro's marginal capacity cost*
Assumes Hydro's marginal capacity costs decrease by 25%.

(v) *Scenario 3: Uncertain accuracy of Hydro's marginal energy cost*
Assumes Hydro's marginal energy costs decrease by 25%.

[7] This scenario tests whether the operation of the CBHC Development remains economic if the Development ceases production in 2041.

Table A-4 shows comparison of the present value of the CBHC Development's operations to the present value of replacement production for the base case and each scenario.

Table A-4
Present Value Sensitivity Analysis Results
($2025)

Scenario	Cost of Continued Operation ($M)	Cost of Replacement Production		Net Savings ($M)
		Run-of-River ($M)	Fully Dispatchable ($M)	
Base Case[8]	31.3	115.2	117.0	83.9 – 85.7
Scenario 1A	19.6	65.7	66.8	46.1 – 47.2
Scenario 1B	31.3	106.6	108.3	75.3 – 77.0
Scenario 1C	31.3	111.9	113.7	80.6 – 82.4
Scenario 2	31.3	98.1	99.5	66.8 – 68.2
Scenario 3	31.3	103.5	105.3	72.2 – 74.0

The sensitivity analysis shows that the cost of continuing to operate the CBHC Development will provide an economic benefit under all scenarios.

5.0 CONCLUSION

The results indicate that continued operation of the Cape Broyle – Horse Chops hydroelectric development is economically justified under current forecast capital, operating, marginal energy and capacity costs. Continued operation is also justified within reasonable variations in costs, including uncertainty of marginal costs.

[8] The base case provides the results of the levelized costs provided in Table A-3 expressed as present value of costs as opposed to the levelized cost per kWh.

Attachment A:

Summary of Capital Costs

Table A-1
CBHC Development Economic Analysis
Summary of Capital Costs (2025-2074)
($000s)

Description	2025	2026	2027	2028	2029	2030	2031	2036	2058	2062	2070
Civil											
Dam, Spillways and Gates	3,608	1,008	1,625			400	400				
Penstock and Surge Tank				900	2,300				1,000	2,000	
Access Road and Bridges											
Powerhouse			200			300					600
Mechanical											
Turbine				600		1,250			550	1,800	
Powerhouse Systems									300	300	
Electrical											
Generator Refurbishment				1,400							
Control Systems											
Switchgear			150	700	600						
Protection and Control Systems			50	300	200				300	350	
Other											
Substation								1,500			1,500
Transmission Line											2,500
Distribution Line		1,500									
Communications		125									
Total ($2025)	$3,608	$2,633	$2,025	$3,900	$3,100	$1,950	$400	$1,500	$2,150	$4,450	$4,600

Attachment B:

Summary of Operating Costs

Table B-1
CBHC Development
Economic Evaluation
Summary of Operating Costs
($2025)

Year	Amount
2019	381,313
2020	333,554
2021	304,927
2022	282,967
2023	294,258
Average[1]	$319,404
Water Power Rental[2]	259,615
Total Average Operating Cost	$579,019

1 Cost excludes the water power rental rate.
2 Calculated using the Provincial Government's current water rental rate ($3.00/MWh in 2023 escalated using CPI All Items for Canada) multiplied by the normal annual output of the plant.

Attachment C:

Marginal Costs Estimates

Table C-1
Marginal Cost Projections 2024-2042[1]
Island Interconnected System
At Hydro's Delivery Point to Newfoundland Power

Year	Energy Supply Costs			Generation and Transmission Capacity Costs			
	Winter		Non-Winter	Winter		Non-Winter	
	On-Peak	Off-Peak	All-Hours	On-Peak	Off-Peak	All-Hours	Annual
	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/kW·yr
2024	144.89	124.50	34.21	150.28	58.46	2.58	304.72
2025	122.40	103.38	29.95	152.86	59.46	2.63	309.94
2026	84.71	69.40	27.05	155.48	60.48	2.67	315.26
2027	62.51	48.76	25.44	158.15	61.52	2.72	320.67
2028	61.38	49.95	28.39	160.87	62.58	2.76	326.17
2029	58.98	50.29	26.72	163.64	63.65	2.81	331.78
2030	54.00	45.47	24.56	166.46	64.75	2.86	337.49
2031	50.59	42.25	22.02	169.33	65.86	2.91	343.30
2032	50.15	41.23	24.48	172.25	66.99	2.96	349.22
2033	54.66	45.96	23.64	175.23	68.15	3.01	355.24
2034	56.49	48.31	25.09	178.26	69.32	3.06	361.38
2035	51.38	45.86	24.66	181.34	70.52	3.11	367.62
2036	48.29	44.00	24.46	184.48	71.74	3.16	373.98
2037	48.29	44.37	22.08	187.68	72.98	3.22	380.46
2038	46.48	43.57	23.88	190.93	74.24	3.27	387.05
2039	49.04	46.26	21.40	194.25	75.53	3.33	393.76
2040	47.51	47.53	21.41	197.62	76.84	3.39	400.60
2041	56.70	57.20	25.62	201.06	78.18	3.44	407.56
2042	55.23	55.45	26.18	204.56	79.53	3.50	414.65

[1] 2024-2042 based on the marginal cost projections provided by Hydro in the summary report, Marginal Cost Update, dated October 2023.

Attachment D:

Calculation of Levelized Costs and Benefits

Table D-1
Calculation of Levelized Costs

	PV Costs[1] ($000)	Levelized Annual Cost ($000)	Annual Production (GWh)	Levelized Unit Cost (¢/kWh)
Lifecycle Cost of Plant	31,284	2,167	81.64	2.65
Cost of Replacement Production (Run-of-River)				
Energy Cost	46,840	3,245	81.64	3.97
Capacity Cost	68,342	4,734	81.64	5.80
Total	115,182	7,979		9.77
Cost of Replacement Production (Fully Dispatchable)				
Energy Cost	46,840	3,245	81.64	3.97
Capacity Cost	70,181	4,861	81.64	5.96
Total	117,021	8,106		9.93

1 See Cumulative Present Value at 50-year life on pages D-2 to D-5.

Table D-2
Present Worth Analysis of the Lifecycle Cost of the CBHC Development

Production Year	Year	Generation Hydro 65.7 yrs 8% CCA	Generation Hydro 65.7 yrs 100% CCA	Transmission 51.9 yrs 8% CCA	Substation 48.5 yrs 8% CCA	Distribution 52.9 yrs 8%CCA	Capital Revenue Requirement	Operating Costs	Spillage Cost	Net Benefit	Present Worth Benefit	Cumulative Present Value Benefit
0	2025	3,608,000	0	0	0	0	330,080	579,019	0	-909,099	-909,099	-909,099
1	2026	1,133,000	0	0	0	1,500,000	600,698	588,448	0	-1,189,146	-1,114,999	-2,024,097
2	2027	2,025,000	0	0	0	0	798,082	598,816	0	-1,396,898	-1,228,126	-3,252,224
3	2028	3,900,000	0	0	0	0	1,153,041	609,162	0	-1,762,203	-1,452,691	-4,704,915
4	2029	3,100,000	0	0	0	0	1,444,422	620,103	0	-2,064,525	-1,595,794	-6,300,708
5	2030	2,126,470	0	0	0	0	1,629,678	631,419	0	-2,261,097	-1,638,758	-7,939,466
6	2031	444,119	0	0	0	0	1,645,170	642,883	0	-2,288,054	-1,554,895	-9,494,361
7	2032	0	0	0	0	0	1,602,688	654,557	0	-2,257,245	-1,438,311	-10,932,672
8	2033	0	0	0	0	0	1,557,576	666,278	0	-2,223,854	-1,328,677	-12,261,349
9	2034	0	0	0	0	0	1,514,403	678,034	0	-2,192,436	-1,228,229	-13,489,578
10	2035	0	0	0	0	0	1,473,013	690,077	0	-2,163,089	-1,136,229	-14,625,807
11	2036	0	0	0	1,819,632	0	1,605,112	702,401	0	-2,307,513	-1,136,514	-15,762,321
12	2037	0	0	0	0	0	1,584,779	714,855	0	-2,299,634	-1,062,010	-16,824,330
13	2038	0	0	0	0	0	1,541,977	727,510	0	-2,269,487	-982,735	-17,807,065
14	2039	0	0	0	0	0	1,500,720	740,394	0	-2,241,114	-909,938	-18,717,003
15	2040	0	0	0	0	0	1,460,883	753,581	0	-2,214,465	-843,055	-19,560,058
16	2041	0	0	0	0	0	1,422,355	766,980	0	-2,189,334	-781,517	-20,341,575
17	2042	0	0	0	0	0	1,385,029	780,607	0	-2,165,635	-724,854	-21,066,430
18	2043	0	0	0	0	0	1,348,809	794,505	0	-2,143,314	-672,652	-21,739,081
19	2044	0	0	0	0	0	1,313,608	808,697	0	-2,122,304	-624,527	-22,363,608
20	2045	0	0	0	0	0	1,279,343	823,153	0	-2,102,496	-580,120	-22,943,729
21	2046	0	0	0	0	0	1,245,940	837,820	0	-2,083,760	-539,100	-23,482,829
22	2047	0	0	0	0	0	1,213,330	852,748	0	-2,066,078	-501,196	-23,984,025
23	2048	0	0	0	0	0	1,181,449	867,943	0	-2,049,391	-466,149	-24,450,175
24	2049	0	0	0	0	0	1,150,239	883,408	0	-2,033,646	-433,725	-24,883,900
25	2050	0	0	0	0	0	1,119,646	899,148	0	-2,018,794	-403,711	-25,287,611
26	2051	0	0	0	0	0	1,089,621	915,169	0	-2,004,790	-375,912	-25,663,523
27	2052	0	0	0	0	0	1,060,119	931,476	0	-1,991,594	-350,153	-26,013,676
28	2053	0	0	0	0	0	1,031,097	948,073	0	-1,979,170	-326,271	-26,339,947
29	2054	0	0	0	0	0	1,002,518	964,965	0	-1,967,483	-304,121	-26,644,068
30	2055	0	0	0	0	0	974,345	982,159	0	-1,956,505	-283,567	-26,927,635
31	2056	0	0	0	0	0	946,547	999,659	0	-1,946,206	-264,486	-27,192,121
32	2057	0	0	0	0	0	919,093	1,017,471	0	-1,936,565	-246,766	-27,438,886
33	2058	3,845,368	0	0	0	0	1,245,665	1,035,600	0	-2,281,266	-272,563	-27,711,449
34	2059	0	0	0	0	0	1,247,775	1,054,053	0	-2,301,828	-257,872	-27,969,321
35	2060	0	0	0	0	0	1,209,752	1,072,834	0	-2,282,586	-239,771	-28,209,092
36	2061	0	0	0	0	0	1,172,539	1,091,950	0	-2,264,489	-223,038	-28,432,130
37	2062	8,541,615	0	0	0	0	1,921,757	1,111,406	0	-3,033,163	-280,120	-28,712,250
38	2063	0	0	0	0	0	1,950,295	1,131,209	0	-3,081,504	-266,839	-28,979,090
39	2064	0	0	0	0	0	1,889,722	1,151,365	0	-3,041,087	-246,919	-29,226,009
40	2065	0	0	0	0	0	1,830,983	1,171,880	0	-3,002,863	-228,613	-29,454,622
41	2066	0	0	0	0	0	1,773,932	1,192,761	0	-2,966,693	-211,776	-29,666,399
42	2067	0	0	0	0	0	1,718,434	1,214,013	0	-2,932,447	-196,279	-29,862,678
43	2068	0	0	0	0	0	1,664,364	1,235,644	0	-2,900,008	-182,005	-30,044,682
44	2069	0	0	0	0	0	1,611,608	1,257,661	0	-2,869,269	-168,847	-30,213,529
45	2070	1,326,454	0	5,526,892	3,316,135	0	2,521,702	1,280,070	0	-3,801,772	-209,772	-30,423,301
46	2071	0	0	0	0	0	2,572,496	1,302,878	0	-3,875,374	-200,500	-30,623,801
47	2072	0	0	0	0	0	2,489,679	1,326,093	0	-3,815,772	-185,107	-30,808,908
48	2073	0	0	0	0	0	2,409,296	1,349,721	0	-3,759,017	-170,983	-30,979,891
49	2074	0	0	0	0	0	2,331,152	1,373,771	0	-3,704,923	-158,015	-31,137,905
50	2075	0	0	0	0	0	2,255,068	1,398,249	0	-3,653,316	-146,098	-31,284,003

Table D-3 Present Value of the Cost of Replacement Energy (Reduced Exports)					
Production Year	Year	Marginal Energy Costs ($)	Total Present Worth ($)	Cumulative Present Worth ($)	Export Sales (¢/kWh)
0	2025	0	0	0	0.00
1	2026	3,875,973	3,634,293	3,634,293	4.75
2	2027	3,082,059	2,709,687	6,343,980	3.78
3	2028	3,226,274	2,659,614	9,003,595	3.95
4	2029	3,112,301	2,405,682	11,409,277	3.81
5	2030	2,844,038	2,061,252	13,470,529	3.48
6	2031	2,611,092	1,774,423	15,244,951	3.20
7	2032	2,705,124	1,723,698	16,968,649	3.31
8	2033	2,818,818	1,684,147	18,652,797	3.45
9	2034	2,959,192	1,657,774	20,310,571	3.62
10	2035	2,812,934	1,477,580	21,788,150	3.45
11	2036	2,720,916	1,340,126	23,128,276	3.33
12	2037	2,612,668	1,206,574	24,334,850	3.20
13	2038	2,655,790	1,150,013	25,484,863	3.25
14	2039	2,624,599	1,065,641	26,550,504	3.21
15	2040	2,622,042	998,221	27,548,725	3.21
16	2041	3,140,578	1,121,078	28,669,803	3.85
17	2042	3,113,679	1,042,172	29,711,975	3.81
18	2043	3,169,114	994,586	30,706,561	3.88
19	2044	3,225,723	949,228	31,655,789	3.95
20	2045	3,283,387	905,951	32,561,741	4.02
21	2046	3,341,890	864,598	33,426,339	4.09
22	2047	3,401,436	825,132	34,251,471	4.17
23	2048	3,462,043	787,468	35,038,938	4.24
24	2049	3,523,730	751,522	35,790,461	4.32
25	2050	3,586,516	717,218	36,507,679	4.39
26	2051	3,650,420	684,480	37,192,158	4.47
27	2052	3,715,463	653,235	37,845,394	4.55
28	2053	3,781,665	623,418	38,468,811	4.63
29	2054	3,849,047	594,961	39,063,772	4.71
30	2055	3,917,629	567,803	39,631,575	4.80
31	2056	3,987,434	541,885	40,173,459	4.88
32	2057	4,058,482	517,149	40,690,609	4.97
33	2058	4,130,796	493,543	41,184,152	5.06
34	2059	4,204,398	471,015	41,655,167	5.15
35	2060	4,279,312	449,515	42,104,682	5.24
36	2061	4,355,561	428,996	42,533,678	5.34
37	2062	4,433,169	409,414	42,943,092	5.43
38	2063	4,512,159	390,725	43,333,817	5.53
39	2064	4,592,556	372,890	43,706,707	5.63
40	2065	4,674,387	355,869	44,062,576	5.73
41	2066	4,757,675	339,625	44,402,201	5.83
42	2067	4,842,447	324,122	44,726,323	5.93
43	2068	4,928,730	309,327	45,035,651	6.04
44	2069	5,016,550	295,207	45,330,858	6.14
45	2070	5,105,935	281,732	45,612,590	6.25
46	2071	5,196,912	268,872	45,881,462	6.37
47	2072	5,289,511	256,599	46,138,062	6.48
48	2073	5,383,759	244,886	46,382,948	6.59
49	2074	5,479,687	233,708	46,616,656	6.71
50	2075	5,577,324	223,040	46,839,696	6.83

