WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

June 27, 2025

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 2026 Capital Budget Application

Enclosed are the original and 10 copies of Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") *2026 Capital Budget Application* (the "Application").

The Application seeks an order approving the Company's proposed 2026 capital budget and fixing and determining Newfoundland Power's average rate base for 2024.

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 are filed in compliance 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

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.
2026 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 2026 Capital Budget; and
(b) fixing and determining its 2024 rate base.

2026 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 2026 Capital Budget; and
(b) fixing and determining its 2024 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 2026 capital expenditures in the amount of $75,158,000 comprising projects and programs costing in excess of $750,000;

    (b) proposed single-year 2026 capital expenditures of $10,212,000 comprising projects and programs costing $750,000 and under;

    (c) proposed multi-year projects commencing in 2026 with capital expenditures of $6,131,000 in 2026, $40,848,000 in 2027 and $8,040,000 in 2028; and

    (d) ongoing multi-year projects previously approved in Order No. P.U. 2 (2024) and Order No. P.U. 27 (2024) with capital expenditures of $46,442,000 in 2026 and $9,816,000 in 2027 (the "Previously Approved Multi-Year Projects").

3. The proposed 2026 Capital Budget includes contributions toward the cost of improvements or additions to property that Newfoundland Power intends to demand from its customers in 2026 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.[1]

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[1] In its *2025 Capital Budget Application*, Newfoundland Power sought the Board's approval of additional expenditures in 2026 for previously approved projects in relation to the rebuilding of Transmission Line 94L.The request was approved in Order No. P.U. 27 (2024).

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 2024 of $1,357,191,000.[2]

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 2026 in the amount of $137,943,000 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 $75,158,000;
      ii. single-year project and program expenditures $750,000 and under in the amount of $10,212,000;
      iii. multi-year projects with 2026 expenditures of $6,131,000; and
      iv. previously approved multi-year projects with 2026 expenditures of $46,442,000.

   (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 $40,848,000 in 2027 and $8,040,000 in 2028 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 2024 in the amount of $1,357,191,000 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.

[2] Additional information regarding deferred charges and a reconciliation of average rate base to invested capital is provided in report *5.1 Rate Base: Additions, Deductions and Allowances* filed with the Application in compliance with Order No. P.U. 19 (2003).

DATED at St. John's, Newfoundland and Labrador, this 27th day of June, 2025.

NEWFOUNDLAND POWER INC.

Dominic Foley

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

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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 2026 Capital Budget; and
(b) fixing and determining its 2024 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 27th day of June, 2025:

Dominic Foley
Barrister and Solicitor

Byron Chubbs

2026 CAPITAL BUDGET SUMMARY

Expenditure Type	Budget ($000s)
Single-Year Projects and Programs Over $750,000	75,158
Single-Year Projects and Programs $750,000 and Under	10,212
Multi-Year Projects Commencing in 2026	6,131
Multi-Year Projects Approved in Previous Years	46,442
Total	**$ 137,943**

Asset Class	Budget ($000s)
Distribution	61,824
Substations	22,634
Transmission	22,114
Generation - Hydro	2,142
Generation - Thermal	331
Information Systems	12,673
Telecommunications	281
General Property	4,089
Transportation	5,805
Unforeseen Allowance	750
General Expenses Capitalized	5,300
Total	**$ 137,943**

2026 CAPITAL BUDGET
SINGLE-YEAR PROJECTS AND PROGRAMS
OVER $750,000

Projects and Programs	**Budget ($000s)**
Distribution	
Extensions	16,747
Reconstruction	7,674
LED Street Lighting Replacement	5,559
Rebuild Distribution Lines	5,263
Replacement Transformers	4,954
New Transformers	4,394
New Services	4,218
Relocate/Replace Distribution Lines for Third Parties	3,702
New Street Lighting	2,425
Mount Carmel Pond Feeder Extension CAB 01	1,346
Replacement Street Lighting	914
Total Distribution	**$57,196**
Substations	
Substation Replacements Due to In-Service Failures	4,733
Total Substations	**$4,733**
Transmission	
Transmission Line Maintenance	3,306
Total Transmission	**$3,306**

2026 CAPITAL BUDGET
SINGLE-YEAR PROJECTS AND PROGRAMS
OVER $750,000

Projects and Programs	**Budget ($000s)**
Information Systems	
Shared Server Infrastructure	990
Application Enhancements	968
System Upgrades	965
Cybersecurity Upgrades	950
Total Information Systems	**$3,873**
Unforeseen Allowance	
Allowance for Unforeseen Items[1]	750
Total Unforeseen Allowance	**$750**
General Expenses Capitalized	
General Expenses Capitalized	5,300
Total General Expenses Capitalized	**$5,300**
Total	**$75,158**

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.

2026 CAPITAL BUDGET
SINGLE-YEAR PROJECTS AND PROGRAMS
$750,000 AND UNDER

Projects and Programs	Budget ($000s)
Distribution	
Distribution Feeder GDL 03 Loop 1 and 2 Refurbishment	722
New Meters	701
Distribution Feeder Automation	648
Replacement Meters	562
Replacement Services	382
Allowance for Funds Used During Construction	223
Total Distribution	**$3,238**
Substations	
Substation Protection and Control Replacements	719
Substation Ground Grid Upgrades	350
Total Substations	**$1,069**
Generation - Hydro	
Hydro Plant Replacements Due to In-Service Failures	736
Cape Broyle and Horsechops Plant Control Upgrades	398
Total Generation - Hydro	**$1,134**
Generation - Thermal	
Thermal Plant Replacements Due to In-Service Failures	331
Total Generation - Thermal	**$331**
Information Systems	
Personal Computer Infrastructure	733
Network Infrastructure	495
Total Information Systems	**$1,228**

2026 CAPITAL BUDGET
SINGLE-YEAR PROJECTS AND PROGRAMS
$750,000 AND UNDER

Projects and Programs	Budget ($000s)
Telecommunications	
Mount Carmel Pond Dam Fibre	150
Communications Equipment Upgrades	131
Total Telecommunications	**$281**
General Property	
Additions to Real Property	714
Specialized Tools and Equipment	616
Tools and Equipment	605
Physical Security Upgrades	506
Building Accessibility Improvements	490
Total General Property	**$2,931**
Total	**$10,212**

2026 CAPITAL BUDGET
MULTI-YEAR PROJECTS

Multi-Year Projects Commencing in 2026

Class	Project Description		2026	2027	2028	Total
Distribution	Feeder Additions for Load Growth[2]		250	887	-	1,137
Substations	Lewisporte-Boyd's Cove 138kV Conversion		568	7,551	-	8,119
Substations	Substation Spare Power Transformer Inventory		13	3,906	-	3,919
Substations	King's Bridge Substation Power Transformer Replacement		12	93	2,866	2,971
Substations	Greenspond Substation Refurbishment & Modernization		374	2,578	-	2,952
Substations	Molloy's Lane Substation Power Transformer Replacement		12	2,789	-	2,801
Substations	Mobile Substation Power Transformer Replacement		12	93	2,522	2,627
Transmission	Transmission Line Rebuild - 100L Sunnyside to Clarenville		450	13,323	-	13,773
Information Systems	Customer Communications Modernization		782	1,175	-	1,957
Information Systems	Geographic Information System Upgrade		500	5,173	2,652	8,325
General Property	Summerford Building Replacement		155	562	-	717
Transportation	Replace Vehicles and Aerial Devices 2026-2027		3,003	2,718	-	5,721
		Total	**$6,131**	**$40,848**	**$8,040**	**$55,019**

2 DLK-03 is a 2-year Feeder Additions for Load Growth project proposed to commence in 2026.

2026 CAPITAL BUDGET
MULTI-YEAR PROJECTS

Multi-Year Projects Approved in Previous Years

Class	Project Description	2025	2026	2027	Total
Distribution	Distribution Feeder SCT 01 & BLK 01 Relocation3	649	1,140	-	1,789
Substations	Summerville Substation Refurbishment & Modernization[4]	511	4,510	-	5,021
Substations	Lockston Substation Refurbishment & Modernization[5]	305	4,521	-	4,826
Substations	Gander Substation Power Transformer Replacement[6]	17	3,905	263	4,185
Substations	Pulpit Rock Substation Power Transformer Replacement[7]	17	2,905	-	2,922
Transmission	New Transmission Line from Lewisporte to Boyd's Cove[8]	1,886	9,283	9,553	20,722
Transmission	Transmission Line 94L Rebuild[9]	3,485	9,075	-	12,560
Generation - Hydro	Mount Carmel Pond Dam Refurbishment[10]	3,608	1,008	-	4,616
Information Systems	Asset Management Technology Replacement[11]	3,479	4,534	-	8,013
Information Systems	Outage Management System Upgrade[12]	1,811	1,459	-	3,270
Information Systems	Microsoft Enterprise Agreement[13]	297	297	-	594
General Property	Port Union Building Replacement[14]	278	1,003	-	1,281
Transportation	Replace Vehicles and Aerial Devices 2025-2026[15]	2,173	2,802	-	4,975
	Total	**$18,516**	**$46,442**	**$9,816**	**$74,774**

3 Approved in Order No. P.U. 27 (2024). See Newfoundland Power's *2025 Capital Budget Application*, Schedule B, pages 10 to 11.
4 Approved in Order No. P.U. 27 (2024). See Newfoundland Power's *2025 Capital Budget Application*, Schedule B, pages 51 to 54.
5 Approved in Order No. P.U. 27 (2024). See Newfoundland Power's *2025 Capital Budget Application*, Schedule B, pages 59 to 62.
6 Approved in Order No. P.U. 27 (2024). See Newfoundland Power's *2025 Capital Budget Application*, Schedule B, pages 63 to 66.
7 Approved in Order No. P.U. 27 (2024). See Newfoundland Power's *2025 Capital Budget Application*, Schedule B, pages 67 to 70.
8 Approved in Order No. P.U. 27 (2024). See Newfoundland Power's *2025 Capital Budget Application*, Schedule B, pages 77 to 82.
9 Approved in Order No. P.U. 27 (2024). See Newfoundland Power's *2025 Capital Budget Application*, Schedule B, pages 83 to 87.
10 Approved in Order No. P.U. 27 (2024). See Newfoundland Power's *2025 Capital Budget Application*, Schedule B, pages 100 to 103.
11 Approved in Order No. P.U. 27 (2024). See Newfoundland Power's *2025 Capital Budget Application*, Schedule B, pages 113 to 115.
12 Approved in Order No. P.U. 27 (2024). See Newfoundland Power's *2025 Capital Budget Application*, Schedule B, pages 110 to 112.
13 Approved in Order No. P.U. 02 (2024). See Newfoundland Power's *2024 Capital Budget Application*, Schedule B, pages 121 to 123.
14 Approved in Order No. P.U. 27 (2024). See Newfoundland Power's *2025 Capital Budget Application*, Schedule B, pages 134 to 136.
15 Approved in Order No. P.U. 27 (2024). See Newfoundland Power's *2025 Capital Budget Application*, Schedule B, pages 138 to 142.

2026 CAPITAL PROJECTS AND PROGRAMS

OVER $750,000

2026 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 2026, 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 2026:

(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	2	3	4	5
		Negligible	Minor	Moderate	Serious	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 *2026 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.

2026 CAPITAL BUDGET

SCHEDULE B TABLE OF CONTENTS

DISTRIBUTION

Title: **LED Street Lighting Replacement**
Asset Class: **Distribution**
Category: **Project**
Investment Classification: **Service Enhancement**
Budget: **$5,559,000**

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 2026 represent the final year of this plan.[2] Approximately 9,400 street light fixtures are forecast to be replaced with LED fixtures in 2026.[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 2026 for the *LED Street Lighting Replacement* project.

Table 1
LED Street Lighting Replacement Project
2026 Budget
($000s)

Cost Category	2026
Material	3,716
Labour – Internal	1,614
Labour – Contract	229
Engineering	-
Other	-
Total	$5,559

1 See Newfoundland Power's *2021 Capital Budget Application, Volume 1, LED Street Lighting Replacement Plan.*
2 Expenditures associated with the first five 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), Order No. P.U. 2 (2024) and Order No. P.U. 27 (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 $5,559,000 for 2026.

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 for 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 more reliable than 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 Municipalities Newfoundland and Labrador, the largest municipal organization in the province.[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]

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4 Current Rates are reflected in the *Schedule of Rates, Rules and Regulations* effective August 1, 2024.

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.

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 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 by end of 2026.

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.

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.

RISK ASSESSMENT

The *LED Street Lighting Replacement* project provides 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 9,400 street lights will be reduced by between 12% and 44% in 2026 by executing this project.

Table 2 summarizes the risk assessment of the 2026 *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: **$250,000 in 2026 and $887,000 in 2027**

PROJECT DESCRIPTION

The *Feeder Additions for Load Growth* project involves addressing overload conditions and providing additional capacity to address system load growth. For 2026, the proposed *Feeder Additions for Load Growth* project addresses an overloaded section of Deer Lake ("DLK") Substation distribution feeder DLK-03 in the area of Bonne Bay Big Pond. Specifically, a section of DLK-03 will be upgraded from single-phase to three-phase and will be transferred to a new feeder extension from Newfoundland & Labrador Hydro's ("Hydro") Wiltondale ("WDL") Terminal Station.

Engineering design work, environmental surveying and brush clearing for the *Feeder Additions for Load Growth* project will be completed in 2026. Construction will begin the following year and will be completed by the end of 2027. 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 2026 for the *Feeder Additions for Load Growth* project.

Table 1
Feeder Additions for Load Growth Project
2026 and 2027 Budget
($000s)

Cost Category	2026	2027	Total
Material	-	248	248
Labour – Internal	-	401	401
Labour - Contract	200	194	394
Engineering	50	27	77
Other	-	17	17
Total	250	887	1,137

Proposed expenditures for the *Feeder Additions for Load Growth* project are $250,000 for 2026 and $887,000 for 2027, totaling $1,137,000.

ASSET BACKGROUND

Distribution feeder DLK-03 serves approximately 1,490 customers in the communities of Deer Lake, Reidville, Cormack, and Bonne Bay. A 16-kilometre section of distribution feeder extending along the Viking Trail Highway to serve customers in the Bonne Bay Big Pond area is overloaded. Load growth on this single-phase line can be attributed to customer connection growth and electrical service upgrades in the area. The number of customers supplied by this single-phase line has increased by 30% over the last 16 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.

Three categories of alternatives that are generally available to address overloaded conductor are not applicable to DLK-03. Feeder balancing is not applicable as the identified section of DLK-03 is single phase. A new feeder build from DLK substation is not applicable due to the magnitude of the associated costs. A non-wires alternative such as a utility-scale battery system is not feasible due to the prolonged duration of the overload condition.

As a result, the alternatives evaluated to mitigate the overloaded section of distribution feeder DLK-03 include: (i) upgrading the tap from single-phase to three-phase and (ii) transferring customers in the Bonne Bay Big Pond area to Hydro's WDL Terminal Station distribution feeder WDL-L1.

The capital cost of the alternative to upgrade the 16-kilometre section of DLK-03 from single-phase to three-phase to resolve the overload condition is estimated to be $1,196,000 in 2026 and $2,320,000 in 2027. The capital cost to transfer customer load in the Bonne Bay Big Pond area to Hydro's WDL-L1 distribution feeder is estimated to be $250,000 in 2026 and $887,000 in 2027. To accommodate this load transfer, Hydro is required to upgrade their WDL distribution system at estimated costs of $408,700 in 2026 and $952,700 in 2027, as per their *Upgrade Distribution System (2026-2027) – Wiltondale* report as part of their 2026 Capital Budget Application. As a result, a net-present value ("NPV") analysis was conducted that considers Hydro's additional costs.

The results of the NPV analysis indicate that of the technically viable alternatives considered, the load transfer option to Hydro's WDL-L1 distribution feeder 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 an overload condition on distribution feeder DLK-03 resulting from customer growth in the Bonne Bay Big Pond area to customers with safe and adequate service.

Title:	**Distribution Feeder CAB-01 Extension**
Asset Class:	**Distribution**
Category:	**Project**
Investment Classification:	**Access**
Budget:	**$1,346,000**

PROJECT DESCRIPTION

The *Distribution Feeder CAB-01 Extension* project involves constructing 9.2km of new single-phase distribution line with 1/0 AASC conductor to extend CAB-01 to Mount Carmel Pond Dam gatehouse to provide automation as part of the *Mount Carmel Pond Dam Refurbishment* project.

This project will occur concurrently with the refurbishment of the Mount Carmel Pond Dam during 2026. Engineering for the CAB-01 extension will occur in the first quarter of 2026 with construction completed by the end of the third quarter.

Additional information on this project is included in Newfoundland Power's *2025 Capital Budget Application* in the report *4.1 Mount Carmel Pond Dam Refurbishment.*

PROJECT BUDGET

The budget for the *Distribution Feeder CAB-01 Extension* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2026 for the *Distribution Feeder CAB-01 Extension* project.

Table 1
Distribution Feeder CAB-01 Extension
2026 Budget
($000s)

Cost Category	2026
Material	464
Labour – Internal	194
Labour – Contract	584
Engineering	38
Other	66
Total	$1,346

Proposed expenditures for the *Distribution Feeder CAB-01 Extension* project total $1,346,000 in 2026.

ASSET BACKGROUND

Distribution feeder CAB-01 serves approximately 1,240 customers on the Avalon Peninsula in the communities of Cape Broyle, Ferryland and Brigus South.

The distribution feeder has a single-phase tap that runs along Horse Chops Road but ends 9.2km before the Mount Carmel Pond Dam. To provide power to the gatehouse as part of the *Mount Carmel Pond Dam Refurbishment* project, the distribution feeder CAB-01 must be extended. The costs of completing the *Distribution Feeder CAB-01 Extension* project have been included in the net-present value ("NPV") analysis for the least-cost alternative in the *Mount Carmel Pond Dam Refurbishment* project.

Figure 1 shows the route for the *Distribution Feeder CAB-01 Extension* project.

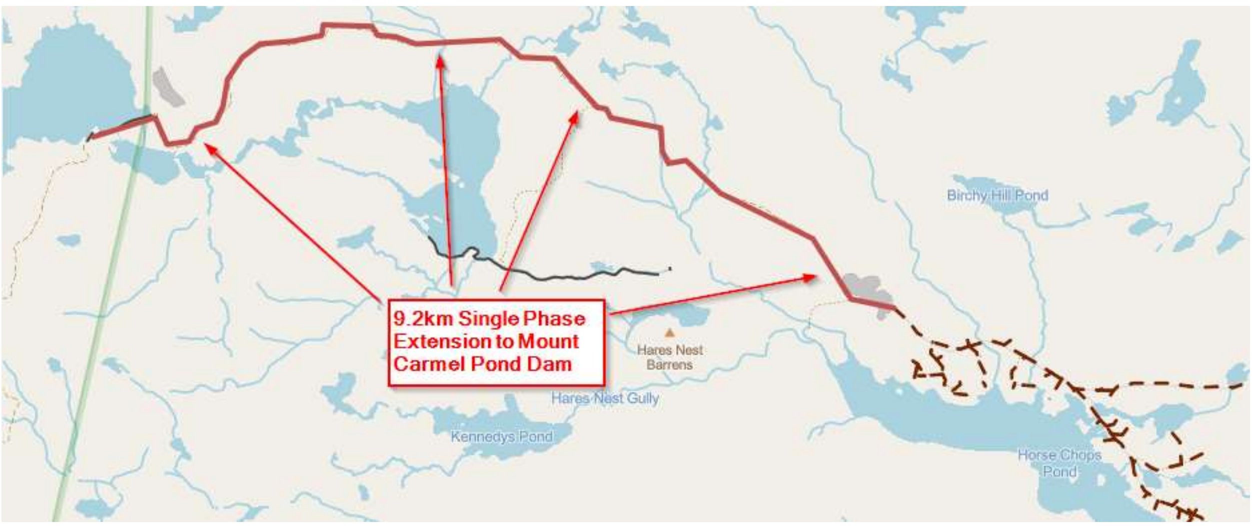


Figure 1: Distribution Feeder CAB-01 Extension Project.

RISK ASSESSMENT

The *Distribution Feeder CAB-01 Extension* project is necessary to permit the completion of the least-cost alternative in the *Mount Carmel Pond Dam Refurbishment* project mitigating the risks associated with that previously approved project.[10]

Table 2 summarizes the risk assessment of the 2026 *Distribution Feeder CAB-01 Extension* project.

Table 2
Distribution Feeder CAB-01 Extension
Risk Assessment Summary

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

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

JUSTIFICATION

The *Distribution Feeder CAB-01 Extension* project is required to ensure the delivery of reliable service to customers at least cost as part of the previously approved *Mount Carmel Dam Refurbishment* project. The extension of *CAB-01* is necessary to permit the completion of *Mount Carmel Dam Refurbishment* and to continue providing low-cost capacity and energy.

10 See Newfoundland Power's *2025 Capital Budget Application*, report *4.1 Mount Carmel Pond Dam Refurbishment*, page 10.

Title: **Extensions**
Asset Class: **Distribution**
Category: **Program**
Investment Classification: **Access**
Budget: **$16,747,000**

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, contractors or 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.[11]

Table 1 provides the cost per customer connection for the *Extensions* program from 2021 to 2026.

Table 1
Extensions Program
Cost per Customer

Year	2021	2022	2023	2024	2025F	2026F
Total ($000s)	12,427	12,489	15,145	19,601	19,982	16,747
Adjusted Costs ($000s)[1]	14,019[2]	13,637[3]	14,915[4]	15,887[5]	19,982	16,278
New Customers	2,448	2,646	2,372	3,052	3,310	2,865
Cost/Customer[1]	5,727	5,154	6,288	5,202	6,037	5,845

1 2025 dollars.
2 Excludes approximately $590,000 related to several large CIAC projects in 2021.
3 Excludes approximately $343,000 related to the connection of the new Western Memorial Regional Hospital.
4 Excludes approximately $1,117,000 related to several large CIAC projects in 2023.
5 Excludes approximately $4,100,000 associated with large CIAC projects in Joe Batts Pond and Cormack cabin areas.

11 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).

Newfoundland Power is forecasting 2,865 new customer connections in 2026 at a cost per connection under the *Extensions* program of $5,862.

Table 2 provides a breakdown of expenditures proposed for 2026 for the *Extensions* program.

Table 2
Extensions Program
2026 Budget
($000s)

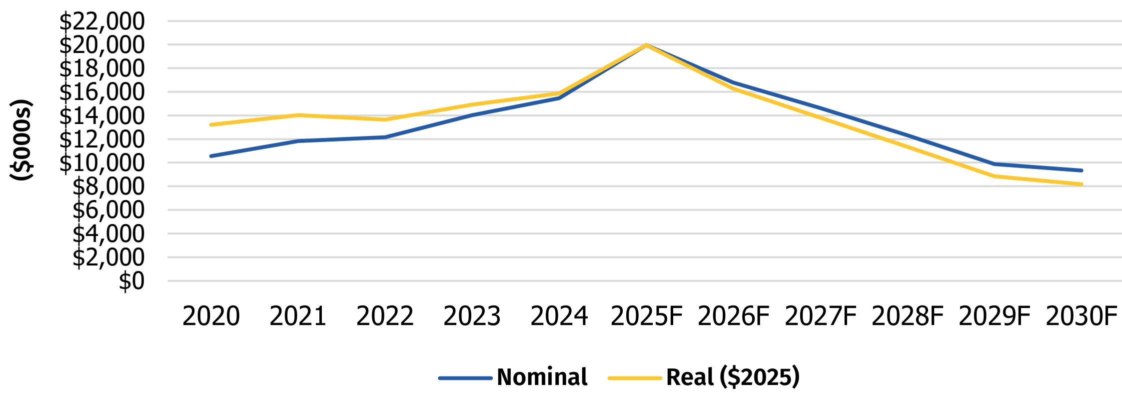
Cost Category	2026
Material	5,533
Labour – Internal	4,313
Labour – Contract	4,124
Engineering	1,896
Other	881
Total	$16,747

Proposed expenditures for the *Extensions* program total $16,747,000 for 2026.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Extensions* program from 2020 to 2030.[12]

Figure 1
Extensions Program Expenditures
(2020-2030F)



12 For forecast expenditures for the *Extensions* program, see the *2026-2030 Capital Plan,* Appendix A, page A-2. Historical expenditures have been adjusted as described in table 1 above.

Annual expenditures under the *Extensions* program are expected to decrease after 2026 due to a forecast decline in new customer connections. Annual expenditures under this program averaged approximately $15.9 million from 2021 to 2025, or approximately $15.7 million when adjusted as described in Table 1. Annual expenditures under this program are forecast to average approximately $12.5 million over the next five years.

ASSET BACKGROUND

Newfoundland Power operates approximately 9,500 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:	**$7,674,000**

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.[13]

Table 1 provides the annual expenditures for the *Reconstruction* program from 2021 to 2025.

Table 1
Reconstruction Program
Historical Expenditures
($000s)

Year	2021	2022	2023	2024	2025F
Total	5,959	6,179	7,622	8,633	7,425
Adjusted Costs[1]	6,689[2]	6,654[3]	8,136	8,285[4]	7,425

1 2025 dollars
2 Excludes approximately $355,000 related to Hurricane Larry.
3 Excludes approximately $314,000 related to Hurricane Earl, Hurricane Fiona and an additional winter storm on February 8th.
4 Excludes approximately $601,000 related to a storm in March of 2024 and a landslide near Corner Brook.

The average annual adjusted cost for the *Reconstruction* program was approximately $7.4 million from 2021 to 2025.

13 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 2026 for the *Reconstruction* program.

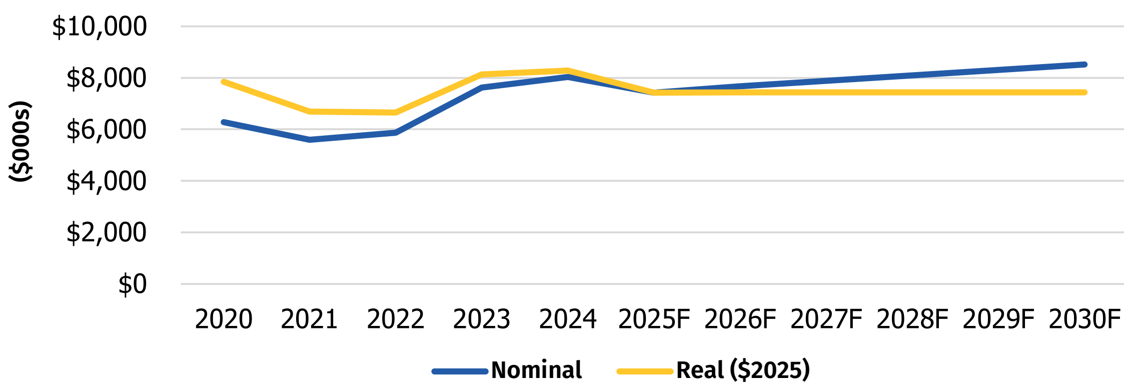
Table 2 Reconstruction Program 2026 Budget ($000s)	
Cost Category	2025
Material	1,846
Labour – Internal	3,113
Labour – Contract	1,658
Engineering	712
Other	345
Total	$7,674

Proposed expenditures for the *Reconstruction* program total $7,674,000 for 2026.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Reconstruction* program from 2020 to 2030.[14]

Figure 1
Reconstruction Program Expenditures
(2020-2030F)



Annual expenditures under this program averaged approximately $7.2 million from 2021 to 2025, or approximately $7.4 million when adjusted as described above. Annual expenditures are forecast to average approximately $8.1 million over the next five years.

14 For forecast annual expenditures for the *Reconstruction* program, see the *2026-2030 Capital Plan,* Appendix A, page A-2. Historical expenditures have been adjusted as described in table 1 above.

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 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 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 228,000 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. Approximately 14% of wooden support structures on Newfoundland Power's distribution system have exceeded 54 years in service. Approximately 21% of distribution overhead conductor has exceeded 50 years in service.[15]

The effect of age on Newfoundland Power's electrical system can be observed through its recent experience with equipment failures. An average of approximately 1,050 equipment failures per year were experienced on the distribution system from 2020 to 2024. Distribution equipment failures are primarily driven by overhead conductor, insulators, poles and transformers that have become deteriorated due to their age and exposure to climatic conditions.

An average of 588 deficiencies were corrected annually under the *Reconstruction* program from 2020 to 2024, ranging from 380 in 2022 to 819 in 2024. 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, broken insulators and damaged conductor. The probability of failure of components in this condition is near certain.

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15 For more information, see the *2026-2030 Capital Plan,* section *2.4.2 Distribution*, pages 7-8.

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:	**$5,263,000**

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 42 distribution feeders will undergo inspection in 2025 with planned preventative maintenance in 2026:

BCV-02	CLV-02	GFS-04	ISL-01	PBD-01	WAL-02
BFS-02	FER-01	GFS-05	KEN-04	PEP-02	WAL-07
BIG-02	GAL-05	GFS-10	LGL-01	PUL-05	
BOT-02	GAN-04	GLV-02	LLK-02	SLA-09	
CAR-03	GDL-05	GPD-01	MIL-02	SPO-01	
CAR-04	GDL-06	HAR-02	NHR-01	SPO-02	
CLK-03	GFS-01	HGR-02	NWB-01	VIR-07	
CLK-04	GFS-03	HWD-02	PAS-02	VIR-08	

The specific deficiencies to be corrected on these distribution feeders will depend on the outcomes of the inspections completed throughout 2025, 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.[16]

[16] 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 2021 to 2025.

Table 1 Rebuild Distribution Lines Historical Expenditures ($000s)					
Year	2021	2022	2023	2024	2025F
Total	4,143	3,956	5,085	5,253	5,115
Adjusted Costs[1]	4,970	4,514	5,437	5,428	5,115

1 2025 dollars.

The average annual adjusted cost for the *Rebuild Distribution Lines* program was approximately $5.1 million from 2021 to 2025.

Table 2 provides a breakdown of expenditures proposed for 2026 for the *Rebuild Distribution Lines* program.

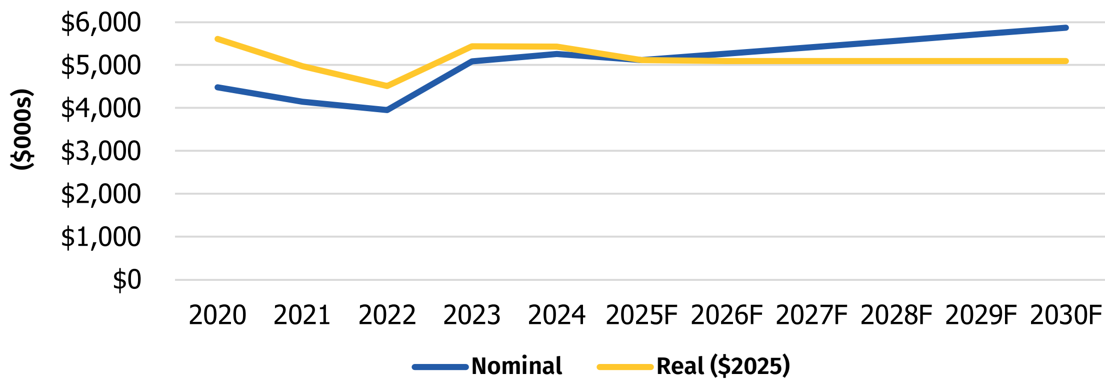
Table 2 Rebuild Distribution Lines 2026 Budget ($000s)	
Cost Category	2026
Material	1,272
Labour – Internal	2,636
Labour – Contract	877
Engineering	298
Other	180
Total	$5,263

Proposed expenditures for the *Rebuild Distribution Lines* program total $5,263,000 for 2026.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Rebuild Distribution Lines* program from 2020 to 2030.[17]

Figure 1
Rebuild Distribution Lines Program Expenditures
(2020-2030F)



Annual expenditures under this program averaged approximately $4.7 million from 2021 to 2025, or approximately $5.1 million when adjusted for inflation. Annual expenditures are forecast to average approximately $5.6 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.

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[17] For forecast annual expenditures for the *Rebuild Distribution Lines* program, see the *2026-2030 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 9,500 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. 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.[18]

An average of 2,038 deficiencies were corrected annually under the *Rebuild Distribution Lines* program from 2020 to 2024, ranging from 1,463 in 2020 to 2,437 in 2021. These deficiencies were corrected through a combination of rebuilding sections of distribution feeders and the selective replacement of line components.

18 For more information, see the *2026-2030 Capital Plan,* section *2.4.2 Distribution*, pages 7-8.

The *Rebuild Distribution Lines* program will address deficiencies on 42 distribution feeders in 2026. These feeders serve an average of approximately 900 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:	**$3,702,000**

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.[19]

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.

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.

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

Table 1 provides annual expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program from 2021 to 2025.

Table 1 Relocate/Replace Distribution Lines for Third Parties Program Historical Expenditures ($000s)					
Year	2021	2022	2023	2024	2025F
Total	3,060	3,055	3,109	3,905	3,528
Adjusted Costs[1]	3,642	3,442	3,316	4,023	3,528

[1] 2025 dollars.

The average annual adjusted cost for the *Relocate/Replace Distribution Lines for Third Parties* program was approximately $3.6 million from 2021 to 2025.

Table 2 provides a breakdown of expenditures proposed for 2026 for the *Relocate/Replace Distribution Lines for Third Parties* program.

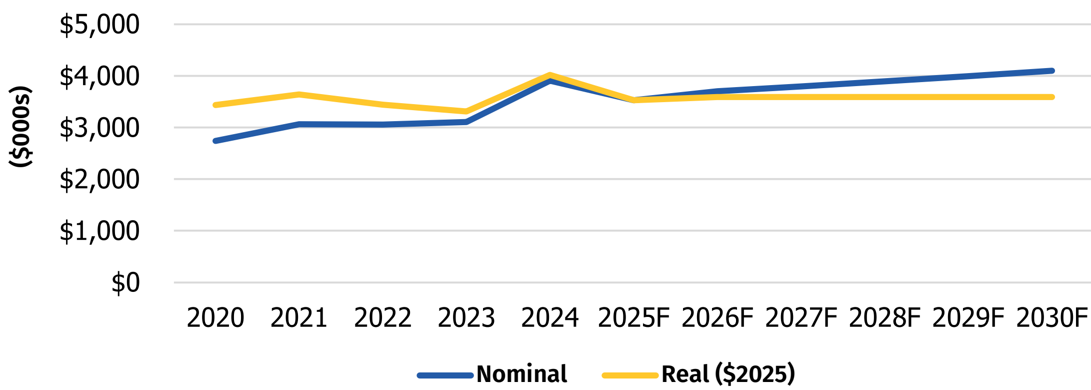
Table 2 Relocate/Replace Distribution Lines for Third Parties Program 2026 Budget ($000s)	
Cost Category	2026
Material	1,018
Labour – Internal	1,314
Labour – Contract	740
Engineering	463
Other	167
Total	$3,702

Proposed expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program total $3,702,000 for 2026.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program from 2020 to 2030.[20]

Figure 1
Relocate/Replace Distribution for Third Parties Program Expenditures (2020-2030F)



Annual expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program vary depending on the quantity and scope of the requests received. Annual expenditures under this program averaged approximately $3.3 million from 2021 to 2025, or approximately $3.6 million when adjusted for inflation. Annual expenditures are forecast to average approximately $3.9 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 to accommodate road widening, and requests from telecommunications companies to replace structures to accommodate the supply of fibre optic internet service.

An average of approximately 290 requests from third parties were received under the *Relocate/Replace Distribution Lines for Third Parties* program from 2020 to 2024.

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.

[20] For forecast annual expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program, see the *2026-2030 Capital Plan,* Appendix A, page A-2.

Title:	**Replacement Transformers**
Asset Class:	**Distribution**
Category:	**Program**
Investment Classification:	**Renewal**
Budget:	**$4,954,000**

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 are expressed in current-year dollars as Adjusted Costs.

Table 1 provides annual expenditures for the *Replacement Transformers* program from 2023 to 2025.

Table 1
Replacement Transformers Program
Historical Expenditures
($000s)

Year	2023	2024	2025F
Total	3,397	5,931	6,340
Adjusted Costs[1]	3,565	6,047	4,996[2]

[1] 2025 dollars.
[2] Excludes costs related to maintaining transformer inventory levels as described in the *2025 Capital Budget Application*.

The average annual adjusted cost for the *Replacement Transformers* program was approximately $4.9 million from 2023 to 2025.

Table 2 provides a breakdown of expenditures proposed for 2026 for the *Replacement Transformers* program.