Table D-4
Present Value of the Cost of Replacement Capacity
(Run-of-River Assumption)

Production Year	Year	Marginal Capacity Costs ($)	Total Present Worth ($)	Cumulative Present Worth ($)	Avoided Generation Capacity (¢/kWh)
0	2025	0	0	0	0.00
1	2026	3,704,299	3,473,323	3,473,323	4.54
2	2027	3,767,878	3,312,647	6,785,969	4.62
3	2028	3,832,606	3,159,451	9,945,420	4.69
4	2029	3,898,504	3,013,384	12,958,804	4.78
5	2030	3,965,594	2,874,114	15,832,918	4.86
6	2031	4,033,899	2,741,321	18,574,239	4.94
7	2032	4,103,443	2,614,703	21,188,942	5.03
8	2033	4,174,248	2,493,971	23,682,912	5.11
9	2034	4,246,340	2,378,850	26,061,762	5.20
10	2035	4,319,742	2,269,077	28,330,839	5.29
11	2036	4,394,480	2,164,402	30,495,241	5.38
12	2037	4,470,579	2,064,588	32,559,830	5.48
13	2038	4,548,066	1,969,408	34,529,237	5.57
14	2039	4,626,968	1,878,644	36,407,881	5.67
15	2040	4,707,310	1,792,090	38,199,971	5.77
16	2041	4,789,122	1,709,551	39,909,523	5.87
17	2042	4,872,431	1,630,839	41,540,362	5.97
18	2043	4,959,179	1,556,375	43,096,737	6.07
19	2044	5,047,763	1,485,397	44,582,134	6.18
20	2045	5,137,999	1,417,675	45,999,810	6.29
21	2046	5,229,548	1,352,963	47,352,773	6.41
22	2047	5,322,728	1,291,205	48,643,978	6.52
23	2048	5,417,568	1,232,266	49,876,245	6.64
24	2049	5,514,098	1,176,018	51,052,262	6.75
25	2050	5,612,348	1,122,337	52,174,599	6.87
26	2051	5,712,349	1,071,106	53,245,705	7.00
27	2052	5,814,132	1,022,214	54,267,918	7.12
28	2053	5,917,728	975,553	55,243,472	7.25
29	2054	6,023,170	931,023	56,174,494	7.38
30	2055	6,130,491	888,525	57,063,019	7.51
31	2056	6,239,724	847,967	57,910,985	7.64
32	2057	6,350,903	809,260	58,720,245	7.78
33	2058	6,464,064	772,320	59,492,565	7.92
34	2059	6,579,241	737,066	60,229,631	8.06
35	2060	6,696,469	703,422	60,933,053	8.20
36	2061	6,815,787	671,313	61,604,366	8.35
37	2062	6,937,231	640,670	62,245,036	8.50
38	2063	7,060,838	611,426	62,856,462	8.65
39	2064	7,186,648	583,516	63,439,978	8.80
40	2065	7,314,700	556,881	63,996,858	8.96
41	2066	7,445,033	531,461	64,528,319	9.12
42	2067	7,577,689	507,202	65,035,521	9.28
43	2068	7,712,708	484,050	65,519,571	9.45
44	2069	7,850,133	461,955	65,981,525	9.62
45	2070	7,990,007	440,868	66,422,393	9.79
46	2071	8,132,373	420,744	66,843,137	9.96
47	2072	8,277,276	401,538	67,244,675	10.14
48	2073	8,424,760	383,210	67,627,885	10.32
49	2074	8,574,872	365,717	67,993,602	10.50
50	2075	8,727,660	349,024	68,342,626	10.69

Table D-5
Present Value of the Cost of Replacement Capacity
(Fully Dispatchable Assumption)

Production Year	Year	Effective Capacity (MW)[2]	Marginal Capacity Costs ($)	Total Present Worth ($)	Cumulative Present Worth ($)	Avoided Generation Capacity (¢/kWh)
0	2025	0.00	0	0	0	0.00
1	2026	12.07	3,804,079	3,566,882	3,566,882	4.66
2	2027	12.07	3,869,359	3,401,866	6,968,748	4.74
3	2028	12.07	3,935,817	3,244,534	10,213,282	4.82
4	2029	12.07	4,003,476	3,094,523	13,307,805	4.90
5	2030	12.07	4,072,359	2,951,493	16,259,298	4.99
6	2031	12.07	4,142,489	2,815,115	19,074,413	5.07
7	2032	12.07	4,213,891	2,685,080	21,759,493	5.16
8	2033	12.07	4,286,588	2,561,090	24,320,583	5.25
9	2034	12.07	4,360,605	2,442,862	26,763,446	5.34
10	2035	12.07	4,435,967	2,330,128	29,093,574	5.43
11	2036	12.07	4,512,701	2,222,630	31,316,203	5.53
12	2037	12.07	4,590,833	2,120,123	33,436,327	5.62
13	2038	12.07	4,670,389	2,022,376	35,458,702	5.72
14	2039	12.07	4,751,396	1,929,164	37,387,867	5.82
15	2040	12.07	4,833,883	1,840,277	39,228,144	5.92
16	2041	12.07	4,917,878	1,755,513	40,983,657	6.02
17	2042	12.07	5,003,411	1,674,679	42,658,336	6.13
18	2043	12.07	5,092,490	1,598,213	44,256,549	6.24
19	2044	12.07	5,183,456	1,525,328	45,781,877	6.35
20	2045	12.07	5,276,117	1,455,785	47,237,662	6.46
21	2046	12.07	5,370,127	1,389,333	48,626,995	6.58
22	2047	12.07	5,465,812	1,325,915	49,952,910	6.70
23	2048	12.07	5,563,202	1,265,392	51,218,302	6.81
24	2049	12.07	5,662,327	1,207,631	52,425,933	6.94
25	2050	12.07	5,763,218	1,152,507	53,578,440	7.06
26	2051	12.07	5,865,907	1,099,899	54,678,339	7.19
27	2052	12.07	5,970,426	1,049,693	55,728,032	7.31
28	2053	12.07	6,076,807	1,001,778	56,729,810	7.44
29	2054	12.07	6,185,084	956,050	57,685,860	7.58
30	2055	12.07	6,295,289	912,410	58,598,270	7.71
31	2056	12.07	6,407,459	870,761	59,469,031	7.85
32	2057	12.07	6,521,627	831,014	60,300,045	7.99
33	2058	12.07	6,637,829	793,081	61,093,126	8.13
34	2059	12.07	6,756,102	756,880	61,850,006	8.28
35	2060	12.07	6,876,482	722,331	62,572,337	8.42
36	2061	12.07	6,999,008	689,359	63,261,697	8.57
37	2062	12.07	7,123,716	657,892	63,919,589	8.73
38	2063	12.07	7,250,646	627,862	64,547,451	8.88
39	2064	12.07	7,379,838	599,202	65,146,653	9.04
40	2065	12.07	7,511,332	571,851	65,718,503	9.20
41	2066	12.07	7,645,169	545,748	66,264,251	9.36
42	2067	12.07	7,781,391	520,836	66,785,087	9.53
43	2068	12.07	7,920,040	497,062	67,282,149	9.70
44	2069	12.07	8,061,159	474,373	67,756,521	9.87
45	2070	12.07	8,204,793	452,719	68,209,241	10.05
46	2071	12.07	8,350,986	432,054	68,641,295	10.23
47	2072	12.07	8,499,784	412,332	69,053,627	10.41
48	2073	12.07	8,651,233	393,511	69,447,138	10.60
49	2074	12.07	8,805,380	375,548	69,822,687	10.79
50	2075	12.07	8,962,275	358,406	70,181,093	10.98

2 Effective Capacity reflects winter capacity and an allowance for a 5% forced outage rate and a 14% reserve margin.

Attachment E:

Economic Analysis Financial Assumptions

Economic Evaluation
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects a statutory income tax rate of 30%.

Operating Costs: Operating costs were assumed to be in 2025 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:		Capital Structure	Return	Weighted Cost
	Debt	55.00%	5.122%	2.82%
	Common Equity	45.00%	8.500%	3.83%
	Total	100.00%		6.65%

CCA Rates:	Class	Rate	Details
	17.1 & 47	8.00%	All generating, transmission, substation and distribution equipment not otherwise noted.
	43.2	75.00%	Expenditures related primarily to new generation or additions/alterations that increase the capacity of generating facilities.

Escalation Factors: Conference Board of Canada GDP deflator, medium term forecast dated February 14, 2024, and long term forecast dated December 18, 2023.

Supporting Documents: Newfoundland and Labrador Hydro's Marginal Cost Update, dated October 2023.

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5.1 Port Union Building Replacement

June 2024

Prepared by: Alex Hawco, P.Eng

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1.0 INTRODUCTION

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") maintains office buildings throughout its service territory to support the operations and maintenance of the electricity system.

Figure 1 shows the location of the Company's office buildings within its service territory.

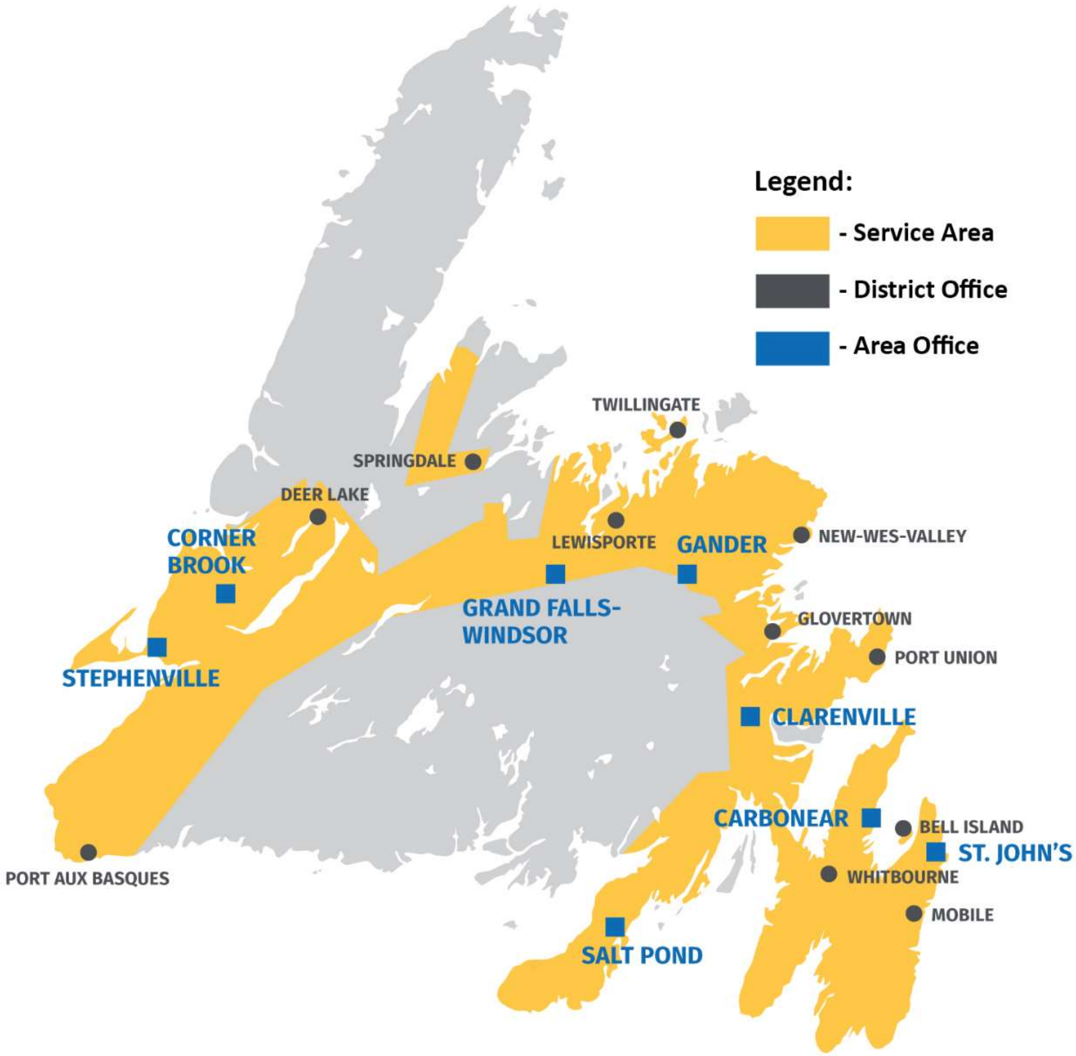

Figure 1: Service Territory

Area offices provide local management, engineering, operational support, warehouse facilities and customer service throughout each geographic region. Within the St. John's, Eastern and Western regions, there are district offices that provide operational support and storage of materials in areas remote from the area offices.[1]

[1] To decrease the duration of customer outages, more remote areas are provided with powerline technician crew(s) and commonly required materials (distribution transformers, cross-arms, conductor, streetlights and hardware). The company targets a response within 2 hours 85% of the time.

The Company periodically reviews its general property assets to identify infrastructure that requires upgrade, refurbishment, additions or decommissioning. The Company has identified the Port Union district building (the "Facility") as containing deficient and deteriorated infrastructure.

2.0 BACKGROUND

The Facility was acquired by the Company during the amalgamation of the then Newfoundland Light and Power Company with Union Electric Light and Power in 1966. The Facility was in use at that time as a diesel generating station adjacent to the Port Union Hydroelectric Plant. Subsequent to the amalgamation, the Facility was first used as a warehouse before being renovated into its current configuration as a combined warehouse and office space.