Table 2
Replacement Transformers Program
2026 Budget
($000s)

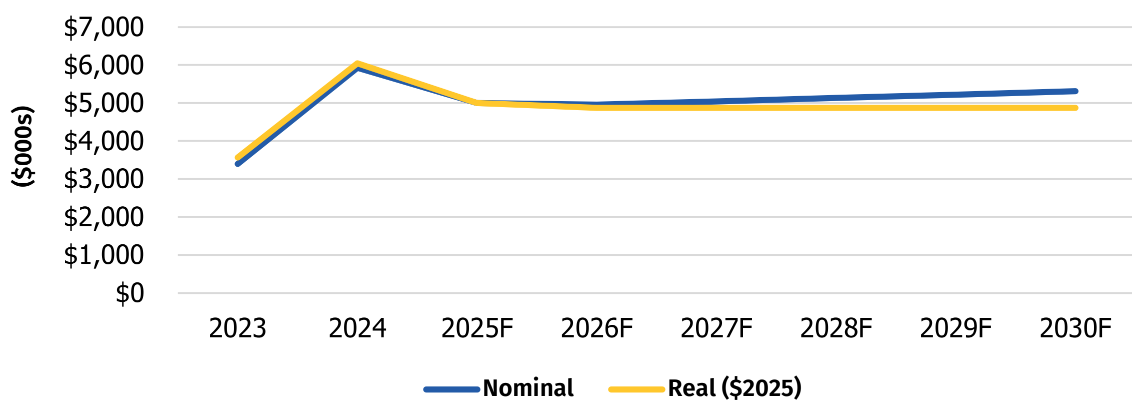
Cost Category	2026
Material	4,954
Labour – Internal	-
Labour – Contract	-
Engineering	-
Other	-
Total	$4,954

Proposed expenditures for the *Replacement Transformers* program total $4,954,000 for 2026.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Replacement Transformers* program from 2023 to 2030.[21]

Figure 1
Replacement Transformers Program Expenditures
(2023-2030F)



Annual expenditures under this program averaged approximately $5.2 million from 2023 to 2025, or approximately $4.9 million when adjusted as described above. Annual expenditures are forecast to average approximately $5.1 million over the next five years.

21 For forecast annual expenditures for the *Replacement Transformers* program, see the *2026-2030 Capital Plan,* Appendix A, page A-2.

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 654 transformers were replaced annually from 2020 to 2024, ranging from 461 in 2022 to 789 in 2024. 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: **$4,394,000**

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 are expressed in current-year dollars as Adjusted Costs.

Table 1 shows annual expenditures for the *New Transformers* program from 2023 to 2025.

Table 1
New Transformers Program
Historical Expenditures
($000s)

Year	2023	2024	2025F
Total	3,013	5,260	5,622
Adjusted Costs[1]	3,161	5,363	4,430[2]

1 2025 dollars.
2 Excludes costs related to maintaining transformer inventory levels as described in the *2025 Capital Budget Application*.

The average annual adjusted cost for the *New Transformers* program was approximately $4.3 million from 2023 to 2025.

Table 2 provides a breakdown of expenditures proposed for 2026 for the *New Transformers* program.

Table 2
New Transformers Program
2026 Budget
($000s)

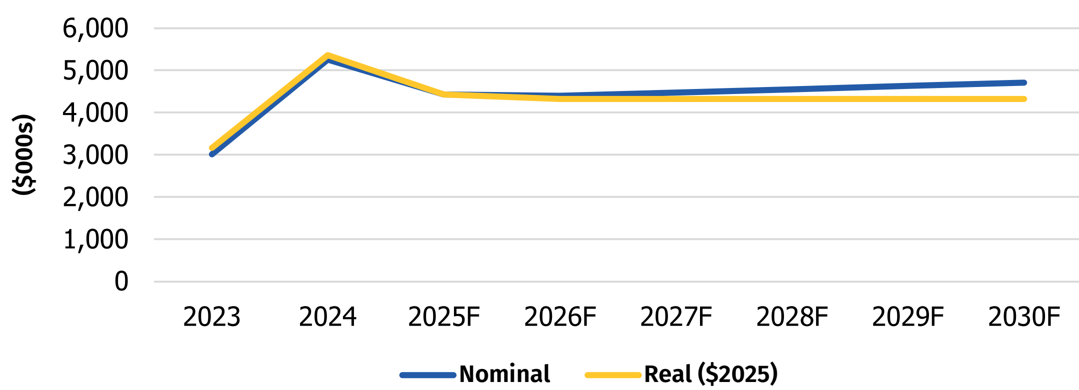
Cost Category	2026
Material	4,394
Labour – Internal	-
Labour – Contract	-
Engineering	-
Other	-
Total	$4,394

Proposed expenditures for the *New Transformers* program total $4,394,000 for 2026.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *New Transformers* program from 2023 to 2030.[22]

Figure 1
New Transformers Program Expenditures
(2023-2030F)



Annual expenditures under this program averaged approximately $4.6 million from 2023 to 2025, or $4.3 million when adjusted as described above. Annual expenditures under this program are forecast to average approximately $4.6 million over the next five years.

22 For forecast annual expenditures for the *New Transformers* program, see the *2026-2030 Capital Plan,* Appendix A, page A-2.

ASSET BACKGROUND

Distribution transformers convert distribution system voltages to lower voltages required to supply customers' premises. A single distribution transformer can provide 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 1,174 new transformers were installed annually from 2020 to 2024.

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: **$4,218,000**

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.

Table 1 provides annual expenditures for the *New Services* program from 2021 to 2026.

Table 1
New Services Program
Cost per Customer

Year	2021	2022	2023	2024	2025F	2026F
Total ($000s)	2,936	3,469	3,260	3,661	4,784	4,218
Adjusted Costs ($000s)[1]	3,529	3,995	3,493	3,791	4,784	-
New Customers	2,448	2,646	2,372	3,052	3,310	2,865
Cost/Customer[1]	1,442	1,510	1,473	1,242	1,445	1,473

1 2025 dollars.

Newfoundland Power is forecasting 2,865 new customer connections in 2026 at a cost per connection of $1,473.

Table 2 provides a breakdown of expenditures proposed for 2026 for the *New Services* program.

Table 2
New Services Program
2026 Budget
($000s)

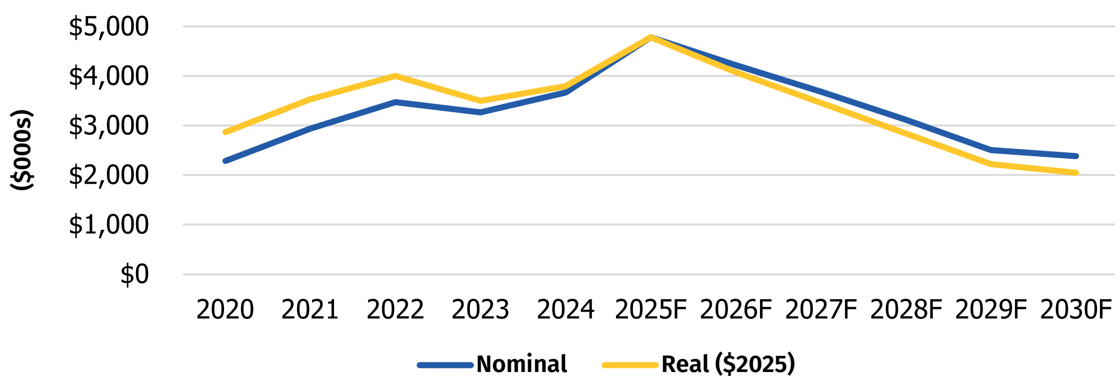
Cost Category	2026
Material	1,233
Labour – Internal	2,416
Labour – Contract	199
Engineering	290
Other	80
Total	4,218

Proposed expenditures for the *New Services* program total $4,218,000 for 2026.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *New Services* program from 2020 to 2030.[23]

Figure 1
New Services Program Expenditures
(2020-2030F)



Annual expenditures under this program averaged approximately $3.6 million from 2021 to 2025, or $3.9 million when adjusted for inflation. Annual expenditures under this program are forecast to average approximately $3.2 million over the next five years.

[23] For forecast annual expenditures for the *New Services* program, see the *2026-2030 Capital Plan,* Appendix A, page A-2.

ASSET BACKGROUND

Service wires are low-voltage wires that connect a customer's electrical service 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:	**$2,425,000**

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.

Table 1 provides the annual expenditures for the *New Street Lighting* program from 2021 to 2025.

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

Year	2021	2022	2023	2024	2025F
Total	1,494	2,209	2,267	2,666	2,460
Adjusted Costs[1]	1,759	2,457	2,403	2,734	2,460

[1] 2025 dollars.

The average annual adjusted cost for the *New Street Lighting* program was approximately $2.4 million from 2021 to 2025.

Table 2 provides a breakdown of expenditures proposed for 2026 for the *New Street Lighting* program.

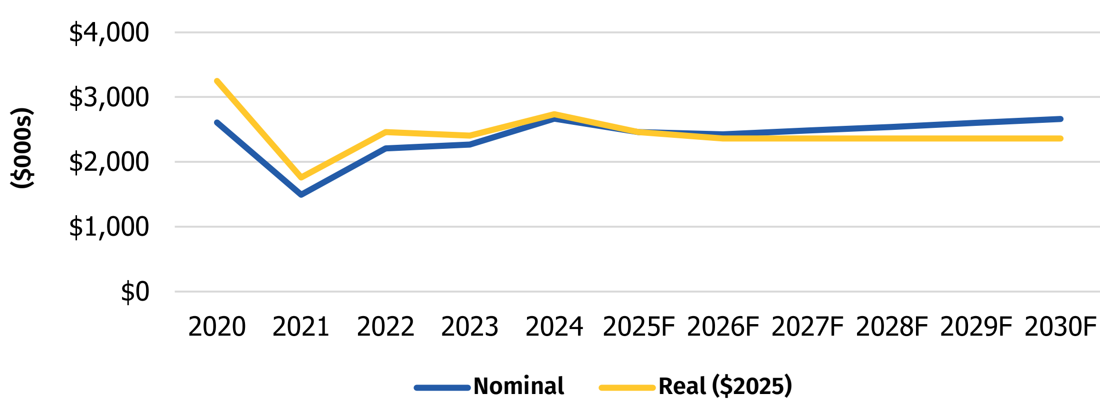
Table 2 New Street Lighting Program 2026 Budget ($000s)	
Cost Category	2026
Material	1,408
Labour – Internal	569
Labour – Contract	352
Engineering	54
Other	42
Total	$2,425

Proposed expenditures for the *New Street Lighting* program total $2,425,000 for 2025.

PROGRAM TREND

Figure 1 shows historical and forecast annual expenditures for the *New Street Lighting* program from 2020 to 2030.[24]

Figure 1
New Street Lighting Program Expenditures
(2020-2030F)



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 $2.2 million from 2021 to 2025, or approximately $2.4 million when adjusted for inflation. Annual expenditures under this program are forecast to average approximately $2.5 million over the next five years.

[24] For forecast annual expenditures for the *New Street Lighting* program, see *2026-2030 Capital Plan,* Appendix A, page A-2.

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 591 new street lights were installed annually from 2020 to 2024, 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:	**$914,000**

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 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.

Table 1 provides the annual expenditures for the *Replacement Street Lighting* program from 2021 to 2025.

Table 1
Replacement Street Lighting Program
Historical Expenditures
($000s)

Year	2021	2022	2023	2024	2025F
Total	730	937	774	890	884
Adjusted Costs[1]	851	1,010	815	909	884

1 2025 dollars.

The average annual adjusted cost for the *Replacement Street Lighting* program was approximately $894,000 from 2021 to 2025.

Table 2 provides a breakdown of expenditures proposed for 2026 for the *Replacement Street Lighting* program.

Table 2
Replacement Street Lighting Program
2026 Budget
($000s)

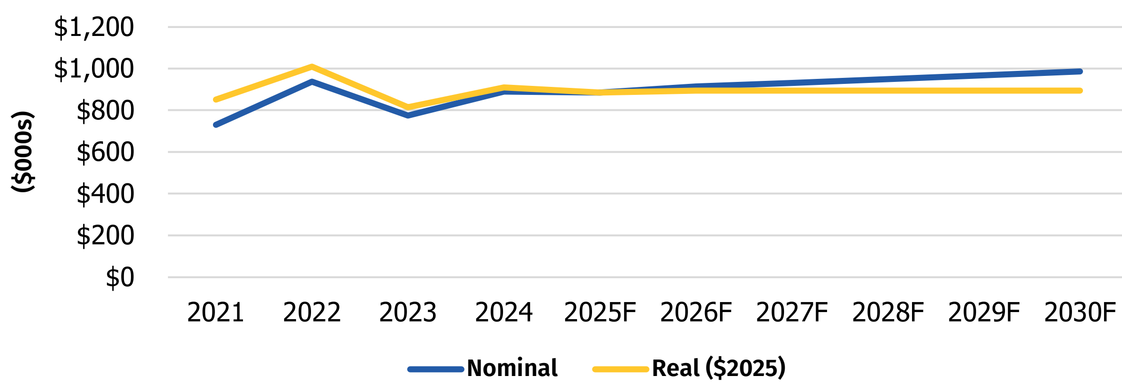
Cost Category	2026
Material	635
Labour – Internal	100
Labour – Contract	164
Engineering	8
Other	7
Total	$914

Proposed expenditures for the *Replacement Street Lighting* program total $914,000 for 2026.

PROGRAM TREND

Figure 1 shows historical and forecast annual expenditures for the *Replacement Street Lighting* program from 2021 to 2030.[25]

Figure 1
Replacement Street Lighting Program Expenditures
(2021-2030F)



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 $843,000 from 2021 to 2025,

25 For forecast annual expenditures for the *Replacement Street Lighting* program, see *2026-2030 Capital Plan,* Appendix A, page A-2.

or approximately $894,000 when adjusted for inflation. Annual expenditures under this program are forecast to average approximately $950,000 over the next five years.

ASSET BACKGROUND

Newfoundland Power currently provides service to approximately 11,500 Street and Area Lighting customers. There are approximately 68,000 street lights in operation throughout the Company's service territory. Approximately 56,000 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.*[26]

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.

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 68,000 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.

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26 See Newfoundland Power's *2021 Capital Budget Application, LED Street Lighting Replacement Plan*.

Table 3 summarizes the risk assessment of the *Replacement Street Lighting* program.

Table 3
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:	**Lewisporte-Boyd's Cove 138 kV Conversion**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$568,000 in 2026; $7,551,000 in 2027**

PROJECT DESCRIPTION

The *Lewisporte-Boyd's Cove 138 kV Conversion* project was identified as part of the least cost alternative in the *Gander – Twillingate Transmission System Planning Study.* [27] This project includes the modification of existing Lewisporte (LEW), Boyd's Cove (BOY), and Gander (GAN) Substations. This project is required in conjunction with the previously approved construction of a new 138kV Transmission Line from LEW to BOY Substations, and in conjunction with the previously approved GAN-T2 transformer replacement.[28, 29]

The proposed 2026 and 2027 scope of work for the *Lewisporte-Boyd's Cove 138 kV Conversion* project includes:

(i) Expand the existing yard at BOY;
(ii) Construct a new control building at BOY;
(iii) Construct new 138 kV and 66 kV steel structures at BOY and LEW;
(iv) Install new grounding transformer with spill containment at GAN;
(v) Install new 138 kV and 66 kV circuit breakers at BOY and LEW;
(vi) Install new 138 kV and 66 kV switches at BOY, LEW, and GAN;
(vii) Relocate two 66kV Circuit Breakers from GAN to BOY;
(viii) Install new 138kV Potential Transformers at BOY;
(ix) Install new digital relays and associated communications equipment at BOY, LEW, and GAN;
(x) Upgrade and extend the existing ground grid at BOY;

Engineering design and procurement of long lead time equipment will be completed in 2026. Construction will begin in the second quarter of 2027 and will be completed in the fourth quarter of 2027. Commissioning of the substations will be completed during the fourth quarter of 2027.

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27 For details of the assessment, see Newfoundland Power's *2025 Capital Budget Application,* report *3.1 Gander – Twillingate Transmission System Planning Study,* section *5.0*.

28 See Newfoundland Power's *2025 Capital Budget Application*, report *2.2 Substation Power Transformer Replacements*, section *3.2.*

29 As part of the least cost alternative in the *Gander – Twillingate Transmission System Planning Study* , the 138/66 kV system power transformer would no longer be required at GAN Substation. As a result, the GAN-T2 transformer replacement would be purchased and installed directly at BOY Substation. 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.

PROJECT BUDGET

The budget for the *Lewisporte-Boyd's Cove 138 kV Conversion* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2026 and 2027 for the *Lewisporte-Boyd's Cove 138 kV Conversion* project.

Table 1
Lewisporte-Boyd's Cove 138 kV Conversion Project Budget
($000s)

Cost Category	2026	2027	Total
Material	233	6,099	6,332
Labour – Internal	17	278	295
Labour - Contract	-	-	-
Engineering	318	630	948
Other	-	544	544
Total	$568	$7,551	$8,119

Proposed expenditures for the *Lewisporte-Boyd's Cove 138 kV Conversion* project are $568,000 in 2026 and $7,551,000 in 2027 for a total project budget of $8,119,000.

ASSET BACKGROUND

BOY Substation is a transmission substation supplied by Newfoundland Power 66 kV Transmission Line 114L from Gander Bay ("GBY") Substation. BOY supplies 66 kV Transmission Lines 114L to Summerford ("SUM") Substation and Newfoundland and Labrador Hydro's 66 kV Transmission Line TL254.

LEW Substation is a transmission and distribution substation supplied by Newfoundland Power 138 kV Transmission Lines 147L from Cobb's Pond ("COB") Substation and 137L from Rattling Brook ("RBK") Substation.

GAN Substation is a transmission and distribution substation supplied by Newfoundland Power 138 kV Transmission Lines 144L from Cobb's Pond ("COB") Substation and 146L from Gambo ("GAM") Substation. GAN Substation supplies 66 kV Transmission Lines 108L to Gander Bay ("GBY") Substation and 102L to Roycefield ("RFD") Substation.

The *Lewisporte-Boyd's Cove 138 kV Conversion* project will add a 138 kV Transmission Line from LEW to BOY. The 66kV Transmission system will be removed from GAN, with the GAN-T2 replacement transformer being installed at BOY. A 138 kV grounding transformer will be installed at GAN to maintain a ground source following the relocation of GAN-T2.

ASSESSMENT OF ALTERNATIVES

There are no identified alternatives for this project as the *Lewisporte-Boyd's Cove 138 kV Conversion* was identified as the least cost alternative in the *Gander – Twillingate Transmission System Planning Study.*[30] Failure to complete the necessary substation work for the *New Transmission Line from Lewisporte to Boyd's Cove* would prohibit the termination of the new transmission line into LEW and BOY substations.

RISK ASSESSMENT

The *Lewisporte-Boyd's Cove 138 kV Conversion* project is necessary to permit the completion of the *New Transmission Line from Lewisporte to Boyd's Cove* project approved in the Company's *2025 Capital Budget Application.* The new transmission line and associated substation work was identified.

Table 2 summarizes the risk assessment for the *Lewisporte-Boyd's Cove 138 kV Conversion* project.

Table 2
Lewisporte Boyd's Cove 138 kV Conversion Project Risk Assessment Summary

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

Overall, failing to complete the Lewisporte-Boyd's Cove 138 kV conversion poses a High (20) risk to the delivery of least cost, reliable, safe, and environmentally responsible service to customers. Action is required in 2026 and 2027 to mitigate these risks for customers.

JUSTIFICATION

The *Lewisporte-Boyd's Cove 138 kV Conversion* project is required to complete the *New Transmission Line from Lewisporte to Boyd's Cove* project as approved in the Company's *2025 Capital Budget Application.* Completion of the project will ensure customers receive reliable service at the lowest possible cost consistent with the analysis performed in report 3.1 *Gander – Twillingate Transmission System Planning Study*.

[30] For further details, see Newfoundland Power's *2025 Capital Budget Application,* report *3.1 Gander – Twillingate Transmission System Planning Study,* section *5.0*.

Title:	**Greenspond Substation Refurbishment and Modernization**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$374,000 in 2026; $2,578,000 in 2027**

PROJECT DESCRIPTION

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

The proposed 2026 and 2027 scope of work for the *Greenspond Substation Refurbishment and Modernization* project includes:

(i) Expand the existing yard;
(ii) Construct a new control building;
(iii) Construct new 66 kV and 12.5 kV steel structures to replace deteriorated wood structures;
(iv) Construct new spill containment foundations for existing transformer and voltage regulators;
(v) Install a new set of 66 kV fuses;
(vi) Replace deteriorated 66 kV and 12.5 kV switches;
(vii) Install 66 kV potential transformer;
(viii) Install new 12.5 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 12.5 kV equipment.

Engineering design and procurement of long lead time equipment will be completed in 2026. Construction will begin in the second quarter of 2027 and will be completed in the fourth quarter of 2027. Commissioning of the substation will be completed during the fourth quarter of 2027.

Additional information on this project is provided in Appendix A of report *2.1 2026 Substation Refurbishment and Modernization* filed with the Application.

PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2026 and 2027 for the *Greenspond Substation Refurbishment and Modernization* project.

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

Cost Category	2026	2027	Total
Material	112	1,803	1,915
Labour – Internal	34	214	248
Labour - Contract	-	-	-
Engineering	220	347	567
Other	8	214	222
Total	$374	$2,578	$2,952

Proposed expenditures for the *Greenspond Substation Refurbishment and Modernization* project are $374,000 in 2026 and $2,578,000 in 2027 for a total project budget of $2,952,000.

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 18 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.[31] Continued execution of the *Substation Refurbishment and Modernization Plan* is therefore necessary to replace obsolete and deteriorated equipment and infrastructure.

In 2026, Newfoundland Power is proposing to refurbish and modernize GPD Substation. The substation was built in 1981 as a distribution substation. A condition assessment determined the substation contains a significant amount of deteriorated and obsolete equipment. Several pieces of equipment are at end of life, including: (i) 66 kV and 12.5 kV wood pole structures; (ii) 66 kV and 12.5 kV switches; and (iii) 12.5 kV recloser. Additionally, new transformer and

31 For details of the assessment, see the *2026 Capital Budget Application,* report *2.1 2026 Substation Refurbishment and Modernization,* section *2.2*.

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 GPD Substation, the number of components requiring preventative and corrective maintenance at this time justifies the requirement to refurbish and modernize the substation in 2026 and 2027. Deferral of the GPD Substation refurbishment and modernization project would increase the risk that some components will fail in service, which would result in outages to approximately 260 customers in the Greenspond area. Deferring this project is therefore not a viable alternative.

RISK ASSESSMENT

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

GPD Substation provides service to approximately 260 customers in the Greenspond area. Equipment failure in the GPD Substation exposes all customers supplied by GPD 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.

GPD 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. Many of the switches require replacement based on their age and mechanical condition. The 12.5 kV recloser is at the end of its useful life and requires replacement.

Power transformer GPD-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 GPD Substation that pose a risk to safe and reliable operation of the electric equipment. The substation has sections with insufficient grounding, and areas where there is no connection between the main ground grid and the fence grounding. 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 GPD substation, the probability of failure is likely.

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

Table 2
Greenspond Substation Refurbishment and Modernization Project Risk Assessment Summary

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

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

JUSTIFICATION

The *Greenspond 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 Greenspond area.

Title:	**King's Bridge Substation Power Transformer Replacement**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$12,000 in 2026; $93,000 in 2027; $2,866,000 in 2028**

PROJECT DESCRIPTION

The *King's Bridge Substation Power Transformer Replacement* project involves the replacement of the King's Bridge Substation ("KBR") power transformer KBR-T3. KBR-T3 is deteriorating, and an assessment of alternatives determined that the unit should be replaced.

The proposed 2026, 2027 and 2028 scope of work for the *King's Bridge Road Substation Power Transformer Replacement* project includes:

(i) Remove existing power transformer KBR-T3; and,
(ii) Install and commission new 15/20/25 MVA, 66-12.5/25 kV power transformer complete with new spill containment foundation.

King's Bridge (KBR") Substation was constructed in 1948 as both a distribution and transmission substation. This substation is supplied by Newfoundland Power 66 kV Transmission Line 12L from Memorial ("MUN") Substation, 66kV Transmission Line 16L from Pepperrell ("PEP") Substation, and 66kV Transmission Line 30L from Ridge Road ("RRD" Substation). Two 15/20/25 MVA distribution power transformers, KBR-T3 ("200293") and KBR-T4 ("200372"), supply six 12.5 kV distribution feeders, serving approximately 5,740 customers in St. John's.

Engineering design and procurement of the new power transformer will be completed in 2026 and 2027. Delivery, installation, testing, and commissioning of the new power transformer will be completed in 2028.

For additional details, see the *2026 Capital Budget Application,* report *2.2 Substation Power Transformer Strategy*.

PROJECT BUDGET

The budget of the *King's Bridge Substation Power Transformer Replacement* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2026, 2027 and 2028 for the *King's Bridge Substation Power Transformer Replacement* project.

Table 1
King's Bridge Substation Power Transformer Replacement Project Budget
($000s)

Cost Category	2026	2027	2028	Total
Material	-	-	2,660	2,660
Labour - Internal	-	-	13	13
Labour - Contract	-	-	-	0
Engineering	8	34	90	131
Other	4	59	103	166
Total	$12	$93	$2,866	$2,971

Proposed expenditures for the *King's Bridge Substation Power Transformer Replacement* project are $12,000 in 2026, $93,000 in 2027, and $2,866,000 in 2028 for a total project budget of $2,971,000.

ASSET BACKGROUND

KBR-T3 is a 49-year-old, 15/20/25 MVA, 66-12.5/25 kV power transformer manufactured by Federal Pioneer, and is a sister unit to MOL-T2. This transformer has remained at KBR since its original installation in 1977.

All power transformers receive regular maintenance on a 12-year cycle. KBR-T3 last underwent full maintenance in August of 2016. Additionally, all power transformers undergo annual oil sampling to monitor their condition.

Results of oil samples have indicated deteriorating mechanical strength of the internal paper insulation of the transformer. Oil sampling in October of 2024 indicated that the mechanical strength of the paper is less than 50 percent tensile strength and may not withstand a fault on the electrical system.[32] The Electrical Power Research Institute ("EPRI") Power Transformer Expert System ("PTX") software indicates that the Normal Degradation Index of the transformer highly correlates with units that have insulating paper that is no longer capable of providing reliable service.

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32 Results of oil sampling are presented as Transformer Condition Assessments™ ("TCA") provided by TJ/H2b Analytic Services Incorporated ("TJ/H2b"). For details, see the *2026 Capital Budget Application*, report *2.2 Substation Power Transformer Strategy,* Appendix E.

ASSESSMENT OF ALTERNATIVES

Three alternatives were assessed to address the condition of power transformer KBR-T3: (i) Condition based monitoring; (ii) Remove and Repair; and (iii) Replace and Assess.

In the event of a KBR-T3 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 longer duration outages and potentially impact the Company's annual capital and maintenance programs for substations.

Repairing KBR-T3 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 *King's Bridge Substation Power Transformer Replacement* project would increase the risk of failure, which could expose up to approximately 5,740 customers to the risk of outages. Deferring this project is therefore not a viable alternative.

RISK ASSESSMENT

The *King's Bridge Substation Power Transformer Replacement* project will mitigate risks to the delivery of reliable service to 5,740 customers in the St. John's 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 case of a KBR-T3 failure, KBR-T4 is unable to supply the existing peak load of the KBR Substation. System load forecasts indicate that up to 13.3 MVA of KBR-T3 load can be transferred to either KBR-T4 or offloaded to adjacent feeders. 8.1 MVA of load would be exposed to an outage.[33] A portable substation or a spare transformer would need to be installed in the event of a KBR-T3 failure.

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[33] A max peak load of 43.7 MVA is being forecasted over the next five years at KBR Substation.

Newfoundland Power has three portable substations and one spare power transformer that can be used for the emergency response of KBR-T3. Failure of KBR-T3 would result in an unplanned short-term installation of a portable substation followed by a long-term installation of a spare power transformer when available.[34]

Delivery times for power transformers have increased significantly, from an average of 34 weeks in 2019 to an average of 110 weeks in 2025. 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 *King's Bridge Substation Power Transformer Replacement* project.

Table 2
King's Bridge Substation Power Transformer Replacement Project
Risk Assessment Summary

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

Overall, the condition of power transformer KBR-T3 poses a Medium-High (16) risk to the delivery of reliable, safe, and environmentally responsible service to customers. Action is required in 2026, 2027 and 2028 to mitigate these risks for customers.

JUSTIFICATION

The *King's Bridge 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 St. John's area.

[34] Another spare power transformer would need to be procured if this spare power transformer is utilized to respond to a failure as it is the only 15/20/25 MVA, 66-25/12.5 kV transformer in the Company's inventory. Present power transformer delivery times are estimated between 24 and 36 months, and upwards of 60 months for some manufacturers. Being without this spare transformer for this timeframe would present additional risks to customer reliability.

Title:	**Mobile Plant Substation Power Transformer Replacement**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$12,000 in 2026; $93,000 in 2027; $2,522,000 in 2028**

PROJECT DESCRIPTION

The *Mobile Plant Substation Power Transformer Replacement* project involves the replacement of the Mobile Plant ("MOP") Substation power transformer MOP-T1. MOP-T1 is deteriorating, and an assessment of alternatives determined that the unit should be replaced.

The proposed 2026, 2027 and 2028 scope of work for the *Mobile Plant Substation Power Transformer Replacement* project includes:

(i) Remove power transformer MOP-T1; and,
(ii) Install and commission new 10/13.3/16.7 MVA, 66-6.9 kV power transformer at Mobile Plant Substation complete with new spill containment foundation.

MOP Substation was constructed in 1951 as a generation substation for the Mobile Hydro Plant. The plant's 11 MVA generator supplies the MOP Substation 10 MVA power transformer that interconnects the generating plant to Newfoundland Power's 66 kV transmission line in Mobile ("MOB") Substation in the Town of Mobile.

Engineering design and procurement of the new power transformer will be completed in 2026 and 2027. Delivery, installation, testing, and commissioning of the new power transformer will be completed in 2028.

For additional details, see the *2026 Capital Budget Application,* report *2.2 Substation Power Transformer Strategy*.

PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2026, 2027 and 2028 for the *Mobile Plant Substation Power Transformer Replacement* project.

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

Cost Category	2026	2027	2028	Total
Material	-	-	2,323	2,323
Labour - Internal	-	-	13	13
Labour - Contract	-	-	-	-
Engineering	8	34	90	131
Other	4	59	96	159
Total	$12	$93	$2,522	$2,627

Proposed expenditures for the *Mobile Plant Substation Power Transformer Replacement* project are $12,000 in 2026, $93,000 in 2027, and $2,522,000 in 2028 for a total project budget of $2,627,000.

ASSET BACKGROUND

MOP-T1 is a 75-year-old, 10 MVA, 66-6.9 kV power transformer manufactured by Westinghouse. This transformer has remained at MOP since its original installation in 1951.

All power transformers receive regular maintenance on a 12-year cycle. MOP-T1 last underwent full maintenance in September of 2020. Additionally, all power transformers undergo annual oil sampling to monitor their condition.

Results of oil samples have indicated deteriorating mechanical strength of the internal paper insulation of the transformer. Oil sampling in January of 2025 indicated that the mechanical strength of the paper is at approximately 70 percent tensile strength.[35] The Electrical Power Research Institute ("EPRI") Power Transformer Expert System ("PTX") software indicates that the Normal Degradation Index of the transformer is approaching a value that highly correlates with units that have insulating paper that is no longer capable of providing reliable service.

MOP-T1 continues to be monitored.

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[35] Results of oil sampling are presented as Transformer Condition Assessments™ ("TCA") provided by TJ/H2b Analytic Services Incorporated ("TJ/H2b"). For details, see the *2026 Capital Budget Application*, report *2.2 Substation Power Transformer Strategy,* Appendix E.

ASSESSMENT OF ALTERNATIVES

Three alternatives were assessed to address the condition of power transformer MOP-T1: (i) condition-based monitoring; (ii) remove and repair; and (iii) replace and assess.

In the case of a MOP-T1 failure, the MOP generation plant will be unable to supply any generation into the electrical system. This will decrease the supply of on-island generation by approximately 10 MVA during peak requirements.

Newfoundland Power has three portable substations and no spare power transformer that can be used for the emergency response of MOP-T1. Failure of MOP-T1 would result in an unplanned long-term installation of a portable substation to keep the plant operational, until a replacement can be procured. Present power transformer delivery times are estimated between 24 and 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.

MOP-T1 is not a candidate for repair. Due to the age of MOP-T1, shipment of the unit to a repair facility risks introducing additional issues beyond the degraded insulation and rusting. Years of service and exposure to the elements have likely weakened the integrity of the unit, making it susceptible to damage during transport.

These risks to customer reliability are amplified by the long delivery lead times for 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 *Mobile Plant Substation Power Transformer Replacement* project would increase the risk of failure, which could decrease energy and capacity on the system by 10 MVA.

RISK ASSESSMENT

The *Mobile Plant Substation Power Transformer Replacement* project will mitigate risks to the supply of 10 MVA of generation to customers on the island integrated electricity system.

In the event of a MOP-T1 failure, a portable substation would be required to restore supply from the plant. Furthermore, there is no spare power transformer in Newfoundland Power's fleet of spares capable of replacing MOP-T1.

Delivery times of power transformers have increased from an average of 34 weeks in 2019 to an average of 110 weeks in 2025. 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 *Mobile Plant Substation Power Transformer Replacement* project.

Table 2
Mobile Plant Power Transformer Replacement Project
Risk Assessment Summary

Consequence	Probability	Risk
Critical (4)	Moderate (4)	Medium-High (16)

Overall, the condition of power transformer MOP-T1 poses a Medium-High (16) risk to the delivery of reliable, safe, and environmentally responsible service to customers. Action is required in 2026, 2027 and 2028 to mitigate these risks.

JUSTIFICATION

The *Mobile Plant 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 supply of 10 MVA of generation from the Mobile Plant.

Title:	**Molloy's Lane Substation Power Transformer Replacement**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$12,000 in 2026; $2,789,000 in 2027**

PROJECT DESCRIPTION

The *Molloy's Lane Substation Power Transformer Replacement* project involves the replacement of the Molloy's Lane ("MOL") Substation power transformer MOL-T2.

The proposed 2026 and 2027 scope of work for the *Molloy's Lane Substation Power Transformer Replacement* project includes:

(i) Remove existing power transformer MOL-T2; and,
(ii) Install and commission new 15/20/25 MVA, 66-12.5/25 kV, power transformer.

Molloy's Lane ("MOL") Substation was constructed in 1960 as both a distribution and transmission substation. This substation is supplied by Newfoundland Power 66 kV Transmission Lines 15L from Stamps Lane ("SLA") Substation and 19L from Hardwoods ("HWD") Substation. Two 15/20/25 MVA power transformers supply eight 12.5 kV distribution feeders, serving approximately 9,040 customers in the west end area of St. John's.

Engineering design and procurement of the new power transformer will be completed in the first quarter of 2026. Delivery, installation, testing and commissioning of the new power transformer will be completed in 2027.

For additional details, see the *2026 Capital Budget Application,* report *2.2 Substation Power Transformer Strategy.*

PROJECT BUDGET

The budget of the *Molloy's Lane Substation Power Transformer Replacement* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2026 and 2027 for the *Molloy's Lane Substation Power Transformer Replacement* project.

Table 1
Molloy's Lane Substation Power Transformer Replacement
Project Budget
($000s)

Cost Category	2026	2027	Total
Material	-	2,498	2,498
Labour - Internal	-	13	13
Labour - Contract	-	-	-
Engineering	8	121	129
Other	4	157	161
Total	$12	$2,789	$2,801

Proposed expenditures for the *Molloy's Lane Substation Power Transformer Replacement* project are $12,000 in 2026, and $2,789,000 in 2027 for a total project budget of $2,801,000.

ASSET BACKGROUND

MOL-T2 is a 49-year-old, 15/20/25 MVA, 66-12.5/25 kV power transformer manufactured by Federal Pioneer, and is a sister unit to KBR-T3. This transformer has remained at MOL since its original installation in 1976.

All power transformers receive regular maintenance on a 12-year cycle. MOL-T2 last underwent full maintenance in June of 2024. Additionally, all power transformers undergo annual oil sampling to monitor their condition.

Results of oil samples have indicated deteriorating mechanical strength of the internal paper insulation of the transformer. Oil sampling in January of 2025 indicated that the mechanical strength of the paper is at approximately 50 percent tensile strength.[36] The Electrical Power Research Institute ("EPRI") Power Transformer Expert System ("PTX") software indicates that the Normal Degradation Index of the transformer highly correlates with units that have insulating paper that is no longer capable of providing reliable service.

Additionally, the radiators on the transformer are in very poor condition and require replacement.

MOL-T2 continues to be monitored.

36 Results of oil sampling are presented as Transformer Condition Assessments™ ("TCA") provided by TJ/H2b Analytic Services Incorporated ("TJ/H2b"). For details, see the *2026 Capital Budget Application*, report *2.2 Substation Power Transformer Strategy,* Appendix E.