The Facility is Newfoundland Power's centre of operations for the Bonavista area (the "Area"). The Area's service territory extends from Bonavista in the north to Charleston in the south. The Facility supports service to 5,903 customers, representing 2.2% of all customers served by the Company.

The Facility provides support for nine employees and stores equipment necessary for operations in the Area. Four employees, two Powerline Technician Lead Hands and two Powerline Technicians, use the Facility as their daily headquarters. Five additional employees, including two Electrical Maintenance persons, one Materials Handler, one Meter Reader and one Customer Service Representative, use the Facility part time while completing work in the Area. The Facility also supports corporate functions, such as emergency material storage required for regional storm response.

Table 1 lists major upgrades that have been completed at the Facility over the last 25 years.[2]

Table 1
Port Union Building Upgrades

Year	Upgrade
1999	Windows and Siding Replacement
2021	Roofing Replacement

Additional minor maintenance work has been completed on the Facility to address deficiencies as identified.

2 Major upgrades are defined as upgrade work valued over $25,000.

3.0 CONDITION ASSESSMENT

3.1 General

Newfoundland Power completed a visual condition assessment of the Facility in 2024 to identify deteriorated, obsolete and non-standard equipment. This included assessments of: (i) superstructure; (ii) building envelope; (iii) architectural systems; (iv) mechanical systems; (v) electrical systems; and (vi) sitework. Below are the results of the condition assessment.

3.2 Superstructure

A superstructure's role is to safely transfer all exterior and interior loading from the roofs, walls and floors to a building's foundation.[3] Superstructures are comprised of the main structural components, typically beams, columns and foundations. The superstructure in the Facility consists of dimensional timber framing and a concrete foundation. The building's roof truss system is of a non-standard design. Typically, timber framed buildings contain a pre-engineered roof truss system whereby the forces applied to the roofing truss from environmental conditions are transferred to the foundation through the exterior walls. In the Facility, the roofing system is comprised of stick framing construction techniques such that the roof is supported by not only the exterior walls, but also interior walls. The superstructure is showing signs of inadequacy. Large deflections are observed in the interior flooring system, indicating under sizing of the main structural components.

Figure 2 shows the Facility's roofing system and load transfer mechanism.

Figure 2: Roofing System

[3] Exterior loads can be classified as environmental loading from wind, rain and snow. Interior loads are comprised of interior finishes, furniture, materials and human occupants.

3.3 Building Envelope

The building envelope provides two main purposes: (i) to transfer environmental loading applied to the buildings exterior to the superstructure where it will further be transferred to the foundation; and (ii) to ensure temperature and moisture are prevented from entering the building structure. Building envelopes typically consist of the roofing system, siding, windows, doors, insulation and vapour barriers. The Facility's building envelope is comprised of asphalt shingles, pre-formed metal siding, vinyl windows, steel doors and fibreglass batt insulation. The asphalt shingles, pre-formed metal siding, steel doors and fibreglass batt insulation are in good condition. The vinyl windows are in poor condition and are no longer able to lock sufficiently. The Facility does not contain a vapour barrier which decreases the building's energy efficiency as well as its ability to keep moisture out of the structure, resulting in interior water damage.

Figure 3 shows exterior window deterioration.

Figure 3: Exterior Window Deterioration

3.4 Architectural Systems

Architectural finishes are interior facing components that cover the superstructure such that the space is suitable for human occupation. Architectural elements consist of plywood and gyprock wall coverings, plaster and painting, vinyl flooring, and cabinetry. The Facility's plywood and gyprock coverings are in poor condition with damage from water and moisture. Plaster and painted surfaces are in poor condition with peeling and flaking from the same moisture. The vinyl flooring is in poor condition with cuts, damage and excessive wear throughout. The cabinetry is in fair condition, with minor water damage present.

Figure 4 shows interior moisture damage. Figure 5 shows kitchen architectural finishes. Figure 6 shows small office space.

Figure 4: Ceiling Moisture Damage

Figure 5: Kitchen Architectural Finishes

Figure 6: Small Office Space

3.5 Mechanical Systems

Mechanical systems are required in office spaces to transport air and water throughout the building structure. Mechanical systems typically consist of domestic water supply and distribution, sewer distribution and discharge, fresh air supply, exhaust air discharge, heating, cooling and air conditioning and fixtures. The Facility's domestic water supply and distribution systems are in fair condition. Penetrations through the foundation concrete slab are not sealed and are open to the earth below. The sewer distribution and discharge system are in good condition. There is no fresh air supply into the structure apart from when exterior doors are opened. Without adequate fresh air supply and extraction, the Facility does not meet the Newfoundland and Labrador Occupational Health and Safety Regulations.[4] The Facility also does not have a gas extraction system installed to mitigate the possibility of exhaust gasses from all-terrain vehicles stored within the structure from becoming a workplace hazard. There are small exhaust fans in the kitchen and bathrooms that discharge air to the outside. Heating is provided by baseboard heaters and no air conditioning is present. Mechanical fixtures, heaters, fans, sinks and toilets are in fair condition with moderate to excessive wear present.

Figure 7 shows the existing kitchen exhaust fan.

Figure 7: Kitchen Exhaust Fan

[4] Section 45 of the *Occupational Health and Safety Regulations, 2012 (Newfoundland and Labrador Regulation 5/12)* details ventilation requirements for a workspace.

3.6 Electrical Systems

Electrical systems distribute electricity from the electrical service connection to fixtures through the building. Electrical systems typically consist of electrical panels, distribution wiring and fixtures. The Facility's electrical panel is in good condition. The distribution wiring is in fair condition. Some wiring is original cloth insulated type which is a suspected asbestos hazard based on similar wire observed in other locations. The electrical fixtures are in fair condition with wear and broken components present.

Figure 8 shows cloth insulated wiring.

Figure 8: Cloth Insulated Wiring

3.7 Sitework

Sitework is required to provide safe access to and from the Facility as well as to provide laydown areas for material storage. Facility sitework consists of asphalt parking lot and driveway, storm water drainage and ditching, fencing and material storage racking. The asphalt parking lot and driveway are in poor condition with widespread cracking and section loss. The storm water drainage system is in fair condition with standing water present behind the building structure. The fencing is in good condition. The material storage racking is in fair condition. No load rating is presently available for the installed racking as it is not an engineered solution.

Figure 9 shows the deteriorated asphalt parking lot. Figure 10 shows the existing material storage racking.

Figure 9: Deteriorated Asphalt Parking Lot

Figure 10: Material Storage Racking

4.0 RISK ASSESSMENT

The Facility was originally constructed as a diesel generation facility and was later converted into office/storage space. The interior layout of the Facility consists of many small office/storage spaces that cannot be reconfigured without replacement of the roofing system as the interior walls provide load bearing support to the current roofing system. The Facility does not have fresh air supply without opening exterior doors which is neither efficient nor practical. The lack of air circulation has resulted in moisture damage to interior finishes. To provide a suitable healthy workspace, fresh air supply and air treatment must be provided, and a vapour barrier installed. To effectively install a vapour barrier, interior partitions must be removed.

The estimated cost of renovation of the existing Facility including replacement of the roofing system to install vapour barrier and reconfigure the space is cost prohibitive, and details are provided in section *5.0 Assessment of Alternatives*.

5.0 ASSESSMENT OF ALTERNATIVES

5.1 General

A condition assessment and corresponding risk assessment determined that the Facility has deteriorated significantly and requires significant intervention to enable continued occupancy.

Newfoundland Power identified and assessed two alternatives to address the deteriorated condition of the Port Union service building: (i) replace the Facility in 2025 and 2026; and (ii) refurbish the existing Facility. The assessment of each alternative is detailed below.

5.2 Alternative 1: Replace Facility in 2025/2026

Alternative 1 involves replacing the Facility with a newly constructed 240m^2 building including backup generator, asphalt parking lot and upgraded storm sewer infrastructure. The cost of Alternative 1 is estimated to be $1,281,000.

5.3 Alternative 2: Refurbish Existing Facility

Alternative 2 involves refurbishment of the existing 650m^2 Facility including removal of the Facility's roofing system, temporary stabilization of the exterior walls and demolition of the buildings interior. A new roofing system would be installed, and superstructure upgrades completed to the exterior walls and foundation to support the new roofing load transfer through the buildings exterior walls. The Facility would receive new interior partitions and finishes, plumbing system, HVAC system and upgrades to the existing electrical system. This alternative also includes a backup generator, asphalt parking lot and upgraded storm sewer infrastructure. The cost of Alternative 2 is estimated to be $1,810,000.

Due to the existing Facility's larger size, complexities associated with refurbishment and greater cost, replacement of the Facility in 2025 and 2026 is recommended.

6.0 PROJECT SCOPE

The assessment of alternatives determined that replacement of the Facility in 2025 and 2026 is the least-cost alternative to address the deteriorated condition of the building.

The *Port Union Building Replacement* project includes demolition of the existing Facility, construction of the new Facility, installation of a backup generator, replacement of the asphalt parking lot and upgrades to the storm sewer infrastructure.

Design and procurement will be completed in 2025 with construction completed by the end of 2026.

7.0 PROJECT COST

Table 2 provides a breakdown by category of the cost of the *Port Union Building Replacement* project.

Table 2
Port Union Building Replacement Project Budget
($000s)

Cost Category	2025	2026	Total Cost
Material	235	938	1,173
Labour – Internal	-	5	5
Labour – Contract	-	-	-
Engineering	33	32	65
Other	10	28	38
Total	278	1,003	1,281

The *Port Union Building Replacement* project is estimated to cost $1,281,000 including $278,000 in 2025 and $1,003,000 in 2026.

8.0 CONCLUSION

A condition assessment has determined that the Port Union Building requires upgrades. The assessment of alternatives has confirmed that replacement of the building is the most economic solution for customers. This project is required to replace deteriorated infrastructure, to ensure compliance with occupational health and safety regulations, and to ensure adequate facilities are available to provide safe, least-cost and reliable electrical service to customers in the Area.

6.1 Outage Management System Upgrade

June 2024

Prepared by: Julie Pearce

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1.0 INTRODUCTION

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") Outage Management System ("OMS") is a cornerstone of reliability management that plays a critical role in outage assessment, outage response and customer communications. While the importance of OMS increases substantially during major electrical system events, it is essential to the delivery of least-cost, reliable service in all conditions including normal day-to-day operations.

Newfoundland Power modernized its OMS technology in 2019 by implementing a commercial OMS system consistent with Canadian utility best practice.[1] This was in alignment with a review completed during the Newfoundland and Labrador Board of Commissioners of Public Utilities' (the "Board") *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System*. The current OMS is integrated with the Company's Geographical Information System ("GIS") and uses this integration to determine outage customer counts and provide predictive analysis on fault location.

The Company upgrades its operational technologies on a required basis to maintain vendor support for bug fixes, for software updates, and to protect against potential cybersecurity vulnerabilities. The Company's OMS requires an upgrade before November 1, 2026 to remain supported by the vendor.[2] Following this upgrade, another major upgrade will be required by 2028 to allow the OMS to remain compatible with the Company's GIS. A net present value ("NPV") analysis determined that completing a major upgrade in 2026 is the most economical option for customers. The estimated cost to complete the major upgrade to the OMS in 2025 and 2026 is $3,270,000.

2.0 BACKGROUND

2.1 Outage Management at Newfoundland Power

Newfoundland Power is the primary distributor of electricity in Newfoundland and Labrador. The Company serves approximately 276,000 customers or 87% of all customers in the province, and manages an average of over 5,700 power outages per year. Since 2020, the Company has responded to over 66,000 power system incidents and managed over 2,700 planned outages.

Newfoundland Power modernized its OMS in 2019 when it implemented a modern, commercially available product.[3] The modern product enabled the Company to improve operational efficiency and customer communications and enabled improved data-driven decision making as outlined below.

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1 See Newfoundland Power's *2018 Capital Budget Application,* report *5.5. Outage Management System Replacement and Enhancement Plan*.

2 The current version of the Company's OMS system will be retired as of November 1, 2026. After that date, no vendor support is available including security patches, bug fixes and software updates.

3 The implementation of the modern OMS was approved by the Board in Order No. P.U. 37 (2017).

Predictive Outage Identification and Response

The Company's OMS is directly integrated with its GIS and Supervisory Control and Data Acquisition ("SCADA") system. This provides the OMS with a real-time model of the electrical system, including the status and location of infrastructure that provides electricity to customers. As outages are reported by customers or via telemetered devices, this connectivity model allows the OMS to predict the likely source of failure. This improves efficiency by enabling the deployment of the Company's field staff to the predicted device location, thereby reducing the frequency or duration of detailed patrols of area infrastructure to locate problems.

The OMS is essential during the management of large-scale outages resulting from major weather events. Through integration with the Company's Workforce Management System ("WFMS"), incidents are dispatched to field staff for assessment. Information from the field is then updated in the OMS to inform planning and prioritization efforts. Resources, such as vegetation management, pole setting and line crews, are effectively dispatched to minimize outage durations and maximize restoration effectiveness.[4]

The Company measures its field response using the Customer Average Interruption Duration Index ("CAIDI"). CAIDI measures the average time it takes to restore service to customers following an outage.[5]

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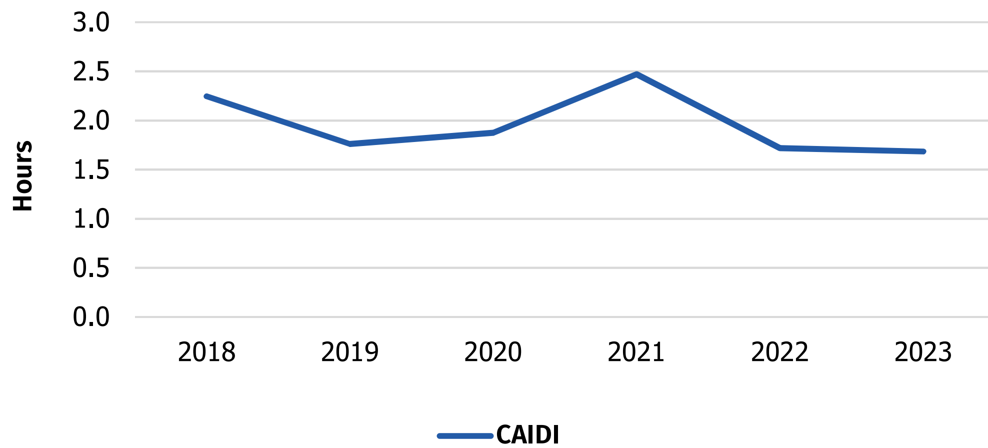
[4] In September 2021, the Company sustained widespread outages and damages as a result of Hurricane Larry. Using OMS technology to aid in assessment and prioritization of response, 86% of affected customers were restored within 24 hours. OMS technology assisted with the identification of outage locations and prioritization of restoration.

[5] CAIDI is the restoration time measure used by Electricity Canada. In arithmetic terms, CAIDI is expressed as System Average Interruption Duration Index / System Average Interruption Frequency Index.

Figure 1 shows Newfoundland Power's average restoration time for unscheduled outages over the period 2018 to 2023.[6]

Figure 1:
Unplanned CAIDI
2018 - 2023



Newfoundland Power's average restoration time for unscheduled outages has been trending downward overall since the implementation of the current OMS in 2019.[7] The OMS is an integral tool in assisting the Company's outage response. Providing an efficient and effective response to system outages is essential to the delivery of safe reliable service to customers at the lowest possible cost.

Customer Communications

The OMS facilitates targeted customer communications and allows the Company to provide timely details of an outage and its expected duration. This information is available to customers through self-service options, such as on the Company's website and through the automated call answering system. Customers who choose to subscribe to the Company's Outage Alerts service receive notifications to their mobile device or email to provide outage cause and restoration information.[8] Company employees such as Call Centre agents are able to use this information to provide optimal service to customers. When scheduled interruptions are required for maintenance and construction, the OMS permits the Company to quickly identify affected customers and provide advance notice.

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6 Includes all power outages of duration greater than 1 minute, including major weather events, and excludes loss of supply outages from Newfoundland and Labrador Hydro.

7 There has been an improvement of 25% from 2023 vs 2018. Unplanned CAIDI: 2018 = 2.25 and 2023 = 1.68. (1.68-2.25)/2.25 = 25%.

8 Over 95,000 customers have subscribed to Newfoundland Power's Outage Alerts service to date.

Capital Planning

The Company uses data collected by the OMS to improve decision making with respect to capital investments. For instance, outage data collected by the OMS at the customer level has allowed the Company to identify sections of feeders experiencing poor performance that were not available using previous reliability statistics.[9] Increased collection and trending of this granular reliability data over time will allow the Company to continue strategically prioritizing investment to improve service to customers experiencing poor reliability.

3.0 ASSESSMENT OF ALTERNATIVES

3.1 General

OMS is a critical business application for Newfoundland Power. The Company maintains vendor support for all critical business applications, including OMS.[10] Vendor support ensures that critical applications operate reliably and securely during the day-to-day provision of service to customers. Unsupported applications are more prone to failure and are at risk of cybersecurity threats and breaches.

The software vendor has indicated that the current version of OMS will require an upgrade as it will no longer be supported as of November 1, 2026. The Company's GIS is nearing the end of its useful life and will require a major upgrade in 2028. Due to the close integration of OMS with GIS, this GIS upgrade will necessitate a large-scale upgrade to OMS in order to remain compatible with the upgraded GIS. It is possible to complete the major upgrade to OMS in 2026, which will result in only minor changes being required during the GIS upgrade in 2028.

Given the criticality of OMS in customer service and outage response functions, as well as integrations with other critical business systems, continuing to operate OMS without vendor support is not a viable option.[11] The current OMS was implemented in 2019 after a comprehensive market evaluation and implementation project. Returning to market to identify a replacement OMS would require another evaluation and implementation project, development of new integrations to other systems, and vendor license costs. The estimated cost for such a project would exceed upgrade options with the existing vendor and introduce increased uncertainty and risk. Therefore, replacement of the OMS with a new product was not considered a viable option.

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9 The *Distribution Reliability Initiative* projects for BCV-04 in the *2022 Capital Budget Application* and WAV-01 in the *2024 Capital Budget Application* were identified using granular reliability data not previously available prior to the installation of the OMS.

10 See Newfoundland Power's *2021 Capital Budget Application, Schedule B,* page 87 of 98. The *Shared Server Infrastructure (Pooled)* project included an upgrade to the Company's OMS. This was a minor version update from 10.2.1 to 10.8.1. This upgrade would be a major version upgrade moving from version x to version y.

11 Continuing to operate the existing version of the OMS without support would mean increased cybersecurity risks, as patching of identified vulnerabilities would no longer be provided from the vendor, as well as heightened operational risk in the event the system ceased to function. Furthermore, a cybersecurity incident affecting the OMS could potentially put sensitive customer information at risk.

3.2 Description of Alternatives

Newfoundland Power completed an assessment of alternatives to identify the least-cost solution to provide continuity in its outage management response. The Company identified two viable alternatives: (i) complete a minor upgrade in 2026 followed by a major upgrade in 2027 and 2028; and (ii) complete a major upgrade in 2025 and 2026.

Alternative 1: Minor Upgrade in 2026 and Major Upgrade in 2027-2028

The OMS vendor offers a minor upgrade version with a published end-of-life date of 2028. At that point, a major upgrade of the OMS would be required to remain compatible with the Company's GIS system. The vendor has advised against performing the GIS and OMS upgrades concurrently due to increased project complexity and risk. This alternative would require an estimated capital cost of $507,000 in 2026 to complete a minor upgrade to the existing OMS, followed by a two-year project in 2027 and 2028 to complete the major upgrade at an estimated capital cost of $3,685,000.

Alternative 2: Major Upgrade in 2025-2026

The major upgrade required for the OMS is currently commercially available from the vendor. This version is compatible with both versions of GIS, including the version the Company currently maintains, as well as the anticipated upgraded GIS in 2028. This alternative would require a two-year project in 2025 and 2026 at an estimated capital cost of $3,270,000.[12]

Newfoundland Power evaluated both alternatives using a NPV analysis to determine the least-cost solution to provide continuity in its field response.

[12] The Company's GIS system is also approaching the end of its useful life, and a major upgrade to the GIS system is anticipated to be required by the end of 2028.

3.3 Evaluation of Alternatives

The NPV analysis assesses whether the cost of deferring the major upgrade to 2027 and 2028 and completing a minor upgrade in 2026 would exceed the cost of completing the major upgrade in 2025 and 2026. The analysis considers capital costs of multiple projects under this plan until 2037.

Table 1 summarizes the results of the NPV analysis for each alternative.

Table 1
Net Present Value Analysis Results
($000s)

	Total Costs	NPV
Alternative 1 – Minor Upgrade in 2026 and Major Upgrade in 2027-2028	4,192	3,605
Alternative 2 – Major Upgrade in 2025-2026	3,520	3,326
Difference	672	279

The NPV analysis determined that completing the major OMS upgrade in 2025 and 2026 is the least-cost alternative to maintain the OMS with full vendor support.

Proceeding with the major upgrade starting in 2025 would provide a benefit to customers of approximately $279,000 on an NPV basis. This is primarily because deferring the upgrade until 2028 would necessitate a smaller upgrade project in 2026, and deferring the larger project for two years does not provide enough excess value to negate the cost of the additional upgrade this would require.

Appendix A provides the detailed results of the NPV analysis.

4.0 PROJECT SCOPE AND COST

Newfoundland Power plans to upgrade its OMS over two years commencing in 2025. This timeframe will ensure the upgraded system is implemented prior to the expiration of vendor support as of November 1, 2026. The upgraded OMS will continue to deliver functionality equivalent to that of the existing system, including the monitoring, analysis, dispatching and communications of outages.[13]

[13] Additional functionality will be available with the upgraded OMS, including support for Advanced Metering Infrastructure ("AMI") integration, and future Advanced Distribution Management System ("ADMS") functionality, such as automatic fault location, isolation and service restoration ("FLISR"). These ancillary benefits are not accounted for in the NPV analysis.

Hardware and software configuration will commence in 2025 and be finalized in 2026. System training, testing and deployment will occur in 2026.
Table 2 provides a breakdown of the cost of upgrading the OMS.

Table 2
Outage Management System Upgrade Project Costs
($000s)

Cost Category	2025	2026	Total
Labour – Internal	905	619	1,524
Other	906	840	1,746
Total	1,811	1,459	3,270

Completing the major upgrade to the Company's OMS system by 2026, in advance of the anticipated GIS upgrade, is the least-cost option to continue providing safe, reliable service to customers.

5.0 CONCLUSION

The *Outage Management System Upgrade* project for 2025 includes:

(i) performing a major upgrade on the OMS to the latest available release including end-to-end testing; and
(ii) updating existing integrations as required with other systems, including WFMS, GIS, customer website and Asset Management.

This upgrade is the least-cost solution in maintaining a supported, secure OMS. Completing this work in 2025 and 2026 will ensure the continued provision of safe reliable service to customers.

APPENDIX A:

NET PRESENT VALUE ANALYSIS

Table A-1: NPV Analysis Alternative 1: Minor Upgrade in 2026 and Major Upgrade in 2027-2028 ($000s)						
Year	Project Costs Software[1]	Revenue Requirement	Present Value	Cumulative Present Value	Present Worth of Sunk Costs	Total Present Value
2025	0	0	0	0	0	0
2026	507	60	57	57	-426	-483
2027	0	77	68	124	-358	-483
2028	3,685	536	442	566	-3,039	-3,605
2029	0	655	506	1,073	-2,532	-3,605
2030	0	608	441	1,513	-2,092	-3,605
2031	0	584	397	1,910	-1,695	-3,605
2032	0	559	356	2,266	-1,339	-3,605
2033	0	535	320	2,586	-1,019	-3,605
2034	0	511	286	2,872	-733	-3,605
2035	0	511	268	3,140	-465	-3,605
2036	0	411	203	3,343	-262	-3,605
2037	0	568	262	3,605	0	-3,605

1 Assumed 10 years and 100% Capital Cost Allowance ("CCA").

Table A-2: NPV Analysis Alternative 2: Major Upgrade in 2025-2026 ($000s)						
Year	Project Costs Software[2]	Revenue Requirement	Present Value	Cumulative Present Value	Present Worth of Sunk Costs	Total Present Value
2025	0	0	0	0	0	0
2026	3,270	389	365	365	-2,749	-3,114
2027	0	498	438	803	-2,312	-3,114
2028	250	510	421	1,223	-2,103	-3,326
2029	0	499	386	1,609	-1,717	-3,326
2030	0	478	346	1,955	-1,371	-3,326
2031	0	457	311	2,266	-1,060	-3,326
2032	0	437	278	2,544	-782	-3,326
2033	0	416	249	2,793	-533	-3,326
2034	0	396	222	3,015	-312	-3,326
2035	0	533	280	3,295	-32	-3,326
2036	0	28	14	3,308	-18	-3,326
2037	0	39	18	3,326	0	-3,326

[2] Assumed 10 years and 100% CCA.

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6.2 Asset Management Technology Replacement

June 2024

Prepared by: Mikayla Chislett, Samuel Losinski
Approved by: Liz Palmera-Nunez

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1.0 INTRODUCTION

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") uses asset management technology to manage its transmission, distribution, substation, and generation assets. These assets include: (i) 131 substations; (ii) 23 hydro plants; (iii) six backup generators; (iv) 2,100 kilometers of transmission lines; and (v) 9,400 kilometers of distribution lines. Newfoundland Power manages its assets to ensure safe, reliable service of electricity to customers in an environmentally responsible manner.

In the early 2000s, the Company shifted from reactive maintenance to preventative, implementing a cyclical approach to inspections, testing and scheduled maintenance. A commercial asset management technology (the "Technology") was implemented in 2003 to manage substation and generation asset classes. Transmission and distribution assets were added in 2005 and 2006 respectively.

The Technology is the central repository of the Company's asset information. It maintains information on over 480,000 assets and is utilized to manage the assets throughout their lifecycle. The Technology is used:

(i) To manage preventative and corrective work, including inspections, scheduled maintenance and testing;
(ii) By employees to identify, plan, schedule and track executed work; and
(iii) To create asset reporting to inform data driven decisions for operations and capital expenditures.

The Technology impacts approximately 50% of the Company's employees. It is a critical business application and is also integrated with other core applications, such as the Company's Workforce Management System and Geographic Information System ("GIS").

The Technology is at the end of its useful life and requires replacement. The existing contract is expiring and the vendor is discontinuing support of the system on January 1st, 2027. Replacement is required to eliminate the risk of the Technology failing while unsupported, disrupting Company operations and asset management practices.

The Company engaged Asset Management Consulting Limited ("AMCL") to begin a review of the Company's asset management practices, which included guidance on the replacement of the asset management technology. AMCL recommends that the existing technology be replaced with a modern equivalent before it becomes obsolete on January 1st, 2027. This aligns with the Company's assessment. Replacing the Technology with a modern equivalent aligns with industry best practice and will allow the Company to meet current requirements and provide a foundation for enhancements as asset management matures.

The estimated cost to replace the Company's current asset management technology with a modern equivalent in 2025 and 2026 is $8,013,000.

2.0 BACKGROUND

2.1 Asset Management at Newfoundland Power

Newfoundland Power's approach to asset management has delivered sound outcomes for its customers, including reasonable levels of service reliability and customer satisfaction. In 2014, an independent review of Newfoundland Power's operations found that the Company's asset management conformed to good utility practice.[1] While historical results have been sound, the context within which the Company manages its assets is changing.

Maintaining reliable service for customers is expected to require increased investments in the planned refurbishment and replacement of assets going forward. Optimizing the future replacement of these assets in order to balance performance, cost and risk is a key consideration for Newfoundland Power's asset management journey.

High-quality asset information forms the foundation of effective asset management. Access to consistent, reliable information underpins decisions about managing an asset's lifecycle. A consistent, repeatable approach is required for making asset-related decisions. The decision-making process is aided by data and technology.

In 2022, the Company began a review of its asset management practices to confirm they are both adequate and aligned with industry best practice.[2] A total of 22 opportunities were identified for assessment as part of this review. The Company engaged AMCL to provide guidance on the opportunities, including the replacement of the asset management technology.[3]

AMCL recommends that the existing technology be replaced with a modern equivalent before it becomes obsolete on January 1st, 2027. This will allow the Company to meet current requirements and provide a foundation for enhancements as asset management matures. See Appendix A for AMCL's report.

2.2 Asset Management Technology

Newfoundland Power utilizes asset management technology to help manage its electrical system assets. The Technology is the central repository for substation, generation, transmission, and distribution asset information. It is used to manage preventative and corrective work, including inspections, scheduled maintenance and testing. The Technology is used by employees to identify, plan, schedule, and track executed work. Information contained in the Technology is used to create asset reporting to inform data driven decisions for operations and capital expenditures.