ASSESSMENT OF ALTERNATIVES

Three alternatives were assessed to address the condition of power transformer MOL-T2: (i) condition-based monitoring; (ii) remove and repair; and (iii) replace and assess.

In the event of a MOL-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 MOL-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 long delivery lead times for 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 *Molloy's Lane Substation Power Transformer Replacement* project would increase the risk of failure, which could expose up to approximately 9,040 customers to the risk of outages. Deferring this project is therefore not a viable alternative.

RISK ASSESSMENT

The *Molloy's Lane Substation Power Transformer Replacement* project will mitigate risks to the delivery of reliable service to approximately 9,040 customers in the St. John's 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 case of a MOL-T2 failure, MOL-T1 is unable to supply the existing peak load of the MOL Substation. System load forecasts indicate that up to 19.2 MVA of MOL-T2 load can be transferred to either MOL-T1 or offloaded to adjacent feeders. 6.9 MVA of load would be exposed to an outage.[37] A portable substation or a spare transformer would need to be installed in the event of a MOL-T2 failure.

[37] A max peak load of 53.7 MVA is being forecasted over the next five years at MOL Substation.

Newfoundland Power has three portable substations and one spare power transformer that can be used for the emergency response of MOL-T2. Failure of MOL-T2 would result in an unplanned short-term installation of a portable substation followed by a long-term installation of a spare power transformer when available.[38]

Delivery times for power transformers have increased significantly, from an average of 34 weeks in 2019 to an average of 110 weeks in 2025. 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 *Molloy's Lane Substation Power Transformer Replacement* project.

Table 2
Molloy's Lane Substation Power Transformer Replacement Project
Risk Assessment Summary

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

Overall, the condition of MOL-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 2026 and 2027 to mitigate these risks for customers.

JUSTIFICATION

The *Molloy's Lane 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 9,040 customers in the St. John's area.

38 Another spare power transformer would need to be procured if this spare power transformer is utilized to respond to a failure as it is the only 15/20/25 MVA, 66-25/12.5 kV transformer in the Company's inventory. Present power transformer delivery times are estimated between 24 and 36 months, and upwards of 60 months for some manufacturers. Being without this spare transformer for this timeframe would present additional risks to customer reliability.

Title:	**Substation Spare Power Transformer Inventory**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$13,000 in 2026; $3,906,000 in 2027**

PROJECT DESCRIPTION

The *Substation Spare Power Transformer Inventory* project involves the procurement of a spare 138-25/12.5 kV, 25 MVA power transformer to serve as a spare transformer in the Company's inventory. This additional transformer is necessary to address a significant gap in the Company's current inventory of spare transformers and to ensure continued system reliability. Maintaining an adequate inventory of spare power transformers is consistent with current utility practices and is essential for managing the risks associated with an aging transformer fleet.

The proposed 2026 and 2027 scope of work for the *Substation Spare Power Transformer Inventory* project includes:

(i) Receive and perform acceptance testing on the new spare 138-25/12.5 kV, 25 MVA power transformer.

Engineering design and procurement of the new power transformer will be completed in the first quarter of 2026. Delivery and testing of the new power transformer will be completed by the end of 2027.

For additional details, see report *2.2 Substation Power Transformer Strategy.*

PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2026 and 2027 for the *Substation Spare Power Transformer Inventory* project.

Table 1
Substation Spare Power Transformer Inventory Project Budget
($000s)

Cost Category	2026	2027	Total
Material	-	3,730	3,730
Labour - Internal	-	1	1
Labour - Contract	-	-	-
Engineering	9	22	31
Other	4	153	157
Total	$13	$3,906	$3,919

Proposed expenditures for the *Substation Spare Power Transformer Inventory* project are $13,000 in 2026, and $3,906,000 in 2027 for a total project budget of $3,919,000.

ASSET BACKGROUND

Newfoundland Power currently has 191 substation power transformers in service. Power transformers are essential to the delivery of reliable service to customers as the failure of a single transformer can result in a prolonged outage to thousands of customers.

The frequency of power transformer failures on the Company's system has increased over the last decade. Newfoundland Power has experienced 13 power transformer failures over the last decade, 10 of which have occurred in the past five years.

Newfoundland Power's operations are exposed to increasing risk of power transformer failure going forward due to the age of the Company's power transformer fleet. Industry experience suggests the expected service life of a power transformer is typically between 30 and 50 years under ideal conditions and that failure rates increase with age. Approximately 48% of Newfoundland Power's power transformers are aged 50 years or older. An additional 19% of power transformers are between 45 and 49 years old.

When a power transformer fails, Newfoundland Power initiates emergency response to restore service to customers as quickly as possible. 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 and whether a portable substation is nearby.

Newfoundland Power has typically had a small quantity of spare power transformers available to respond to a transformer failure. The Company's spares have historically been limited to power transformers that were removed from service due to system load growth. Newfoundland Power's inventory of spares currently consists of eight units. The coverage provided by these units is limited, at approximately 66% of Newfoundland Power's transformer fleet.

The Company's current inventory has no spare transformer available for 15 in-service 138-12.5 kV power transformers or for two in-service 138-25 kV, 25 MVA power transformers. The proposed spare transformer will provide backup coverage for these 17 critical units, significantly improving the Company's ability to respond to transformer failures.

Newfoundland Power conducted a survey in 2021 through the Centre for Energy Advancement through Technological Innovation to determine current utility practices for managing power transformer failures. The survey indicates that utilities currently manage power transformer failures through a combination of portable substations and spare transformers.

ASSESSMENT OF ALTERNATIVES

Three alternatives were assessed to respond to the increased risk of power transformer failure: (i) manage risk through existing emergency response capabilities, which include the use of portable substations; (ii) increase emergency response capabilities through the purchase of an additional portable substation; and (iii) maintain an inventory of spare power transformers by purchasing a power transformer to act as an emergency spare. The alternatives were assessed from the perspective of risk mitigation.

Managing the increased risk of power transformer failure through existing emergency response capabilities is not a viable alternative as it would place considerable upward pressure on the availability of portable substations. This, in turn, would expose customers to a high risk of prolonged outages.

The purchase of an additional portable substation would provide a degree of risk mitigation by partially relieving expected pressures on the availability of portable substations. However, portable substations are best suited for applications that require deployment for short periods of time, such as during substation maintenance. Newfoundland Power's limited and diminishing availability of spare power transformers would therefore reduce the degree of risk mitigation provided by this alternative.

Maintaining an inventory of spare power transformers by purchasing units to act as emergency spares would provide the greatest degree of risk mitigation. The purchase of a 138-25/12.5 KV, 25 MVA transformer to act as a spare would improve the emergency backup coverage provided by the Company's existing inventory from 66% to 75%. This would reduce expected pressures on the availability of portable substations and associated risks of customer outages.

Maintaining an inventory of spare power transformers by purchasing units to act as emergency spares is therefore the recommended alternative.

RISK ASSESSMENT

The *Substation Spare Power Transformer Inventory* project will mitigate risks to the delivery of reliable service to customers.

Power transformer failures can have a significant impact on the service reliability experienced by customers. For example, the failure of Bonavista ("BVA") Substation transformer BVA-T1 in November 2018 resulted in an outage to approximately 2,600 customers and approximately 24 hours was required to fully restore service to customers. A portable substation was required to be installed at BVA Substation for 11 months while the transformer was repaired.

A readily available portable substation can be deployed to restore service to customers within 24 to 36 hours. However, redeploying a portable substation that is already in service may not be possible or may require four or more days to uninstall and redeploy before service is restored to customers. An increased frequency of power transformer failures is likely to reduce the availability of portable substations, thereby exposing customers to a risk of prolonged outages.

Compounding this risk is the significant increase in transformer delivery lead times. In recent years, the average delivery time for power transformers has risen from approximately 34 weeks in 2019 to over 110 weeks in 2025, with some manufacturers quoting lead times of up to 60 months. These extended timelines mean that, in the event of a failure, a replacement transformer may not be available for at least two to three years. Without a suitable spare on hand, Newfoundland Power would be forced to rely on portable substations for prolonged periods, which could severely impact system reliability.

Maintaining an adequate inventory of spare power transformers will reduce the potential for prolonged customer outages due to power transformer failures. With a spare unit readily available, a substation can be restored to its normal configuration, thereby allowing a portable substation to be removed from service and made available for deployment elsewhere.

Overall, an increased probability of power transformer failure, 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 of the *Substation Spare Power Transformer Inventory* project.

Table 2
Substation Spare Power Transformer Inventory Project
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Substation Spare Power Transformer Inventory project* would pose a Medium-High (16) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Substation Spare Power Transformer Inventory* project is required to provide reliable service to customers at the lowest possible cost. Purchasing a spare transformer will enhance Newfoundland Power's ability to respond to equipment failures, reduce the risk of prolonged customer outages, and support the continued delivery of safe and reliable service to its customers. This is especially important given the risks associated with an aging transformer fleet and the extended timelines now required to procure replacement transformers.

Title: **Substation Replacements Due to In-Service Failures**
Asset Class: **Substations**
Category: **Program**
Investment Classification: **Renewal**
Budget: **$4,733,000**

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.[39]

Table 1 provides the annual expenditures for the *Substation Replacements Due to In-Service Failures* program from 2021 to 2025.

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

Year	2021	2022	2023	2024	2025F
Total	4,113	4,562	5,101	5,841	4,927
Adjusted Cost[1]	4,833	5,039	4,342[2]	3,938[3]	4,927

1 2025 dollars.
2 Excludes approximately $1,000,000 associated with the purchase of spare voltage regulators.
3 Excludes approximately $2,000,000 associated with the purchase of spare reclosers and breakers.

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).

The average annual adjusted cost for the *Substation Replacements Due to In-Service Failures* program was approximately $4.6 million from 2021 to 2025 when adjusted as described above.

Table 2 provides a breakdown of expenditures proposed for 2026 for the *Substation Replacements Due to In-Service Failures* program.

Table 2
Substation Replacements Due to In-Service Failures Program
2026 Budget
($000s)

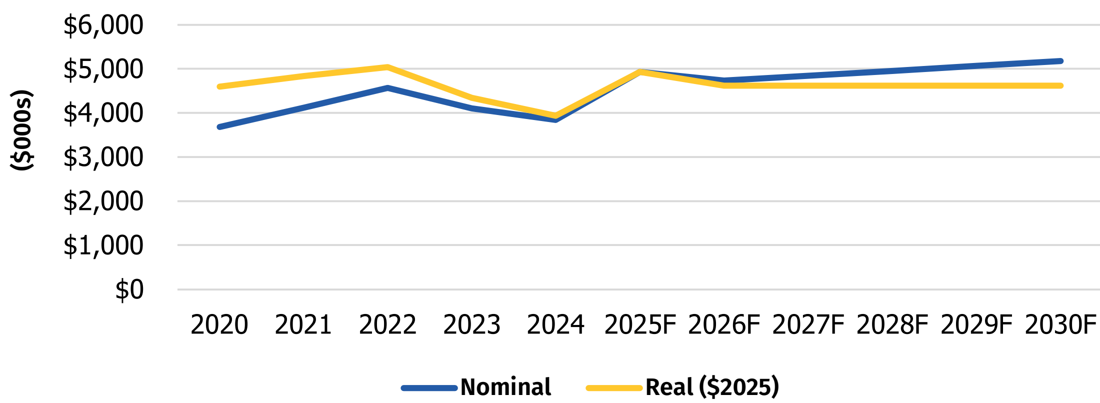
Cost Category	2026
Material	3,340
Labour – Internal	966
Labour – Contract	0
Engineering	258
Other	169
Total	$4,733

Proposed expenditures for the *Substation Replacements Due to In-Service Failures* program total $4,733,000 for 2026.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Substation Replacements Due to In-Service Failures* program from 2020 to 2030.[40]

Figure 1
Substations In-Service Failure Program Expenditures
(2020-2030F)



Annual expenditures under the *Substation Replacements Due to In-Service Failures* program averaged approximately $4.9 million from 2021 to 2025, or approximately $4.6 million when adjusted for inflation. Annual expenditures are forecast to average approximately $5.0 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. Three power

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[40] For forecast annual expenditures for the *Substation Replacements Due to In-Service Failures* program, see the *2026-2030 Capital Plan,* Appendix A, page A-3. Historical expenditures have been adjusted for the purchases described in Table 1.

transformers were replaced or repaired under this program from 2020 to 2024.[41] Over the same period, an average of seven 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 2026 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 the BVA 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.

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)

[41] 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.

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:	**Transmission Line 100L Rebuild**
Asset Class:	**Transmission**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$450,000 in 2026; $13,323,000 in 2027**

PROJECT DESCRIPTION

The *Transmission Line 100L Rebuild* project involves rebuilding Transmission Line 100L between Sunnyside ("SUN") Substation and Clarenville ("CLV") Substation to address deterioration and deficiencies identified through inspection.

Transmission Line 100L is scheduled for a multi-year rebuild beginning in 2026 and continuing into 2027. During the first year, engineering and pre-construction activities will be carried out, including obtaining environmental and development permits and approvals, acquiring necessary property rights, clearing brush along the new right-of-way, collecting topographic data, finalizing engineering and design work, and ordering materials. Completing all this work in the first year allows the Company to better manage lengthening timelines related to project approvals, environmental assessments, and permitting associated with transmission line rebuild projects. The second year will involve establishing construction contracts, procuring materials, and construction of the new line.

Additional information on this project is provided in report *3.1 Transmission Line 100L Rebuild* filed with the Application.

PROJECT BUDGET

The budget for the *Transmission Line 100L Rebuild* project is based on detailed engineering estimates.

Table 1 provides a breakdown of planned expenditures from 2026 to 2027 required to complete the execution of the *Transmission Line 100L Rebuild* project.

Table 1
Transmission Line 100L Rebuild Project
2026-2027 Budget
($000s)

Description	2026	2027	Total
Material	-	4,535	4,535
Labour – Internal	-	195	195
Labour - Contract	-	6,970	6,970
Engineering	188	35	223
Other	262	1,588	1,850
Total	$450	$13,323	$13,773

The new cost of the revised transmission scope for the *Transmission Line 100L Rebuild* project is estimated to be $13,773,000, including $450,000 in 2026 and $13,323,000 in 2027.

ASSET BACKGROUND

Transmission Line 100L is a 138 kV H-Frame radial line running between SUN Substation and CLV Substation, forming part of the Central Newfoundland 138 kV looped transmission system. The Central Newfoundland 138 kV looped transmission system is supplied primarily from SUN and Stony Brook ("STY") infeed supply points from Newfoundland and Labrador Hydro's ("Hydro") bulk power system. The SUN-STY loop is a key transmission supply network providing power to 35 Newfoundland Power substations.

Transmission Line 100L was originally constructed in 1964, apart from a two-kilometre section connecting the transmission line to the Clarenville Substation which was constructed in 1975. The total line is 34.13 kilometres in length and consists of approximately 148 H-Frame structures with 397.5 ACSR conductor.[42] Having been in service for over 61 years the conductor is approaching the end of the typical useful service life.[43]

Transmission Line 100L does not meet current standards for the construction of overhead lines.[44] The Canadian Standards Association ("CSA") establishes standards for the construction of overhead systems based on local climatic conditions. At the time of construction in 1964, Transmission Line 100L was designed to withstand sustained winds of 90 km/hour. Current CSA

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42 ACSR is a bare overhead conductor with aluminum outer strands and a steel core.
43 The typical useful service life of transmission overhead conductor is 63 years.
44 As noted in Newfoundland Power's 2006 *Transmission Line Rebuild Strategy*, 37 of Newfoundland Power's transmission lines constructed between the 1940s and 1960s were not built to adequate design and construction standards by present day criteria. For example, the current version of *CSA standard C22.3 – Overhead Systems* includes design criteria for maximum wind load conditions which were not considered in the original design of 100L.

standards require that overhead lines be constructed based on actual historical climate data. Based on this parameter and actual historical wind speed data provided in the standard, Transmission Line 100L should be designed to withstand winds of upwards of 120 km/hour, which is over 33% higher than its current design.[45] The substandard design of this line means it is not built to withstand local climatic conditions, which increases its probability of failure.

In 2024, Newfoundland Power initiated an engineering assessment of Transmission Line 100L. A detailed inspection of the line was completed by planners in accordance with the Company's Transmission Line Inspection and maintenance practices to quantify the transmission lines overall condition. The inspection determined that 135 of 148, or 91% of H-Frame structures on Transmission Line 100L have deficiencies.

ASSESSMENT OF ALTERNATIVES

Transmission Line 100L is critical to the reliability of the Central Newfoundland 138 kV looped transmission network. Newfoundland Power evaluated three alternatives to address the deteriorated condition of Transmission Line 100L to mitigate risks to the delivery of reliable service to customers. These are: (i) replace the deteriorated structures in place and defer the rebuild of the remainder of the line; (ii) rebuild the existing line in a new, parallel right-of-way; and (iii) rebuild the existing line in a new, partially re-routed right-of-way.

The assessment of alternatives included a net present value analysis to determine the least-cost alternative to addressing the deteriorated condition of Transmission Line 100L. The assessment determined that rebuilding Transmission Line 100L in a new, partially re-routed right-of-way is the least-cost alternative to addressing the identified deficiencies.

RISK ASSESSMENT

The *Transmission Line 100L Rebuild* project will mitigate risks to the delivery of reliable service to customers supplied by the Central Newfoundland 138 kV looped transmission network. 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 100L, are maintained in accordance with the Company's *Transmission Inspection and Maintenance Practices*.

While the historical reliability performance of Transmission Line 100L has been reasonable, the line's sub-standard design and deteriorated condition exposes it to an increased probability of failure going forward.

Inspections have identified that 135 structures on this line are deteriorated to the point where replacement is required. A significant quantity of the remaining poles are past the end of their useful service lives while also being in a deteriorated condition. Based on these factors the probability of failure is likely.

[45] *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."*

Transmission Line 100L plays a critical role in the Central Newfoundland 138 kV transmission system. An outage to Transmission Line 100L results in a significant section of the Central Newfoundland 138 kV transmission system effectively becoming radial. During an outage to the line, all substations on the Bonavista peninsula, as well as Terra Nova, Port Blandford, Northwest Brook and Clarenville Substations become effectively radially supplied by Transmission Line 109L which originates from SUN Substation. When these substations are radially supplied, any single failure on transmission line 109L could result in outages to up to 15,200 customers downstream of the affected line.

The criticality of Transmission Line 100L and its 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 Transmission Line 100L Rebuild project.

Table 2
Transmission Line 100L Rebuild Project
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Transmission Line 100L Rebuild* project would pose a High (20) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Transmission Line 100L Rebuild* project is required to ensure the delivery of reliable service to approximately 15,200 customers. A review of the Project and an updated assessment of alternatives determined that rebuilding Transmission Line 100L between SUN and CLV substations in a partially re-routed right-of-way is the least cost option to address existing deterioration and deficiencies while mitigating risks of equipment failures.

Title:	**Transmission Line Maintenance**
Asset Class:	**Transmission**
Category:	**Program**
Investment Classification:	**Renewal**
Budget:	**$3,306,000**

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 components to re-treat transmission line assets with wood preservative and 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.[46]

Table 1 provides the annual expenditures for the *Transmission Line Maintenance* program from 2021 to 2025.

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

Year	2021	2022	2023	2024	2025F
Total	2,404	2,488	3,449	2,826	4,229
Adjusted Cost[1]	2,798	2,706	3,647	2,895	2,884

[1] 2025 dollars.

The average annual adjusted cost for the *Transmission Line Maintenance* program was approximately $3.0 million from 2021 to 2025.

[46] 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 2026 for the *Transmission Line Maintenance* program.

Table 2
Transmission Line Maintenance Program
2026 Budget
($000s)

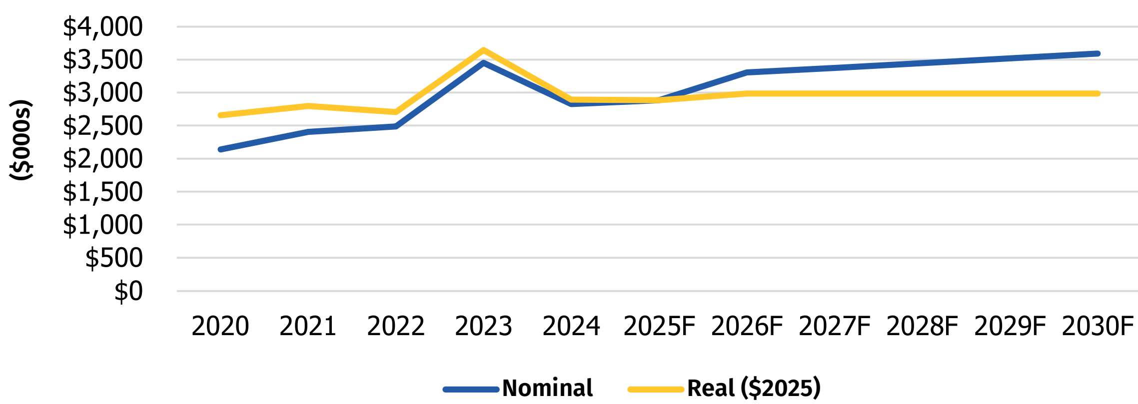
Cost Category	2026
Material	924
Labour – Internal	590
Labour – Contract	1,578
Engineering	54
Other	160
Total	$3,306

Proposed expenditures for the *Transmission Line Maintenance* program total $3,306,000 for 2026.

PROGRAM TREND

Figure 1 provides historical and forecast costs for the *Transmission Line Maintenance* program from 2020 to 2030.[47]

Figure 1
Transmisson Line Maintenance Program Expenditures
(2020-2030F)



Annual expenditures under this program averaged approximately $2.8 million from 2021 to 2025, or approximately $3.0 million when adjusted for inflation. Annual expenditures are forecast to average approximately $3.4 million over the next five years.

[47] For forecast annual expenditures for the *Transmission Line Maintenance* program, see the *2026-2030 Capital Plan,* Appendix A, page A-4.

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.[48] 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. Beginning in 2026, corrective maintenance under this program will also include retreatment of selected transmission poles with wood preservative.

The number of deficiencies addressed under the *Transmission Line Maintenance* program varies annually. From 2020 to 2024, an average of 140 poles, 257 framing structures and 429 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 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.

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

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	61-70	Total
Kilometres	293	262	126	141	753	389	22	1,986
Percentage of Total	15%	13%	6%	7%	38%	20%	1%	100%

As shown 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.

INFORMATION SYSTEMS

Title: **Application Enhancements**
Asset Class: **Information Systems**
Category: **Project**
Investment Classification: **General Plant**
Budget: **$968,000**

PROJECT DESCRIPTION

The *Application Enhancements* project involves upgrading several software applications in 2026, with the goal of reducing customer costs and enhancing service delivery. The planned initiatives for 2026 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.

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 2026 for the *Application Enhancements* project.

Table 1
Application Enhancements Project
2026 Budget
($000s)

Cost Category	2026
Material	300
Labour – Internal	593
Labour – Contract	-
Engineering	-
Other	75
Total	$968

Proposed expenditures for the *Application Enhancements* project total $968,000 for 2026.

ASSET BACKGROUND

The items included under the 2026 *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, Technology, 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 provide a central reporting tool for information sharing in a secure and auditable manner. Examples include financial reporting, IT security data, Customer call analysis and Customer meter data.
(ii) Digitizing paper-based forms and manual processes will achieve operational efficiencies. Examples include the digitization of HR dental forms, field vegetation forms, and inspection forms.
(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.

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 ($79,000)*

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 approximately 568,000 visits to the takeCHARGE website in 2024.

(iii) *Various Minor Enhancements ($539,000)*

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) improvements to the Aliant Billing invoice process to ensure all invoices are sent to Aliant in the same format regardless of the source; (ii) Automating the invoice process for third parties from the Work Management system to the Finance system; (iii) Enhancing the Customer Rebate system to automate the data received from the takeCHARGE website (iv) improvements to field staff time entry collection and approval process.

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 2026 will advance operational efficiency and provide cost savings for customers. Deferring the 2026 *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. The project 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 2026 *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 2026 *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: **Customer Correspondence Modernization**
Asset Class: **Information Systems**
Category: **Project**
Investment Classification: **General Plant**
Budget (Multi-Year): **$782,000 in 2026; and $1,175,000 in 2027;**

PROJECT DESCRIPTION

The *Customer Correspondence Modernization* ("CCM") project involves upgrading customer bill design and delivery over two years commencing in 2026. The CCM project will deliver comprehensive, personalized and accessible account related communications to customers.

Additional information on this project is provided in report *4.1 Customer Correspondence Modernization* filed with the Application.

PROJECT BUDGET

The budget for the CCM project is based on detailed cost estimates.

Table 1 provides a breakdown of expenditures proposed for 2026 & 2027 for the CCM project.

Table 1
Customer Correspondence Modernization
2026-2027 Budget
($000s)

Cost Category	2026	2027	Total
Material	601	738	1,376
Labour – Internal	162	398	531
Labour – Contract	-	-	-
Engineering	-	-	-
Other	19	39	50
Total	$782	$1,175	$1,957

Proposed expenditures for the CCM project total $1,957,000, with $782,000 in 2026, and $1,175,000 in 2027.

ASSET BACKGROUND

With over three million bills generated annually, as well as tens of thousands of letters and notifications, this is a business operation that is essential for fostering strong customer relationships, building trust and ensuring that customer service expectations are met.

Newfoundland Power's current billing and correspondence solution has dependably generated customer bills for nearly two decades. The technology supporting the production of bills and letters, as well as their design, now struggles to meet customers' evolving needs, lacking the ability to effectively manage current and future business requirements.

ASSESSMENT OF ALTERNATIVES

The Company identified and assessed two alternatives to ensure continuity of its customer correspondence solution: (i) maintaining the existing solution; and (ii) re-platform and redesign.

Re-platform and redesign, which was selected as the alternative, is a full replacement of the underlaying systems responsible for bill and letter production, printing and distribution. It also includes a comprehensive redesign of the customer bill and its delivery channels. The re-platforming and redesign of customer bills is required to deliver service to customers in a manner that is least cost and results in more efficient and effective customer service delivery.

RISK ASSESSMENT

Customer billing is a critical business operation for Newfoundland Power. The Company maintains support for all critical business applications. Due to the age of bill legacy components that have been customized over years of use, the primary concern is the risk of obsolescence and reduced supportability.

Safeguarding the integrity of Newfoundland Power systems, protecting vital customer information, and ensuring the secure delivery of services stands as paramount pillars in the Company's mission. The Company continues to focus efforts to systematically lower cybersecurity and fraud risk.

The current bill and, by extension, letter design has several defects that would be addressed by the Project. These deficiencies result in hours of effort daily to manually review, correct, and redistribute billing documents or to answer customer calls and emails to explain or correct information previously distributed.

Table 2 summarizes the risk assessment of the CCM project.

Table 2 Customer Correspondence Modernization Risk Assessment Summary		
Consequence	Probability	Risk
Serious (5)	Likely (3)	Medium-High (15)

Based on this assessment, not proceeding with the CCM project would pose a Medium-High (15) risk to the delivery of reliable service to customers.

JUSTIFICATION

The CCM project is required to ensure the secure, personalized and efficient communication of customer billing information which is a critical business operation to continue to support customers.

Title: **Geographic Information System Upgrade**
Asset Class: **Information Systems**
Category: **Project**
Investment Classification: **General Plant**
Budget (Multi-Year): **$500,000 in 2026; and $5,173,000 in 2027 and $2,652,000 in 2028**

PROJECT DESCRIPTION

Newfoundland Power has used Geographic Information System (GIS) technology since 2013, to manage its electrical infrastructure. GIS is integral to the entire Newfoundland Power operation. It provides a real-time model of the electrical system, including the status and location of infrastructure that delivers electricity to customers. GIS is used by the majority of the Company's employees to support numerous business functions and is connected to many critical operational systems such as Outage Management, Customer Service System, Asset Management, and allows the Company to have real time access to the grid.

Newfoundland Power will upgrade the existing technology over a three-year period, with a proposed start date of 2026.

Additional information on this project is provided in report *4.2 Geographic Information System Upgrade* filed with the Application.

PROJECT BUDGET

The budget for *the Geographic Information System Upgrade* project is based on detailed cost estimates.

Table 1 provides a breakdown of expenditures proposed for 2026 for the *Geographic Information System Upgrade* project.

Table 1
Geographic Information System Upgrade Project
2026-2028 Budget
($000s)

Cost Category	2026	2027	2028	Total
Material	142	2,880	671	3,693
Labour – Internal	355	1,703	1,249	3,307
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	3	590	732	1,325
Total	$500	$5,173	$2,652	$8,325

Proposed expenditures for the Geographic Information System Upgrade project total is $8,325,000, with $500,000 in 2026, $5,173,000 in 2027, and $2,652,000 in 2028.

ASSET BACKGROUND

Prior to deployment of GIS technology at Newfoundland Power, the Company maintained multiple applications that used geographic location and electrical connectivity information to support the engineering and operation of the distribution system and to provide customers with information on field operations. The information flowing into and from these applications was largely a series of manual processes.

In 2013, the Company purchased and installed a commercial GIS system to streamline the manual processes used to maintain and distribute information associated with the Company's various distribution assets. Prior to the introduction of the GIS, there was significant duplication of effort, an increased risk of errors with manual data entry, and complexity in ensuring multiple versions of documentation were updated and distributed properly.

The GIS technology currently in use is at the end of its useful life and requires a major upgrade. The existing Geometric Network is being discontinued on February 28, 2028. Migrating the GIS to the newer Utility Network standard is required to maintain vendor support and security. Failing to complete this migration could result in widespread disruption to Company operations, geographic tools and integrations.

ASSESSMENT OF ALTERNATIVES

The Company identified and assessed three alternatives to migrating its geographic information system: (i) do nothing; (ii) upgrade GIS technology; and (iii) replace GIS technology.

Upgrading GIS, which was selected as the alternative, involves a major system upgrade to eliminate the risk to Company's operations, work management and customer service. The upgraded technology will support all existing functionality and maintain current business processes. The upgrade will maintain existing processes and provide the Company with an ability to continue the visualization and analysis capabilities of data and enhanced security through a web-services architecture.

RISK ASSESSMENT

GIS is a critical business application for Newfoundland Power. It is the central repository for the Company's geolocation information. Spatial analysis capabilities provided through the GIS have enabled efficiency gains and improved service offerings across virtually all customer operations business functions. Employees in engineering, operations, technology, planning and customer service departments all rely on GIS to effectively and efficiently complete their tasks daily.

The vendor has indicated that the current technology will no longer be supported as of February 28, 2028. Vendor support ensures that critical applications operate reliably and securely. Unsupported applications are more prone to failure and are at risk of cybersecurity threats.

Table 2 summarizes the risk assessment of the *Geographic Information System Upgrade* project.

Table 2 Geographic Information System Upgrade Project Risk Assessment Summary		
Consequence	Probability	Risk
Serious (5)	Likely (4)	High (20)

Based on this assessment, not proceeding with the *Geographic Information System Upgrade* project would pose a High (20) risk to the Company operations.

JUSTIFICATION

Newfoundland Power's current GIS technology will no longer be supported by the vendor as of February 28, 2028. The Company will perform a major upgrade of the GIS system commencing in 2026. Replacement of the Technology is in alignment with the Company's best practices of running supported software and will allow the Company to continue GIS practices, while providing a foundation for GIS maturity.

Title:	**System Upgrades**
Asset Class:	**Information Systems**
Category:	**Project**
Investment Classification:	**General Plant**
Budget:	**$965,000**

PROJECT DESCRIPTION

The *System Upgrades* project involves upgrades to third-party software products that comprise Newfoundland Power's information systems. System upgrades proposed for 2026 involve the Database Management system (DBMS), Human Resources system, Financial Management System, PI Reporting and Supervisory Control and Data Acquisition ("SCADA") system.

Upgrades to the DBMS, Human Resources and Financial Management System are critical to ensure continued vendor support that include bug fixes and security patches. Upgrades to the PI Reporting and 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 2026 for the *System Upgrades* project.

Table 1
System Upgrades Project
2026 Budget
($000s)

Cost Category	2026
Material	323
Labour – Internal	642
Labour – Contract	-
Engineering	-
Other	-
Total	$965

Proposed expenditures for the *System Upgrades* project total $965,000 for 2026.

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 2026 are:

(i) *Database Management Software Upgrade ($108,000)*

This item involves upgrading Newfoundland Power's Database Management Software to the latest versions supported by the vendor.

The Company operates multiple versions of Database Management Software to support over 150 database applications. The Database Management Software version selected for an application is typically the latest version available from the vendor at the time of implementation or upgrade.

One of Newfoundland Power's Database Management Software versions will no longer be supported by the vendor as of July 2026. This Database Management Software affects ten different applications and databases that support applications in the customer relations, metering and technology areas of the Company.

An upgrade of the Database Management Software is required in 2026 to ensure continued vendor support of the software. The upgrade will also apply the latest database security patches to minimize any potential vulnerabilities. The project is anticipated to be completed before July 2026.

(ii) *Human Resource Management System Upgrade ($134,000)*

This item involves upgrading Newfoundland Power's Human Resource Management System to the latest version supported by the vendor.

Newfoundland Power's Human Resource Management System was implemented in 2020. The system is used by the Company's Human Resources and Finance departments to manage employee information, payroll, benefits administration, employee self-service, recruitment and onboarding. The system is also used for retiree benefits and payroll.

The Human Resource Management System is a vendor-managed product that requires regular upgrades to maintain vendor support. Upgrades typically include bug fixes, functionality upgrades, security upgrades and overall functional improvements. Failure to comply with regular lifecycle upgrades to the system would result in the product becoming unsupported by the vendor. Keeping current with the latest versions of software helps protect employee information against evolving cybersecurity threats.

The project is anticipated to commence in January 2026 and will be completed in June 2026.

(iii) *Financial Management System Upgrade ($145,000)*

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 daily 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 2026, the proposed upgrade of the Company's Financial Management System will apply the latest software release available from the vendor. Commencing the 2023 upgrade, the vendor introduced a new policy that requires upgrades on an annual cycle. The 2026 upgrade is required 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 2026 and will be completed in the third quarter.

(iv) *PI Reporting Upgrade ($140,000)*

This item involves upgrading the Company's SCADA Reporting System ("PI System") to ensure system operations benefit from the latest functionality and security updates available from the vendor.

Newfoundland Power's PI System was implemented in 2016. The PI System extracts electrical system data from the SCADA System and creates a version of the SCADA database on the Company's business network. This approach to application design ensures that the security of the SCADA System is not compromised while making the necessary information available to other Newfoundland Power employees for system analysis and planning.

The current PI System is on a technical support only plan and the vendor is recommending customers upgrade to the current version. Upgrading the software will be completed in the first quarter of 2026 to ensure full vendor support moving forward.

(v) *SCADA System Upgrade ($61,000)*

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 2026, 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 2026 and will be completed in the second quarter.

(vi) *Various Minor Upgrades ($377,000)*

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 2026 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 $61,000 to $377,000 and do not constitute major product releases that warrant consideration of system replacement. Completing the required system upgrades in 2026 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 2026 are essential to Newfoundland Power's operations. Upgrades of the DBMS, Human Resources and the 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 PI Reporting and 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 Human Resource system could compromise employee 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 2026 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 2026 *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 2026 *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:	**$990,000**

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 2026, two items are proposed to improve the functionality of Newfoundland Power's shared server infrastructure. These include: (i) Server Infrastructure Upgrades and (ii) Backup and Disaster Recovery Infrastructure Expansion.

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 2026 for the *Shared Server Infrastructure* project.

Table 1
Shared Server Infrastructure Project
2026 Budget
($000s)

Cost Category	2026
Material	870
Labour – Internal	120
Labour – Contract	-
Engineering	-
Other	-
Total	$990

Proposed expenditures for the *Shared Server Infrastructure* project total $990,000 for 2026.

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 always operate effectively.

Two upgrades are proposed for 2025:

(vii) *Server Infrastructure Upgrades ($730,000)*

Upgrades are required in 2026 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.[49]

(viii) *Backup and Disaster Recovery Infrastructure Upgrade ($260,000)*

Upgrades are required in 2026 to improve the Company's ability to recover information systems from failure and ensure business continuity in all scenarios. The Company relies on information systems to monitor and operate the electrical system, business systems and to provide customer service. The current backup and recovery system is nearing capacity and must be expanded to allow additional data to be backed up. This upgrade will allow the company to ensure a continued ability to recover systems from failure and maintain business continuity under all scenarios.

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 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

[49] 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.

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 74% of proposed 2026 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 26% of proposed 2026 expenditures relate upgrading the Company's backup and data recovery infrastructure. This critical infrastructure underpins the Company's ability to recover from system failures and ensure business continuity. Deferring these upgrades would impede the Company's ability to adequately backup information systems and expose the Company to an increased risk of data loss.

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.[50] 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.