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1 See *The Liberty Consulting Group, Executive Summary of Report on Island Interconnected System to Interconnection with Muskrat Falls* addressing Newfoundland Power Inc., December 17, 2014, page ES-1.

2 Over the last two years, the Company completed the first two phases of its asset management review. Opportunities for asset management maturity have been identified and are being considered in the implementation planning phase. For more information on the Company's asset management review, see Newfoundland Power's *2025 Capital Budget Application, 2025-2029 Capital Plan,* Appendix B.

3 AMCL provided education on asset management best practices. Workshops were held with employees to determine work requirements and processes. Functional and technical requirements for an asset management technology were provided along with potential vendors.

The Technology maintains information on over 480,000 in-service assets. It manages approximately 350 preventative maintenance programs, which encompass around 3,800 asset inspections and 1,800 maintenance and testing activities annually. Approximately 6,400 work requests are entered and 15,000 work orders completed annually.

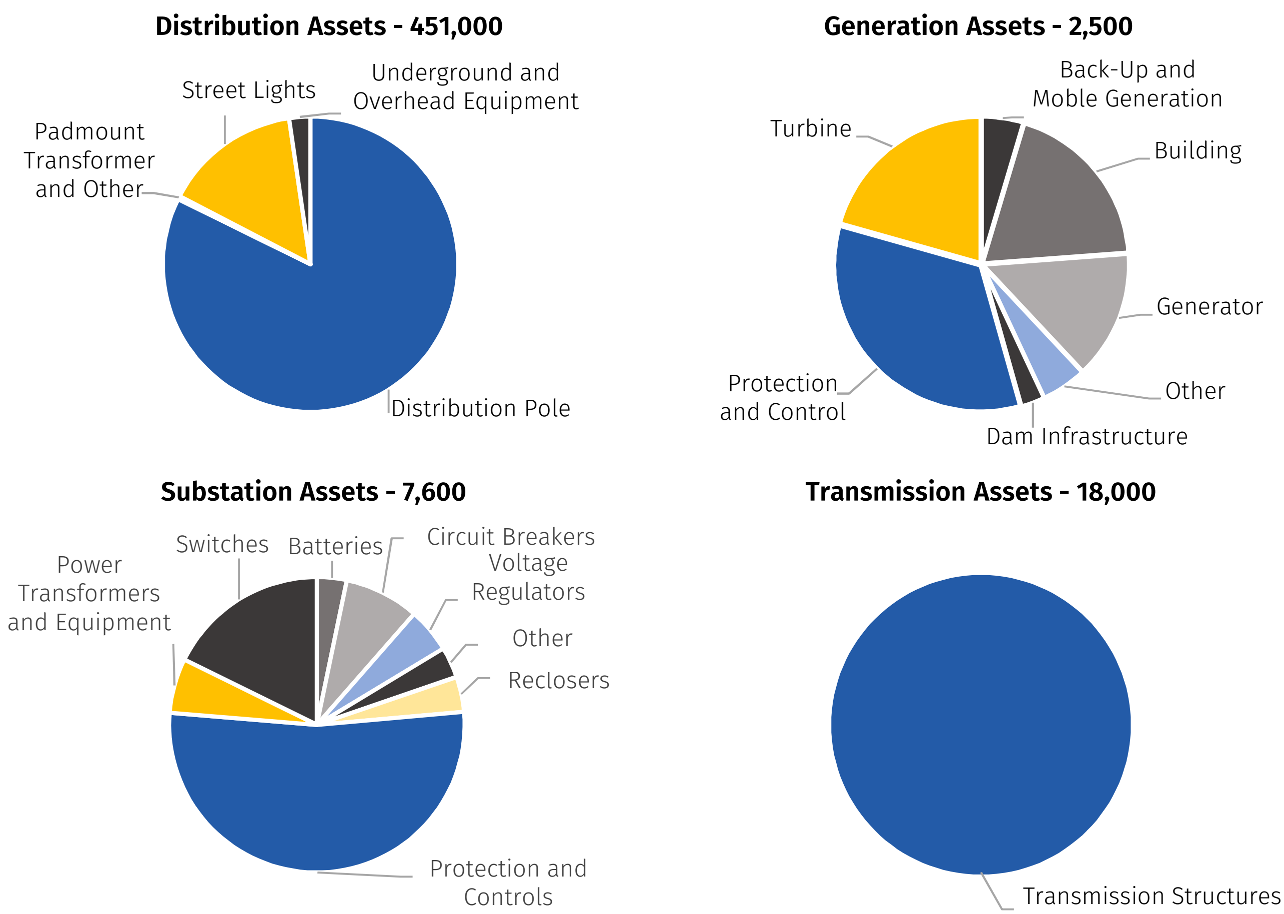
The Technology has been upgraded since its implementation in 2003 to allow for continuous support from the vendor. Enhancements, including integrations to other applications, were implemented to improve efficiency of operations and data collection.[4]

[4] See Newfoundland Power's *2008 Capital Budget Application, section 6.1 2008 Application Enhancements*, page 3 of 7. Enhancements were made to the asset management system to enable employees equipped with mobile devices to complete power plant maintenance work orders in the field using mobile devices.

2.2.1 Functionality

Asset Registry
The asset registry maintains information on over 480,000 in-service substation, generation, transmission, and distribution assets, shown in Figure 1. Each asset is uniquely identified and tracked throughout its lifecycle.

Figure 1
Asset Breakdown



Assets are added to the system upon acquisition and details such as asset type, model, serial number, manufacturer, and manufacture date are captured. The registry stores reference material associated with the asset, such as equipment manuals and warranty information. Specific attributes, such as oil volume, voltage level, and polychlorinated biphenyl ("PCB") content, are also assigned to the asset in the registry. Asset records, such as installation date, location, and service status, are updated throughout its lifecycle and are retained with the asset when retired.

The information contained in the asset registry is necessary for effective asset management. It provides an accessible, wholistic view of assets and allows the Company to gain insights from asset trends.

Preventative Maintenance Programs
The Company relies on the Technology’s recurring, time-based preventative maintenance programs to coordinate asset inspections, testing, and maintenance. Asset owners create programs when an asset is added to the Technology. Programs are configured to automatically generate tasks for field staff who will monitor their frequency, status, and due dates. Parameters are set to align with Company asset management practices and to maintain the validity of manufacturer warranties. Approximately 350 programs are active in the system.

Examples of preventative maintenance programs include:
- (i) Partial discharge analysis testing;
- (ii) Vibration analysis;
- (iii) Brush gear maintenance;
- (iv) Oil sampling and analysis;
- (v) Padmount transformer inspections; and,
- (vi) Infrared thermography of substation and downline equipment.

Inspections
Asset condition is monitored through inspections. This enables the early detection of issues before they lead to equipment failure or more significant problems. Safety hazards can be identified and mitigated, protecting employees and the public. The Company plans approximately 3,800 asset inspections through the Technology annually.

Distribution lines are inspected twice over a seven-year cycle; one detailed inspection and another focused on vegetation growth. Padmount transformers and transmission lines are both inspected annually. Field staff execute inspections and log the completion of work in the Technology. Due to the Technology's geolocation limitations, the Company's GIS is used to capture the location and details of asset deficiencies. This information is then automatically recorded in the Technology through a software integration.

Substations are inspected eight times annually and once with a thermal imaging camera. Generation plants are inspected monthly. Dams, and related infrastructure, are inspected twice annually. Other equipment, such as cranes, are inspected on varying frequencies. Employees use custom applications, SUBMobile and GENMobile, to capture inspection results due the Technology's inability to accept digital forms. Details are stored within the Technology through a software integration.

Maintenance and Testing
Regular maintenance and testing reduce the likelihood of unexpected failures and power outages. Potential problems can be identified early and proactively addressed before they escalate, minimizing repair costs and downtime. These practices can extend the lifespan of equipment, delaying the need for costly replacements and upgrades.

Maintenance and testing are planned through their respective preventative maintenance programs. The Company plans approximately 1,800 maintenance and testing activities on assets annually. Once scheduled, field staff carry out tasks ranging from oil sampling to equipment overhauls. Results are documented and retained in the asset management technology. Analysis of this information can provide an understanding of equipment degradation patterns over time, help predict potential failures, and optimize maintenance schedules. Maintenance and testing records also serve as evidence to support warranty claims. If additional work is required, a work request is logged into the system for subsequent review.

Work Requests[5]
The process of identifying, addressing, and resolving asset deficiencies is managed through the asset management technology. This begins with the creation of a work request. Work requests are used to capture asset deficiencies, their perceived priority, and a short description of the corrective action.

The majority of work requests are created by field staff following inspections, tests, or maintenance. This is done through the Technology, the Company's internal website, mobile applications, or through integrations to other applications. Approximately 6,400 work requests are created by employees annually.

Work requests are reviewed and, if necessary, are incorporated into work orders. This starts the planning process leading up to work execution.

Work Orders[5]
All non-emergency work must be planned prior to the work being executed.[6] This begins with the creation of a work order, either from a work request or from preventative maintenance programs.

Planning details captured on the work order include, but are not limited to, a description of the deficiency and corrective action, priority, schedule timeframe, estimated duration, equipment and material requirements, and resource requirements. Field staff update work orders with progress and effort through to the completion of the work. This is done within the Technology directly or through integrated applications, such as Workforce Management, SUBMobile, and GENMobile. Results and documentation are captured upon work completion, with all information being retained in the asset registry. On average, the Company completes approximately 15,000 work orders annually.

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5 Deficiencies from inspections, maintenance, and testing are logged in the technology as work requests. These requests are reviewed and, if approved, become work orders. Work orders are prioritized in a queue and are used to plan and execute work

6 Emergency work is documented in a work order after it has been completed.

Analytics and Reporting
The asset management technology is the Company's central repository for asset management information. It retains asset details, documentation, maintenance programs, historical and outstanding deficiencies, and results from inspections, testing, and maintenance. Analyzing and reporting on this data provides insight into asset trends, informs operational decisions, and supports capital expenditures. Some examples include:

(i) A holistic view of all outstanding deficiencies to prioritize tasks or pool work into efficient projects;
(ii) Predicting failures based on historical or industry data, such as asset age, type, or location;
(iii) Efficient identification of assets affected by a recalled component; and
(iv) Tracking the progress of programs or initiatives (e.g. removal of equipment containing PCBs).

Data-driven analysis and reporting allow employees to base decisions on empirical evidence. The current technology has limited functionality to support this type of data analysis. Data is currently stored on separate documents due to lack of digital form support within the Technology. This reduces the efficiency of interpreting and reporting results. Due to these challenges, the Company uses external software for analysis and reporting.

2.2.2 Integrations

The Technology has been enhanced since initial implementation to include integrations to other technologies. These integrations allow information to flow from one technology to another and, in some cases, have been implemented due to the Technology's functional limitations.

Workforce Management
Planned work stored in the Technology is scheduled in the Company's workforce management software. This integration enables dispatching and monitoring of work for supervisors and field staff. The software includes a mobile application that allows field staff to access their schedule and interact with work orders from a mobile device.

SUBMobile and GENMobile
Custom applications were built for the Substation and Generation groups that support their daily operations. They provide a data link to the Technology that allows for digital form completion, oil sample analysis management, and maintenance status reporting. They are accessible through a desktop or mobile device.

Geographic Information System
Integrating with the Company's GIS system assists in capturing the geospatial information of assets. It improves accessibility of information for field staff, allows for updates to be made from the field, and provides customers with the ability to report street light outages via the Newfoundland Power corporate website.

The Company's GIS vendor also provides a mobile application that enables the collection of data through digital forms. This is used to capture deficiency details and create work requests in the asset management technology.

Outage Management System ("OMS")
Field staff use the Company OMS to respond to system disturbances. If follow-up work is needed, the OMS captures the details and creates a work request in the asset management technology.

Financial System
Inventory and project numbers are synced with the asset management technology to support work planning.

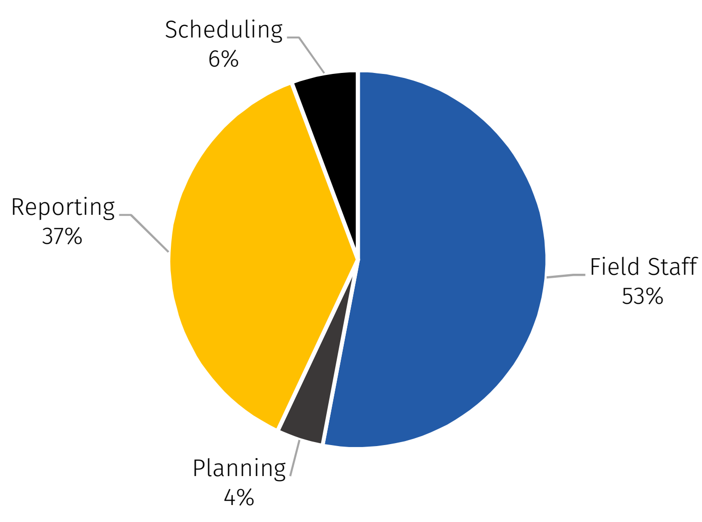
Reporting Software
Due to the asset management technology's limited reporting capabilities, data connections have been established with reporting software. Data is exported, analyzed, and reported through this software.

3.0 RISK ASSESSMENT

The asset management technology is a critical business application for Newfoundland Power. It is the central repository for the Company's substation, generation, transmission and distribution asset information. High-quality asset information forms the foundation for effective asset management.

The Technology is utilized by approximately 50% of the Company's employees (see Figure 2). Approximately 78% of the Company's asset management workflows are dependent on the Technology and would be disrupted in the event of a failure.[7]

Figure 2
Technology Users



[7] The Company's asset management processes contain 46 workflows and 36 are dependent on the Technology. 36/46=78%.

The vendor has indicated that the current technology will no longer be supported as of January 1st, 2027. Vendor support ensures that critical applications operate reliably and securely. Unsupported applications are more prone to failure and are at risk of cybersecurity threats and breaches.

The Technology is at the end of useful life and requires replacement. Given the criticality of the Company's asset management technology, as well as integrations to other critical business systems, continuing to operate the Technology without vendor support is not a viable option. Should a failure occur, processes that use the Technology would require additional effort, reducing employee efficiency.[8] Users would not have direct access to information necessary to support the Company's asset management program, including operational decisions and capital expenditures. The Technology, once unavailable, will no longer accommodate data storage. This will cause a disconnect between previously stored and newly generated information. Employees would have to rely upon paper notes, emails, and phone calls to communicate requirements and results, presenting higher risk of human error. The reliability and accessibility of the Company's asset information would decrease.