[50] 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:	**$950,000**

PROJECT DESCRIPTION

The Cybersecurity Upgrades project focuses on strengthening the Company's cybersecurity infrastructure. Proposed capital investments for 2026 include implementing new technologies and enhancing existing systems to reduce risk and improve security in areas such as email protection, vulnerability management, security alerting within operational technologies and SCADA environments, and improvements to 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 2026 for the *Cybersecurity Upgrades* project.

Table 1
Cybersecurity Upgrades Project
2026 Budget
($000s)

Cost Category	2026
Material	385
Labour – Internal	405
Labour – Contract	-
Engineering	-
Other	160
Total	$950

Proposed expenditures for the *Cybersecurity Upgrades* project total $950,000 for 2026.

ASSET BACKGROUND

Electrical system assets are operated using a combination of physical and technological 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.

Newfoundland Power continually assesses its infrastructure to identify measures to improve the Company's cybersecurity. The cybersecurity measures identified for implementation in 2026 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.

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.

TRANSPORTATION

Title:	**Replace Vehicles and Aerial Devices 2026-2027**
Asset Class:	**Transportation**
Category:	**Project**
Investment Classification:	**General Plant**
Budget (Multi-Year):	**$3,003,000 in 2026 and $2,718,000 in 2027**

PROJECT DESCRIPTION

The *Replace Vehicles and Aerial Devices 2026-2027* 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 2026 and continuing into 2027 under this project.

Table 1
2026-2027 Proposed Vehicle Replacements

Category	2026 No. of Units	2027 No. of Units
Passenger Vehicles	18	-
Light-Duty Vehicles	2	-
Heavy/Medium-Duty Vehicles	-	6
Total	20	6

Newfoundland Power has identified 18 passenger vehicles and two light-duty vehicles for replacement in 2026 and six heavy/medium-duty vehicles for replacement in 2027. The project also includes expenditures for the replacement of miscellaneous off-road vehicles in 2026. 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 2026-2027* 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 2026-2027* project for 2026 and 2027.

Table 2
Replace Vehicles and Aerial Devices
2026-2027 Project
Budget
($000)

Cost Category	2026	2027	Total
Material	2,860	2,718	5,578
Labour – Internal	143	-	143
Labour – Contract	-	-	-
Engineering	-	-	-
Other	-	-	-
Total	$3,003	$2,718	$5,721

Proposed expenditures for the *Replace Vehicles and Aerial Devices 2026-2027* project total approximately $5,721,000, including $3,003,000 in 2026 and $2,718,000 in 2027.

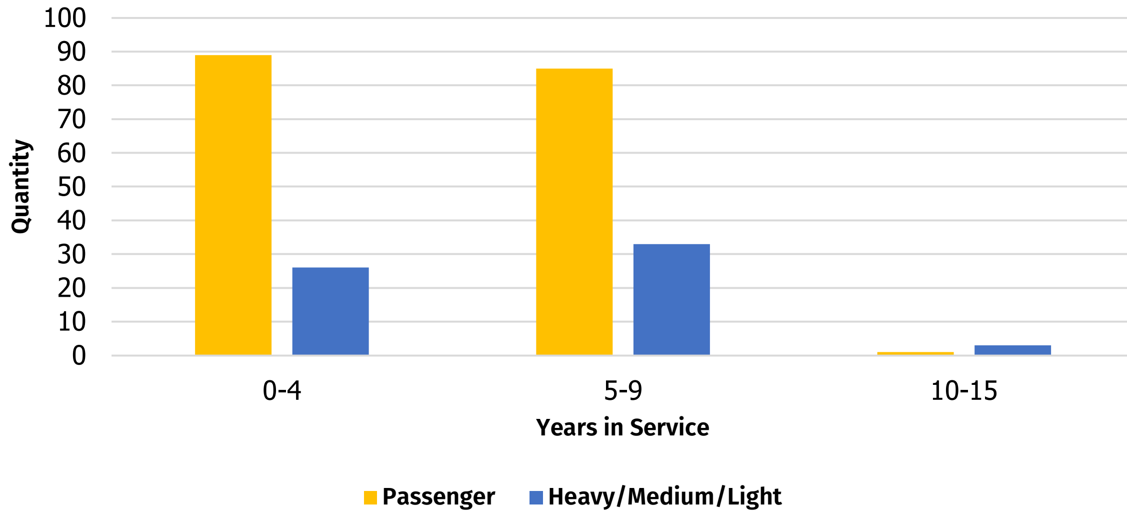
ASSET BACKGROUND

Newfoundland Power maintains a fleet of approximately 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.[51] 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 repair may not ultimately extend the service life of a vehicle due to heavy rust or other

51 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.

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 2026-2027* project will mitigate risks to the delivery of safe and reliable service to customers.

Newfoundland Power actions an average of 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 2026 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 2026-2027* project.

Table 3
Replace Vehicles and Aerial Devices 2026-2027 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 2026-2027* project would pose a Medium-High (16) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Replace Vehicles and Aerial Devices 2026-2027* 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 2026 and 2027 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 Provisional Guidelines.

JUSTIFICATION

This project provides funds for timely service restoration in accordance with Section V.A.7 Allowance for Unforeseen Items of the Provisional Guidelines.

GENERAL EXPENSES CAPITALIZED

Title: **General Expenses Capitalized**
Asset Class: **General Expenses Capitalized**
Category: **Project**
Investment Classification: **Mandatory**
Budget: **$5,300,000**

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.[52] 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*.[53]

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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52 In Order No. P.U. 3 (2022), the Board approved a change in the calculation of GEC to remove pension costs.
53 See Newfoundland Power's *2022/2023 General Rate Application, Volume 2,* report 6 *Review of General Expenses Capitalized.*

2026 CAPITAL PROJECTS AND PROGRAMS

$750,000 AND UNDER

Distribution

Distribution Feeder GDL-03 Refurbishment

Budget: $722,000 *Investment Classification: Renewal* *Category: Project*

This project involves replacing deteriorated underground infrastructure on Loop 1 and Loop 2 of Glendale ("GDL") Substation distribution feeder GDL-03. Loop 1 and Loop 2 of distribution feeder GDL-03 are 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 Barbour Drive area of Mount Pearl.

New Meters

Budget: $701,000 *Investment Classification: Access* *Category: Program*

This program involves the purchase and installation of meters for new customers. Newfoundland Power (the "Company") is forecasting the requirement to install meters to serve 2,865 new customer connections in 2026. 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 Feeder Automation

Budget: $648,000 *Investment Classification: Service Enhancement* *Category: Project*

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

Replacement Meters

Budget: $562,000 *Investment Classification: Renewal* *Category: Program*

This program involves the replacement of deteriorated meters for existing customers, and the sampling and replacement of meters. This program is necessary to provide reliable service to customers as it provides for the replacement of deteriorated or failed meters. The program is also necessary to maintain compliance of meter assets with the federal *Electricity and Gas Inspection Act* and associated regulations.

Distribution

Replacement Services

Budget: $382,000 *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 and is therefore required to provide safe and reliable service to customers.

Allowance for Funds Used During Construction

Budget: $223,000 *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 necessary to implement the Company's capital program and is justified on the same basis as the approved distribution capital expenditures to which it relates.

Substations

Substation Protection and Control Replacements

Budget: $719,000 *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 necessary to provide safe and reliable service to customers at the lowest possible cost as it provides for the replacement of obsolete protection and controls systems at substations.

Substation Ground Grid Upgrades

Budget: $350,000 *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 necessary to maintain safe and adequate facilities as it provides for the correction of ground grid deficiencies identified at the Company's substations.

Generation – Hydro

Hydro Plant Replacements Due to In-Service Failures

Budget: $736,000 *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 necessary for the Company's hydro plants to continue provide reliable service to customers at the lowest possible cost together with their localized reliability benefits and contribution to system capacity.

Cape Broyle and Horse Chops Plant Control Upgrades

Budget: $398,000 *Investment Classification: Renewal* *Category: Project*

This project involves the replacement of control equipment in the Cape Broyle and Horse Chops hydroelectric plants including programmable logic controllers, human-machine interfaces and exciter control systems. This project is necessary to ensure the provision of control equipment necessary for the continued safe and reliable production of electricity in both plants.

Generation – Thermal

Thermal Plant Replacements Due to In-Service Failures

Budget: $331,000 *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: $733,000 *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 reliable service to customers at the lowest possible cost as it provides for the replacement of PCs and related information technology equipment that have reached the end of their useful service lives.

Network Infrastructure

Budget: $495,000 *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 safe and reliable service to customers at the lowest cost. This project is necessary as it provides for the replacement of obsolete network equipment that is essential to the Company's day-to-day operations.

Telecommunications

Mount Carmel Pond Dam Fibre

Budget: $150,000 *Investment Classification: Renewal* *Category: Project*

This project involves installing a new fibre optic cable from the spillway to the outlet gate. This project is to be completed as part of the Mount Carmel Pond Dam Refurbishment project that was approved in the *2025 Capital Budget Application*. The spillway was commissioned in 1954, and the outlet gate currently requires manual operation by hydro plant operations staff. Failure to replace and automate gate operations could result in an inability to control water flow through the facility, resulting in a loss of generation.

Communications Equipment Upgrades

Budget: $131,000 *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 safety and efficiency in the operations of field crews working to provide service to customers. This program is therefore necessary to provide reliable service to customers at the lowest possible cost as it provides for the replacement of failed, obsolete, or deteriorated communications equipment.

General Property

Additions to Real Property

Budget: $714,000 *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. The Company maintains district and area offices throughout its service territory with related facilities for the Company's employees and customers. These offices ensure a prompt response to customer outages and other customer service requests. Building components and systems that are upgraded, refurbished or replaced under this program are ones that have failed or are at imminent risk of failure.

Specialized Tools and Equipment

Budget: $616,000 *Investment Classification: General Plant* *Category: Project*

This project is necessary to purchase specialized tools and equipment beyond those provided for in the Company's *Tools and Equipment* program (see below). The Company must have an adequate supply of tools and equipment to provide reliable service to customers. 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. The 2026 project includes procurement of tools for electrical maintenance and a forklift.

Tools and Equipment

Budget: $605,000 *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. The Company must have an adequate supply of tools, equipment, and office furniture to provide prompt and reliable service to customers. The replacement of deteriorated and obsolete equipment on an ongoing basis is also necessary to ensure the safety of employees working in offices and the field.

General Property

Physical Security Upgrades

Budget: $506,000 *Investment Classification: General Plant* *Category: Program*

This program involves upgrading physical security infrastructure at the Company'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.

Building Accessibility Improvements

Budget: $490,000 *Investment Classification: General Plant* *Category: Project*

This project involves upgrading, refurbishing, and replacing equipment and facilities to improve accessibility at Company facilities. The Company 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.

Summerford Building Replacement

Budget: 2026-$155,000 *Investment Classification: General Plant* *Category: Multi-year Project*
2027-$562,000

This multi-year project involves the replacement of the Summerford building which was constructed in 1968. This building supports the Company's operations from Twillingate to Musgrave Harbour. A condition assessment determined the building is exhibiting significant deterioration and a replacement is required to deliver effective and timely service to customers in the area.

Newfoundland Power Inc.
Computation of Average Rate Base
For the Years Ended December 31
($000s)

	2024	2023
Net Plant Investment		
Plant Investment	2,403,246	2,311,786
Accumulated Depreciation	(1,004,688)	(957,928)
Contributions in Aid of Construction	(47,797)	(47,887)
	$1,350,761	$1,305,971
Additions to Rate Base		
Deferred Pension Costs	108,293	101,430
Credit Facility Costs	167	105
Cost Recovery Deferral – Conservation	21,280	20,708
Cost Recovery Deferral – 2022 Revenue Shortfall	0	229
Cost Recovery Deferral – Load Research and Retail Rate Design Review	635	189
Cost Recovery Deferral – Hearing Costs	874	0
Cost Recovery Deferral – Pension Capitalization	1,198	799
Customer Finance Programs	1,049	1,199
	$133,496	$124,659
Deductions from Rate Base		
Weather Normalization Reserve	2,896	(6,321)
Demand Management Incentive Account	(1,545)	(978)
Other Post-Employment Benefits	86,308	84,357
Customer Security Deposits	618	653
Accrued Pension Obligation	5,512	5,397
Accumulated Deferred Income Taxes	33,287	30,609
Refundable Investment Tax Credits	294	292
Excess Earnings Account	0	3,714
	$127,370	$117,723
Year End Rate Base	1,356,887	1,312,907
Average Rate Base Before Allowances	1,334,897	1,267,997
Rate Base Allowances		
Materials and Supplies Allowance	14,743	14,778
Cash Working Capital Allowance	7,551	7,304
Average Rate Base at Year End	$1,357,191	$1,290,079

June
2025

2026 Capital Budget Overview

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 APPLICATION OVERVIEW

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") proposed 2026 Capital Budget totals approximately $137.9 million. The 2026 Capital Budget includes:

(i) Proposed single-year projects and programs in excess of $750,000 in the amount of $75,158,000;
(ii) Proposed single-year projects and programs $750,000 and under in the amount of $10,212,000;
(iii) Proposed multi-year projects with capital expenditures of $6,131,000 in 2026, $40,848,000 in 2027 and $8,040,000 in 2028; and
(iv) Previously approved multi-year projects with capital expenditures of $46,442,000 in 2026, and $9,816,000 in 2027

The 2026 Capital Budget includes 22 recurring capital programs and 42 capital projects, 13 of which have been previously approved. The 2026 Capital Budget is approximately $10.0 million more than the approved *2025 Capital Budget Application*.[1]

Approximately half of the capital expenditures included in the 2026 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 2026 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 three substation power transformers as part of a broader transformer strategy. This strategy is intended to ensure the effective management of an aging power transformer fleet.

Approximately one quarter of capital expenditures included in the 2026 Capital Budget are associated with requirements to connect new customers to the electrical grid and to respond to system load growth. The Company is forecasting 2,865 new customer connections in 2026, as well as the requirement to address load growth on a distribution feeder in Western region.

The remaining quarter of capital expenditures included in the 2026 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 with a budget of approximately $5.6 million in 2026. This project, which is in its sixth and final year, provides customers with higher quality lighting at a lower cost of service.

Overall, the 2026 Capital Budget represents the capital additions and improvements necessary to continue providing safe and reliable service to customers at the lowest possible cost.

1 The Board approved Newfoundland Power's *2025 Capital Budget Application* in the amount of $127,951,000 in Order No. P.U. 27 (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 *2026 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.

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

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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.

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 based on 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 forecasted housing starts. This data is then used to 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 based on 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 three or 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 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 expenditures, forecast inflation, and identified operational requirements. For example, identified operational requirements could include the need to purchase tools and equipment for use by field staff.

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

[6] Inflation is calculated based on the GDP Deflator for Canada for non-labour costs and the Company's internal labour inflation rate for labour costs.

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 capital project, such as a like-for-like replacement or upgrade, and alternatives that could result in the deferral of capital expenditures.

The 2026 Capital Budget identifies four capital projects that were planned for 2026 but have been deferred to future years. There are no capital projects that were previously deferred or modified and are now proposed for 2026. One capital project was planned for a subsequent year and advanced to 2026. Appendix B provides the list of the capital projects that were deferred, modified or advanced.

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[7] For example, Newfoundland Power 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 the *2025 Capital Budget Application* and has maintained that approach in this budget.

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 the 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 2026 capital expenditures.

2.3 Balancing Cost and Service

2.3.1 Service Reliability

Newfoundland Power owns and operates approximately 9,500 kilometres of distribution line, approximately 2,000 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, Transmission Line Rebuild Strategy* and the proposed *Substation Power Transformer Strategy* filed as part of this capital budget application 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, adequate tools and equipment are necessary to ensure the effective and efficient deployment of the Company's workforce.

Annual capital expenditures are essential to maintaining both the Company's electrical system condition and its operational response. To ensure continued reliability and alignment with asset management industry practices, Newfoundland Power completed a comprehensive review of its asset management practices in 2022.[9] The review identified several opportunities for improvement, including enhancements in data and technology.

The Company is currently focused on implementing an *Asset Management Technology Replacement* project, as approved in the *2025 Capital Budget Application*.[10] Replacement of the technology is in alignment with industry best practice and will allow the Company to continue to

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8 The primary engineering standard for distribution and transmission systems is Canadian Standards Association ("CSA") standard *C22.3 No.1-15 Overhead Systems*.

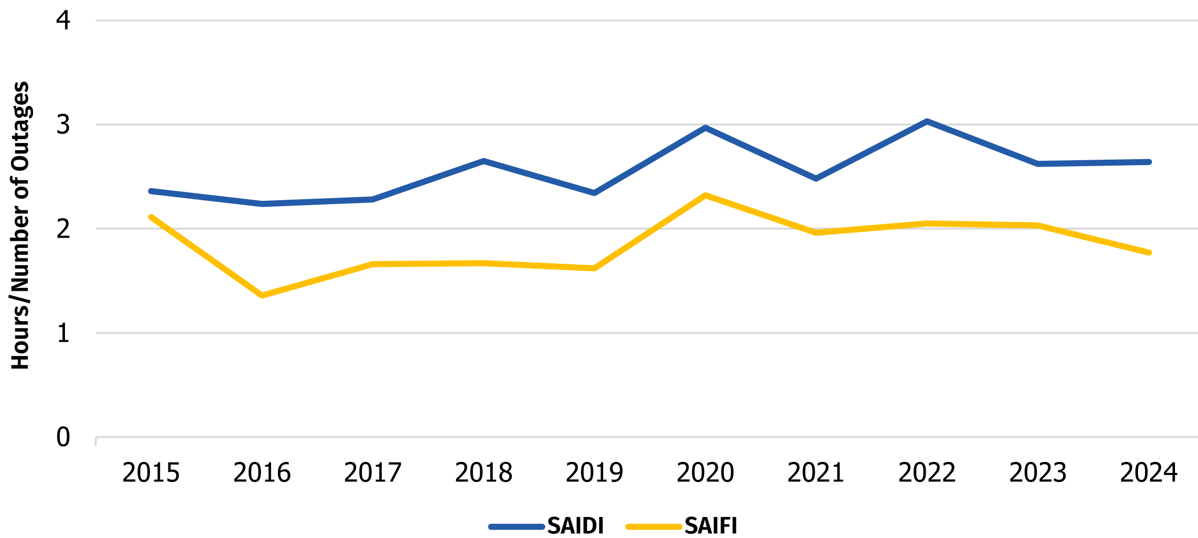
9 See the *Asset Management Update Report* filed as Appendix B in the 2025-2029 Capital Plan of the *2025 Capital Budget Application* for additional information.

10 See Newfoundland Power's *2025 Capital Budget Application*, report 6.2, *Asset Management Technology Replacement* for additional information.

meet current requirements. The replacement Asset Management Technology will also provide a foundation for future enhancements as asset management practices evolve.

Figure 1 shows the average duration ("SAIDI") and frequency ("SAIFI") of outages to Newfoundland Power's customers from 2015 to 2024 under normal operating conditions.[11]

Figure 1
Newfoundland Power
SAIDI and SAIFI - Normal Operating Conditions
(2015-2024)



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 2.3 outages per year.

[11] 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 2015 to 2024.[12]

Figure 2
Newfoundland Power vs. Canadian Average
SAIDI - Normal Operations
(2015-2024)

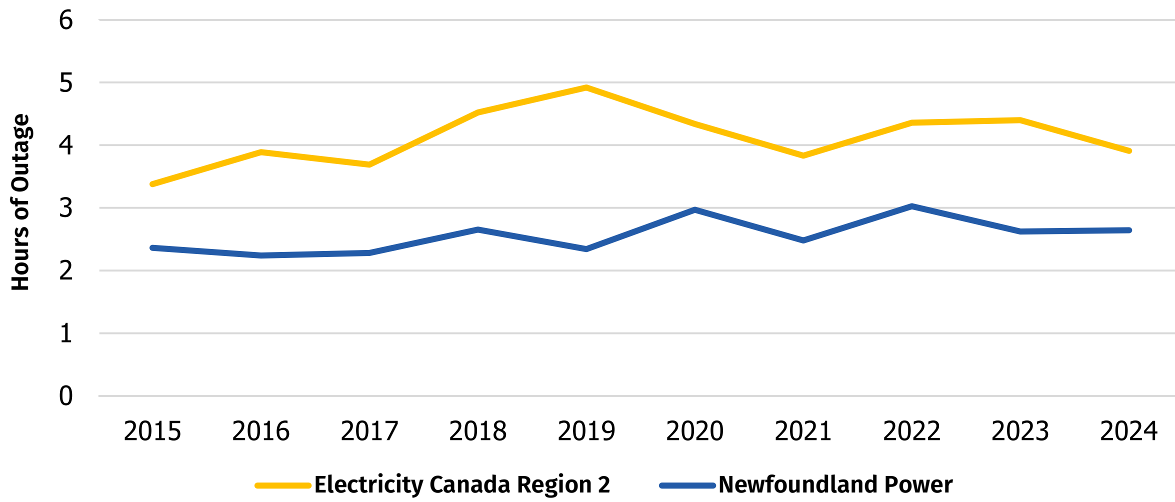
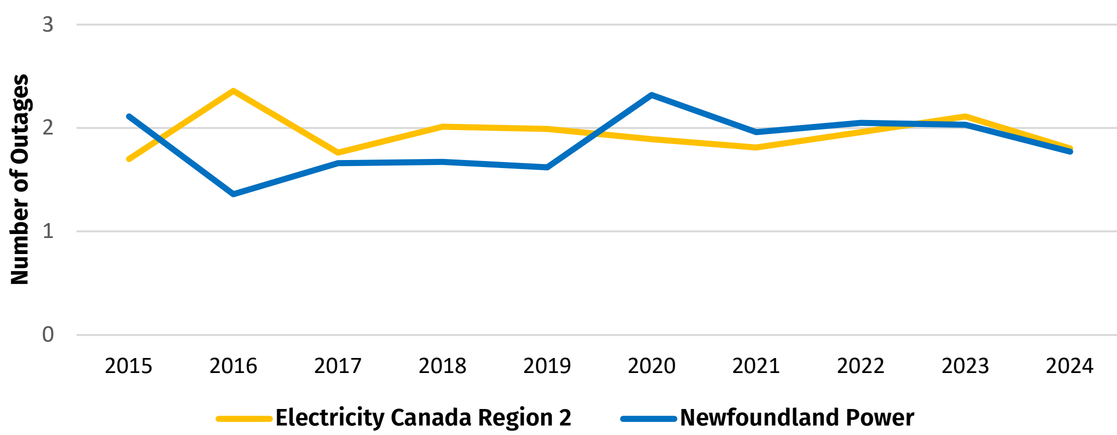


Figure 3
Newfoundland Power vs. Canadian Average
SAIFI - Normal Operating Conditions
(2015-2024)



12 At the time of filing, 2024 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, Fortis Alberta, 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.

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.[13] The average frequency of customer outages has been consistent with the Canadian average over this period.[14]

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.

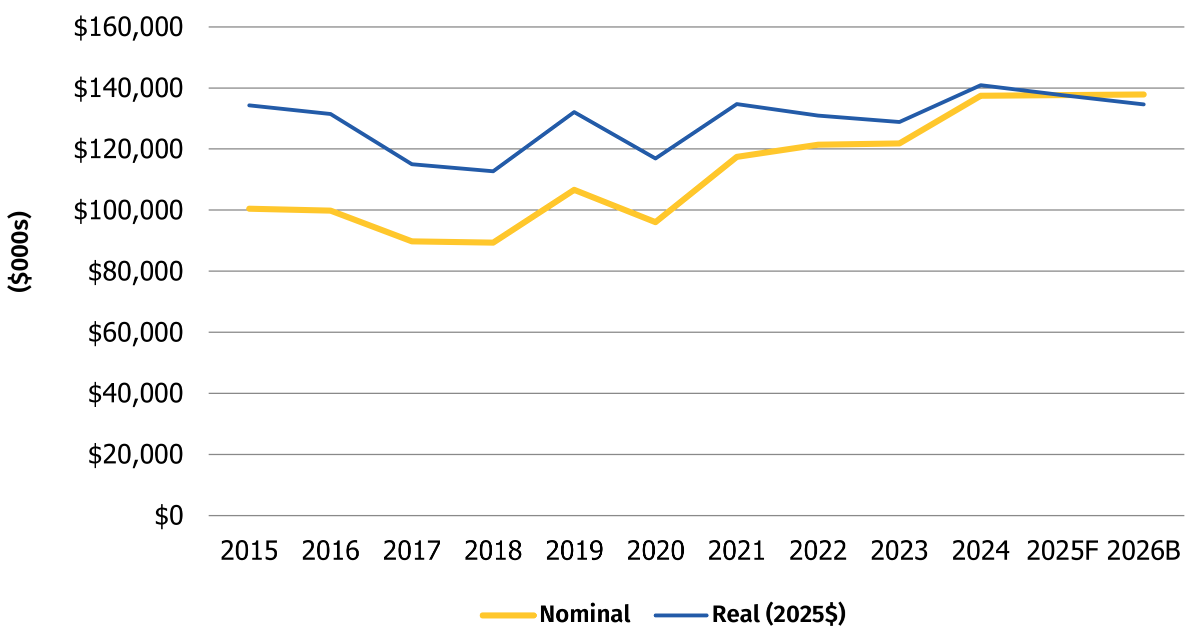
While overall levels of service reliability are viewed as acceptable, customers in certain areas experience service reliability that is below Newfoundland Power's corporate average. Appendix D provides a list of the Company's worst performing feeders.

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 2015 to 2024, the 2025 forecasted expenditure and the 2026 Capital Budget.

Figure 4:
Newfoundland Power Capital Expenditures
(2015-2026F)



[13] Newfoundland Power's SAIDI averaged approximately 2.6 hours/year from 2015 to 2024. This compares to an Electricity Canada average SAIDI of 4.1 hours/year over the same period.

[14] Newfoundland Power's SAIFI averaged approximately 1.9 outages/year from 2015 to 2024. This compares to an Electricity Canada average SAIFI of 1.9 outages/year over the same period.

Newfoundland Power's capital expenditures have averaged approximately $113.0 million annually from 2015 to 2026, or $129.2 million when adjusted for inflation. On an inflation-adjusted basis, annual expenditures have ranged from approximately $109 million in 2018 to $139.9 million in 2024. The 2026 Capital Budget of approximately $137.9 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.[15] Customer rates also reflect Newfoundland Power's Customer, Energy and Demand forecasts and Board-approved rate structures.[16] The capital projects proposed in the Application are estimated to increase the Company's annual revenue requirement by approximately $7 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.[17]

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.[18]

The Board has previously recognized the complex relationship between capital investments, revenue requirements and customer rates.[19] The Board has also recognized that fully justified capital expenditures enable the delivery of least-cost service to customers.[20]

The complex relationship between revenue requirements, customer rates and capital investments can be observed over the last decade.

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15 See Order No. P.U. 7 (2002-2003), page 31.

16 See Order No. P.U. 40 (2005), page 13.

17 The refurbishments associated with the Company's Cape Broyle, Horsechops and Lockston hydro plants included in the Application will result in the continued provision of low-cost electricity production to customers. Further, the *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 $8 million on a *pro forma* basis.

18 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.

19 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*."

20 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 2017 and 2026.[21]

Table 1
Newfoundland Power
Contribution to Revenue Requirement
($millions)

	2017	2026[22]	Change
Actual	222.9[23]	291.0	31%
Inflation Adjusted[24]	292.2	291.0	0%

Newfoundland Power's contribution to revenue requirement increased by approximately 31% from 2017 to 2026. On an inflation-adjusted basis, the Company's contribution to revenue requirement in 2026 remained consistent with 2017.

Table 2 compares Newfoundland Power's total contribution to average customer rates in cents per kWh in 2017 and 2026.

Table 2
Newfoundland Power
Contribution to Customer Rates
(¢/kWh)

	2017	2026[25]	Change
Actual	3.72	4.87	31%
Inflation Adjusted[26]	4.88	4.87	0%

Newfoundland Power's contribution to average customer rates increased by approximately 31% from 2017 to 2026. On an inflation-adjusted basis, the Company's contribution to average customer rates in 2026 remained consistent with 2017.

21 Based on the Company's 2017 and 2026 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.

22 Newfoundland Power's 2026 revenue requirement was $806.6 million. Excluding purchased power costs of $515.6 million, it was $291.0 million. See the Company's application filed in compliance with Order No. P.U. 3 (2025), Schedule 1, Appendix C, page 2.

23 Newfoundland Power's 2017 revenue requirement was $671.0 million. Excluding purchased power costs of $448.1 million, it was $222.9 million. See the Company's application filed in compliance with Order No. P.U. 18 (2016), Schedule 1, Appendix E, page 2.

24 Inflation adjusted based on the GDP Deflator for Canada.

25 Based on Newfoundland Power's 2026 test year revenue requirement which is reflected in customer rates approved in the application filed in compliance with Order No. P.U. 3 (2025) with effect on July 1, 2025.

26 Inflation adjusted based on the GDP Deflator for Canada.

As Newfoundland Power's contribution to revenue requirement and customer rates remained consistent on an inflation-adjusted basis over the past decade, the Company's annual capital investments have averaged approximately $115 million per year over this period.

In Newfoundland Power's view, the Company's approach to capital planning aims to minimizes 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 2014 to 2023; 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)[27]			Service Reliability (SAIDI)
Utility	2014	2023	Growth	2014-2023
Newfoundland Power	1,153	1,675	45%	2.6
Atlantic Canadian Utilities[28]	1,232	1,976	60%	4.0

27 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. Due to this change, Newfoundland Power is unable to compare NB Powers 2014 and 2023 capital investment, NB Power was not included in the Atlantic Canadian average. 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 financial statements of each utility.

28 The aggregate investment of Nova Scotia Power and Maritime Electric was $2,465 million in 2014 ($2,465 million / 2 = $1,232 million) and $3,951 million in 2023 ($3,951 million / 2 = $1,976 million).

Newfoundland Power's investment in T&D assets has increased by 45% over the 10-year period ending 2023. This is lower than the 60% average increase of other Atlantic Canadian utilities.

Over the same period, the Company's customers have experienced 35% fewer outage hours in comparison to customers of other Atlantic Canadian utilities.[29] The Company's average outage duration was the lowest of any Atlantic Canadian utility over this period.[30]

Overall, in Newfoundland Power's view, the Company's capital investments and service reliability are reasonable in comparison to other Atlantic Canadian utilities.

3.0 SUMMARY OF 2026 EXPENDITURES

3.1 2026 Capital Budget Overall

Newfoundland Power's proposed 2026 Capital Budget totals approximately $137.9 million, including approximately $10.2 million of 2026 expenditures that are $750,000 and under and approximately $46.4 million of 2026 expenditures that were previously approved by the Board.[31] The Application also proposes 12 new multi-year projects. The new multi-year projects include expenditures of approximately $6.1 million in 2026.

The following sections provide breakdowns of the 2026 Capital Budget by asset class, category, investment classification and materiality.

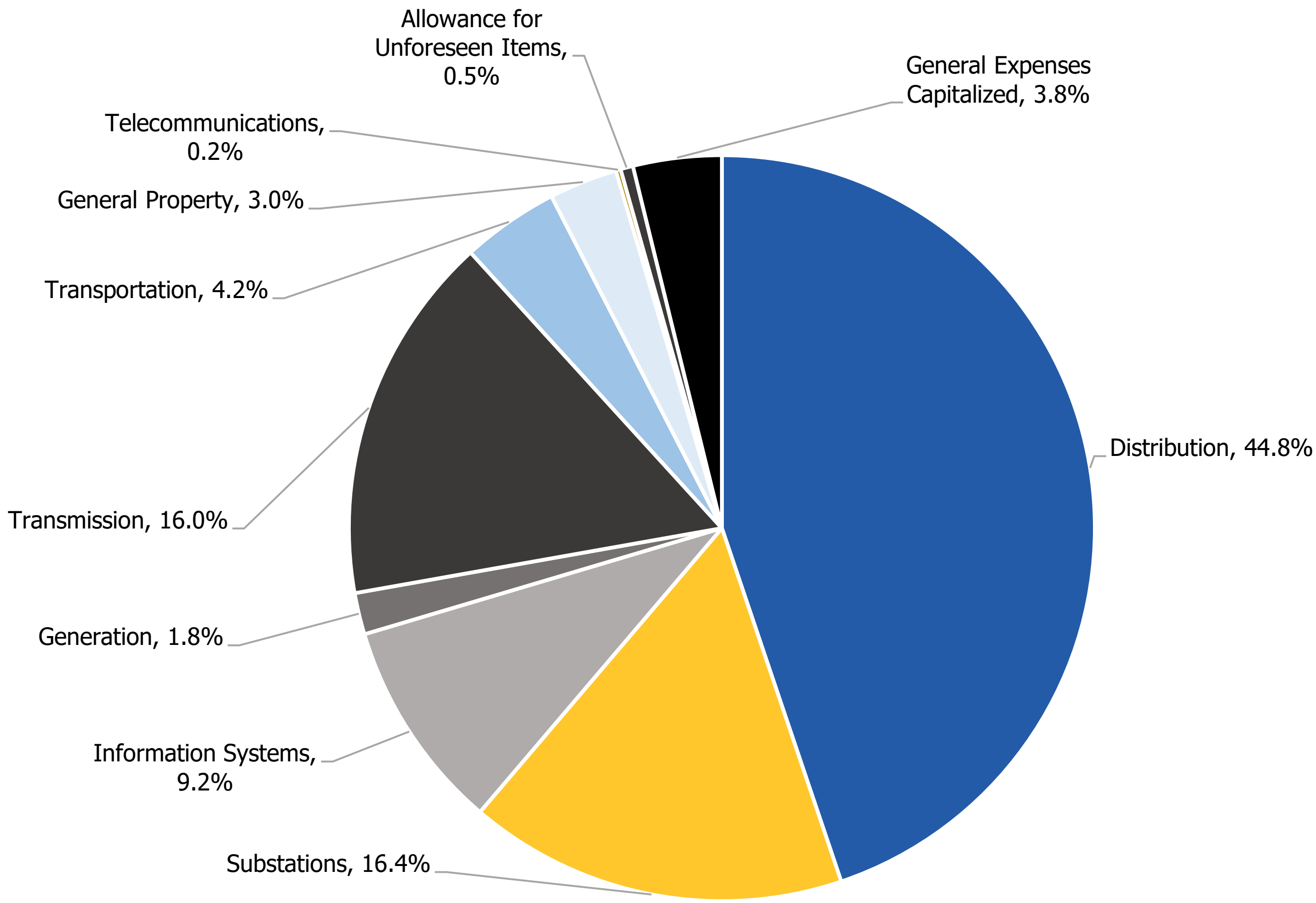
29 (2.6 – 4.0) / 4.0 = -0.35, or -35%.
30 The average SAIDI for the other Atlantic Canadian utilities ranged from 2.9 to 5.1.
31 For expenditures incurred to date, see the *2025 Capital Expenditure Status Report* provided with the Application.

3.2 2026 Capital Budget by Asset Class

Newfoundland Power organizes its annual capital budget by asset class.

Figure 5 provides the proposed 2026 Capital Budget by asset class, including previously approved multi-year projects.

Figure 5
2026 Capital Budget by Asset Class



The Distribution asset class accounts for approximately 45% of proposed capital expenditures for 2026. Approximately one third 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 largest expenditure under the Distribution asset class is *Extensions* at $16,747,000.

The Substations asset class accounts for approximately 16% of proposed capital expenditures for 2026. The majority of substation expenditures relate to previously approved transformer replacements at Gander and Pulpit Rock substations, and the refurbishment and modernization of the Lockston and Summerville substations at combined cost of $15.8 million in 2026.

The Transmission asset class accounts for approximately 16% of proposed capital expenditures for 2026. The majority of transmission expenditures relate to the rebuilding of transmission lines constructed in the 1960s and 1970s. This includes the second 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 $9.3 million in 2026. Transmission expenditures also include approximately $9.0 million in 2026 to conclude the 94L rebuild project.

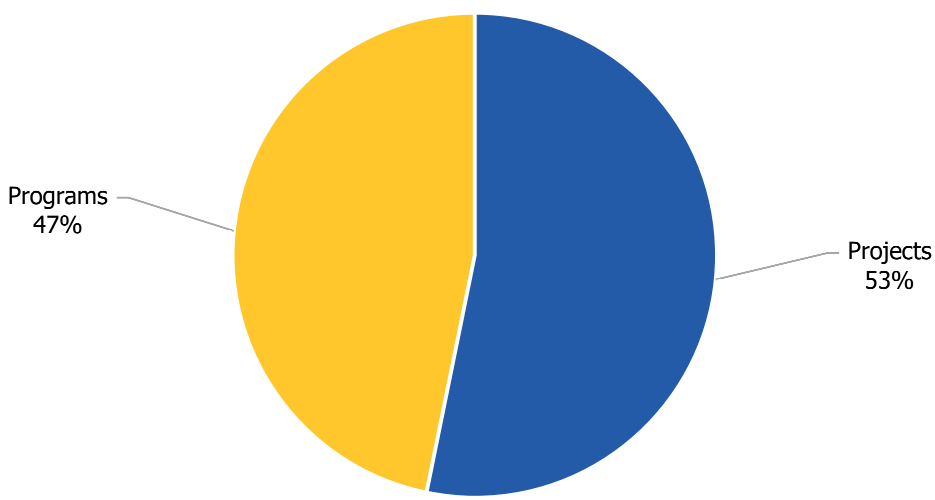
The Information Systems asset class accounts for approximately 9% of proposed capital expenditures for 2026. The majority of Information Systems expenditures relate to the multi-year projects associated with the replacement of the Company's Asset Management Technology and upgrading of the Outage Management System at a combined expenditure of $6.0 million in 2026.