4.0 ASSSESSMENT OF ALTERNATIVES

The Company identified and assessed three alternatives to replacing its asset management technology: (i) do nothing; (ii) replace with modern equivalent; and (iii) replace with modern equivalent that includes advanced functionality. The assessment of each alternative is detailed below.

4.1 Description of Alternatives

(i) Alternative 1: Do Nothing
Alternative 1 involves continuing to use the existing technology after it has reached its end of life. The Technology would be unsupported by the vendor and the risk of "run-to-failure" would have to be accepted.

(ii) Alternative 2: Replace with Modern Equivalent
Alternative 2 involves replacing the existing technology with a modern equivalent. The new technology will support the Company's current asset management practices with the addition of enhancements that are native to modern solutions. The solution will be able to incorporate additional functionality as the Company's asset management capability matures.

(iii) Alternative 3: Replace with Advanced Functionality
Alternative 3 involves replacing the existing technology with a modern equivalent that includes advanced functionality. The new technology would support all current processes, with the addition of new functions to support advanced asset management. Additional functionality could include, but is not limited to predictive analytics, risk modelling, economic analysis, performance prediction, and asset investment planning.

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8 For example, preventative maintenance programs are facilitated automatically in the Technology. If programs were unavailable, employees would have to manually create preventative maintenance work orders and track the frequency, status, and due dates of all related work.

4.2 Evaluation of Alternatives

Alternative 1: Do Nothing introduces risk to the Company's operations and asset management practices. The Technology will be unsupported by the vendor on January 1st, 2027. There is risk that the unsupported technology will fail as surrounding IT infrastructure continues to evolve. This will cause a disruption to operations and asset management practices, impacting approximately 50% of the Company's employees. Implementing a new asset management technology to restore regular operations would take two years. *Alternative 1: Do Nothing* is not an acceptable option due to its associated risks.

Alternative 2: Replace with Modern Equivalent involves replacing the existing technology to eliminate the risk to Company's operations and asset management practices. The new technology will support all existing functionality, with the addition of enhancements that are native to modern solutions. Current business processes and asset management practices will continue to be supported, while enabling the Company to explore opportunities, such as improving data analytics and increasing the digitalization and utilization of data. *Alternative 2: Replace with Modern Equivalent* is an acceptable option as it aligns with industry best practices and will enable asset management maturity.[9,10]

Alternative 3: Replace with Advanced Functionality involves replacing the existing technology with a modern equivalent that includes advanced functionality. The Company does not currently have the data sources or processes in place to support advanced asset management functionality. These functions would be underutilized and their outputs would have low data integrity.[11] Implementation at this time would be complex, disruptive and expensive without providing the intended benefits. *Alternative 3: Replace with Advanced Functionality* is not right-sized for Newfoundland Power and therefore not an acceptable option.[12]

Implementing Alternative 2 avoids the risks of continuing to operate an unsupported technology while ensuring the replacement technology is a modern equivalent solution that is right-sized for Newfoundland Power's operations. This will avoid interruptions to the Company's operations and asset management procedures and enable the Company to explore new opportunities as it moves through its asset management journey.

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9 AMCL recommends the Company to replace its current technology with a modern equivalent that supports current asset management practices and can be extended to support future needs. See Appendix A for AMCL's report.

10 Newfoundland Power conducted a survey via the Center for Energy Advancement through Technological Innovation in 2022 to obtain a summary of asset management technology used in electric utilities. Out of the 18 North American utilities that responded, 16 of those currently use a commercial off-the-shelf asset management technology, one is in the process of implementing a commercial off-the-shelf asset management technology, and one uses an internally-developed solution.

11 Data models will be incomplete or inaccurate without an adequate input of data. Functions may not operate if data is missing.

12 AMCL does not recommend this alternative for Newfoundland Power. See Appendix A for AMCL's report.

5.0 PROJECT SCOPE AND COST

5.1 Project Overview

Newfoundland Power will replace its existing asset management technology over a two-year period at a cost of approximately $8,013,000. The replacement technology will be implemented prior to decommissioning the existing software, which will be end of life on January 1st, 2027.

The Company completed a Request for Information ("RFI") exercise to evaluate asset management technology solutions. The RFI results, combined with the Company's knowledge from past projects, were used to develop project cost and schedule estimates. Following Board approval, a Request for Proposal ("RFP") will be issued in preparation for the project to begin in 2025.

The replacement technology will support the functionality of the current technology with enhancements that are native to modern solutions.

5.2 Project Planning

The Company engaged AMCL to guide its asset management journey and recommend system capabilities for its technology replacement. AMCL reviewed the Company's practices, conducted workshops with each asset class group, and identified requirements for Newfoundland Power to use as a guide for the Technology replacement. The Company assessed these requirements and aligned them with *Alternative 2: Replace with Modern Equivalent*. The requirements were then used in an RFI to get an understanding of what vendor solutions offer.

AMCL provided an overview of the asset management landscape, including software types, functionalities, and potential vendors. Using AMCL's recommendations, an assessment from Gartner, and the Company's business relationships, 16 potential vendors were identified. The RFI was sent to these vendors with 11 responses received. Each submission was assessed, including alignment with current and future business requirements, implementation costs, ongoing operating costs, vendor viability and project duration. Six vendors were selected for software demonstrations, with each vendor showcasing how their software could meet the Company's requirements.

The RFI results and the Company's knowledge from past projects were used to develop project cost and schedule estimates. The Company is currently completing workshops internally to further refine project scope and requirements. Following Board approval, a RFP will be issued in preparation for the project to begin in 2025.

5.3 Project Cost

Table 1 provides a breakdown of the costs of replacing The Company's current asset management technology.

Table 1 Asset Management Technology Replacement Project Costs from 2025-2026 ($000s)			
Cost Category	2025	2026	Total
Material	1,794	2,512	4,306
Labour - Internal	1,357	1,694	3,051
Other	328	328	656
Total Additions	3,479	4,534	8,013

5.4 Project Schedule

Table 2 provides the schedule for implementing the asset management technology replacement.

Table 2 Asset Management Technology Replacement Project Schedule 2025-2026	
Stage/Phase	Timeframe
Pre-Implementation	Q1 2025
Procurement	3 months
Design and Configuration	Q2 2025 to Q1 2026
Design	3 months
Configuration and Integrations	9 months
Testing and Training	Q1 2026 – Q3 2026
Testing and Training	7 months
Implementation	Q4 2026
Deployment	2 months
Legacy Technology Retirement	Dec 2026

The project is scheduled to commence in Q1 2025, following Board approval. A replacement solution is expected to be implemented by Q4 2026.

6.0 CONCLUSION

Newfoundland Power's current asset management technology will no longer be supported by the vendor as of January 1st, 2027. The Company will replace the existing technology with a modern equivalent, starting in 2025. Replacement of the Technology is in alignment with industry best practice and will allow the Company to continue asset management practices, while providing a foundation for asset management maturity.

APPENDIX A:

AMCL Technology Report

LEADING ASSET MANAGEMENT

NEWFOUNDLAND POWER

Asset Management Advisory Services

Guidance on AM Technology Replacement

Version: Final

Date: 12th June 2024

endorsed ASSESSOR

endorsed TRAINER

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Draft	07/06/2024	Sarah Vine	Malcolm Christie	Sarah Vine

EXECUTIVE SUMMARY

Newfoundland Power's asset management software has been operating for over 20 years and is facing upcoming obsolescence. An extended support contract with the vendor has prolonged the service life of the current software, allowing Newfoundland Power to defer software replacement. However, the vendor will discontinue software support as of January 1st, 2027. Therefore, the need to select and implement a replacement system is urgent.

Asset Management Consulting Limited ("AMCL") was engaged by Newfoundland Power Inc. ("Newfoundland Power" or the "Company") to provide expertise and guidance on opportunities for its asset management journey and make recommendations on system requirements to consider for replacing its asset management software. This included making recommendations on system capability requirements for replacing its current asset management software and considering planned improvements in its asset management practices.

AMCL reviewed Newfoundland Power's Asset Management ("AM") practices to gather information regarding its software and technology solutions capabilities and business processes for collecting, managing, and utilizing asset information to support AM processes and decision-making.

This report is based on AMCL's review of Newfoundland Power's work management processes implemented in its current software and technology solutions. It aims to provide Newfoundland Power with insights to facilitate an informed decision in selecting the most suitable path forward.

Newfoundland Power currently uses its asset management software, technology, business processes, and other integrations to support business activities. Replacing the functionality available in the current asset management software, like with like, will adequately support Newfoundland Power's current asset management practices. However, given the improvements in software and technology since the original implementation, replacing the existing functionality like-for-like is no longer an option.

While the software's functionality was adequate when installed, it is now considerably limited compared to technological advances made over the past twenty years and the evolution of accepted good practices in asset management. Modern equivalent software and technologies are more sophisticated and will drive the need to increase data capture and improve data management.

At this time, it would be prudent to select and implement modern equivalent asset management software that can be expanded to incorporate additional functionality in the future. This will enable Newfoundland Power to progress on its asset management journey based on business need and capacity, unconstrained by software demands and limitations, and continue to support its asset management endeavours better into the future.

TABLE OF CONTENTS

1. ABOUT AMCL

AMCL is recognized as one of the world's leading Asset Management professional services firms, with a global reputation for leadership in Asset Management thinking and on-the-ground delivery. AMCL was founded in London in 1997 and has offices in New York, Toronto, Sydney, Dubai, and Hong Kong; we are now arguably the world's largest specialized Asset Management Advisory team. AMCL has been providing services to clients in North America since 2012 and has experience in Asset Management across the power, transit, municipalities, and water sectors.

AMCL is at the forefront of asset management thinking and practice and was a key participant in preparing the original 2004 version of BSI PAS 55, its 2008 revision, and the development of ISO 55001; AMCL has supported good Asset Management practices for over two decades. From supporting the creation of the Institute of Asset Management (IAM), the design of the original IAM 'six-box-model', the development of accredited training courses, and the dominance of ISO 55001; our influence is far more significant than we can imagine.

We have supported over 300 asset-intensive organizations globally; our recent North American Asset Management clients in the power sector include

- BC Hydro
- Columbia Power
- ComEd
- Constellation Energy
- ENAMX Power Corporation
- Manitoba Hydro
- National Grid
- New Brunswick Power
- New York Power Authority
- Newfoundland Power
- PG&E Power Generation
- SaskPower
- Southern California Edison
- Tacoma Power
- Tennessee Valley Authority
- Toronto Hydro
- TransAlta

Furthermore, AMCL is one of the few organizations worldwide to be an IAM-Endorsed Assessor for the IAM 39 subjects and ISO 55001, as well as an IAM-Endorsed Trainer; we are one of the major global providers of Institute of Asset Management (IAM) endorsed courses, including training several thousand people in North America.

Our Project Director, Sarah Vine, is the Director of Asset Management for AMCL Canada. She is a Chartered Engineer and registered Asset Management Professional with 30 years of industry experience in asset management in utilities, transportation, defence and civil infrastructure across the UK, Canada, the US and the UAE.

Sarah is also an IAM Canada Board Director, a Fellow of the IAM, sits on the IAM Global Knowledge Committee, and has been an Asset Management Assessor for over 15 years. Over her career, Sarah has been involved with various facets of asset management, including developing industry sector-specific asset management maturity models and regulatory assessment models.

In addition to her extensive experience leading maturity assessments and improvement plans, Sarah is a leader in developing industry standards for those practices. She contributed to the update of IAM's Asset Management – An Anatomy, a foundational document in asset management and is currently contributing to several of the IAM's Subject Specific Guidance documents.

2. INTRODUCTION

AMCL was engaged by Newfoundland Power to provide expertise on opportunities for progressing on its asset management journey and make recommendations on system requirements to consider when replacing its asset management software. These recommendations will enable future improvements in Newfoundland Power's asset management practices.

Through a number of workshops and a document review, AMCL reviewed Newfoundland Power's AM practices to gather information regarding its software and technology solutions capabilities and business processes for collecting, managing, and utilizing asset information to support AM processes and decision-making. Through the review, AMCL understood how Newfoundland Power uses its asset management technology and provided recommendations for the replacement of the existing AM Software.

Newfoundland Power is facing the upcoming obsolescence of its asset management software, which has been operating for over 20 years. While the functionality was adequate when installed, the software is now limited in functionality compared to the advances in software and technology made over the past twenty years, alongside the evolution of accepted good practices in asset management.

An extended support contract with the vendor has prolonged the service life of the current AM software, allowing Newfoundland Power to defer software replacement. This vendor support ensures the existing software receives critical security updates and software 'patches' to maintain compatibility with other software systems that receive ongoing security updates. However, the existing contract is expiring, and the vendor will discontinue software support as of January 1st, 2027. From this date, an alternate software solution will need to provide the functionality of the existing AM software. This will allow Newfoundland Power to continue supporting its asset management practices incorporated in the existing software.

Newfoundland Power currently uses its software and technology, along with a combination of business processes and other integrations. Integrations allow information to flow from one technology to another and, in some cases, have been implemented due to the existing technologies' functional limitations, including, but not limited to, in-house-developed inspection tools and external reporting. The existing asset management software supports existing work management processes for maintenance activities, including workflow management and tracking planned and corrective work orders. These functions include an asset registry, workflow management for preventative maintenance programs, work request tracking, and work order tracking to obtain a complete asset history.

Without an adequate work management system, Newfoundland Power would have to revert to manual processes for planning and dispatching work instructions to field staff, tracking completion, and incorporating corrective work orders, to name a few; the whole process would become a significant additional administrative burden. Therefore, they must replace their technology before the current technology becomes obsolete.

Replacing the functionality available in the current asset management software, like with like, will adequately support Newfoundland Power's current asset management practices. However, given the improvements in software and technology since the original implementation, replacing the existing functionality like-for-like is no longer an option. Newfoundland Power must consider replacing its technology with a modern equivalent. A modern equivalent will incorporate the evolution of good practice in asset management, provide the current technology functionality, and provide an opportunity for asset management to mature.

A detailed implementation program cannot be developed until after the software selection has been made. The obsolescence of this software necessitates a replacement solution before the expiration date; therefore, selecting and implementing a replacement system is now urgent.

2.1 ASSET INFORMATION AND DATA INTEGRITY

Newfoundland Power derives information from data sources to support decision-making. While information is available, it is typically consolidated from multiple data repositories and business systems. These information-gathering exercises are undertaken repeatedly, at different frequencies and are not automated. This includes asset Key Performance Indicators (KPIs) and asset condition information.