The remaining asset classes account for between less than 1% and 5% of proposed capital expenditures for 2026.

3.3 2026 Capital Budget by Category

Figure 6 provides a breakdown of Newfoundland Power's 2026 Capital Budget by category, including previously approved multi-year projects.

Figure 6
2026 Capital Budget by Category

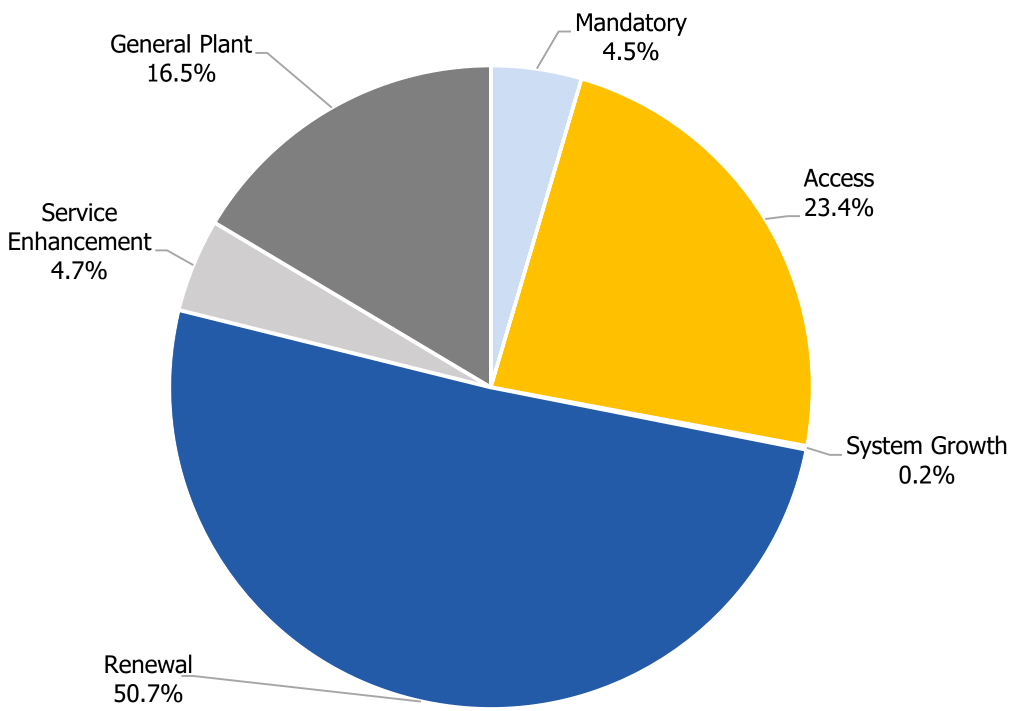


Newfoundland Power's proposed 2026 Capital Budget includes 42 capital projects and 22 capital programs. Capital projects account for approximately 53% of capital expenditures for 2026, with the remaining 47% attributable to recurring programs.

3.4 2026 Capital Budget by Investment Classification

Figure 7 shows Newfoundland Power's proposed 2026 Capital Budget by investment classification, including previously approved multi-year projects.

Figure 7
2026 Capital Budget by Investment Classification



Renewal expenditures account for approximately 51% of proposed capital expenditures for 2026. 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 2026. Subsequent years of previously approved multi-year project account for approximately half of the cost of renewal.

Access expenditures account for approximately 23% of proposed capital expenditures for 2026. 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 2,865 new customer connections in 2026.

General Plant expenditures account for approximately 16% of proposed capital expenditures for 2026. 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. Transportation asset class is 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 5% of proposed capital expenditures for 2026. The *LED Street Lighting Replacement* project accounts for most Service Enhancement expenditures in 2026. 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. The *LED Street Light Replacement* project will conclude in 2026.

Mandatory expenditures account for approximately 5% of proposed capital expenditures for 2026. 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 less than 1% of proposed capital expenditures in 2026. There is just one multi-year capital project proposed for 2026 to address system growth. The *Feeder Additions for Load Growth* project addresses localized load growth on one distribution feeder in the Deer Lake area.

3.5 2026 Capital Budget by Materiality

Table 4 provides an overview of the 2026 Capital Budget by materiality, including previously approved multi-year projects.[32]

Table 4
2026 Capital Budget by Materiality

Threshold	Quantity of Projects/Programs	Total Expenditures ($000s)	Percentage of Total Expenditures
Less than $1 million[33]	28	16,201	12%
$1 million - $5 million	23	49,276	36%
Greater than $5 million	13	72,466	52%
Total	64	$137,943	100%

[32] 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.

[33] This includes 22 capital projects and programs that are $750,000 and under.

Of the 64 total capital projects and programs included in the 2026 Capital Budget, 51 are less than $5 million. The 13 capital projects and programs greater than $5 million including the previously approved *Asset Management Technology Solution, Summerville Substation Refurbishment & Modernization, New Transmission Line from LEW to BOY, and Transmission Line 94L*. There has been no change in the nature, scope or magnitude of these projects.

The remaining 9 capital programs and projects greater than $5 million that are proposed for 2026 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 $16.8 million for 2026. 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 $7.7 million for 2026. The budget estimate is based on historical expenditures.

(iii) ***LED Street Lighting Replacement***, which involves the replacement of existing street lights with LED fixtures to provide customers with lower rates for more reliable service. Capital expenditures for this project total approximately $5.6 million for 2026, this project is in its sixth and final year. The budget estimate is based on detailed engineering estimates.

(iv) ***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 $5.3 million for 2026. The budget estimate is determined in accordance with the percentage allocations as presented in Newfoundland Power's *2022/2023 General Rate Application*.

(v) ***Rebuild Distribution Lines***, which involves the preventive maintenance of deteriorated distribution structure and electrical equipment identified through inspections. Capital expenditures for this project total approximately $5.3 million in 2026. The budget estimate is based on historical expenditures.

(vi) ***Replace Vehicles and Aerial Devices 2026-2027,*** which involves the replacement of the Company's vehicle fleet 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. Capital expenditures for this project in 2026 total approximately $3.0 million. The budget estimate is based on detailed estimates.

(vii) ***Lewisporte-Boyd's Cove 138 kV Conversion,*** which is the modification of existing Lewisporte (LEW), Boyd's Cove (BOY), and Gander (GAN) Substations based on the least cost alternative of the *Gander -Twillingate Transmission System*

Planning Study.[34] Capital expenditures for this project in 2026 total approximately $568,000. The budget estimate is based on detailed estimates

(viii) ***Geographic Information System Upgrade,*** which is required to ensure the secure and reliable operation of information systems that are essential to the delivery of service to customers. The software used by the majority of the Company's employees to support numerous business functions and is connected to many critical operational systems. Capital expenditures for this project in 2026 total approximately $500,000. The budget estimate is based on detailed estimates.

(ix) ***Transmission Line 100L Rebuild,*** which is required to ensure the delivery of reliable service to approximately 15,200 customers. 100L currently does not meet current industry standards and is deteriorated due to age. Capital expenditures for this project in 2026 total approximately $450,000. The budget estimate is based on detailed estimates.

Including previously approved expenditures, the thirteen capital projects and programs exceeding $5 million in materiality account for approximately 53% of capital expenditures for 2026.

34 See Newfoundland Power's *2025 Capital Budget Application,* report *3.1 Gander – Twillingate Transmission Planning Study.*

APPENDIX A:

Capital Expenditure Classification and Categorization Summary

Table A-1 2026 Capital Budget Proposed Single-Year Projects and Programs in Excess of $750,000			
Investment Classification	Budget ($000s)	Asset Class	Category
Mandatory			
General Expenses Capitalized	5,300	GEC	Project
Allowance for Unforeseen Items	750	Unforeseen Allowance	Project
Total Mandatory	$6,050		
Access			
Extensions	16,747	Distribution	Program
New Transformers	4,394	Distribution	Program
New Services	4,218	Distribution	Program
Relocate/Replace Distribution Lines for Third Parties	3,702	Distribution	Program
New Street Lighting	2,425	Distribution	Program
Total Access	$31,486		
System Growth			
Total System Growth	$0		
Renewal			
Reconstruction	7,674	Distribution	Program
Rebuild Distribution Lines	5,263	Distribution	Program
Replacement Transformers	4,954	Distribution	Program
Substation Replacements Due to In-Service Failures	4,733	Distribution	Program
Transmission Line Maintenance	3,306	Transmission	Program
Feeder Extension CAB-01	1,346	Distribution	Project

Table A-1
2026 Capital Budget
Proposed Single-Year Projects and Programs in Excess of $750,000

Investment Classification	Budget ($000s)	Asset Class	Category
Replacement Street Lighting	914	Distribution	Program
Total Renewal	$28,190		
Service Enhancement			
LED Street Lighting Replacement	5,559	Distribution	Project
Total Service Enhancement	$5,559		
General Plant			
Shared Server infrastructure	990	Information Systems	Project
Application Enhancements	968	Information Systems	Project
System Upgrades	965	Information Systems	Project
Cybersecurity Upgrades	950	Information Systems	Project
Total General Plant	$3,873		
Total	$75,158		

Table A-2 2026 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	223	Distribution	Project
Total Mandatory	$223		
Access			
New Meters	701	Distribution	Program
Total Access	$701		
System Growth			
Total System Growth	$0		
Renewal			
Hydro Plant Replacements Due to In-Service Failures	736	Generation – Hydro	Program
Distribution Feeder GDL-03 Refurbishment	722	Distribution	Project
Substation Protection and Control Replacements	719	Substations	Program
Replacement Meters	562	Distribution	Program
Cape Broyle and Horsechops Plant Control Upgrades	398	Generation - Hydro	Project
Replacement Services	382	Distribution	Program
Thermal Plant Replacements Due to In-Service Failures	331	Generation - Thermal	Project
Mount Carmel Pond Dam Fibre	150	Telecommunications	Project
Total Renewal	$4,000		
Service Enhancement			
Distribution Feeder Automation	648	Distribution	Project

Table A-2 2026 Capital Budget Proposed Single-Year Projects and Programs $750,000 and Under			
Investment Classification	Budget ($000s)	Asset Class	Category
Substation Ground Grid Upgrades	350	Substations	Project
Total Service Enhancement	$998		
General Plant			
Personal Computer Infrastructure	733	Information Systems	Program
Additions to Real Property	714	General Property	Program
Purchase Specialized Tools and Equipment	616	General Property	Project
Tools and Equipment	605	General Property	Program
Physical Security Upgrades	506	General Property	Program
Network Infrastructure	495	General Property	Project
Building Accessibility Improvements	490	General Property	Project
Telecommunications	131	Telecommunications	Program
Total General Plant	$4,290		
Total	$10,212		

Table A-3
2026 Capital Budget
Proposed Multi-Year Projects

Title	Asset Class	Investment Classification	Project / Program	Budget ($000s) 2026	2027	2028	Total
Feeder Additions for Load Growth	Distribution	System Growth	Project	250	887		1,137
Lewisporte-Boyd's Cove 138 kV Conversion	Substations	Renewal	Project	568	7,551		8,119
Greenspond Substation Refurbishment & Modernization	Substations	Renewal	Project	374	2,578		2,952
Substation Spare Power Transformer Inventory	Substations	Renewal	Project	13	3,906		3,919
Kings Bridge Substation Power Transformer Replacement	Substations	Renewal	Project	12	93	2,866	2,971
Mobile Plant Substation Power Transformer Replacement	Substations	Renewal	Project	12	93	2,522	2,627
Molloys Lane Substation Power Transformer Replacement	Substations	Renewal	Project	12	2,789		2,801
Transmission Line Rebuild – 100L Sunnyside to Clarenville	Transmission	Renewal	Project	450	13,323		13,773
Customer Communications Modernization	Information Systems	General Plant	Project	782	1,175		1,957
Geographic Information System Upgrade	Information Systems	General Plant	Project	500	5,173	2,652	8,325
Summerford Building Replacement	General Property	General Plant	Project	155	562		717
Replace Vehicles and Aerial Devices 2026-2027	Transportation	General Plant	Project	3,003	2,718		5,721
			Total	$6,131	$40,848	$8,040	$55,019

Table A-4
2026 Capital Budget
Previously Approved Multi-Year Projects

Title	Asset Class	Investment Classification	Project / Program	Budget ($000s)				
				2024	2025	2026	2027	Total
Distribution Feeder SCT-01 & BLK-01 Relocation	Distribution	Renewal	Project		649	1,140		1,789
Summerville Substation Refurbishment & Modernization	Substations	Renewal	Project		511	4,510		5,021
Lockston Substation Refurbishment & Modernization	Substation	Renewal	Project		305	4,521		4,826
Pulpit Rock Substation Power Transformer Replacement	Substation	Renewal	Project		17	2,905		2,922
Gander Substation Power Transformer Replacement	Substation	Renewal	Project		17	3,905	263	4,185
Transmission Line 94L	Transmission	Renewal	Project		3,485	9,075		12,560
New Transmission Line from LEW to BOY	Transmission	Renewal	Project		1,886	9,283	9,553	20,722
Mount Carmel Pond Spillway Replacement	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
Microsoft Enterprise Agreement	Information Systems	General Plant	Project	297	297	297		891
Port Union Building Replacement	General Property	General Plant	Project		278	1,003		1,281
Replace Vehicles and Aerial Devices 2025-2026	Transportation	General Plant	Project		2,173	2,802		4,975
			Total		$18,516	$46,442	$9,816	$74,774

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.

There is no capital expenditures proposed for 2026 that were deferred from previous years or modified through the Company's capital planning process.

Table B-1 lists the capital expenditures that were planned for 2026 but have been deferred to subsequent years.

Table B-1
Capital Projects Deferred from 2026 to Subsequent Years

Project	Description
Rocky Pond Hydro Plant Refurbishment	The Rocky Pond Hydro Plant Refurbishment was originally planned for 2026 and has been deferred to allow for further engineering assessment. The project is now planned for 2027.
Petty Harbour Hydro Plant Refurbishment	The Petty Harbour Hydro Refurbishment was planned for 2026 and has been deferred to allow for further engineering assessment of plant components. The project is now planned for 2027.
Victoria Hydro Plant Refurbishment	The Victoria Hydro Plant Refurbishment was planned for 2026-2027 and has been deferred to allow for further engineering and economic assessment. This project is now planned for 2027-2028.
Hearts Content Hydro Plant Refurbishment	The Hearts Content Hydro Plant Refurbishment was originally planned for 2026 and has been deferred to allow for further engineering assessment of plant components. The project is now planned for 2027.

Table B-2 lists the capital expenditures that were planned for future years but have been advanced to 2026.

Table B-2 2026 Capital Projects Advanced from Future Years	
Project	Description
Cape Broyle and Horsechops Plant Control Upgrades	The Cape Broyle and Horsechops Plant Control Upgrades have been advanced to coordinate the work with the second year of the Mount Carmel Pond Dam Replacement approved in the *2025 Capital Budget Application*.[1] Control work will be coordinated with Mount Carmel gate automation.

[1] For additional information see Newfoundland Power's *2025 Capital Budget Application,* report *4.1 Mount Carmel Pond Dam Refurbishment*.

APPENDIX C:

Prioritized List of 2026 Capital Expenditures

Prioritized List of 2026 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 2026 are provided below. The Company expects its approach may evolve going forward as its asset management review is completed.

[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.

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.

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[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.

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.

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 judgment 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 2026 Capital Expenditures

Table C-2 provides the prioritized list of 2026 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 2026 Capital Expenditures

Project/Program Name	Priority Score
Previously Approved Multi-Year Projects	
Mount Carmel Pond Dam Refurbishment	-
Transmission Line 94L	-
Asset Management Technology Solution	-
Replace Vehicles and Aerial Devices 2025-2026	-
New Transmission Line from LEW-BOY	-
Outage Management System Upgrade	-
Distribution Feeder SCT-01 & BLK-01 Relocation	-
Summerville Substation Refurbishment & Modernization	-
Lockston Substation Refurbishment & Modernization	-
Microsoft Enterprise Agreement	-
Port Union Building Replacement	-
Gander Substation Power Transformer Replacement	-
Pulpit Rock Substation Power Transformer Replacement	-
Mandatory	
General Expenses Capitalized	-
Allowance for Unforeseen Items	-
Access	
Extensions	-
New Transformers	-
New Services	-
Relocate/Replace Distribution Lines for Third Parties	-
New Street Lighting	-

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 2026 Capital Expenditures	
Project/Program Name	Priority Score
System Growth	
Feeder Additions for Load Growth	-
Renewal, Service Enhancement, General Plant	
Reconstruction	25
Substation Replacements Due to In-Service Failures	25
Transmission Line Maintenance	25
Lewisporte-Boyd's Cove 138 kV Conversion Project Budget	20
Rebuild Distribution Lines	20
Replacement Transformers	20
Transmission Line Rebuild – 100L Sunnyside to Clarenville	20
Geographic Information System Upgrade	20
Cybersecurity Upgrades	20
Mount Carmel Pond Feeder Extension CAB-01	20
LED Street Lighting Replacement	20
Shared Server Infrastructure	20
Replace Vehicles and Aerial Devices 2026-2027	16
Greenspond Substation Refurbishment & Modernization	16
Molloys Lane Substation Power Transformer Replacement	16
System Upgrades	16
Mobile Substation Power Transformer Replacement	16
Kings Bridge Road Substation Power Transformer Replacement	16
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APPENDIX D:

List of Worst Performing Feeders

List of Worst Performing Feeders

The 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 (2015-2024) Sorted by Customer Minutes of Interruption				
Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
SUM-01	7,111	919,252	3.92	8.44
GLV-02	6,523	672,614	4.25	7.30
DOY-01	5,965	605,078	3.40	5.74
BVS-04	4,677	563,503	2.91	5.81
DLK-03	4,114	493,267	2.87	5.76
DUN-01	4,365	428,877	4.16	6.82
SCR-01	2,595	419,898	2.69	7.26
BLK-02	3,577	409,848	1.73	3.26
BOT-01	3,711	407,925	2.15	3.94
ROB-01	1,978	392,151	1.83	6.05
Company Average	1,172	91,893	1.40	1.83

Table D-2 Unscheduled Distribution-Related Outages 10-Year Average (2015-2024) Sorted by Distribution SAIFI				
Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
BHD-01	5,802	359,008	6.12	6.29
SJM-11	7,761	178,305	5.34	2.07
SCT-01	3,482	201,946	4.82	4.59
SCT-02	1,228	109,102	4.77	7.04
GLV-02	6,523	672,614	4.25	7.30
DUN-01	4,365	428,877	4.16	6.82
ABC-02	4,174	301,293	4.10	4.95
TWG-03	1,194	85,081	4.03	4.59
SUM-01	7,111	919,252	3.92	8.44
TWG-02	2,716	155,059	3.86	3.69
Company Average	1,172	91,893	1.40	1.83

Table D-3 Unscheduled Distribution-Related Outages 10-Year Average (2015-2024) Sorted by Distribution SAIDI				
Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
SBK-01	4	2,453	1.77	17.43
SUM-01	7,111	919,252	3.92	8.44
ROB-02	420	97,011	2.06	7.90
GLV-02	6,523	672,614	4.25	7.30
SCR-01	2,595	419,898	2.69	7.26
SUM-02	1,766	262,325	2.92	7.19
BUC-02	391	67,538	2.45	7.06
SCT-02	1,228	109,102	4.77	7.04
DUN-01	4,365	428,877	4.16	6.82
HBS-01	9	2,032	1.81	6.63
Company Average	1,172	91,893	1.40	1.83

Table D-4
Unscheduled Distribution-Related Outages
10-Year Average
(2015-2024)
Sorted by Distribution CHIKM

Feeder	Annual Distribution CHIKM
KBR-10	240
WAV-03	236
SLA-13	205
SJM-06	197
SJM-04	182
PAB-05	180
PEP-04	180
SLA-10	179
KBR-13	174
PEP-01	158
Company Average	53

Table D-5 Unscheduled Distribution-Related Outages 10-Year Average (2015-2024) Sorted by Distribution CIKM	
Feeder	Annual Distribution CIKM
SJM-11	242
KBR-10	214
WAL-05	192
PEP-01	164
PAB-03	155
TWG-02	154
KEN-03	153
SLA-06	145
HWD-07	143
KBR-11	142
Company Average	44

APPENDIX E:

Previously Approved Multi-Year Projects

Previously Approved Multi-Year Projects

The Provisional Guidelines require that proposed expenditures for each year of a multi-year capital project be considered together 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 2026 Capital Budget includes thirteen capital projects that were previously approved by the Board. Capital expenditures for these project total approximately $46,442,000 in 2026.

The following section provides an update on each multi-year project for 2026 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: **New Transmission Line from Lewisporte to Boyd's Cove**
Asset Class: **Transmission**
Category: **Project**
Investment Classification: **Renewal**
2026 Expenditures: **$9,283,000**

The *New Transmission Line from Lewisporte to Boyd's Cove* project was included as a multi-year project in Newfoundland Power's *2025 Capital Budget Application*.[1] The 66 kV transmission network supplying the Gander - Twillingate 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 customers.

The Board approved the *New Transmission Line from Lewisporte to Boyd's Cove* project as apart of the *Gander-Twillingate Transmission System Planning Study* as a three-year project in Order No. P.U. 27 (2024). The project is proceeding as approved. Engineering design and acquiring environmental approvals for the project are ongoing. Brush clearing activities are planned to begin later in 2025. Construction of the new line will begin in 2026 and continue in 2027.

Table E-1 provides the approved expenditures for the *New Transmission Line from Lewisporte to Boyd's Cove* project.

Table E-1
New Transmission Line from LEW to Boyd's Cove
Multi-Year Expenditures
($000s)

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

Expenditures for the *New Transmission Line from Lewisporte to Boyd's Cove Project* total approximately $20,722,000, including $9,283,000 in 2026. For expenditures incurred to date, see the *2025 Capital Expenditure Status Report* filed with the Application.

[1] See Newfoundland Power's *2025 Capital Budget Application,* report *3.1 Gander-Twillingate Transmission System Planning Study*.

Title: **Transmission Line 94L Rebuild**
Asset Class: **Transmission**
Category: **Project**
Investment Classification: **Renewal**
2026 Expenditures: **$9,075,000**

The *Transmission Line 94L Rebuild* project was included as a multi-year project in Newfoundland Power's *2025 Capital Budget Application*.[2] Transmission Line 94L is a 66 kV H-Frame radial line running between the 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. Cathrines ("SCT") and RVH substations along with Trepassey Substation via Transmission Line 95L. The line's sub-standard design and deteriorated condition was the primary justification on this project. In total, the three substations serve approximately 2,500 customers.

The Board approved the *Transmission Line 94L Rebuild* project as a two-year project in Order No. P.U. 27 (2024). The project is proceeding as approved. Engineering design is ongoing, and construction is set to begin in the third quarter of 2025 and continue throughout 2026.

Table E-2 provides the approved expenditures for the *Transmission Line 94L Rebuild* project.

Table E-2
Transmission Line 94L
Multi-Year Expenditures
($000s)

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

Expenditures for the *Transmission Line 94L Rebuild Project* total approximately $12,560,000, including $9,075,000 in 2026. For expenditures incurred to date, see the *2025 Capital Expenditure Status Report* filed with the Application

2 See Newfoundland Power's *2025 Capital Budget Application,* report *3.2 Transmission Line 94L Rebuild.*

Title: **Lockston Substation Refurbishment and Modernization**
Asset Class: **Substations**
Category: **Project**
Investment Classification: **Renewal**
2026 Expenditures: **$4,521,000**

The *Lockston Substation Refurbishment and Modernization* was included as a multi-year project in Newfoundland Power's *2025 Capital Budget Application*.[3] The *Lockston Substation Refurbishment and Modernization* project involves the replacement and modernization of deteriorated equipment at Lockston Substation located in the Lockston area. The equipment requiring replacement was identified through inspections, engineering assessments and operating experience. Lockston Substation ensures reliable service for approximately 1,100 customers.

The Board approved the *Lockston Substation Refurbishment and Modernization* project as a three-year project in Order No. P.U. 27 (2024). The project is proceeding as approved. Engineering design and procurement of replacement components is being completed in 2025, with construction to begin in the second quarter of 2026.

Table E-3 provides the approved expenditures for the *Lockston Substation Refurbishment and Modernization.*

Table E-3
Lockston Substation Refurbishment and Modernization
Multi-Year Expenditures
($000s)

Cost Category	2025F	2026F	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

Expenditures for the *Lockston Substation Refurbishment and Modernization* total approximately $4,826,000, including $4,521,000 in 2026. For expenditures incurred to date, see the *2025 Capital Expenditure Status Report* filed with the Application.

[3] See Newfoundland Power's *2025 Capital Budget Application,* report *2.1 Substation Refurbishment and Modernization*.

Title:	**Asset Management Technology Replacement**
Asset Class:	**Information Systems**
Category:	**Project**
Investment Classification:	**General Plant**
2026 Expenditures:	**$4,534,000**

The *Asset Management Technology Replacement project* was included as a multi-year project in Newfoundland Power's *2025 Capital Budget Application*.[4] 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

The Board approved the Asset Management Technology Replacement project as a two-year project in Order No. P.U. 27 (2024). The project is proceeding as approved. Vendor evaluation and selection have been completed. Design workshops are ongoing, and the project is still scheduled to be completed by the fourth quarter of 2026.

Table E-4 provides the approved expenditures for the *Asset Management Technology Replacement project.*

Table E-4
Asset Management Technology Replacement Project
Multi-Year Expenditures
($000s)

Cost Category	2025F	2026F	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

Expenditures for the *Asset Management Technology Replacement* total approximately $8,013,000, including $4,534,000 in 2026. For expenditures incurred to date, see the *2025 Capital Expenditure Status Report* filed with the Application.

[4] See Newfoundland Power's *2025 Capital Budget Application,* report *6.2 Asset Management Technology Replacement*.

Title:	**Summerville Substation Refurbishment and Modernization**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
2026 Expenditures:	**$4,510,000**

The *Summerville Substation Refurbishment and Modernization* was included as a multi-year project in Newfoundland Power's *2025 Capital Budget Application*.[5] The *Summerville Substation Refurbishment and Modernization* project involves the replacement and modernization of deteriorated equipment at Summerville Substation located in the Summerville area. The equipment requiring replacement was identified through inspections, engineering assessments and operating experience. Summerville Substation ensures reliable service for approximately 1,130 customers.

The Board approved the *Summerville Substation Refurbishment and Modernization* project as a two-year project in Order No. P.U. 27 (2024). The project is proceeding as approved. Engineering design and procurement of replacement components is being completed in 2025. Civil construction will begin in the fourth quarter of 2025, with the remaining construction to begin in the second quarter of 2026.

Table E-5 provides the approved expenditures for the *Summerville Substation Refurbishment and Modernization*

Table E-5
Summerville Substation Refurbishment and Modernization
Multi-Year Expenditures
($000s)

Cost Category	2025F	2026F	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

Expenditures for the *Summerville Substation Refurbishment and Modernization* total approximately $5,021,000, including $4,510,000 in 2026. For expenditures incurred to date, see the *2025 Capital Expenditure Status Report* filed with the Application.

5 See Newfoundland Power's *2025 Capital Budget Application,* report *2.1 Substation Refurbishment and Modernization*.

Title:	**Gander Substation Power Transformer Replacement**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
2026 Expenditures:	**$3,905,000**

The *Gander Substation Power Transformer Replacement* was included as a multi-year project in Newfoundland Power's *2025 Capital Budget Application*.[6] 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. GAN Substation ensures reliable service for approximately 6,513 customers.

The Board approved the *Gander Substation Power Transformer Replacement* project as a three-year project in Order No. P.U. 27 (2024). The project is proceeding as approved. Engineering design and procurement of the new power transformer is being completed in 2025, with the new transformer scheduled to arrive in the fourth quarter of 2026.

Table E-6 provides the approved expenditures for the *Gander Substation Power Transformer Replacement.*

Table E-6
Gander Substation Power Transformer
Multi-Year Expenditures
($000s)

Cost Category	2025F	2026F	2027F	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

Expenditures for the *Gander Substation Power Transformer Replacement.* total approximately $4,185,000, including $3,905,000 in 2026. For expenditures incurred to date, see the *2025 Capital Expenditure Status Report* filed with the Application.

[6] See Newfoundland Power's *2025 Capital Budget Application,* report *2.2 Substation Power Transformer Replacements*.

Title:	**Pulpit Rock Substation Power Transformer Replacement**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
2026 Expenditures:	**$2,905,000**

The *Pulpit Rock Substation Power Transformer Replacement* was included as a multi-year project in Newfoundland Power's *2025 Capital Budget Application*.[7] The *Pulpit Rock Substation Power Transformer Replacement* project involves the replacement of the Pulpit Rock ("PUL") Substation power transformer PUL-T2. PUL-T2 is deteriorating, and an assessment of alternatives determined that the unit should be replaced. PUL Substation ensures reliable service for approximately 6,724 customers.

The Board approved the *Pulpit Rock Substation Power Transformer Replacement* project as a two-year project in Order No. P.U. 27 (2024). The project is proceeding as approved. Engineering design and procurement of the new power transformer is being completed in 2025, with the new transformer scheduled to arrive in the third quarter of 2026.

Table E-7 provides the approved expenditures for the *Pulpit Rock Substation Power Transformer Replacement.*

Table E-7
Pulpit Rock Substation Power Transformer Replacement
Multi-Year Expenditures
($000s)

Cost Category	2025F	2026F	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

Expenditures for the *Pulpit Rock Substation Power Transformer Replacement.* total approximately $2,922,000 including $2,905,000 in 2026. For expenditures incurred to date, see the *2025 Capital Expenditure Status Report* filed with the Application.

[7] See Newfoundland Power's *2025 Capital Budget Application,* report *2.2 Substation Power Transformer Replacements*.

Title:	**Replace Vehicles and Aerial Devices 2025-2026**
Asset Class:	**Transportation**
Category:	**Project**
Investment Classification:	**General Plant**
2026 Expenditures:	**$2,802,000**

The *Replace Vehicles and Aerial Devices 2025-2026* was included as a multi-year project in Newfoundland Power's 2025 Capital Budget Application.[8] 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.

The Board approved the *Replace Vehicles and Aerial Devices 2025-2026 project* as a two-year project in Order No. P.U. 27 (2024). The project is proceeding as approved. The vehicles have been ordered and are set to arrive in 2026.

Table E-8 provides the approved expenditures for the *Replace Vehicles and Aerial Devices 2025-2026 project.*

Table E-8
Replace Vehicles and Aerial Devices 2025-2026
Multi-Year Expenditures
($000s)

Cost Category	2025F	2026F	Total
Material	2,040	2,802	4,842
Labour – Internal	133	-	133
Labour – Contract	-	-	-
Engineering	-	-	-
Other	-	-	-
Total	$2,173	$2,802	$4,975

Expenditures for the *Replace Vehicles and Aerial Devices 2025-2026 projects* total approximately $4,975,000, including $2,802,000 in 2026. For expenditures incurred to date, see the *2025 Capital Expenditure Status Report* filed with the Application.

8 See Newfoundland Power's *2025 Capital Budget Application, Schedule B,* pages 137 to 142.

Title: **Outage Management System Upgrade**
Asset Class: **Information Systems**
Category: **Project**
Investment Classification: **General Plant**
2026 Expenditures: **$1,459,000**

The *Outage Management System Upgrade* was included as a multi-year project in Newfoundland Power's 2025 Capital Budget Application.[9] The *Outage Management System Upgrade (OMS)* project involves upgrading the Company's 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.

The Board approved the *Outage Management System Upgrade project* as a two-year project in Order No. P.U. 27 (2024*).* The project is proceeding as approved. System design sessions with the vendor have been completed for the system upgrade. The vendor is developing the project plan with the upgrade scheduled to begin in late Q2 of 2025.

Table E-9 provides the approved expenditures for the Outage Management System Upgrade.

Table E-9
Outage Management System Upgrade
Multi-Year Expenditures
($000s)

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

Expenditures for the *Outage Management System Upgrade* total approximately $3,270,000, including $1,459,000 in 2026. For expenditures incurred to date, see the *2025 Capital Expenditure Status Report* filed with the Application.

9 See Newfoundland Power's *2025 Capital Budget Application,* report *6.1 Outage Management System Upgrade.*

Title: **Distribution Feeders SCT-01 and BLK-01 Relocation**
Asset Class: **Distribution**
Category: **Project**
Investment Classification: **Renewal**
2026 Expenditures: **$1,140,000**

The *Distribution Feeders SCT-01 and BLK-01 Relocation* was included as a multi-year project in Newfoundland Power's 2025 Capital Budget Application.[10] The *Distribution Feeders SCT-01 and BLK-01 Relocation* project is for relocating sections of the St. Catherine's substation distribution feeder and Blaketown substation distribution feeder to accommodate the *Transmission Line 94L Rebuild* project.

The Board approved the *Distribution Feeders SCT-01 and BLK-01 Relocation* as a two-year project in Order No. P.U. 27 (2024). This project is proceeding as approved. Work will begin in the third quarter of 2025 and continue into 2026 alongside the Transmission Line 94L Rebuild project.

Table E-10 provides the approved expenditures for the *Distribution Feeders SCT-01 and BLK-01 Relocation*.

Table E-10
Distribution Feeders SCT-01 and BLK-01 Relocation
Multi-Year Expenditures
($000s)

Cost Category	2025F	2026F	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

Expenditures for the *Distribution Feeders SCT-01 and BLK-01 Relocation* total approximately $1,789,000, including $1,140,000 in 2026. For expenditures incurred to date, see the *2025 Capital Expenditure Status Report* filed with the Application.

10 See Newfoundland Power's *2025 Capital Budget Application, Schedule B,* pages 10-11.

Title:	**Mount Carmel Pond Dam Refurbishment**
Asset Class:	**Generation – Hydro**
Category:	**Project**
Investment Classification:	**Renewal**
2026 Expenditures:	**$1,008,000**

The *Mount Carmel Pond Dam Refurbishment* was included as a multi-year project in Newfoundland Power's 2025 Capital Budget Application.[11] *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 and is located on the Avalon Peninsula near the town of Cape Broyle.

The Board approved the *Mount Carmel Pond Dam Refurbishment* as a two-year project in Order No. P.U. 27 (2024). The project is proceeding as approved. Engineering design is completed for spillway replacement. Construction of new spillway structure to begin in Q3 2025 with completion by Q4 2025. Gate automation design to be completed in Q1 2026 with completion scheduled for Q4 2026.

Table E-11 provides the approved expenditures for the *Mount Carmel Pond Dam Refurbishment.*

Table E-11
Mount Carmel Pond Dam Refurbishment
Multi-Year Expenditures
($000s)

Cost Category	2025F	2026F	Total
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

Expenditures for the *Mount Carmel Pond Dam Refurbishment* total approximately $4,616,000, including $1,008,000 in 2026. For expenditures incurred to date, see the *2025 Capital Expenditure Status Report* filed with the Application.

[11] See Newfoundland Power's *2025 Capital Budget Application,* report *4.1 Mount Carmel Pond Dam Refurbishment*.

Title: **Port Union Building Replacement**
Asset Class: **General Property**
Category: **Project**
Investment Classification: **General Plant**
2026 Expenditures: **$1,003,000**

The *Port Union Building Replacement* was included as a multi-year project in Newfoundland Power's 2025 Capital Budget Application.[12] The *Port Union Building Replacement* project involves the replacement of Newfoundland Power's Port Union District Building. 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 Board approved the Port Union Building Replacement as a two-year project in Order No. P.U. 27 (2024). The project is proceeding as approved. Engineering design is underway, construction scheduled to begin in Q4 of 2025 with completion by year end 2026.

Table E-12 provides the approved expenditures for the *Port Union Building Replacement.*

Table E-12
Port Union Building Replacement
Multi-Year Expenditures
($000s)

Cost Category	2025F	2026F	Total
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

Expenditures for the *Port Union Building Replacement* total approximately $1,281,000, including $1,003,000 in 2026. For expenditures incurred to date, see the *2025 Capital Expenditure Status Report* filed with the Application.

[12] See Newfoundland Power's *2025 Capital Budget Application,* report *5.1 Port Union Building Replacement.*

Title:	**Microsoft Enterprise Agreement**
Asset Class:	**Information Systems**
Category:	**Project**
Investment Classification:	**General Plant**
2026 Expenditures:	**$297,000**

The *Microsoft Enterprise Agreement* was included as a multi-year project in Newfoundland Power's 2024 Capital Budget Application.[13] The *Microsoft Enterprise Agreement* project involves ensuring access to the latest versions of each software product purchased under this program. The annual agreement is a fixed price based on the number of eligible employees that use Microsoft software products on Company-assigned personal computers

The Board approved the *Microsoft Enterprise Agreement* as a three-year project in Order No. P.U. 2 (2024). The project is continuing to provide software's and updates to the company-assigned personal computers.

Table E-13 provides the approved expenditures for the *Microsoft Enterprise Agreement.*

Table E-13
Microsoft Enterprise
Multi-Year Expenditures
($000s)

Cost Category	2024	2025F	2026F	Total
Material	297	297	297	891
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	$297	$297	$297	$891

Expenditures for the *Microsoft Enterprise Agreement* total approximately $891,000, including $297,000 in 2026. For expenditures incurred to date, see the *2025 Capital Expenditure Status Report* filed with the Application.

[13] See Newfoundland Power's *2024 Capital Budget Application, Schedule B,* pages 121 to 123.

June 2025

2026 - 2030 Capital Plan

NEWFOUNDLAND POWER
A FORTIS COMPANY

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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").

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'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 $106 million of annual capital expenditures from 2026 to 2030, or 62% of total annual expenditures.

The Company is forecasting the refurbishment 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 refurbishment of these units is forecast to account for approximately $121 million from 2027 to 2030.

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 are 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 2026 to 2030, or 19% of total annual expenditures.

The Company's current capital plan forecasts average annual investments of approximately $172 million from 2026 to 2030. 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.

2.0 PLANNING CONTEXT

2.1 General

Newfoundland Power's investment priorities and five-year capital plan reflect the capital expenditures necessary to meet the Company's 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 increasing requests for new service connections in recent years due to population growth and government sponsored housing initiatives throughout its service area. At the same time, system load growth has been concentrated in urban areas.[2]

Table 1 provides the forecast number of new customer connections from 2026 to 2030.

Table 1
Forecast New Customer Connections
(2026F-2030F)

	2026F	2027F	2028F	2029F	2030F
New Customer Connections	2,865	2,431	1,997	1,559	1,440

New customer connections are forecast to decline from 2,865 in 2026 to 1,440 in 2030. Approximately 44% 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 20 *Feeder Additions for Load Growth* projects completed over the last five years, 18 projects have been on the Avalon Peninsula, including 14 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 in the conversion of their homes from oil heat to electric heat.[5] Approximately 3,140 oil to electric conversions have been completed, with approximately 1,020 further conversions pre-approved as of May 2025.

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. A report outlining the Company's review of the implementation of AMI is included as Appendix B to the *2026-2030 Capital Plan*.

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 electric 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*.

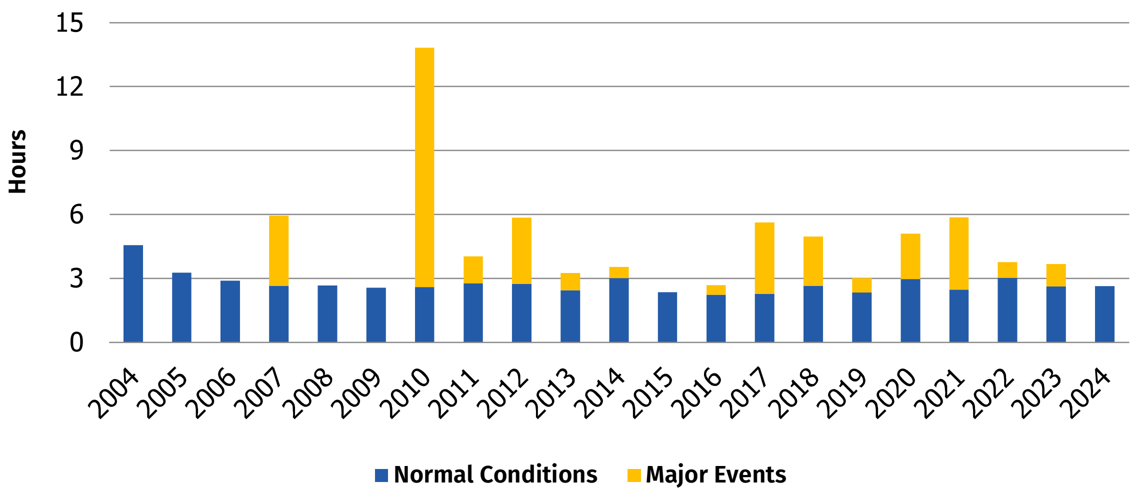
8 For example, Newfoundland Power's deployment of Automated Meter Reading technology required over five years to implement. The deployment of AMI would be more substantial as, in addition to replacing existing meters, the Company would be required to implement new communications infrastructure, a meter data management system, and new customer rate structures.

9 Overall customer satisfaction with Newfoundland Power's service averaged 87% from 2015 to 2024. Customer satisfaction averaged 93% when customers were surveyed about their direct interactions with field staff, including technologists and field service representatives.

In 2026, Newfoundland Power will continue to focus 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 2024 including major events.[10]

Figure 1
Newfoundland Power
Outage Duration Including Major Events
(2004 to 2024)



Major customer outages due to severe weather have become more frequent in the Company's service territory, causing customer outages in eight of the last ten years compared to six 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 customers following such events typically requires a robust operational response as well as capital investments to repair damage to the electrical system.[12]

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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 2005 to 2024, 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, customers 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. Restoration efforts were impacted on the west coast of the island in the Wreckhouse area, where winds continuously exceeded 120 kilometres per hour throughout the day and into the late evening.

[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).

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. As part of the ongoing *Reliability and Resource Adequacy Study*, Hydro identified the need for additional generation to meet load growth and system reliability requirements. The assessment of the electrical system in the *2024 Resource Adequacy Plan* determined that urgent investment in increased electrical supply is required to maintain reliable power supply for customers on the island.[15]

To address the forecast requirement for new sources of supply, Hydro has proposed the purchase and installation of Bay d'Espoir Unit 8 and an Avalon Combustion Turbine in the *Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine* (the "2025 Build Application"). The 2025 Build Application is currently under review by the Board.

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 continue to pose a risk to Newfoundland Power's *2026-2030 Capital Plan*. Supply chain challenges continue to contribute to reduced availability, extended delivery times and higher than inflation cost pressures for certain materials and equipment. For example, the procurement of heavy-duty vehicles, conductors, meters and power transformers continues to be subject to these issues. In response, the Company has increased its use of multi-year capital projects. This includes the procurement of heavy-duty fleet vehicles and substation refurbishment and modernization projects where power transformer replacements are required. The Company continues to monitor market conditions to assess potential impacts on its operations.

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[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 *Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine*, filed with the Board on March 21, 2025.

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 Company's asset management practices have been found to conform with good utility practice.[16] Currently, Newfoundland Power is undertaking a comprehensive asset management review to guide the maturation of asset management practices and is also replacing its asset management technology.[17]

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 fail.

The condition of Newfoundland Power's aging electrical system can be observed through its recent experience with equipment failures. An average of approximately 1,050 equipment failures per year were experienced on the distribution system from 2020 to 2024.[18] Distribution equipment failures are primarily driven by overhead conductor, insulators, poles and transformers that have become deteriorated due to their age and exposure to climatic conditions.

Newfoundland Power is exposed to an increasing risk of equipment failure going forward due to the age of its electrical system. As detailed below, significant quantities 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.

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[16] 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. 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] See report *6.2 Asset Management Technology Replacement* in the *2025 Capital Budget Application*. In Order No. P.U.27 (2024) Reasons for Decision, the Board stated: "*The Board accepts that the evidence filed demonstrates that the proposed replacement of Newfoundland Power's asset management technology with a modern equivalent is aligned with industry best practice and will allow Newfoundland Power to meet current requirements as well as provide a foundation for enhancements as its asset management matures.*"

[18] This only includes equipment failures resulting in an outage to customers. It excludes transmission and protection equipment failures.

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.

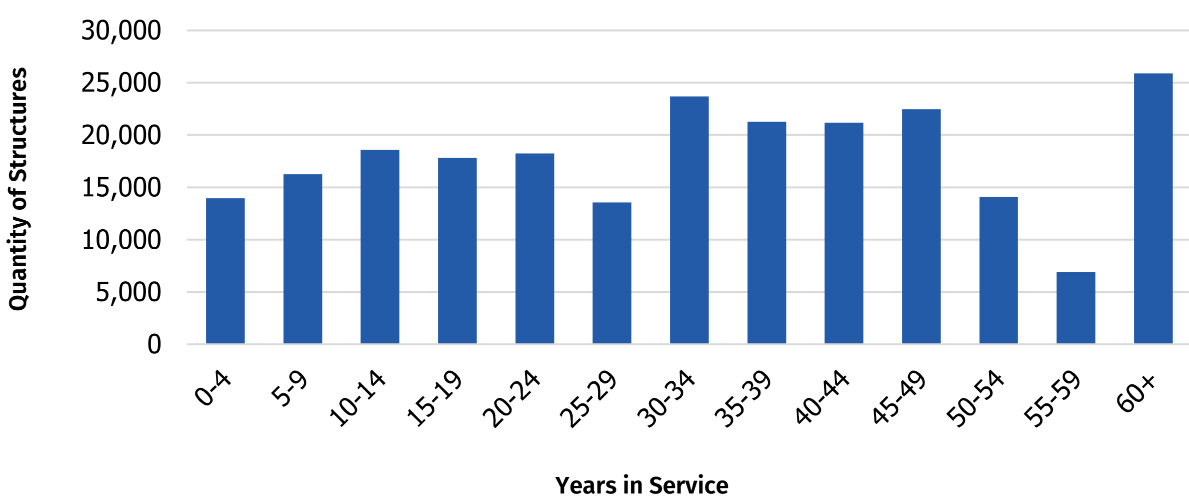
The distribution system performance is addressed through the *Distribution Reliability Initiative*, which targets the worst performing feeders for capital investment.[19]

Newfoundland Power's distribution system includes approximately 228,000 wooden support structures and overhead conductor on approximately 9,600 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.

Figure 2 provides the age distribution of wooden support structures on the Company's distribution system.

Figure 2
Distribution Wooden Support Structures
Asset Age



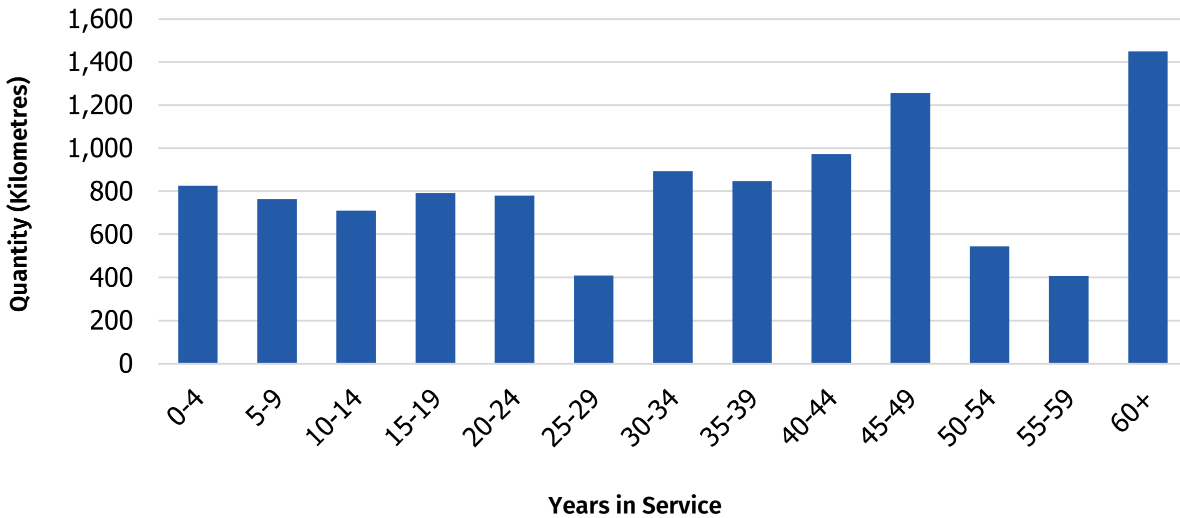
19 The *Distribution Reliability Initiative* project has evolved in recent years to include isolated, discrete sections of feeders or neighbourhoods that are experiencing poor reliability performance. Additionally, the Outage Management System is capable of providing outage data with greater granularity 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.

Approximately 14% of distribution wooden support structures have exceeded the average industry expected useful service life of 54 years. An additional 19% 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 24% of distribution overhead conductor has currently exceeded the average industry expected useful service life of 50 years. An additional 20% of distribution overhead conductor will reach 50 years in service within the next decade.

2.4.3 Transmission

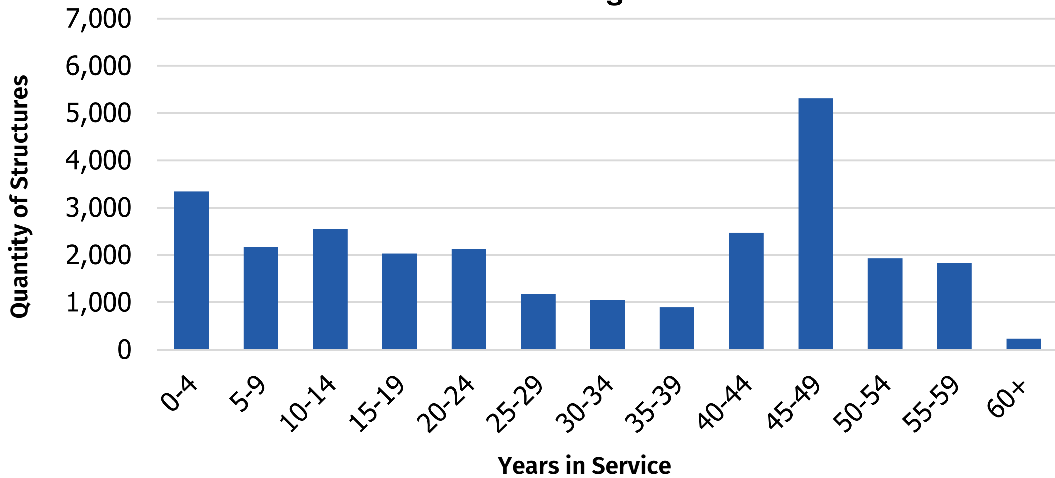
Transmission lines are the backbone of the electricity system serving customers. Transmission lines are inspected annually to identify deficiencies. Deficiencies are prioritized for correction based on severity through the annual *Transmission Line Maintenance* program. The condition of the transmission 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.

Figure 4 provides the age distribution of wooden support structures on the Company's transmission system.

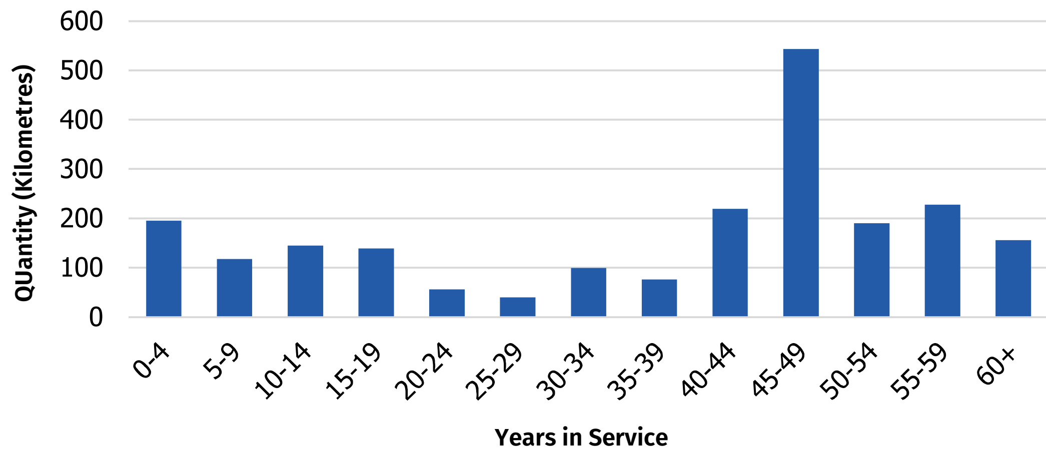
Figure 4
Transmission Wooden Support Structures
Asset Age



Approximately 3% of transmission wooden support structures have exceeded the average industry expected useful service life of 58 years.[22] An additional 19% of transmission wooden support structures will reach 58 years in service over the next decade.

Figure 5 provides the age distribution of overhead conductor on the Company's transmission system.

Figure 5
Transmission Overhead Conductor
Asset Age



[22] The relatively favourable age profile of the Company's transmission lines 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.

Approximately 2% of transmission overhead conductor has currently exceeded the average industry expected useful service life of 63 years. An additional 14% of transmission overhead conductor will reach 63 years in service within the next decade.

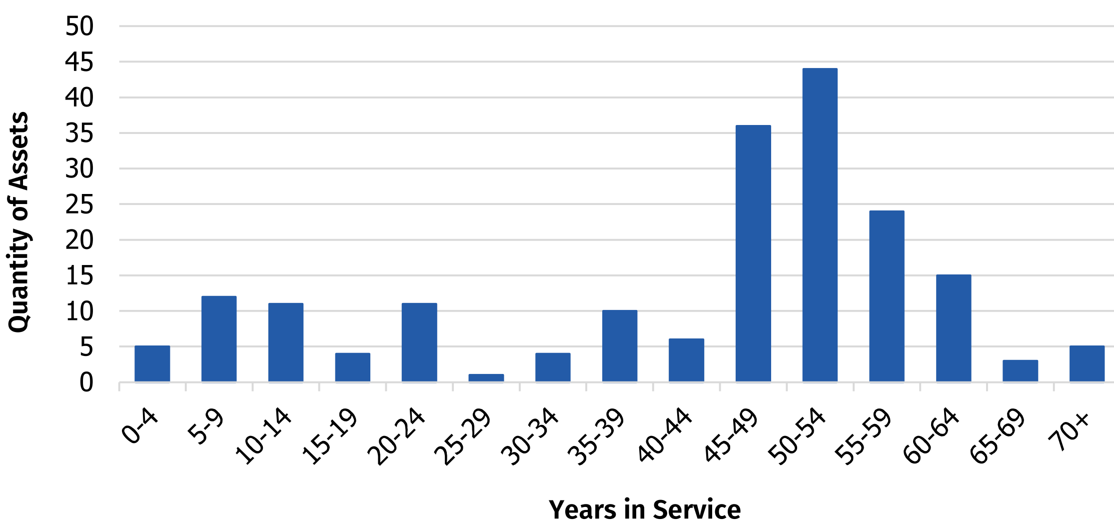
2.4.4 Substations

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 implemented a component-based program to address obsolete substation protection and control systems within Newfoundland Power's substations.

The most critical equipment in substations are power transformers. There are currently 191 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 failure.

Figure 6 provides the age distribution of Newfoundland Power's substation power transformers.

Figure 6
Substation Power Transformers
Asset Age



23 Practical conditions, such as high ambient temperature, high loading and fault exposure, can reduce the expected service lives 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.

Approximately 48% of substation power transformers have exceeded the industry expected useful service life of 50 years. An additional 22% of substation power transformers will reach 50 years in service over the next decade.[24]

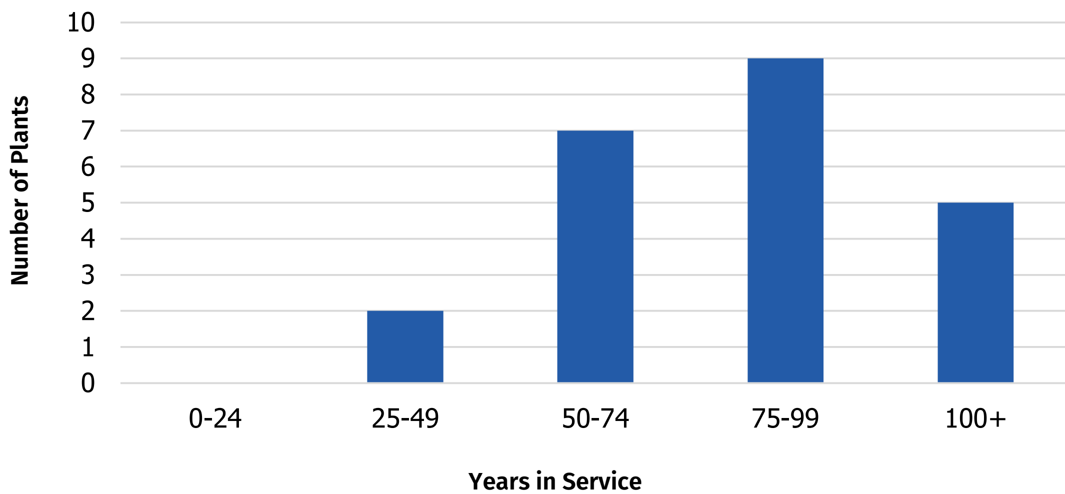
2.4.5 Generation

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 and the *Thermal Plant Replacements Due to In-Service Failures* program. 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 2024.

Figure 7
Hydro Plants
Asset Age



Of Newfoundland Power's 23 hydro plants, 16 have been in service for between 50 and 100 years and five 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 hydro plants when proven economical for customers.[25]

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24 To address the significant percentage of substation power transformers approaching and exceeding their expected service lives, the Company has prepared a *Substation Power Transformer Strategy*, filed as report 2.2 of this application.

25 In circumstances where the life extension of a hydro plant is not economical 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.

Newfoundland Power operates six thermal plants on the island with a total generation capacity of 44.5 MW. Four of the thermal plants are stationary. These include the Wesleyville gas turbine, Greenhill gas turbine, Port aux Basques diesel generator, and the Mobile Gas Turbine ("MGT").[26] Two of the thermal plants are mobile. These include the Mobile Diesel #3 and Mobile Gas Turbine #2. The Wesleyville gas turbine has been in service for 55 years.[27] Recent condition assessments have identified that the power turbine has significantly deteriorated and is approaching end of life. The Greenhill gas turbine has been in service for 49 years. Recent condition assessments have identified that the majority of the electrical system components of the gas turbine are obsolete and have reached end of life. In addition, the mechanical system including the gas generator power turbine is obsolete, with no OEM support available, and has reached end of life. Thermal generation units in Port aux Basques have been in service since the 1960s.[28] Recent condition assessments have identified that several components of the MGT and the Port aux Basque diesel generator, including the generator, exciter and electrical system have reached end of life.

Newfoundland Power is currently undertaking a review of three thermal assets. Newfoundland Power's annual 138 kV and 66 kV Loop Assessments show that the Wesleyville and Greenhill assets are required to mitigate transmission planning contingencies associated with Hydro's Sunnyside and Stonybrook 230kV transmission loops.[29] Newfoundland Power will conduct a joint planning study with Hydro to address these planning contingencies. This will include a review of alternatives including the refurbishment of the Wesleyville and Greenhill gas turbines. Planned refurbishment projects for the Company's thermal generation assets are discussed further in section 3.3.5 below.

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[26] The MGT is no longer able to be transported due to the deteriorated condition of the trailer chassis. The MGT is permanently stationed at the Company's Grand Bay Substation on the southwest coast of Newfoundland.

[27] The Wesleyville gas turbine was originally installed and located in the Company's Salt Pond facility. The equipment was relocated to the Wesleyville facility in 2003, where the equipment remains today.

[28] 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 MGT, which was placed into service in 1974. This thermal generation, along with Rose Blanche Hydro Plant and other mobile generators, supplies the Port aux Basques area for planned and unplanned outages on Hydro's transmission lines TL214 and TL215.

[29] The purpose of the annual loop assessment is to simulate various equipment outage scenarios at the transmission level during peak conditions and to provide recommendations to minimize customer impacts and equipment overloads for each transmission loop. The annual loop assessment is included as part of Hydro's *NLSO Report – 2025 Annual Planning Assessment* which was filed with the Board on May 21, 2025.

3.0 SUMMARY OF PLANNED EXPENDITURES

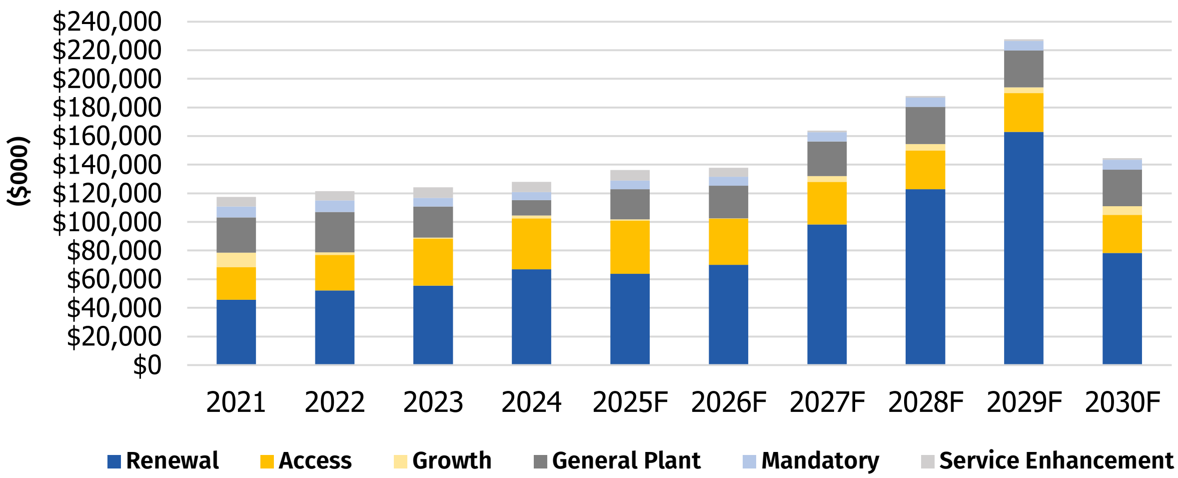
3.1 General

Newfoundland Power's *2026-2030 Capital Plan* forecasts average annual capital expenditures of approximately $172 million from 2026 to 2030. This section provides a breakdown of forecast capital expenditures by investment classification and asset class.[30]

3.2 Planned Expenditures by Investment Classification

Figure 8 provides historical and forecast capital expenditures from 2021 to 2030 by investment classification.

Figure 8
Capital Expenditures by Investment Classification
(2021-2030F)



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.[31] Renewal investments are forecast to account for approximately 62% of capital expenditures from 2026 to 2030, compared to approximately 45% 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 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,* as well as the proposed work to be completed under the *Substation Power Transformer Strategy* over the forecast period. Renewal investments in the Generation asset class reflect both an

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30 Capital expenditures are organized by investment classification in accordance with the Board's provisional *Capital Budget Application Guidelines* effective January 2022.

31 Increases in the Renewal classification in 2028 and 2029 are driven by the planned replacement of the Greenhill and Wesleyville gas turbines.

increase in refurbishment projects for hydro plants, the planned refurbishment 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 19% 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 $7.1 million of investments between 2028 and 2030 relate to transformer capacity additions at Kelligrews, Hardwoods and Pasadena substations to respond to load growth on the distribution system. Newfoundland Power is currently evaluating potential impacts of EV adoption through its EV Load Management Pilot Project and the Potential Study undertaken by Posterity Group. Results from these studies indicate that EV adoption is not likely to impact system peak until 2030 in a high adoption scenario and 2037 in a low adoption scenario.

General Plant investments are forecast to account for approximately 15% 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 1% 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.

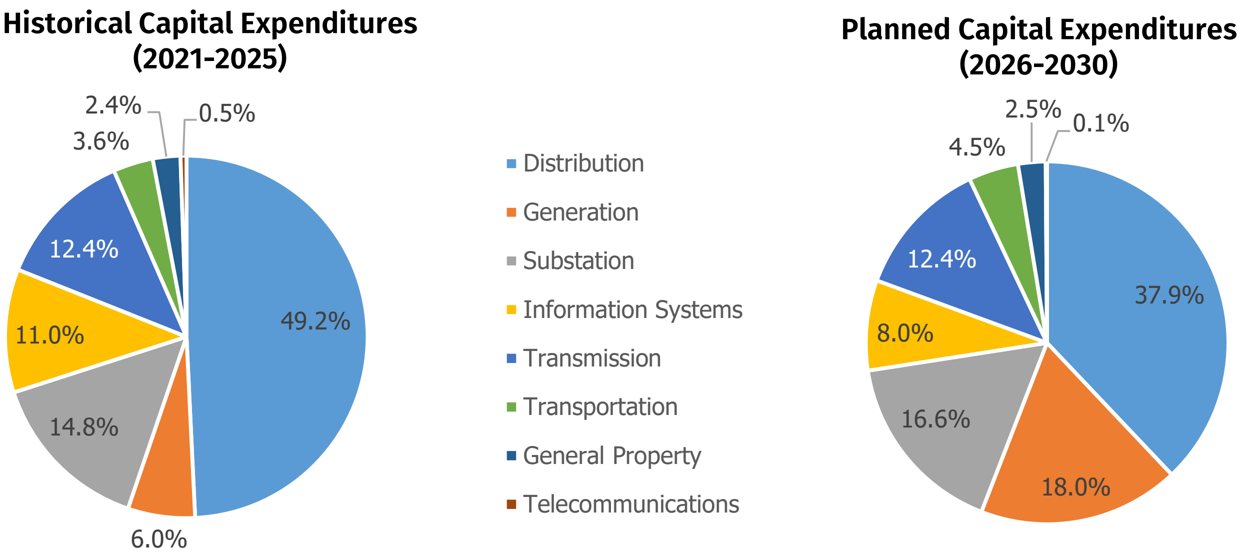
Mandatory investments are forecast to account for approximately 4% of annual capital expenditures over the next five years. Mandatory investments reflect capital expenditures resulting from Board Orders, including *General Expenses Capitalized*, the *Allowance for Unforeseen Items*, and the *Allowance 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.[32]

Figure 9
Capital Expenditures by Asset Class



The distribution asset class is forecast to continue to account for the largest proportion of the capital expenditures from 2026 to 2030. 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.

32 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 2021 to 2030.

Table 2 Distribution Capital Expenditures ($000s)					
Actual/Forecast					Average
2021	2022	2023	2024	2025F	2021-2025F
50,951	50,449	57,328	69,306	67,831	59,173
Plan					Average
2026B	2027B	2028B	2029B	2030B	2026B-2030B
61,284	64,063	63,251	63,266	60,983	62,677

Distribution capital expenditures are forecast to average approximately $62.7 million annually from 2026 to 2030. This compares to an average of approximately $59.2 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 $13.7 million annually. Refurbishment projects for individual distribution feeders are expected to increase over the forecast period, with annual expenditures increasing from approximately $0.7 million in 2026 to approximately $8.1 million in 2030.

Expenditures related to the *Distribution Reliability Initiative* are forecast to average approximately $1.9 million annually as the Company continues to target the worst performing feeders, or discrete sections of feeders, on its distribution system.[33]

[33] 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 2021 to 2030.

Table 3
Substations
Capital Expenditures
($000s)

Actual/Forecast					Average
2021	2022	2023	2024	2025F	2021-2025F
15,507	14,252	21,230	21,983	15,952	17,785

Plan					Average
2026B	2027B	2028B	2029B	2030B	2026B-2030B
22,634	24,592	30,814	30,340	29,046	27,485

Substations expenditures are forecast to average approximately $27.5 million annually from 2026 to 2030. This compares to an average of approximately $17.8 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 18 substations, including the Lockston and Summerville substations in 2026, and one two-year project at Greenspond substation commencing in 2026. 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 $8.5 million from 2026 to 2030.

Newfoundland Power is also forecasting to proactively replace an average of three power transformers annually to address the Company's aging power transformer fleet. Power transformer replacements are forecast to cost on average $6.8 million annually from 2026 to 2030. [34]

Forecast substation expenditures also include approximately $5.0 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.

[34] See report *2.2 Substation Power Transformer Strategy* for further information.

3.3.4 Transmission

Table 4 provides historical and forecast transmission capital expenditures from 2021 to 2030.

Table 4
Transmission
Capital Expenditures
($000s)

Actual/Forecast					Average
2021	2022	2023	2024	2025F	2021-2025F
11,279	18,588	8,662	16,586	19,409	14,905
Plan					**Average**
2026B	2027B	2028B	2029B	2030B	2026B-2030B
22,114	30,724	19,083	14,669	15,553	20,429

Transmission capital expenditures are forecast to average approximately $20.4 million annually from 2026 to 2030. This compares to an average of approximately $14.9 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*.[35] Additionally, the previously approved construction of a 138 kV transmission line from Lewisporte to Boyd's Cove substations that began in 2025 as part of the *Gander – Twillingate Transmission System Planning Study* is expected to cost an average of approximately $9.4 million per year in 2026 and 2027. The rebuild of Transmission Line 100L in 2026 and 2027 is expected to cost approximately $13.8 million. Forecast expenditures from 2026 to 2030 include rebuild projects on nine transmission lines throughout the Company's service territory. The average annual cost of transmission line rebuild projects from 2026 to 2030 is approximately $13.2 million.

Forecast transmission expenditures also include capital maintenance of transmission line structures at an annual average cost of approximately $3.4 million.

[35] As of the end of 2025, execution of this strategy will be 88% complete. Transmission lines 146L and 94L are currently being rebuilt and are scheduled for completion by the end of 2025 and 2026 respectively, which will bring the total number of lines rebuilt as part of the strategy to 30 (30 / 34 = 0.88, or 88%). Four of the remaining transmission line rebuilds are included in Table 4 above.

3.3.5 Generation

Table 5 provides historical and forecast generation capital expenditures from 2021 to 2030.

Table 5
Generation
Capital Expenditures
($000s)

Actual/Forecast					Average
2021	2022	2023	2024	2025F	2021-2025F
9,766	2,869	8,684	7,164	7,585	7,214

Plan					Average
2026B	2027B	2028B	2029B	2030B	2026B-2030B
2,473	5,188	47,010	87,252	6,469	29,678

Generation capital expenditures are forecast to average approximately $29.7 million annually from 2026 to 2030.[36] This compares to an average of approximately $7.2 million annually over the previous five-year period.

Increased generation expenditures include the planned refurbishment of the existing Wesleyville gas turbine in 2027 and 2028 and the Greenhill gas turbine in 2028 and 2029. The cost of refurbishing these gas turbines is approximately $40 million and $80 million, respectively. Expenditures of approximately $1 million are also included in 2030 to start the engineering to refurbish thermal units located in Port aux Basques.[37]

Increased generation expenditures also reflect a forecast requirement to undertake refurbishment projects at 11 hydro plants over the next five years.

[36] Generation-Hydro capital expenditures are forecast to average approximately $5.1 million annually from 2026 to 2030. Generation-Thermal capital expenditures are forecast to average approximately $24.5 million annually from 2026 to 2030.

[37] Newfoundland Power has two thermal generation plants located in Port aux Basques. These are: (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 are 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 2021 to 2030.

Table 6
Information Systems
Capital Expenditures
($000s)

Actual/Forecast					Average
2021	2022	2023	2024	2025F	2021-2025F
15,472	21,495	12,251	6,019	11,009	13,249

Plan					Average
2026B	2027B	2028B	2029B	2030B	2026B-2030B
12,673	13,413	14,481	13,304	12,535	13,281

Information systems capital expenditures are forecast to average approximately $13.3 million annually from 2026 to 2030. This compares to an average of approximately $13.2 million annually over the previous five-year period.

Expenditures from 2026 to 2030 are comparable to the previous five-year average. Forecast expenditures encompass enhancements to Operations Technology, as well as the replacement of SCADA, among other upgrades. These expenditures are expected to be driven by more frequent software and hardware upgrades required to manage cybersecurity risks and to meet vendor requirements.

3.3.7 Transportation

Table 7 provides historical and forecast transportation capital expenditures from 2021 to 2030.

Table 7 Transportation Capital Expenditures ($000s)					
Actual/Forecast					Average
2021	2022	2023	2024	2025F	2021-2025F
4,441	3,212	5,143	3,630	5,042	4,294
Plan					Average
2026B	2027B	2028B	2029B	2030B	2026B-2030B
5,805	7,178	7,319	7,913	8,592	7,361

Transportation capital expenditures are forecast to average approximately $7.4 million annually from 2026 to 2030. This compares to an average of approximately $4.3 million annually over the previous five-year period.

The increase in transportation capital expenditures from 2026 through 2030 primarily reflects inflation and the number of heavy, medium, and light-duty fleet and passenger vehicles forecasted to be replaced over the period.

3.3.8 General Property

Table 8 provides historical and forecast general property capital expenditures from 2021 to 2030.