Asset information serves a dual purpose, supporting individual elements of the Asset Management System while concurrently enhancing the coordination among these elements. Therefore, effectively managing Asset Information is a vital factor for successful asset management, and it should also be well-structured.[1]

Effective asset management by utilities ensures investments are targeted where they will deliver the greatest stakeholder benefit. This means ensuring that ageing infrastructure is replaced or managed on a priority basis and that service levels are maintained. The challenge is in striking a balance between meeting performance targets and managing an ageing asset base with increasing risk of failures and affordability. Newfoundland Power utilizes information to make operational and capital decisions. This includes corrective and preventative maintenance for existing infrastructure, as well as longer-term planning.

[1] *IAM Asset Information, Strategy, Standard and Data Management Subject Specific Guide (SSG).*

3. ASSET MANAGEMENT SUPPORT SOFTWARE

Various decision support technologies are commercially available that focus on different decisions and information related to different stages of the asset lifecycle, from long-term strategic to mid-term tactical decisions, such as asset investment planning, to shorter-term operational decisions, such as maintenance work management, asset performance management, or project management.

Although these technologies may have overlapping functionalities, they usually cater to different business requirements and users. Depending on organizational needs and priorities, asset-intensive organizations may acquire and implement different asset management decision-support solutions.

3.1 ASSET MANAGEMENT SOFTWARE

Asset management software is primarily a transactional workflow system designed to manage asset lifecycle delivery activities and maintenance work management by managing relevant asset information and work processes. This usually includes asset maintenance history data and an asset register. The software supports the dispatch of planned preventative and corrective maintenance tasks.

One of the most important benefits of modern asset management software is capturing and storing field data that would otherwise be labour-intensive to gather manually. This includes data to optimize planned maintenance activities, refine asset standards and inform spare strategies, such as repair time, remedial action taken and maintenance costs. Asset management software is shown in Figure 1.

Many asset-intensive organizations have invested heavily in asset management software to streamline business processes and support operational asset management decisions. Asset management software solutions focus on operational decisions with essential functions for weekly and monthly maintenance planning and work management, all supported by an asset register representing the asset base. These areas of focus for asset management software are consistent with the functionality requirements for Newfoundland Power to support its current business practices.

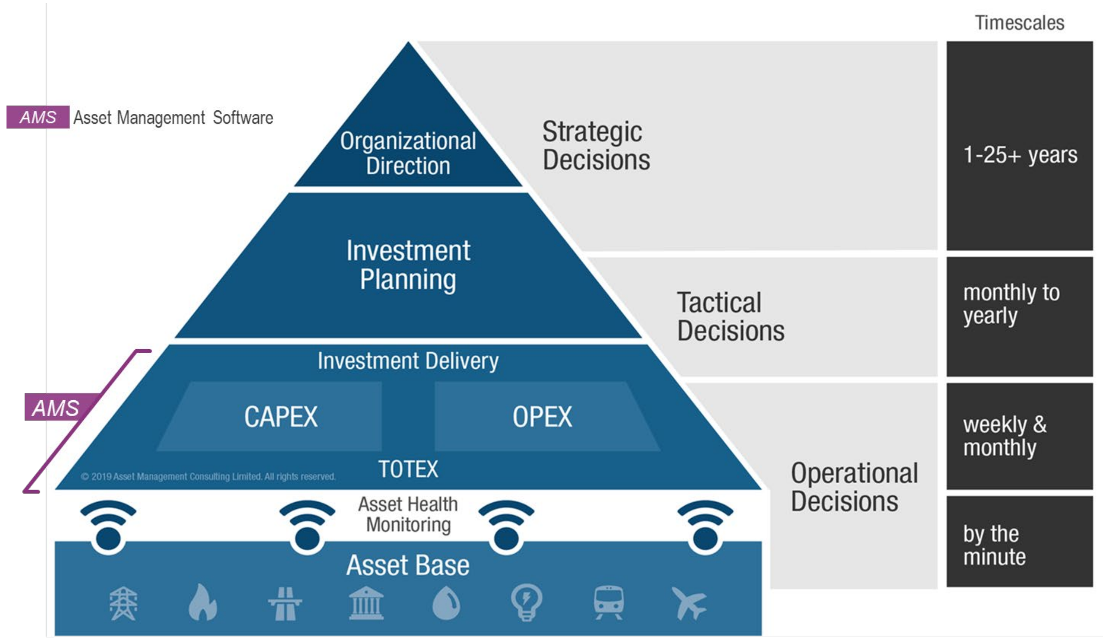

Figure 1 Asset management software and its scope of business support.

Newfoundland Power's existing technology supports near-term planned and corrective work management, annual maintenance scheduling and asset registry. This allows the Company to make informed operational and tactical decisions. These functions are required in a replacement technology to eliminate the risk of disruption in operations.

Modern asset management software systems, specifically those aimed at distributed utilities, also include GIS integration and remote connectivity. These provide the means of digital data collection and information transfer for remote field workers. The current software implementation does not support this functionality, which has led Newfoundland Power to develop other integrations to support these capabilities. Adding these functions in a replacement technology would allow Newfoundland Power to improve its data collection and processes and data integrity while creating some capacity to implement further business improvements as asset management capability matures.

3.2 BUSINESS REQUIREMENTS DEVELOPMENT

To issue a Request for Information (RFI) to potential software vendors, Newfoundland Power needed to define the minimum functionality required to maintain continuity of support to their current business practices.

AMCL undertook a systems and organizational analysis to identify Newfoundland Powers' information systems' current capability and use to define and assess its business requirements. AMCL reviewed Newfoundland Power's documented AM business processes and current practices. The focus was on how information is used to support processes such as engineering design, work management, inventory management, purchasing and requisition, and investment decision-making in the form of a walk-through of the existing solutions and applications that currently support AM decision-making processes.

AMCL developed a Business Requirements Catalogue to capture and summarize the essential business requirements to support current business practices. This was supplemented with additional requirements for good-practice asset decision-making, such as Asset Lifecycle Strategy, Asset Health Monitoring, Inspections & Diagnostics, and performance management reporting.

Given that modern equivalent software and technologies are more sophisticated, Newfoundland Power also needed some means of evaluating the additional functionality provided by each of the vendors, in relation to its current and anticipated future business needs. Capabilities currently supported by the existing asset management software implementation were highlighted to clearly identify the additional functionality available from each vendor more readily.

The Business Requirements Catalogue focuses on supporting Asset Management business capabilities and decision-making support. It does not cover non-functional technical requirements such as technology architecture requirements, cyber security, site reliability, or software license agreements. Newfoundland Power business analysts, the technology team, and asset owners must refine these requirements further to confirm user-specific requirements before they are included in the technology acquisition.

This Business Requirements Catalogue was used to support the Request for Information (RFI) Newfoundland Power recently issued to potential vendors. Newfoundland Power has since undertaken an internal review to identify what would need to occur within the new system when implemented and the medium-term and long-term goals; this will be used to inform the RFP.

4. RECOMMENDATIONS

4.1 IMPLEMENTATION APPROACH

Given the improvements in software and technology during the 20 years since the original implementation, a like-for-like replacement of the existing functionality is no longer an option. Newfoundland Power needs to replace its current software with a modern equivalent. It should consider this an opportunity to enable better asset management practices and increase the maturity of business capabilities that require more comprehensive asset data. Modern equivalent software and technologies are more sophisticated and will drive the need to increase data capture and improve data management.

Considerations around software selection and deployment will impact how Newfoundland Power conducts its business in the short term and its ability to mature its asset management capability in the future. There are two broad approaches to implementing software, including asset management software: business-led change and technology-led change.

- **Business-led** would mean opting for a modern equivalent system that supports current asset management practices but can be extended to incorporate additional functionality as their asset management capability matures or
- **Technology-led** would involve embracing an enhanced solution with extended functionality now, which will drive the need to define and implement new business processes, increase data capture, and improve data management.

Business-led change is driven by an overall vision and structured around achieving long-term organizational objectives and priorities. It is often built around a business improvement plan or road map considering existing business capabilities: people, processes, systems, tools, and culture. The business systems, software, and tools are deployed to support and enable the development of business capabilities.

Technology-led change is driven by the overall vision, but implementing the enabling technology defines the business capability requirements. The software or technology defines the business processes and data that must be in place for 'go-live.' Off-the-shelf (OTS) software will usually have pre-configured workflows and business rules, which Newfoundland Power may need to change its current business practices to suit. This approach puts significant pressure on the business to accommodate the demands of systems implementation alongside their usual day-to-day activities. A technology-led approach is often disproportionately disruptive and expensive for smaller organizations like Newfoundland Power. Technology lead change also requires a foundation of data and processes relevant to the pre-defined workflows which are not currently available within the Company.

Given Newfoundland Power's size and capacity, a business-led change would be the most appropriate. In developing the requirements for the software replacement, the focus should be on supporting the current asset management practices and enabling more mature asset management practices as they evolve within Newfoundland Power.

At this time, it would be prudent to select and implement asset management software that can be expanded to incorporate additional functionality in the future. This will enable Newfoundland Power to progress on its asset management journey based on business need and capacity, unconstrained by software demands and limitations, and continue to support its asset management endeavours better into the future.[2]

[2] *Newfoundland Power Asset Management Review.*

4.2 VENDOR/SOFTWARE SELECTION

In evaluating different solutions, Newfoundland Power should consider the following aspects of vendors in addition to their products' functional capabilities and license cost:

- Company vision and product development strategy;
- The breadth of experience and market penetration in electrical utility companies;
- Previous integration experience with finance systems and GIS for linear assets;
- Implementation methodology;
- User and peer community strength; and
- Support and professional services, including guided and on-demand training materials.

These vendor characteristics can significantly impact the successful implementation by supporting the Newfoundland Power technology and asset management teams and facilitating required change management through high-quality and accessible training material and timely responses to technical issues.

Newfoundland Power should consider software that allows modular or phased deployment of functionality rather than an 'all-in' system dependent on data not currently being captured or stored outside the system; business processes may be required to address short-term functionality gaps. Also, each software will have minimum data requirements, prerequisites, and dependencies to get the proposed system configured and functional.

5. CONCLUSION

For Newfoundland Power, asset management technology provides functionality that supports business practices. As of January 1st, 2027, the vendor will no longer support the technology, so the Company must replace it to allow the continuation of asset management practices and support decision-making.

An asset management technology replacement with a modern equivalent will align with better practices for asset management, focusing on increasing the maturity of business capabilities that require more comprehensive asset data for their improvement. In developing the requirements for the software replacement, the focus should be on supporting the current asset management practices and enabling more mature asset management practices as they evolve within Newfoundland Power. Modern equivalent technologies will allow digital opportunities aligned with good asset management practices.

At this time, it would be prudent to select and implement asset management software that can be expanded to incorporate additional functionality in the future. This will enable Newfoundland Power to progress on its asset management journey based on business need and capacity, unconstrained by software demands and limitations, and continue to support its asset management endeavours better into the future.

NEWFOUNDLAND POWER
A FORTIS COMPANY

7.1 Rate Base: Additions, Deductions and Allowances

June 2024

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1.0 INTRODUCTION

In the *2025 Capital Budget Application* (the "Application"), Newfoundland Power Inc. ("Newfoundland Power" or the "Company") seeks final approval of its 2023 average rate base. This is consistent with current regulatory practice before the Board.

Newfoundland Power's 2023 average rate base of $1,290,079,000 is set out in Schedule D to the Application.

To meet the cost of service standard, rate base, as calculated in accordance with the Asset Rate Base Method, should reflect what the utility must finance. For investment in utility plant, it is the depreciated value of the plant that must be effectively financed. However, for rate base to fully reflect the financing requirements associated with the provision of regulated service, it must also be adjusted to reflect other costs required to provide service.

Conceptually, additions to rate base are costs that have been incurred to provide service, but have not yet been recovered through customer rates. Deductions from rate base represent amounts that have been recovered through customer rates in advance of the required utility payment for those costs. Rate base allowances simply reflect the cost associated with maintaining the required working capital and inventories necessary to provide service. Each of these items affects what the utility must finance.

In Order No. P.U. 19 (2003), the Board, in effect, ordered Newfoundland Power to file with its capital budget applications: (i) evidence related to changes in deferred charges, including pension costs; and (ii) a reconciliation of average rate base and average invested capital.

In Order No. P.U. 32 (2007), the Board approved Newfoundland Power's calculation of rate base in accordance with the Asset Rate Base Method and required Newfoundland Power to continue to file as part of its annual returns, information relating to changes in deferred charges, including pension costs. The Company's calculation of rate base included in its annual returns details the additions to, deductions from, and allowances in rate base.[1]

Further to Newfoundland Power's 2023 annual returns, this report provides a review of the 2022 and 2023 additions, deductions and allowances to support the Company's 2023 average rate base set out in Schedule D to the Application.

[1] Newfoundland Power's 2023 annual returns are provided in its *2023 Annual Report to the Board* which was filed with the Board on March 28, 2024. Return 3 provides the calculation of the Company's 2023 average rate base.

2.0 ADDITIONS TO RATE BASE

2.1 Summary

Table 1 summarizes Newfoundland Power's additions to rate base for 2022 and 2023.

Table 1
Additions to Rate Base
2022-2023
($000s)

	2022	2023
Deferred Pension Costs	95,095	101,430
Credit Facility Costs	87	105
Cost Recovery Deferral – Conservation	19,359	20,708
Cost Recovery Deferral – 2022 Revenue Shortfall	459	229
Cost Recovery Deferral – Load Research and Retail Rate Design Review	20	189
Cost Recovery Deferral – Pension Capitalization	-	799
Customer Finance Programs	1,472	1,199
Total Additions	$116,492	$124,659

Additions to rate base were approximately $124.7 million in 2023. This is approximately $8.2 million higher than 2022. The higher additions to rate base in 2023 primarily reflect: (i) increases in deferred pension costs;[2] ii) increases in deferred recovery of annual customer energy conservation program costs; and iii) the implementation of the pension capitalization cost deferral account in 2023 as approved in Order No. P.U. 3 (2022).

This section outlines the additions to rate base in further detail.

2.2 Deferred Pension Costs

The difference between pension plan *funding* and pension plan *expense* associated with the Company's defined benefit pension plan is captured as a deferred pension cost in accordance with Order No. P.U. 17 (1987).[3]

[2] The increase in 2023 is due primarily to a higher than expected return on the Company's defined benefit pension plan assets, partially offset by an actuarial loss associated with a lower discount rate at December 31, 2023.

[3] Deferred pension costs were approved for inclusion in average rate base in Order No. P.U. 19 (2003).

Table 2 provides details of changes in Newfoundland Power's deferred pension costs for 2022 and 2023.