Table 8
General Property
Capital Expenditures
($000s)

Actual/Forecast					Average
2021	2022	2023	2024	2025F	2021-2025F
2,703	2,843	2,694	2,401	4,010	2,930
Plan					**Average**
2026B	2027B	2028B	2029B	2030B	2026B-2030B
4,089	3,717	4,129	4,103	4,228	4,053

General Property capital expenditures are forecast to average approximately $4.1 million annually from 2026 to 2030. This compares to an average of approximately $2.9 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 2026 to 2030 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.

General Property capital expenditures also include the purchase of tools and equipment necessary for employees to complete job duties in a safe and efficient manner and minor upgrades to improve security and accessibility of corporate offices.

3.3.9 Telecommunications

Table 9 provides historical and forecast telecommunications capital expenditures from 2021 to 2030.

Table 9
Telecommunications
Capital Expenditures
($000s)

Actual/Forecast					Average
2021	2022	2023	2024	2025F	2021-2025F
503	593	707	425	994	644

Plan					Average
2026B	2027B	2028B	2029B	2030B	2026B-2030B
281	134	137	341	145	208

Telecommunications capital expenditures are forecast to average approximately $0.2 million annually from 2026 to 2030. This compares to an average of approximately $0.6 million annually over the previous five-year period.

Expenditures from 2026 to 2030 decrease in comparison to the previous five-year average. This decrease is primarily driven by the completion of the Company's Very High Frequency ("VHF") mobile radio system replacement in 2025. Telecommunications expenditures over the next five years are predominantly focused on fibre optic cable projects, including planned builds in Mount Carmel Pond in 2026 and from Goulds Substation to Glendale Substation in 2029, along with other minor upgrades to communications equipment.

APPENDIX A:

Capital Projects and Programs: 2026-2030

Table A-1
2026-2030 Capital Plan
By Asset Class
($000s)

Asset Class	2026F	2027F	2028F	2029F	2030F
Distribution	61,824	64,063	63,251	63,266	60,983
Substations	22,634	24,592	30,814	30,340	29,046
Transmission	22,114	30,724	19,083	14,669	15,553
Generation	2,473	5,188	47,010	87,252	6,469
Information Systems	12,673	13,413	14,481	13,304	12,535
Transportation	5,805	7,178	7,319	7,913	8,592
General Property	4,089	3,717	4,129	4,103	4,228
Telecommunications	281	134	137	341	145
Allowance for Unforeseen Items	750	750	750	750	750
General Expenses Capitalized	5,300	5,500	5,600	5,800	5,900
Total	$137,943	$155,259	$192,574	$227,738	$144,201

Table A-2
2026-2030 Capital Plan
Distribution
($000s)

	2026F	2027F	2028F	2029F	2030F
Project					
Feeder Additions for Load Growth	250	2,569	4,459	4,134	0
Distribution Reliability Initiative	0	2,000	2,250	2,500	2,750
Distribution Feeder Automation	648	670	694	718	750
LED Street Lighting Replacement	5,559	0	0	0	0
Distribution Feeder GDL-03 Refurbishment	722	0	0	0	0
Distribution Feeder Reconfiguration PHR-GOU	0	2,200	2,200	2,200	0
Distribution Feeder SCT-01 and BLK-01 Relocation[1]	1,140	0	0	0	0
Distribution Feeder Extension CAB-01	1,346	0	0	0	0
Distribution Feeder Extension COB-02	0	1,216	0	0	0
George Street Relocation	0	0	0	3,000	3,000
Distribution Feeder Refurbishments	0	4,977	5,851	5,240	8,096
Allowance for Funds Used During Construction	223	225	228	231	235
Program					
Extensions	16,747	14,562	12,259	9,809	9,284
Reconstruction	7,674	7,880	8,091	8,307	8,530
Rebuild Distribution Lines	5,263	5,409	5,560	5,715	5,874
New Services	4,218	3,684	3,114	2,502	2,378
Replacement Services	382	393	404	415	427
New Meters	701	609	513	410	388
Replacement Meters	562	947	564	674	1,505
New Transformers	4,394	4,471	4,549	4,628	4,708
Replacement Transformers	4,954	5,041	5,130	5,218	5,308
New Street Lighting	2,425	2,482	2,540	2,600	2,661
Replacement Street Lighting	914	931	949	968	987
Relocate/Replace Distribution Lines for Third Parties	3,702	3,797	3,896	3,997	4,102
Total	$61,824	$64,063	$63,251	$63,266	$60,983

[1] Multi-year capital project approved in Board Order No. P.U. 27 (2024).

Table A-3
2026-2030 Capital Plan
Substations
($000s)

	2026F	2027F	2028F	2029F	2030F
Project					
Substation Ground Grid Upgrades	350	360	371	382	393
Lewisporte-Boyd's Cove 138kV Conversion	568	7,551	0	0	0
Grand Falls Substation Conversion	0	60	1,004	0	0
Grand Falls Substation Switch Replacements	0	32	498	0	0
Lockston Substation Refurbishment & Modernization[2]	4,521	0	0	0	0
Summerville Substation Refurbishment & Modernization[3]	4,510	0	0	0	0
Greenspond Substation Refurbishment & Modernization	374	2,578	0	0	0
Gander Substation Power Transformer Replacement[4]	3,905	263	0	0	0
Power Transformer Replacements	0	0	2,500	5,724	6,297
Portable Substation	0	100	3,100	3,800	0
Substation Spare Power Transformer Inventory	13	3,906	0	0	0
Pulpit Rock Substation Power Transformer Replacement[5]	2,905	0	0	0	0
King's Bridge Substation Power Transformer Replacement	12	93	2,866	0	0
Mobile Plant Substation Power Transformer Replacement	12	93	2,522	0	0
Molloy's Lane Substation Power Transformer Replacement	12	2,789	0	0	0
Substation Refurbishment and Modernization	0	1,140	11,208	8,041	10,239
Substation Feeder Terminations	0	0	90	1,080	0
Additions Due to Load Growth	0	0	0	300	6,000
Substation Terminations for Transmission Line Rebuilds	0	0	301	1,679	0
Substation Upgrades for Thermal Generation Projects	0	50	650	3,500	150
Program					
Substation Replacements Due to In-Service Failures	4,733	4,841	4,951	5,063	5,178
Substation Protection and Control Replacements	719	736	753	771	789
Total	$22,634	$24,592	$30,814	$30,340	$29,046

2 Multi-year capital project approved in Board Order No. P.U. 27 (2024).
3 Ibid.
4 Ibid.
5 Ibid.

Table A-4 2026-2030 Capital Plan Transmission ($000s)					
	2026F	2027F	2028F	2029F	2030F
Project					
Transmission Line 94L Rebuild[6]	9,075	0	0	0	0
New Transmission Line from Lewisporte to Boyd's Cove[7]	9,283	9,553	0	0	0
Transmission Line Rebuild – 100L Sunnyside to Clarenville	450	13,323	0	0	0
Transmission Line Extension - 142L	0	1,520	0	0	0
Transmission Line Rebuilds	0	2,953	15,637	11,150	11,960
Program					
Transmission Line Maintenance[8]	3,306	3,375	3,446	3,519	3,593
Total	$22,114	$30,724	$19,083	$14,669	$15,553

6 Multi-year capital project approved in Board Order No. P.U. 27 (2024).
7 Ibid.
8 Includes retreatment of wood transmission poles with preservative.

Table A-5 2026-2030 Capital Plan Generation ($000s)					
	2026F	2027F	2028F	2029F	2030F
Project					
Mount Carmel Pond Dam Refurbishment[9]	1,008	0	0	0	0
Rose Blanche Hydro Plant Refurbishment	0	0	0	859	0
Tors Cove Hydro Plant Refurbishment	0	1,400	1,100	4,700	0
Cape Broyle and Horsechops Control Upgrades	398	0	0	0	0
Horsechops Hydro Plant Refurbishment	0	0	0	0	3,100
Cape Broyle Hydro Plant Refurbishment	0	0	0	800	0
Lawn Hydro Plant Refurbishment	0	198	2,336	0	0
Victoria Hydro Plant Refurbishment	0	198	2,457	0	0
Morris Hydro Plant Refurbishment	0	0	0	0	200[10]
Lookout Brook Plant Dam Refurbishment	0	0	0	750	1,000
Hearts Content Hydro Plant Refurbishment	0	500	0	0	0
Rocky Pond Hydro Plant Refurbishment	0	400	0	0	0
Petty Harbour Hydro Plant Refurbishment	0	400	0	0	0
Greenhill Gas Turbine Refurbishment	0	0	1,000	79,000	0
Wesleyville Gas Turbine Refurbishment	0	1,000	39,000	0	0
Port aux Basques Thermal Generation	0	0	0	0	1,000
Program					
Hydro Plant Replacements Due to In-Service Failures	736	753	770	788	805
Thermal Plant Replacements Due to In-Service Failures	331	339	347	355	364
Total	$2,473	$5,188	$47,010	$87,252	$6,469

9 Multi-year capital project approved in Board Order No. P.U. 27 (2024).
10 First year of a two-year multi-year project in 2030 and 2031

Table A-6 2026-2030 Capital Plan Information Systems ($000s)					
	2026F	2027F	2028F	2029F	2030F
Project					
System Upgrades	965	1,862	5,510	6,845	2,620
Application Enhancements	968	1,299	2,031	1,065	2,601
Cybersecurity Upgrades	950	930	920	855	810
Microsoft Enterprise Agreement[11]	297	350	350	350	380
Network Infrastructure	495	400	355	960	530
Customer Correspondence Modernization	782	1,175	0	0	0
Geographic Information System Upgrade	500	5,173	2,652	0	0
Technical Work Request Software Replacement	0	0	0	750	1,000
Shared Server Infrastructure	990	1,476	1,900	1,700	1,800
Outage Management System Upgrade[12]	1,459	0	0	0	0
Asset Management Technology Replacement[13]	4,534	0	0	0	0
SCADA Replacement	0	0	0	0	2,000
Program					
Personal Computer Infrastructure	733	748	763	779	794
Total	$12,673	$13,413	$14,481	$13,304	$12,535

11 Multi-year capital project approved in Board Order No. P.U. 02 (2024).
12 Multi-year capital project approved in Board Order No. P.U. 27 (2024).
13 Ibid.

Table A-7 2026-2030 Capital Plan Transportation ($000s)					
	2026F	2027F	2028F	2029F	20230F
Project					
Replace Vehicles and Aerial Devices 2025-2026[14]	2,802	0	0	0	0
Replace Vehicles and Aerial Devices 2026-2027	3,003	2,718	0	0	0
Replace Vehicles and Aerial Devices 2027-2028	0	3,660	2,409	0	0
Replace Vehicles and Aerial Devices 2028-2029	0	0	4,070	3,876	0
Replace Vehicles and Aerial Devices 2029-2030	0	0	0	4,037	4,070
Replace Vehicles and Aerial Devices 2030-2031	0	0	0	0	4,522[15]
Purchase Specialized Offroad Vehicles	0	800	840	0	0
Total	$5,805	$7,178	$7,319	$7,913	$8,592

14 Multi-year capital project approved in Order No. P.U. 27 (2024).
15 First year of a two-year multi-year project in 2030 and 2031.

Table A-8 2026-2030 Capital Plan General Property ($000s)					
	2026F	2027F	2028F	2029F	2030F
Project					
Company Building Renovations	0	150	1,050	950	1,000
Port Union Building Replacement[16]	1,003	0	0	0	0
Summerford Building Replacement	155	562	0	0	0
Building Accessibility Improvements	490	510	530	550	570
Specialized Tools and Equipment	616	635	655	675	695
Program					
Additions to Real Property	714	728	741	754	768
Physical Security Upgrades	506	516	526	537	547
Tools and Equipment	605	616	627	637	648
Total	$4,089	$3,717	$4,129	$4,103	$4,228

[16] Multi-year capital project approved in Board Order No. P.U. 27 (2024).

Table A-9 2026-2030 Capital Plan Telecommunications ($000s)					
	2026F	2027F	2028F	2029F	2030F
Project					
Mount Carmel Pond Dam Fibre	150	0	0	0	0
Fibre Optic Cable Build	0	0	0	200	0
Program					
Communications Equipment Upgrades	131	134	137	141	145
Total	$281	$134	$137	$341	$145

Table A-10 2026-2030 Capital Plan Allowance for Unforeseen Items ($000s)					
	2026F	2027F	2028F	2029F	2030F
Project					
Allowance for Unforeseen Items	750	750	750	750	750
Total	$750	$750	$750	$750	$750

Table A-11 2026-2030 Capital Plan General Expenses Capitalized ($000s)					
	2026F	2027F	2028F	2029F	2030F
Project					
General Expenses Capitalized	5,300	5,500	5,600	5,800	5,900
Total	$5,300	$5,500	$5,600	$5,800	$5,900

APPENDIX B:

AMI Update

June 2025

AMI Update

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 INTRODUCTION

In Order No. P.U. 3 (2025), the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") directed Newfoundland Power Inc. ("Newfoundland Power" or the "Company") to file an update on its review of the implementation of Advanced Metering Infrastructure ("AMI") as part of its *2026 Capital Budget Application*.[1] This update is filed in compliance with Order No. P.U. 3 (2025).

Metering is a core function of Newfoundland Power's operations. The Company provides electrical service to approximately 278,000 customers. The Company's current metering system, automated meter reading ("AMR"), was implemented over the 2013 to 2018 timeframe. The implementation of AMR reduced meter reading costs by nearly 80%, providing for the provision of service to customers at the lowest possible cost. With an average useful life of approximately 20-years, the Company's AMR technology will require mass replacement in the mid-2030s. Based on current Canadian utility practice, Newfoundland Power anticipates that transitioning to AMI at that time will be a reasonable alternative to re-investing in AMR technology. In accordance with the *Capital Budget Application Guidelines (Provisional),* a transition to AMI at that time would require a fulsome business case, including detailed engineering assessments and assessment of alternatives, to support approval of an AMI capital project by the Board.[2]

In the interim, Newfoundland Power has been developing its business case for AMI on a preliminary basis. The primary purpose for this exercise is to be in a position to apply for government funding that could enable an adoption of AMI in the shorter term. It also builds internal knowledge and capacity associated with an AMI implementation ahead of a full engineering assessment.

2.0 CURRENT METERING TECHNOLOGY

Newfoundland Power currently uses AMR as part of its metering operations. The Company first assessed AMR in 2006. At that time, it was determined that adoption of AMR on a broad basis was not cost-effective for customers.[3] The Company continued to evaluate AMR in the following years. In 2012, AMR was demonstrated to be cost-beneficial for customers. As a result, the Company sought Board approval to transition to AMR as part of its *2013 Capital Budget Application*. This project was approved in Order No. P.U. 31 (2012), after which the Company began to deploy AMR across its service territory.[4]

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1 See Order No. P.U. 3 (2025), page 64. In addition, the Board noted that the Company is advancing studies that will help quantify the potential benefits of an AMI implementation and found that Newfoundland Power should not be directed to provide a cost benefit analysis with respect to an AMI implementation at this time.

2 Fulsome business cases for larger projects are lengthy and costly processes that typically occur near the end of life of the current assets. For example, with respect to the Company's transition to its modern Customer Information System ("CIS"), the assessment of CIS cost $1.2 million and occurred primarily from 2019 to 2020 and that cost was included in the Company's 2019 and 2020 revenue requirements approved by the Board in Order No. P.U. 2 (2019). Following the assessment, the process for Board approval occurred from 2020 to 2021. Newfoundland Power estimates the cost of a fulsome business case for AMI to be approximately $2.5 million and would take roughly 16 months to complete.

3 See *Newfoundland Power's 2006 Capital Budget Application, Volume II: Supporting Materials, 4.1 Metering Strategy*, page 7.

4 See Order No. P.U. 31 (2012).

Newfoundland Power's implementation of AMR took place between 2013 and 2018. AMR eliminated the need for manual reading processes, reducing meter reading costs by nearly 80%.[5] Other benefits realized through the implementation of AMR included: (i) enhanced billing accuracy through reduced bill estimations; (ii) reduced environmental footprint through route optimization; and (iii) decreased safety incidents associated with manual meter reading processes.

Based on an approximate 20-year life of an AMR meter, the Company's existing metering technology will require mass replacement in the mid-2030s.

As part of Newfoundland Power's *2025/2026 General Rate Application*, the Consumer Advocate proposed that the Company begin to install AMI meters whenever a new or replacement meter is required.[6] Unlike the transition to AMR, the transition to AMI requires distinct supporting infrastructure and communications networks.[7] Maintaining and operating two metering technologies concurrently would result in additional costs and operational complexities for the Company.

Concerns that AMR technology may be obsolete were also raised as part of the Company's *2025/2026 General Rate Application*.[8] While adoption rates of AMI in electrical utilities have increased,[9] Newfoundland Power notes that AMR and its predecessor technology, electromechanical metering, are both still used by Canadian electrical utilities.[10]

Newfoundland Power will continue with the use of AMR technology to satisfy its obligation to provide least-cost service to customers and to comply with government regulations until a fulsome business case supports a full-scale AMI deployment.

3.0 PRELIMINARY ASSESSMENTS

3.1 Jurisdictional Scan

Newfoundland Power completed a jurisdictional scan of 20 utilities across Canada with respect to their metering practices. The results of that scan are provided in Attachment A. The scan found that seven utilities have implemented AMI, with one of those utilities transitioning from powerline carrier AMI to AMI, and another five currently transitioning from AMR to AMI. The remaining eight utilities continue to use AMR, electromechanical meters, or a combination of these technologies.

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5 Newfoundland Power's meter reading costs were $2.8 million in 2012, compared to $0.6 million in 2019 ($0.6 million - $2.8 million) / $2.8 million = -0.7857).

6 See *Pre-Filed Evidence of C. Douglas Bowman*, page 40, lines 24-27, filed as part of Newfoundland Power's *2025/2026 General Rate Application.*

7 See *Newfoundland Power Rebuttal Evidence*, *4.6 – Advanced Metering Infrastructure*, filed as part of Newfoundland Power's *2025/2026 General Rate Application*.

8 *Ibid.*

9 At the end of 2023, the smart meter penetration rate in North America was 80%. See *Berg Insights, Smart Metering in North America – 6th edition*.

10 See section *3.1 Jurisdictional Scan* for further information. AMR is also used by water utilities across North America. See *Berg Insights, Smart Water Metering in Europe and North America – 3rd edition, November 2023*. Further, Newfoundland Power has not received notice of the discontinuance of its AMR technology.

The Company has observed that the deployment and realized benefits of AMI projects vary by situation and jurisdiction-specific factors such as the age and type of its existing metering technology, government mandates and funding opportunities, as well as other anticipated benefits.[11]

3.2 Government Funding Opportunities

Newfoundland Power applied for financial assistance for a potential AMI project on three separate occasions. In 2021, the Company applied for funding under the Government of Canada's Smart Renewables and Electrification Pathways ("SREPs") program to study how to integrate certain technologies, including AMI, into the Company's operations. In 2023, the Company applied to the Provincial Government's Green Transition Fund Program for financial assistance in completing an AMI feasibility study. In 2024, the Company submitted an expression of interest under the SREPs program under the Utility Support Stream for funding towards an AMI project.

In each case, the applications were not successful. In general, the government funding programs received a high level of uptake and included projects that likely had greater alignment with the purpose of the government funding than an AMI project.

Newfoundland Power will continue to apply for provincial and federal funding opportunities as they arise.

3.3 Preliminary Cost Estimates

Table 1 provides a breakdown of the estimated capital cost of an AMI implementation in Newfoundland Power's service territory, on a preliminary basis. They are based on broad assumptions, primarily associated with the AMI network type, and therefore the cost estimates will change following detailed engineering assessments.[12]

Table 1
Preliminary AMI Capital Project Costs

Cost Description	Nominal
AMI meters and installation	$82 million
Network, systems and integrations	$19 million
Project engineering, resourcing and training	$17 million
Total	$118 million

[11] Nova Scotia Power applied to the Nova Scotia Utility and Review Board for an AMI project when their existing electromechanical meters were nearing the end of expected life and were due to be replaced in mass quantities. Maritime Electric applied to the Island Regulatory and Appeals Commission for an AMI project, which included government funding. Utilities in Ontario were mandated by the Government of Ontario to implement AMI.

[12] AMI network types include mesh, point to point and point to multi-point and vary by utility due to factors such as service territory geography. The cost estimates were prepared with the assistance of Capgemini Canada Inc., an information technology services and consulting company.

On a preliminary basis, the capital cost associated with an AMI implementation is estimated to be approximately $118.0 million. For comparison, the average cost of an AMI meter is an estimated $220 per meter which is roughly double the average cost of an AMR meter of an estimated $110 per meter.[13] In addition, an AMI implementation would require communication networks and supporting infrastructure costs as well as project engineering, resourcing and training costs.

In addition to the capital costs of an AMI implementation, Newfoundland Power has also assessed, on a preliminary basis, the operating costs associated with AMI technology. The annual costs associated with operating AMI technology is estimated to be approximately $2.0 million in 2025 dollars.[14] This compares to the annual cost for operating AMR technology of approximately $1.4 million in 2025.[15]

3.4 Ongoing Analyses

In addition to continuing to refine its preliminary cost estimates, the Company is also currently assessing potential use cases associated with AMI technology that could provide benefits to customers, net of the associated costs. Positive benefit-to-cost use cases would help offset the incremental cost of AMI technology when compared to AMR technology.

The potential benefit of time-varying rate structures is currently being assessed as part of the next five-year *Electrification, Conservation and Demand Management Plan*. Newfoundland Power and Newfoundland and Labrador Hydro are currently developing the plan, which is anticipated to be completed by the end of 2025.

In addition, Newfoundland Power is currently assessing how the use of AMI technology could improve the efficiency of its customer service and field operations. As examples, AMI technology will provide the ability to complete disconnection-reconnection remotely and the ability to provide customers with more self-service options. In addition, more detailed energy information could help customers save on their energy costs and thereby reduce system costs.

4.0 CONCLUSION

Newfoundland Power's current metering technology allows for the delivery of least-cost service to customers. Newfoundland Power will continue with the use of AMR technology to fulfill its obligation to provide service to customers at least-cost and to comply with government regulations until a fulsome business case supports a full-scale AMI deployment.

With an average useful life of 20 years, the Company's AMR technology will require mass replacement in the mid-2030s. Based on current Canadian utility practice, Newfoundland Power anticipates that transitioning to AMI technology at that time will be a reasonable alternative to re-investing in AMR technology. A potential transition to AMI at that time would require a fulsome business case to support approval of an AMI capital project by the Board.

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13 The average cost is weighted between residential, multi-unit and general service customers and excludes installation costs.

14 Operating costs for AMI technology include annual subscription, support and data costs associated with meter data management systems, integration platforms and communication systems.

15 Includes meter reading and maintenance costs as well as costs associated with vehicles and support systems.

In the interim, Newfoundland Power will continue to develop its business case for AMI on a preliminary basis. Currently, the estimated capital cost of implementing AMI technology is $118 million. Beyond the upfront network and project costs associated with an AMI implementation, the average cost of an AMI meter is estimated to be roughly double the average cost of an AMR meter. In addition, the annual costs associated with operating AMI technology is estimated to be more than 40% higher than the annual costs to operate AMR technology.[16] Transitioning to AMI at this time would increase the costs borne by customers for metering.

Newfoundland Power will continue to explore funding opportunities, along with assessing potential benefits of AMI such as load management, which could enable the Company's transition to AMI ahead of the potential mid-2030s timeframe.

[16] $2.0 million / $1.4 million – 1 = 43%. See section 3.3 Preliminary Cost Estimates for further information.

Attachment A:

Survey of Canadian Utility Practice on Metering System

Table A-1
Survey of Canadian Utility Practice on Metering Systems

Utility	Metering System
Newfoundland Power	AMR
Newfoundland and Labrador Hydro	AMR
Nova Scotia Power	AMI
New Brunswick Power	Currently transitioning to AMI
Maritime Electric	Currently transitioning to AMI
Hydro-Quebec	AMI
Ontario (All Utilities)[1]	AMI
Manitoba Hydro	AMR
SaskPower	Currently transitioning to AMI
ATCO Electric	Currently transitioning to AMI
Fortis Alberta	Currently transitioning from Powerline carrier AMI to AMI.
ENMAX	Currently transitioning to AMI
EPCOR	AMI
FortisBC	AMI
BC Hydro	AMI
Yukon Energy Corporation	Electromechanical and/or AMR
ATCO Electric Yukon	Electromechanical and/or AMR
Naka Power[2]	AMR, with possible use of electromechanical
Northwest Territories Power Corporation	Electromechanical and possible use of AMR
Quilliq Energy Corporation	Electromechanical, AMR, and AMI[3]

1 For the purposes of the jurisdictional scan, all electric utilities in Ontario were grouped together and counted as one utility given the Government of Ontario Order in Council directing them to implement AMI by December 31, 2010. See Government of Ontario Order in Council dated June 23, 2004.
2 Formerly Northland Utilities.
3 AMI implemented in Iqaluit.

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

April 1, 2025

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: 2024 Capital Expenditure Report

Enclosed please find Newfoundland Power Inc.'s 2024 Capital Expenditure Report (the "Report"). The Report is presented in compliance with enumerated paragraph 5 of Order No. P.U. 2 (2024)[1] of the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") and pursuant to section 41 of the *Public Utilities Act*.

The Report provides information on capital expenditures approved in Order Nos. P.U. 2 (2024), P.U. 14 (2023), P.U. 38 (2022), P.U. 36 (2021) and P.U. 12 (2021), including actual expenditures to December 31, 2024 and variances between actual and budgeted expenditures by project. The Report also provides an explanation of the components that contributed to the overall budget variance.

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 2024 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 materials, please contact the undersigned at your convenience.

Yours truly,

Doug Wright

Douglas Wright
Senior Legal Counsel

Enclosure

ec. Shirley Walsh
Newfoundland & Labrador Hydro

Dennis Browne, K.C.
Browne Fitzgerald Morgan & Avis

[1] See Order P.U. 2 (2024), page 4.

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2024 Capital Expenditure Report

April 1, 2025

Newfoundland Power Inc.

2024 Capital Expenditure Report

Explanatory Note

This report is filed in compliance with Order No. P.U. 2 (2024) of the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board").

Pages one through four of the *2024 Capital Expenditure Report* provides an overview of the 2024 capital expenditures and outlines variances from budget of the capital expenditures approved by the Board in Order Nos. P.U. 2 (2024), P.U. 14 (2023), P.U. 38 (2022), P.U. 36 (2021) and P.U. 12 (2021). The tables on pages five through 17 provide additional detail on capital expenditures in 2024, and also include information on capital projects approved for prior years that were not completed prior to 2024. Page 17 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 2024 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 2024 are provided in Appendix C.

2024 Capital Expenditures Overview

Newfoundland Power's actual 2024 capital expenditures were $137.4 million, resulting in a total variance of $21.6 million, or 18.6%, from the 2024 capital budget amount of $115.8 million. Of the total variance, $16.3 million, or 14.1%, relates to the distribution class with the remaining $5.3 million, or 4.5%, relating to all other asset classes.

The distribution class variance of $16.3 million is largely the result of (i) higher than anticipated new customer connections, (ii) higher transformer expenditures to ensure adequate inventory levels are maintained, and (iii) higher than average contribution in aid of construction ("CIAC") extension work in 2024.

New Customer Connections
Newfoundland Power's new customer connections were 3,052 in 2024, which is 49% higher than the 2,053 new customer connections underpinning the 2024 capital budget. New customer connections have a direct impact on the necessary capital expenditures in the *Extensions*, *New Services* and *New Meters* capital programs.[1]

Table 1 provides the budget variance associated with these programs and analyzes the impact the higher than anticipated new customer connections had on the budget variance.

Table 1:
New Customer Connections Analysis
($000s)

		2,053 New Customer Connections		3,052 New Customer Connections	
Project	2024 Actual	2024 Approved Budget	Budget Variance	2024 *Pro Forma* Budget	*Pro Forma* Budget Variance
Extensions	19,600	11,640	7,960	18,047	1,553
New Services	3,661	2,847	814	4,233	(572)
New Meters	780	302	478	449	331
Total	24,041	14,789	9,252	22,729	1,312

The total budget variance associated with the *Extensions, New Services and New Meters* capital programs was $9.3 million. If the 2024 budget included the 3,052 new customer connections actually experienced in 2024, the total budget variance associated with these programs would have been $1.3 million. The direct impact of the higher customer connections on the total budget variance is therefore estimated to be $8.0 million, or 6.9%.

[1] Each of these programs are determined based on a forecast of new customer connections. New customer connections also impact other capital programs and projects expenditures, such as the *New Transformers* program.

Transformer Expenditures
In its *2024 Capital Budget Expenditure Status Report* filed with the Board as part of its *2025 Capital Budget Application*, Newfoundland Power provided an updated forecast for its 2024 *Replacement Transformers* and *New Transformers* capital programs. Similar to the justification for the 2025 transformer programs, which were approved by the Board in Order No. P.U 27 (2024) Reasons for Decision, the updated forecast was higher than the original budget largely due to supply chain issues resulting in material cost increases and the necessity to ensure adequate transformer inventories.

Table 2 provides the 2024 capital expenditure for these programs compared to the budget amount and the updated forecast provided to the Board in June 2024.

Table 2:
Transformer Programs Analysis
($000s)

		Original Budget		Updated Forecast	
Project	2024 Actual	2024 Approved Budget	Budget Variance	Updated Forecast	Forecast Variance
Replacement Transformers	6,038	3,681	2,357	5,802	236
New Transformers	5,153	3,264	1,889	5,145	8
Total	11,191	6,945	4,246	10,947	244

The total budget variance associated with the *Replacement Transformers* and *New Transformers* capital programs was $4.2 million, or 3.6% of the total budget. Based on the updated forecast, the budget variance associated with these programs would have been $0.2 million, or 0.2% of the total budget.

In 2024, Newfoundland Power purchased 1,940 distribution transformers, an increase of 440 units compared to the previous five-year average of 1,500 units. Based on the budget unit cost of $4,630, $2.0 million, or roughly half, of the total $4.2 million transformer program variance can be attributed to increased transformer purchases.[2] The remaining variance of $2.2 million can be attributed to an increase in material costs.[3]

In 2024, 1,936 distribution transformers, representing effectively the total transformer purchases in 2024, were installed to either replace failed/rusty transformers or to connect new customers to the electricity system.[4]

[2] Budget unit cost: $6,945,000 / 1,500 units = $4,630 per unit. $4,630 x 440 units = $2,037,200.
[3] Actual unit cost: $11,191,000 / 1,940 units = $5,769 per unit. $5,769 - $4,630 = $1,139 increase in unit costs x 1,940 units = $2,209,660.
[4] The increased replacement of rusty transformers in 2024 also resulted in an increase to the *Reconstruction* program, due to the labour and associated materials required to replace a transformer.

CIAC Extensions
The *Extensions* capital program includes CIAC extension work, notably for cabin area developments or larger commercial projects such as the Corner Brook Hospital CIAC in 2021 and 2022. Based on the five-year average, the 2024 capital budget included an estimated $0.5 million related to larger CIAC extension work. 2024 actual capital expenditures related to larger CIAC extension work was $4.2 million, or $3.7 million higher than average.[5]

Summary
Table 3 summarizes the primary drivers of the distribution class variance of $16.3 million, or 14.1%, as explained above.

Table 3:
Distribution Class Variance Drivers

	Variance ($millions)	*Variance (%)*
New customer connections	$8.0M	6.9%
Transformer expenditures	$4.2M	3.6%
Higher than average CIAC extensions	$3.7M	3.2%
Total	$15.9M	13.7%

Of the total distribution class variance, $15.9 million, or 13.7% is due to higher than anticipated new customer connections, higher transformer expenditures to ensure adequate inventory levels, and higher than average CIAC extension work in 2024.

See Appendix A for further information on the distribution class budget variances.

Managing the 2024 Capital Expenditures
As outlined above, $15.9 million, or 13.7% of the total capital budget variance relates to the Company's obligation to provide customers with access to electricity services and to maintain adequate transformer inventory levels. With respect to transformer inventories, the Board recognized in Order No. P.U 27 (2024) Reasons for Decision that maintaining a sufficient inventory of transformers is necessary to enable routine corrective and preventative maintenance and connect new customers to the electricity system.[6]

Excluding the distribution class variance drivers, the remaining budget variance is $5.7 million, or 4.9%. As detailed in Appendix A, the remaining variance is primarily due to higher than anticipated contractor and material costs related to generation, substation and transmission work. A common reason for higher than anticipated contractor and material costs, as demonstrated by the *Substation Spare Transformer Inventory Project*, is higher actual costs compared to the pricing quotes used to prepare the budget estimates. In recent years, the timeline between receiving a pricing quote during capital budget preparation and procuring the necessary work following Board approval has been up to or exceeding a year.

5 The larger CIAC extension developments in 2024 were primarily related to the Joe Batt's Pond cabin area development, which was ongoing at the end of 2024. CIAC extension work occurs ahead of customer connections.
6 See page 7, line 30 to page 8, line 4 of Order No. P.U. 27 (2024) Reasons for Decision.

Overall, 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. As provided in the Company's capital budget applications, Newfoundland Power assesses all viable alternatives for executing the required capital work and defers capital expenditures for a given year to the extent possible.[7] As such, ensuring contractor and material costs are procured in a least cost manner provides the greatest avenue to ensure capital cost pressures compared to budget estimates can be mitigated.[8] Newfoundland Power's contract procurement uses a tender process to ensure the least cost options for qualified contractors are utilized. For example, at least three bids are requested for procurement of any goods and services exceeding $3,000. The Company may also mitigate higher than expected contractor costs by evaluating the structure of the request for proposal and tender, awarding partial contracts, or negotiating with contractors to manage costs. With respect to higher transformer costs, the Company continues to refurbish distribution transformers, where possible, to mitigate supply chain issues and the associated high replacement cost.[9]

Adjustments to Newfoundland Power's capital budget amounts also provide an avenue to reduce capital budget variances. With respect to the distribution class variance drivers, the Company has determined the 2025 budget for *New Transformers* and *Replacement Transformers* based on a 3-year average expenditure, along with an additional 11% cost increase to mitigate larger variances going forward. In the preparation of future capital budgets, the Company will assess anticipated CIAC extension work compared to historical averages. Finally, Newfoundland Power will provide an update on the impact of its latest new customer connection forecast as part of its *2025 Capital Budget Expenditure Status Report* to be filed with the Board as part of the Company's *2026 Capital Budget Application*.

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7 As provided as part of the *2024 Capital Budget Application*, seven capital projects were deferred in 2024 to a subsequent year. In Order No. P.U. 36 (2021), the Board recognized that Newfoundland Power's capital planning process is comprehensive and includes reasonable controls on capital spending. See page 45, lines 15-17 of that order.

8 Internal labour cost increases for 2024 were consistent with forecast.

9 The ability to refurbish transformers locally is limited. Newfoundland Power has engaged a local supplier to refurbish distribution transformers removed from service. In 2024, Newfoundland Power received 182 refurbished distribution transformers from this supplier, which represents 9.4% of distribution transformers purchased in 2024 (182/1,940 = 0.0938). This saved over $0.6 million dollars in transformer costs in 2024.

Newfoundland Power Inc. 2024 Capital Budget Variances ($000s)			
	Approved[10]	Actual	Variance
Generation - Hydro	5,329	7,422[11]	2,093
Generation - Thermal	311	418	107
Substations	22,171	23,676[12]	1,505
Transmission	15,064	17,277[13]	2,213
Distribution	54,865	71,138[14]	16,273
General Property	2,340	2,401[15]	61
Transportation	3,806	3,630[16]	(176)
Telecommunications	502	425	(77)
Information Systems	6,180	6,316[17]	136
Unforeseen Allowance	750	0	(750)
General Expenses Capitalized	4,500	4,701	201
Total	**115,818**	**137,404**	**21,586**
Projects carried forward from prior years		8,453	

10 Approved in Order Nos. P.U. 2 (2024), P.U. 14 (2023), P.U. 38 (2022), P.U. 36 (2021) and P.U. 12 (2021).

11 Includes forecast expenditure of $1,325,000 for *Mobile Hydro Plant Refurbishment*, $478,000 for *Mobile Hydro Plant Surge Tank Refurbishment* and $198,000 for *Hydro Facility Rehabilitation* carried forward into 2025.

12 Includes forecast expenditure of $414,000 for *Gambo Substation Refurbishment and Modernization*, $1,033,000 for *Memorial Substation Refurbishment and Modernization* and $247,000 for *Old Perlican Substation Refurbishment and Modernization* carried forward into 2025.

13 Includes forecast expenditure of $901,000 for *Transmission Line 55L Rebuild*, $691,000 for *Transmission Line 24L Relocation*, $751,000 for *Transmission Line 146L Rebuild*, and $1,447,000 for T*ransmission Line 94L Rebuild* carried forward into 2025.