Table 2
Deferred Pension Costs
2022-2023
($000s)

	2022	2023
Deferred Pension Costs, January 1st	88,888	95,095
Pension Plan Funding	2,730	1,515
Pension Plan Expense	3,477	4,820
Deferred Pension Costs, December 31 st	$95,095	$101,430

2.3 Credit Facility Costs

In Order No. P.U. 1 (2005), the Board approved Newfoundland Power's issue of a $100 million committed revolving term credit facility.

The balance as of January 1, 2022 includes the unamortized credit facility issue costs related to the 2018, 2019 and 2021 amendments.[4] In the Company's *2022/2023 General Rate Application*, the unamortized credit facility issue costs of $31,000 related to the 2018 and 2019 amendments were included as a component of the Company's cost of capital for revenue requirement purposes in 2022 and 2023. As these costs are now reflected in customer rates, they are not included in rate base for those years.

In August 2022, the committed credit facility was renegotiated to extend its maturity date to August 2027. Costs related to this amendment totalled $38,000 and are being amortized over the five-year life of the agreement, beginning in 2022.

In August 2023, the committed credit facility was renegotiated to extend its maturity date to August 2028. Costs related to this amendment totalled $44,000 and are being amortized over the five-year life of the agreement, beginning in 2023.

The unamortized credit facility issue costs associated with the 2021, 2022 and 2023 credit facility amendments are included in rate base for 2022 and 2023 as these costs have not yet been reflected in the Company's revenue requirement.

[4] In August 2018, the maturity date of the committed credit facility was extended to August 2023 at a cost of $40,000 to be amortized over the five-year life of the agreement, beginning in 2018. In August 2019, the maturity date of the committed credit facility was extended to August 2024 at a cost of $35,000 to be amortized over the five-year life of the agreement, beginning in 2019. There were no amendments to the credit facility in 2020. In August 2021, the maturity date of the committed credit facility was extended to August 2026 at a cost of $71,000 to be amortized over the five-year life of the agreement, beginning in 2021.

Table 3 provides details of Newfoundland Power's amortization of deferred credit facility issue costs for 2022 and 2023.

Table 3
Credit Facility Costs
2022-2023
($000s)

	2022	2023
Balance, January 1st	96	87
Cost – Reduction	(31)	-
Cost – Addition	38	44
Amortization	(16)	(26)
Balance, December 31st	$87	$105

2.4 Cost Recovery Deferral – Conservation

In Order No. P.U. 13 (2013), the Board approved the deferral of annual customer energy conservation program costs and the amortization of annual costs over seven years, with recovery through the Rate Stabilization Account ("RSA"). In Order No. P.U. 3 (2022), the Board approved the amortization of annual costs over 10 years, commencing January 1, 2021 for historical balances and annual charges.

Table 4 provides details of the amortizations of the deferred cost recovery related to conservation for 2022 and 2023.

Table 4
Cost Recovery Deferral – Conservation
2022-2023
($000s)

	2022	2023
Balance, January 1st	16,421	19,359
Implementation True Up[5]	1,875	-
Cost	3,659	4,311
Amortization	(2,596)	(2,962)
Balance, December 31st	$19,359	$20,708

5 Implementation of Order No. P.U. 3 (2022) resulted in revised balances for annual deferred customer energy conservation program costs incurred up to December 31, 2021.

2.5 Cost Recovery Deferral – 2022 Revenue Shortfall

The Board's disposition of Newfoundland Power's *2022/2023 General Rate Application* in Order No. P.U. 3 (2022) resulted in a $0.93 million ($0.65 million after-tax) shortfall in the recovery of the revenue requirement for 2022 (the "2022 Revenue Shortfall"). The Order approved the recovery of this shortfall through a regulatory amortization beginning on March 1, 2022 and ending December 31, 2024.

Table 5 provides details of the amortizations of the deferred cost recovery related to the 2022 Revenue Shortfall for 2022 and 2023.

Table 5
Cost Recovery Deferral – 2022 Revenue Shortfall
2022-2023
($000s)

	2022	2023
Balance, January 1st	-	459
Cost	651	-
Amortization	(192)	(230)
Balance, December 31st	$459	$229

2.6 Cost Recovery Deferral – Load Research and Retail Rate Design Review

In Order No. P.U. 3 (2022), the Board approved the deferral of costs incurred in conducting a Load Research Study and a Retail Rate Design Review.

Table 6 provides details of changes to the balances related to Load Research and Retail Rate Design Review for 2022 and 2023.

Table 6
Cost Recovery Deferral – Load Research and Retail Rate Design Review
2022-2023
($000s)

	2022	2023
Balance, January 1st	-	20
Cost	20	169
Balance, December 31st	$20	$189

2.7 Cost Recovery Deferral – Pension Capitalization

In Order No. P.U. 3 (2022), the Board approved the Pension Capitalization Cost Deferral Account to amortize the forecast revenue requirement increase of $1,427,000 related to income tax impacts associated with pension capitalization over a five-year period commencing in January 2023.

Table 7 provides details of the amortizations of the deferred cost recovery related to pension capitalization for 2022 and 2023.

Table 7
Cost Recovery Deferral – Pension Capitalization 2022-2023
($000s)

	2022	2023
Balance, January 1st	-	-
Cost	-	999
Amortization	-	(200)
Balance, December 31st	-	$799

2.8 Customer Finance Programs

Customer finance programs are loans provided to customers for the purchase and installation of products and services related to conservation programs and contributions in aid of construction.

Table 8 provides details of changes to balances related to customer finance programs for 2022 and 2023.

Table 8
Customer Finance Programs
2022-2023
($000s)

	2022	2023
Balance, January 1st	1,755	1,472
Change	(283)	(273)
Balance, December 31st	$1,472	$1,199

3.0 DEDUCTIONS FROM RATE BASE

3.1 Summary

Table 9 summarizes Newfoundland Power's deductions from rate base for 2022 and 2023.

Table 9
Deductions from Rate Base
2022-2023
($000s)

	2022	2023
Other Post-Employment Benefits	80,151	84,357
Customer Security Deposits	1,270	653
Accrued Pension Obligation	5,300	5,397
Accumulated Deferred Income Taxes	18,076	30,609
Weather Normalization Reserve	6,576	(6,321)
Demand Management Incentive Account	107	(978)
Refundable Investment Tax Credits	-	292
Excess Earnings Account	-	3,714
Total Deductions	$111,480	$117,723

Deductions from rate base were approximately $117.7 million in 2023. Newfoundland Power's total deductions from rate base in 2023 were approximately $6.2 million higher than 2022.

The increased deductions from rate base were primarily due to: (i) an increase in accumulated deferred income taxes reflecting continued investment in the electricity system;[6] (ii) an increase in the Other Post-Employment Benefits ("OPEBs") liability which reflects the amortization of the OPEBs regulatory asset;[7] and (iii) excess earnings which reflects regulated earnings in excess of the 6.57% upper limit of the range of return on rate base approved by the Board for 2023. Increases were partially offset by changes in the weather normalization reserve and the demand management incentive account.

This section outlines the deductions from rate base in further detail.

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6 This includes the implementation of the Company's new Customer Information System in 2023.

7 In Order No. P.U. 31 (2010), the Board approved, beginning in 2011, the adoption of the accrual method of accounting for OPEBs and related income tax. In addition, the Board approved a 15-year straight line amortization of a transitional balance starting in 2011.

3.2 Other Post-Employment Benefits

Newfoundland Power's OPEBs are comprised of retirement allowances for retiring employees, as well as health, medical and life insurance for retirees and their dependents.

Table 10 provides details of the changes related to the net OPEBs liability for 2022 and 2023.

Table 10
Other Post-Employment Benefits
2022-2023
($000s)

	2022	2023
Regulatory Asset	10,512	7,008
OPEBs Liability	90,663	91,365
Net OPEBs Liability	$80,151	$84,357

3.3 Customer Security Deposits

Customer security deposits are provided by customers in accordance with the *Schedule of Rates, Rules and Regulations*.

Table 11 provides details on the changes in customer security deposits for 2022 and 2023.

Table 11
Customer Security Deposits
2022-2023
($000s)

	2022	2023
Balance, January 1st	1,401	1,270
Change	(131)	(617)
Balance, December 31st	$1,270	$653

3.4 Accrued Pension Obligation

Accrued pension obligation is the cumulative costs of Newfoundland Power's unfunded pension plans net of associated benefit payments.

Table 12 provides details of changes related to the accrued pension obligation for 2022 and 2023.

Table 12
Accrued Pension Obligation
2022-2023
($000s)

	2022	2023
Balance, January 1st	5,168	5,300
Change	132	97
Balance, December 31st	$5,300	$5,397

3.5 Accumulated Deferred Income Taxes

Accumulated deferred income taxes result from timing differences related to the payment of income taxes and the recognition of income taxes for financial reporting and regulatory purposes.

Currently, Newfoundland Power recognizes deferred income taxes, for regulatory purposes, with respect to timing differences related to plant investment, pension costs and other employee future benefit costs.[8,9,10]

[8] In Order Nos. P.U. 20 (1978), P.U. 21 (1980) and P.U. 17 (1987), the Board approved the Company's use of Tax Accrual Accounting to recognize deferred income tax liabilities associated with plant investment.

[9] In Order No. P.U. 32 (2007), the Board approved the use of Tax Accrual Accounting to recognize deferred income taxes related to timing differences between pension funding and pension expense.

[10] In Order No. P.U. 31 (2010), the Board approved the use of Tax Accrual Accounting to recognize deferred income taxes related to timing differences between other employee future benefits recognized for tax purposes (cash payments) and other employee future benefit expense recognized for accounting purposes (accrual basis).

Table 13 provides details of changes in the accumulated deferred income taxes for 2022 and 2023.

Table 13
Accumulated Deferred Income Taxes
2022-2023
($000s)

	2022	2023
Balance, January 1st	15,976	18,076
Change	2,100	12,533
Balance, December 31st	$18,076	$30,609

3.6 Weather Normalization Reserve

In Order No. P.U. 1 (1974), the Board ordered that rate base be adjusted for the balance in the Weather Normalization Reserve.

Table 14 provides details of changes in the balance of the Weather Normalization Reserve for 2022 and 2023.

Table 14
Weather Normalization Reserve
2022-2023
($000s)

	2022	2023
Balance, January 1st	2,020	6,576
Operation of the reserve	6,576	(6,321)
Transfers to the RSA	(2,020)	(6,576)
Balance, December 31st	$6,576	($6,321)

The disposition of the December 31, 2023 balance in the Weather Normalization Reserve account to the RSA as of March 31, 2024 was approved by the Board in Order No. P.U. 11 (2024).

3.7 Demand Management Incentive Account

In Order No. P.U. 32 (2007), the Board approved the Demand Management Incentive Account (the "DMI Account") to replace the Purchase Power Unit Cost Variance Reserve.

Table 15 provides details of the DMI Account for 2022 and 2023.

Table 15 DMI Account 2022-2023 ($000s)		
	2022	2023
Balance, January 1st	(1,342)	107
Transfers to the RSA	1,342	(107)
Operation of DMI	107	(978)
Balance, December 31st	$107	($978)

The disposition of the December 31, 2023 balance in the DMI Account to the RSA as of March 31, 2024 was approved in Order No. P.U. 12 (2024).

3.8 Refundable Investment Tax Credits

The Refundable Investment Tax Credit relates to the scientific research and experimental development (SR&ED) tax incentives that are recognized into income in a manner that is consistent with the amortization of the capital assets to which they relate.

Table 16 provides details on the Refundable Investment Tax Credits for 2022 and 2023.

Table 16 Refundable Investment Tax Credits 2022-2023 ($000s)		
	2022	2023
Balance, January 1st	-	-
Change	-	292
Balance, December 31st	-	$292

3.9 Excess Earnings Account

In Order No. P.U. 23 (2013), the Board approved the definition of the Excess Earnings Account. In 2023, Newfoundland Power's regulated earnings exceeded the upper limit of the range of return on rate base approved by the Board for 2023 by $3,714,000.[11] Disposition of any balance in the Excess Earnings Account shall be as determined by the Board.

Table 17 provides details of the Excess Earnings Account for 2022 and 2023.

Table 17
Excess Earnings Account
2022-2023
($000s)

	2022	2023
Balance, January 1st	-	-
Change	-	3,714
Balance, December 31st	-	$3,714

4.0 RATE BASE ALLOWANCES

4.1 Summary

The cash working capital allowance, together with the materials and supplies allowance, form the total allowances that are included in the Company's rate base. This represents the average amount of investor-supplied working capital necessary to provide service.

4.2 Cash Working Capital Allowance

The cash working capital allowance recognizes that a utility must finance the cost of its operations until it collects the revenues to recover those costs.

[11] The allowed regulated earnings are based on a rate of return on rate base of 6.57% calculated as the approved rate of return on rate base of 6.39% and 18 basis points for the upper limit of the range as approved by the Board in Order No. P.U. 3 (2022).

Table 18 provides details on changes in the cash working capital allowance for 2022 and 2023.

Table 18
Rate Base Allowances
Cash Working Capital Allowance [12]
2022-2023
($000s)

	2022	2023
Gross Operating Costs	556,396	594,981
Income Taxes	14,055	(3,484)
Municipal Taxes Paid	17,646	18,398
Non-Regulated Expenses	(2,264)	(2,091)
Total Operating Expenses	$585,833	$607,804
Cash Working Capital Factor	1.137%	1.199%
	$6,661	$7,289
HST Adjustment	44	15
Cash Working Capital Allowance	$6,705	$7,304

4.3 Materials and Supplies Allowance

Including a materials and supplies allowance in rate base provides a utility a means to reasonably recover the cost of financing its inventories that are not related to the expansion of the electrical system.[13]

[12] The cash working capital allowance for 2022 and 2023 is calculated based on the method used to calculate the 2022/2023 Test Year average rate base approved by the Board in Order No. P.U. 3 (2022).

[13] Financing costs for inventory related to the expansion of the electrical system are recovered through the use of an allowance for funds used during construction and are capitalized upon project completion.

Table 19 provides details on changes in the materials and supplies allowance for 2022 and 2023.

Table 19
Rate Base Allowances
Materials and Supplies Allowance
2022-2023
($000s)

	2022	2023
Average Materials and Supplies	14,802	18,262
Expansion Factor[14]	19.08%	19.08%
Expansion	2,824	3,484
Materials and Supplies Allowance	$11,978	$14,778

14 The expansion factor is based on a review of actual inventories used for expansion projects. The calculation of the 2022 and 2023 rate base, including a materials and supplies allowance based upon an expansion factor of 19.08%, was approved by the Board in Order No. P.U. 3 (2022).