14 Includes forecast expenditure of $1,336,000 for *Feeder Additions for Load Growth*, $193,000 for *Distribution Feeder BIG-02 Relocation* and $303,000 for *Distribution Reliability Initiative (SUM-01)* carried forward into 2025.

15 Includes forecast expenditure of $35,000 for *Gander Building Renovation* carried forward into 2025.

16 Includes forecast expenditure of $184,000 for *Replace Vehicles and Aerial Devices 2024-2025* and $2,207,000 for *Replace Vehicles and Aerial Devices 2023-2024* carried forward into 2025.

17 Includes forecast expenditures of $215,000 for *Application Enhancements* and $82,000 for *Shared Server Infrastructure* carried forward into 2025.

2024 Capital Expenditure Report
(000s)

	Capital Budget			Actual Expenditure				
	2021 - 2023	2024	Total	2021 - 2023	2024	Carryover	Total	Variance
	A	B	C	D	E	F	G	H
2024 Projects and Programs	$ -	$ 115,818	$ 115,818	$ -	$ 125,365	$ 12,039	137,404	$ 21,586
2021-2023 Projects and Programs	78,486	-	78,486	67,037	6,796	1,657	75,490	(2,996)
Grand Total	**$ 78,486**	**$ 115,818**	**$ 194,304**	**$ 67,037**	**$ 132,161**	**$ 13,696**	**$ 212,894**	**$ 18,590**

Column A	Approved Capital Budget for 2021, 2022 and 2023
Column B	Approved Capital Budget for 2024
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2021, 2022 and 2023
Column E	Actual Capital Expenditure for 2024
Column F	Capital Projects Carried Forward to 2025
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2024 Capital Expenditure Report
(000s)

Category: Generation - Hydro

	Capital Budget			Actual Expenditure					
	2023	2024	Total	2023	2024	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2024 Projects and Programs									
Mobile Hydro Plant Surge Tank Refurbishment	$ -	$ 977	$ 977	$ -	$ 499	$ 478	$ 977	$ -	
Hydro Facility Rehabilitation	-	794	794	-	596	198	794	$ -	
Hydro Plant Replacements Due to In-Service Failures	-	716	716	-	636	-	636	$ (80)	
	$ -	$ 2,487	$ 2,487	$ -	$ 1,731	$ 676	$ 2,407	$ (80)	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2023
Column B	Approved Capital Budget for 2024
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2023
Column E	Actual Capital Expenditure for 2024
Column F	Capital Projects Carried Forward to 2025
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2024 Capital Expenditure Report
(000s)

Category: Generation - Thermal

	Capital Budget			Actual Expenditure					
	2023	2024	Total	2023	2024	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2024 Projects and Programs									
Thermal Plant Replacements Due to In-Service Failures	$ -	$ 311	$ 311	$ -	$ 418	$ -	$ 418	$ 107	1
	$ -	$ 311	$ 311	$ -	$ 418	$ -	$ 418	$ 107	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2023
Column B	Approved Capital Budget for 2024
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2023
Column E	Actual Capital Expenditure for 2024
Column F	Capital Projects Carried Forward to 2025
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2024 Capital Expenditure Report
(000s)

Category: Substations

	Capital Budget			Actual Expenditure					
	2023	**2024**	**Total**	**2023**	**2024**	**Carryover**	**Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
2024 Projects and Programs									
Gambo Substation Refurbishment and Modernization	$ -	$ 5,267	$ 5,267	$ -	$ 5,021	$ 414	$ 5,435	$ 168	
Substation Replacements Due to In-Service Failures	-	4,797	4,797	-	5,841	-	5,841	1,044	2
Memorial Substation Refurbishment and Modernization	-	4,351	4,351	-	3,318	1,033	4,351	-	
Old Perlican Substation Refurbishment and Modernization	-	3,356	3,356	-	3,149	247	3,396	40	
Substation Protection and Control Replacements	-	635	635	-	696	-	696	61	
Substation Ground Grid Upgrades	-	580	580	-	386	-	386	(194)	3
PCB Removal	-	544	544	-	577	-	577	33	
Oxen Pond Substation Bus Upgrade	-	451	451	-	364	-	364	(87)	
Oxen Pond Substation Switch Replacements	-	316	316	-	281	-	281	(35)	
	$ -	$ 20,297	$ 20,297	$ -	$ 19,633	$ 1,694	$ 21,327	$ 1,030	
2023 Projects and Programs									
Walbournes Substation Refurbishment and Modernization	$ 4,955	-	$ 4,955	$ 4,835	$ 235	$ -	$ 5,070	$ 115	
Molloy's Lane Substation Refurbishment and Modernization	4,827	-	4,827	4,325	178	-	4,503	(324)	
Substation Spare Transformer Inventory	1,500	-	1,500	1	144	1,657	1,802	302	4
	$ 11,282	$ -	$ 11,282	$ 9,161	$ 557	$ 1,657	$ 11,375	$ 93	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2023
Column B	Approved Capital Budget for 2024
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2023
Column E	Actual Capital Expenditure for 2024
Column F	Capital Projects Carried Forward to 2025
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2024 Capital Expenditure Report
(000s)

Category: Transmission

	Capital Budget			Actual Expenditure					
	2023	2024	Total	2023	2024	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2024 Projects and Programs									
Transmission Line Maintenance	$ -	$ 2,651	$ 2,651	$ -	$ 2,826	$ -	$ 2,826	$ 175	
Transmission Line 24L Relocation	-	701	701	-	10	691	701	-	
	$ -	$ 3,352	$ 3,352	$ -	$ 2,836	$ 691	$ 3,527	$ 175	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2023
Column B	Approved Capital Budget for 2024
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2023
Column E	Actual Capital Expenditure for 2024
Column F	Capital Projects Carried Forward to 2025
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2024 Capital Expenditure Report
(000s)

Category: Distribution

	Capital Budget			Actual Expenditure					
	2023	2024	Total	2023	2024	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2024 Projects and Programs									
LED Street Lighting Replacement	$ -	$ 5,541	$ 5,541	$ -	$ 5,945	$ -	$ 5,945	$ 404	
Feeder Additions for Load Growth	-	2,811	2,811	-	1,648	1,336	2,984	173	
Distribution Feeder Automation	-	888	888	-	890	-	890	2	
Distribution Reliability Initiative	-	900	900	-	961	-	961	61	
Distribution Feeder BIG-02 Relocation	-	196	196	-	3	193	196	-	
Distribution Feeder GDL-02 Refurbishment	-	667	667	-	638	-	638	(29)	
Distribution Feeder OXP-01 Refurbishment	-	840	840	-	966	-	966	126	5
Allowance for Funds Used During Construction	-	260	260	-	298	-	298	38	
Extensions	-	11,640	11,640	-	19,600	-	19,600	7,960	6
Reconstruction	-	6,953	6,953	-	8,633	-	8,633	1,680	7
Rebuild Distribution Lines	-	4,974	4,974	-	5,253	-	5,253	279	
Relocate/Replace Distribution Lines for Third Parties	-	3,766	3,766	-	3,905	-	3,905	139	
Replacement Transformers	-	3,681	3,681	-	6,038	-	6,038	2,357	8
New Transformers	-	3,264	3,264	-	5,153	-	5,153	1,889	9
New Services	-	2,847	2,847	-	3,661	-	3,661	814	10
New Street Lighting	-	2,429	2,429	-	2,666	-	2,666	237	
Replacement Street Lighting	-	863	863	-	890	-	890	27	
Replacement Meters	-	571	571	-	340	-	340	(231)	11
Replacement Services	-	457	457	-	386	-	386	(71)	
New Meters	-	302	302	-	780	-	780	478	12
	$ -	$ 53,850	$ 53,850	$ -	$ 68,654	$ 1,529	$ 70,183	$ 16,333	
2023 Projects and Programs									
Distribution Feeder Automation	$ 1,054	$ -	$ 1,054	$ 579	$ 418	$ -	$ 997	$ (57)	
	$ 1,054	$ -	$ 1,054	$ 579	$ 418	$ -	$ 997	$ (57)	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2023
Column B	Approved Capital Budget for 2024
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2023
Column E	Actual Capital Expenditure for 2024
Column F	Capital Projects Carried Forward to 2025
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2024 Capital Expenditure Report
(000s)

Category: General Property

	Capital Budget			Actual Expenditure					
	2023	2024	Total	2023	2024	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2024 Projects and Programs									
Energized Conductor Support Tools	$ -	$ 539	$ 539	$ -	$ 514	$ -	$ 514	$ (25)	
Physical Security Upgrades	-	401	401	-	473	-	473	72	
Additions to Real Property	-	655	655	-	642	-	642	(13)	
Tools and Equipment	-	570	570	-	597	-	597	27	
	$ -	$ 2,165	$ 2,165	$ -	$ 2,226	$ -	$ 2,226	$ 61	
2023 Projects and Programs									
Company Building Renovations	$ 741	$ -	$ 741	$ 726	$ 108	$ -	$ 834	$ 93	
	$ 741	$ -	$ 741	$ 726	$ 108	$ -	$ 834	$ 93	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2023
Column B	Approved Capital Budget for 2024
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2023
Column E	Actual Capital Expenditure for 2024
Column F	Capital Projects Carried Forward to 2025
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2024 Capital Expenditure Report
(000s)

Category: Telecommunications

	Capital Budget			Actual Expenditure					
	2023	2024	Total	2023	2024	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2024 Projects and Programs									
Communications Equipment Upgrades	$ -	$ 122	$ 122	$ -	$ 151	$ -	$ 151	$ 29	
Fibre Optic Cable Build	-	380	380	-	274	-	274	(106)	13
	$ -	$ 502	$ 502	$ -	$ 425	$ -	$ 425	$ (77)	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2023
Column B	Approved Capital Budget for 2024
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2023
Column E	Actual Capital Expenditure for 2024
Column F	Capital Projects Carried Forward to 2025
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2024 Capital Expenditure Report
(000s)

Category: Information Systems

	Capital Budget 2023	Capital Budget 2024	Capital Budget Total	Actual Expenditure 2023	Actual Expenditure 2024	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2024 Projects and Programs									
Application Enhancements	$ -	$ 1,892	$ 1,892	$ -	$ 1,680	$ 215	$ 1,895	$ 3	
Shared Server Infrastructure	-	964	964	-	860	82	942	(22)	
System Upgrades	-	957	957	-	981	-	981	24	
Cybersecurity Upgrades	-	930	930	-	992	-	992	62	
Network Infrastructure	-	420	420	-	429	-	429	9	
Personal Computer Infrastructure	-	720	720	-	761	-	761	41	
	$ -	$ 5,883	$ 5,883	$ -	$ 5,703	$ 297	$ 6,000	$ 117	
2023 Projects and Programs									
Application Enhancements	$ 1,538	$ -	$ 1,538	$ 1,529	$ 123	$ -	$ 1,652	$ 114	
Shared Server Infrastructure	1,176	-	1,176	968	319	-	1,287	111	
System Upgrades	962	-	962	581	389	-	970	8	
Network Infrastructure	419	-	419	329	62	-	391	(28)	
	$ 4,095	$ -	$ 4,095	$ 3,407	$ 893	$ -	$ 4,300	$ 205	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2023
Column B	Approved Capital Budget for 2024
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2023
Column E	Actual Capital Expenditure for 2024
Column F	Capital Projects Carried Forward to 2025
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2024 Capital Expenditure Report
(000s)

Category: Unforeseen Allowance

	Capital Budget 2024	Capital Budget Total	Actual Expenditure 2024	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	
2024 Projects and Programs							
Allowance for Unforeseen Items	$ 750	$ 750	$ -	$ -	$ -	$ (750)	14
	$ 750	$ 750	$ -	$ -	$ -	$ (750)	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2024
Column B	Total of Column A
Column C	Actual Capital Expenditure for 2024
Column D	Capital Projects Carried Forward to 2025
Column E	Total of Columns C and D
Column F	Column E less Column B

2024 Capital Expenditure Report
(000s)

Category: General Expenses Capitalized

	Capital Budget 2024	Capital Budget Total	Actual Expenditure 2024	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	
2024 Projects and Programs							
General Expenses Capitalized	$ 4,500	$ 4,500	$ 4,701	$ -	$ 4,701	$ 201	
	$ 4,500	$ 4,500	$ 4,701	$ -	$ 4,701	$ 201	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2024
Column B	Total of Column A
Column C	Actual Capital Expenditure for 2024
Column D	Capital Projects Carried Forward to 2025
Column E	Total of Columns C and D
Column F	Column E less Column B

2024 Capital Expenditure Report
Multi-Year Projects
(000s)

Category: Multi-Year Projects

	Capital Budget			Actual Expenditure					
	2021 - 2023	2024	Total	2021 - 2023	2024	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
Substations									
MUN-T2 Power Transformer Replacement	$ 48	$ 1,566	$ 1,614	2	$ 1,496	$ -	$ 1,498	$ (116)	
Islington Substation Refurbishment and Modernization	-	$ 308	308	-	900	-	900	592	
Transmission									
Transmission Line 55L Rebuild	5,328	5,284	10,612	3,106	9,052	901	13,059	2,447	15
Transmission Line 94L Rebuild	8,819	4,276	13,095	7,899	1,880	1,447	11,226	(1,869)	
Transmission Line 146L Rebuild	-	2,152	2,152	-	1,401	751	2,152	0	
Distribution									
Distribution Reliability Initiative (SUM-01)	656	1,015	1,671	708	652	303	1,663	(8)	
Generation - Hydro									
Mobile Hydro Plant Refurbishment	1,666	2,480	4,146	431	3,532	1,325	5,288	1,142	16
Sandy Brook Plant Penstock Replacement	5,094	-	5,094	4,830	130	-	4,960	(134)	
Lookout Brook Hydro Plant Refurbishment	-	362	362	-	508	-	508	146	
General Property									
Gander Building Renovation	-	175	175	-	140	35	175	-	
Transportation									
Replace Vehicles and Aerial Devices 2024-2025	-	1,940	1,940	-	772	184	956	(984)	
Replace Vehicles and Aerial Devices 2023-2024	2,833	1,866	4,699	1,519	618	2,207	4,344	(355)	
Replace Vehicles and Aerial Devices 2022-2023	5,224	-	5,224	5,149	1,536	-	6,685	1,461	
Information Systems									
Microsoft Enterprise Agreement	-	297	297	-	316	-	316	19	
Customer Service System Replacement	31,646	-	31,646	29,520	924	-	30,444	(1,202)	
	$ 61,314	$ 21,721	$ 83,035	$ 53,164	$ 23,857	$ 7,153	$ 84,174	$ 1,139	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2021, 2022 and 2023
Column B	Approved Capital Budget for 2024
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2021, 2022 and 2023
Column E	Actual Capital Expenditure for 2024
Column F	Capital Projects Carried Forward to 2025
Column G	Total of Columns D, E and F
Column H	Column G less Column C

APPENDIX A:

Variance Notes

Generation – Thermal

1. *Thermal Plant Replacements Due to In-Service Failures:*
   Budget: $311,000 Actual: $418,000 Variance: $107,000

   The actual expenditures for the *Thermal Plant Replacements Due to In-Service Failures* program were $107,000, or 34%, higher than the budget estimate.

   The *Thermal Plant Replacements Due to In-Service Failures* program budget estimate is determined based on the five-year historical average. This increase is largely due to increased required work being identified through inspections and engineering assessments, as compared to the five-year average.[1]

Substations

2. *Substation Replacements Due to In-Service Failures:*
   Budget: $4,797,000 Actual: $5,841,000 Variance: $1,044,000

   The actual expenditures for the *Substation Replacements Due to In-Service Failures* program were $1,044,000, or 22%, higher than the budget estimate.

   The *Substation Replacements Due to In-Service Failures* program budget estimate is determined based on the five-year historical average. The increase is primarily due to material cost increases and additional inventory received in 2024 to maintain adequate equipment levels associated with circuit breakers and reclosers.[2]

   Since 2021, circuit breakers and reclosers have been subject to supply chain issues. In addition, lead times are now ranging from 14 to 24 months. Over the 2021 to 2023 period, only ten circuit breakers and reclosers were received.[3] From 2022 to 2023, the Company ordered 43 units to maintain adequate inventory levels of circuit breakers and reclosers. As a result of supply chain delays, all 43 units ordered by Newfoundland Power from 2022 to 2023 were received by the Company in 2024.

3. *Substation Ground Grid Upgrades*
   Budget: $580,000 Actual: $386,000 Variance: ($194,000)

   The actual expenditure for the *Substation Ground Grid Upgrades* project was $194,000, or 33%, lower than the budget estimate. This decrease is largely due to a reduction in scope at the Greenhill Substation.

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[1] For example, Newfoundland Power's Wesleyville Thermal Generating facility incurred a failure to a combustor discharge nozzle that required replacement.

[2] The cost associated with the circuit breakers and reclosers received in 2024 is approximately $2.7 million. This increase is partially offset by lower-than average costs in 2024 associated with voltage regulators and transformers.

[3] On average, eight circuit breakers and reclosers require replacement annually.

4. *Substation Spare Transformer Inventory (2023 Project):*
   Budget: $1,500,000 Actual: $1,802,000 Variance: $302,000

   The actual expenditure for the *Substation Spare Transformer Inventory* project was $1,802,000, or 20%, higher than the budget estimate, primarily due to higher-than-expected purchase costs for the transformer.

   The original budget estimate for this project was completed early in 2022 based on pricing quotes provided by the supplier at that time. The project was proposed in the 2023 *Capital Budget Application* and the procurement process began following project approval in Order No. P.U. 38 (2022) issued by the Board in late 2022. The actual cost of the power transformer increased 32% from the time the estimate was completed in 2022 to the time the contract to procure the equipment was completed in 2023.

Distribution

5. *Distribution Feeder OXP-01 Refurbishment:*
   Budget: $840,000 Actual: $966,000 Variance: $126,000

   The actual expenditure for the *Distribution Feeder OXP-01 Refurbishment* project was $126,000, or 15% higher than the budget estimate. This increase is largely due to higher-than-expected contractor costs.

   Newfoundland Power renewed its contracts for pole installation services and pole materials in May 2024. These contract renewals resulted in an average increase of 9% in pole installation costs and 6% in pole material costs, as compared to 2023 values.[4]

6. *Extensions:*
   Budget: $11,640,000 Actual: $19,600,000 Variance: $7,960,000

   The actual expenditure for the *Extensions* program was $7,960,000, or 68%, higher than the budget estimate.

   The *Extensions* program budget is determined based on the forecast number of new customer connections and the average historical cost of constructing extensions. As outlined in the *2024 Capital Expenditures Overview* section, the budget variance is largely due to higher than anticipated customer connections and CIAC extension work in 2024.

4 The increase in 2024 costs from 2023 would have been based the GDP Deflator for Canda forecast in the *2024 Capital Budget Application*. The GDP Deflator for Canda increase from 2023 to 2024 was forecast to be 2.1%.

7. *Reconstruction:*
   Budget: $6,953,000 Actual: $8,633,000 Variance: $1,680,000

   The actual expenditure for the *Reconstruction* program was $1,680,000, or 24%, higher than the budget estimate.

   The *Reconstruction* program budget estimate is determined based on the five-year historical average. This increase is largely due to additional work being required as a result of major events in 2024,[5] as well as increased replacement of rusty transformers.[6]

8. *Replacement Transformers:*
   Budget: $3,681,000 Actual: $6,038,000 Variance: $2,357,000

   The actual expenditure for the *Replacement Transformers* program was $2,357,000, or 64%, higher than the budget estimate.

   The *Replacement Transformers* program budget estimate is determined based on the five-year historical average. As outlined in the *2024 Capital Expenditures Overview* section, this increase is largely due to supply chain issues resulting in material cost increases and the necessity to ensure an adequate supply of inventory.

9. *New Transformers:*
   Budget: $3,264,000 Actual: $5,153,000 Variance: $1,889,000

   The actual expenditure for the *New Transformers* program was $1,889,000, or 58%, higher than the budget estimate.

   The *New Transformers* program budget estimate is determined based on the five-year historical average. As outlined in the *2024 Capital Expenditures Overview* section, this increase is largely due to supply chain issues resulting in material cost increases and the necessity to ensure an adequate supply of inventory.

[5] Major events in 2024 included a landslide in the Corner Brook area that required a geotechnical investigation and relocation of a distribution line and an ice storm affecting the Trepassey area. These events combined for a total approximate expenditure of $600,000.

[6] 455 transformers were replaced due to rust in 2024, whereas the planned amount was 366, representing a 24% increase. While the transformer material cost associated with this work is captured in the Replacement Transformer program, other associated materials and labour costs related to the replacement of rusty transformers is included in the Reconstruction program.

10. New Services:
Budget: $2,847,000 Actual: $3,661,000 Variance: $814,000

The actual expenditure for the *New Services* program was $814,000, or 29%, 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. As outlined in the *2024 Capital Expenditures Overview* section, the increase is due to higher than anticipated customer connections.

11. Replacement Meters:
Budget: $571,000 Actual: $340,000 Variance: ($231,000)

The actual expenditure for the *Replacement Meters* program was $231,000, or 40%, lower than the budget estimate.

The *Replacement Meters* program budget was based on the five-year historical average. This decrease is due largely to Newfoundland Power replacing fewer meters than anticipated.

12. New Meters:
Budget: $302,000 Actual: $780,000 Variance: $478,000

The actual expenditure for the *New Meters* program was $478,000, or 158% higher, than the budget estimate.

The *New Meters* program budget was based on the forecast number of new customer connections and the five-year historical average cost. As outlined in the *2024 Capital Expenditures Overview* section, the increase is primarily due to higher than anticipated customer connections as well as higher than anticipated material costs.[7]

Telecommunications

13. Fibre Optic Cable Build
Budget: $380,000 Actual: $274,000 Variance: ($106,000)

The actual expenditure for the *Fibre Optic Cable Build Program* was $106,000, or 28%, lower than the budget estimate.

This decrease is largely due to reduced contractor costs. The *Fibre Optic Cable Build* project was able to utilize pole work completed by a joint use partner that had not been identified when the project was proposed. As a result, less pole work was required, and the cable was constructed on a slightly shorter path than planned.

[7] Metering material costs in 2024 have increased on average 27% when compared to 2023.

Unforeseen Allowance

14. Allowance for Unforeseen Items:
Budget: $750,000 Actual: $0 Variance: ($750,000)

No expenditures were required in 2024.

Multi-Year Projects

15. Transmission Line 55L Rebuild (2023-2024 Multi-Year Project)
Budget: $10,612,000 Actual: $13,059,000 Variance: $2,447,000

The *Transmission Line 55L Rebuild* project was a multi-year project that commenced in 2023. Actual capital expenditures on the project were $13,059,000, including a $901,000 carryover to 2025, or 23% higher than budget. The increase was largely associated with higher-than-expected contractor and material costs.

The budget estimate for the *Transmission Line 55L Rebuild* project was completed in early 2022. The budget estimate largely reflected the cost to complete the Company's most recent transmission line project, the *Transmission Line 363L Rebuild* project in 2020, with annual contractor cost increases of 8% to reflect higher contractor costs being experienced in 2021 and 2022. In 2024, contractor costs are approximately 100% higher than 2020, reflecting an average annual increase of 25%. Similarly, material costs have increased, on average, by 12% from 2020 to 2024. This compared to the 2.3% annual increase for material costs from 2020 to 2024 used in the budget estimate.

16. Mobile Hydro Plant Refurbishment (2023-2024)
Budget: $4,146,000 Actual: $5,288,000 Variance: $1,142,000

The *Mobile Hydro Plant Refurbishment (2023-2024)* project is a multi-year project that commenced in 2023. Actual capital expenditures incurred to date are $5,288,000, including $1,325,000 carried over into 2025. The overall increase in expenditure of $1,142,000 associated with the *Mobile Hydro Plant Refurbishment* project is largely due to worse than anticipated condition of mechanical components and longer lead times associated with the governor, switchgear and generator refurbishment.

The governor was originally estimated at a cost of $225,000 in 2022. When pricing was received in 2024, the cost increased to $441,000. Similarly, the cost of switchgear equipment increased from $270,000 to $405,000 during the same period.

The turbine refurbishment costs increased from an estimated $230,000 to $696,000. This increase was largely due to an increase in material costs and unforeseen repairs that were identified once the unit was disassembled, and the inspection of the interior components completed.

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.[1]

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.

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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.

2024 Capital Expenditures Overall

Approved capital expenditures in 2024 totaled $115.8 million. Actual expenditures were $137.4 million, including forecast expenditures of $12.0 million carried forward into 2025. Actual expenditures were $21.6 million, or 18.6% higher than the total approved capital budget of $115.8 million. As detailed in the *2024 Capital Expenditure Report*, $15.9 million, or 13.7% of the total capital budget variance relates to the Company's obligation to provide customers with access to electricity services and maintaining transformer inventory levels.

For additional information on Newfoundland Power's 2024 capital expenditures, see the 2024 Capital Expenditures Overview on pages one to four of the *2024 Capital Expenditure Report.*

2024 Capital Project Changes

Transmission Line (55L) Rebuild

A portion of the scope of the *Transmission Line (55L) Rebuild* was not completed as approved. During the execution of the Project, Newfoundland Power was unable to secure the required approvals from the Department of Transportation and Infrastructure to construct the transmission line as proposed across the Trans Canada Highway near the town of Whitbourne. In conversations with the department on these approvals, uncertainties with the final design of an upcoming highway twinning project were cited as the main reason for the delay in approvals on the transmission lines construction.

Due to not receiving these approvals, Newfoundland Power did not construct a 5km section of this line, instead tying the new line into a segment of the existing 55L transmission line. This decision was made to mitigate the risk of having to relocate the new line shortly after construction due to the upcoming highway twinning project. Upon completion of the twinning project, Newfoundland Power will reassess the available alternatives to rebuild the remaining section of line. *Transmission Line (55L) Rebuild* project was submitted in the *2023 Capital Budget Application*. This project was approved by the Board in Order No. P.U. 38 (2022).

Transmission Line (94L) Rebuild

The *Transmission Line (94L) Rebuild* 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 has reviewed the remaining scope of work for the *Transmission Line (94L) Rebuild* project due to increased contract prices to complete the work. A revised *Transmission Line (94L) Rebuild* project was submitted in the *2025 Capital Budget Application*. Future expenditures related to this project were approved by the Board in Order No. P.U. 27 (2024).

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]

2024 Capital Projects

In 2024, Newfoundland Power had a total of 39 capital projects, 18 of which were fully completed in 2024.[2] The approved budget of the 18 completed capital projects totaled $21,029,000 and the final cost was $20,693,000.

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
2024 Capital Projects
Planned and Completed

Investment Classification	Materiality Threshold	Planned	Completed
Access	<$1 million	-	-
	$1 million to $5 million	-	-
	>$5 million	-	-
Total Access		**-**	**-**
General Plant	<$1 million	8	5
	$1 million to $5 million	3	-
	>$5 million	-	-
Total General Plant[3]		**11**	**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 2024 and 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 include six multi-year capital projects that commenced in 2024 and continued in 2025. An additional 15 2024 capital projects had forecast carryover expenditures into 2025.

3 Of the six capital projects not completed in 2024, three projects are ongoing multi-year projects with expenditures in 2025. Two capital projects are substantially complete, with small carryovers forecasted in 2025. One capital project with a carryover forecasted in 2025 is anticipated to be completed in 2025 because of vendor delays.

Table 1 2024 Capital Projects Planned and Completed			
Investment Classification	Materiality Threshold	Planned	Completed
Renewal	<$1 million	10	4
	$1 million to $5 million	7	1
	>$5 million	2	-
Total Renewal[4]		**19**	**5**
Service Enhancement	<$1 million	2	2
	$1 million to $5 million	-	-
	>$5 million	1	1
Total Service Enhancement		**3**	**3**
System Growth	<$1 million	1	1
	$1 million to $5 million	1	-
	>$5 million	-	-
Total System Growth[5]		**2**	**1**
Overall	<$1 million	24	15
	$1 million to $5 million	12	2
	>$5 million	3	1
Total Overall		**39**	**18**

[4] Of the 14 capital projects not completed in 2024, three projects are ongoing multi-year projects with expenditures in 2025. An additional three multiyear capital projects are substantially complete with small carryovers forecasted into 2025 to accommodate delivery times of materials or to complete work scopes under favourable weather and loading conditions. A final multiyear capital project has been resubmitted and approved in Newfoundland Power's 2025 Capital Budget Application. The remaining seven single year capital projects with carryovers into 2025 are forecast to be completed by mid-2025.

[5] One capital project was not completed in 2024. This capital project with a carryover forecasted in 2025 is anticipated to be completed in 2025 due to delays associated with environmental assessments.

Table 2 provides the approved 2024 budget amount of the capital projects that were completed in 2024 compared to the final cost of the project, presented by investment classification and materiality threshold.

Table 2
2024 Capital Projects Completed
Budget and Final Costs
($000s)

Investment Classification	Materiality Threshold	Approved Budget	Final Cost
Access	<$1 million	-	-
	$1 million to $5 million	-	-
	>$5 million	-	-
Total Access		**-**	**-**
General Plant	<$1 million	3,226	3,190
	$1 million to $5 million	-	-
	>$5 million	-	-
Total General Plant		**3,226**	**3,190**
Mandatory	<$1 million	1,554	875
	$1 million to $5 million	4,500	4,701
	>$5 million	-	-
Total Mandatory		**6,054**	**5,576**
Renewal	<$1 million	2,723	2,846
	$1 million to $5 million	1,556	1,496
	>$5 million	-	-
Total Renewal		**4,289**	**4,342**
Service Enhancement	<$1 million	1,468	1,276
	$1 million to $5 million	-	-
	>$5 million	5,541	5,945
Total Service Enhancement		**7,009**	**7,221**

Table 2 2024 Capital Projects Completed Budget and Final Costs ($000s)			
Investment Classification	Materiality Threshold	Approved Budget	Final Cost
System Growth	<$1 million	451	364
	$1 million to $5 million	-	-
	>$5 million	-	-
Total System Growth		**451**	**364**
Overall	<$1 million	9,422	8,551
	$1 million to $5 million	6,066	6,197
	>$5 million	5,541	5,945
Total Overall		**21,029**	**20,693**

2024 Capital Programs

In 2024, 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
2024 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	302	780	2,053	3,052	147	256
	Replacement Meters	571	340	3,884	775	147	439[8]
$1 million to $5 million	New Services	2,847	3,661	2,053	3,052	1,387	1,200
>$5 million	Extensions	11,640	19,600	2,053	3,052	5,670	6,422[9]

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.

8 The metering material required to complete the planned units in 2024 was received but less than planned were replaced. As well, metering material costs in 2024 have increased on average 27% when compared to 2023. Reduced units completed combined with the material being received at a higher than anticipated cost resulted in an increased unit cost for 2024.

9 As outlined in the *2024 Capital Expenditures Overview* section of the report, 2024 actual capital expenditures related to larger CIAC extension work was $4.2 million, or $3.7 million higher than average. CIAC extension work occurs ahead of customer connections, for example, Joe Batt's Pond extension work was ongoing at the end of 2024. As a result, there was only one customer connection associated with the larger CIAC developments in 2024. Removing the impact of the larger-than-average CIACs on the 2024 *Extensions* program unit cost would reduce the unit cost to $5,211 (($19,600,000-$3,700,000)/3,051=$5,211).

Comparative Project Data

Table 4 provides a comparison of the number of capital projects planned compared to the number of capital projects completed, presented by investment classification and materiality threshold for the years 2023 and 2024.

Table 4
Capital Projects
Planned and Completed

Investment Classification	Materiality Threshold	2023 Planned	2023 Completed	2024 Planned	2024 Completed
Access	<$1 million	-	-	-	-
	$1 million to $5 million	2	2	-	-
	>$5 million	-	-	-	-
Total Access		**2**	**2**	**-**	**-**
General Plant	<$1 million	6	3	8	5
	$1 million to $5 million	5	2	3	-
	>$5 million	2	-	-	-
Total General Plant		**13**	**5**	**11**	**5**
Mandatory	<$1 million	3	3	3	3
	$1 million to $5 million	1	1	1	1
	>$5 million	-	-	-	-
Total Mandatory		**4**	**4**	**4**	**4**

Table 4 Capital Projects Planned and Completed					
Investment Classification	Materiality Threshold	2023 Planned	2023 Completed	2024 Planned	2024 Completed
Renewal	<$1 million	5	4	10	4
	$1 million to $5 million	6	1	7	1
	>$5 million	3	-	2	-
Total Renewal		**14**	**5**	**19**	**5**
Service Enhancement	<$1 million	1	1	2	2
	$1 million to $5 million	1	-	-	-
	>$5 million	1	1	1	1
Total Service Enhancement		**3**	**2**	**3**	**3**
System Growth	<$1 million	1	1	1	1
	$1 million to $5 million	-	-	1	-
	>$5 million	-	-	-	-
Total System Growth		**1**	**1**	**2**	**1**
Overall	<$1 million	16	12	24	15
	$1 million to $5 million	15	6	12	2
	>$5 million	6	1	3	1
Total Overall		**37**	**19**	**39**	**18**

Table 5 compares the approved budget amount of the capital projects planned in 2023 and 2024 that were completed into the final cost of the project in each respective year, presented by investment classification and materiality threshold.

Table 5
Capital Projects Completed
Budget and Final Costs
($000s)

Investment Classification	Materiality Threshold	2023 Approved Budget	2023 Final Cost	2024 Approved Budget	2024 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	3,226	3,190
	$1 million to $5 million	2,351	1,900	-	-
	>$5 million	-	-	-	-
Total General Plant		**4,054**	**3,778**	**3,226**	**3,190**
Mandatory	<$1 million	1,422	738	1,554	875
	$1 million to $5 million	4,000	5,100	4,500	4,701
	>$5 million	-	-	-	-
Total Mandatory		**5,422**	**5,838**	**6,054**	**5,576**
Renewal	<$1 million	2,659	2,609	2,723	2,846
	$1 million to $5 million	1,577	1,556	1,566	1,496
	>$5 million	-	-	-	-
Total Renewal		**4,236**	**4,165**	**4,289**	**4,342**
Service Enhancement	<$1 million	563	511	1,468	1,276
	$1 million to $5 million	-	-	-	-
	>$5 million	5,453	5,953	5,541	5,945
Total Service Enhancement		**6,016**	**6,464**	**7,009**	**7,221**

Table 5 Capital Projects Completed Budget and Final Costs ($000s)					
Investment Classification	Materiality Threshold	2023 Approved Budget	2023 Final Cost	2024 Approved Budget	2024 Final Cost
System Growth	<$1 million	670	732	451	364
	$1 million to $5 million	-	-	-	-
	>$5 million	-	-	-	-
Total System Growth		**670**	**732**	**451**	**364**
Overall	<$1 million	7,017	6,468	9,422	8,551
	$1 million to $5 million	13,931	14,099	6,066	6,197
	>$5 million	5,453	5,953	5,541	5,945
Total Overall		**26,401**	**26,520**	**21,029**	**20,693**

Comparative Program Data

Table 6 and Table 7 provide a comparison of the number of capital projects planned compared to the number of capital projects completed, presented by investment classification and materiality threshold for the years 2023 and 2024.

Table 6
Capital Programs
Number of Units by Materiality Threshold

Materiality Threshold	Program	2023 Number of Planned Units[10]	2023 Actual Number of Units[11]	2024 Number of Planned Units	2024 Actual Number of Units
<$1 million	New Meters	2,185	2,372	2,053	3,052
	Replacement Meters	4,877	2,898	3,884	775
$1 million to $5 million	New Services	2,185	2,372	2,053	3,052
>$5 million	Extensions	2,185	2,372	2,053	3,052

Table 7
Capital Programs
Cost per Unit by Materiality Threshold ($)

Materiality Threshold	Program	2023 Planned Cost per Unit	2023 Actual Cost per Unit	2024 Planned Cost per Unit	2024 Actual Cost per Unit
<$1 million	New Meters	136	215	147	256
	Replacement Meters	136	183	147	439
$1 million to $5 million	New Services	1,335	1,374	1,387	1,200
>$5 million	Extensions	5,592	6,385	5,670	6,422

10 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, CSOs and GROs.

11 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.

June
2025

2025 Capital Budget Expenditure Status Report

NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

2025 Capital Budget Expenditure
Status Report

Compliance Matter

The *2025 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 6 of Order No. P.U. 27 (2024):

> *"Unless otherwise directed by the Board, Newfoundland Power shall provide, in conjunction with its 2026 Capital Budget Application, a status report on the 2025 capital budget expenditures showing for each project:*
>
> *i) the approved budget for 2025;*
> *ii) the expenditures prior to 2025;*
> *iii) the 2025 expenditures to the date of the application;*
> *iv) the remaining projected expenditures for 2025;*
> *v) the variance between the projected total expenditures and the approved budget; and*
> *vi) an explanation of the variance."*

Overview

Page 1 of the *2025 Capital Budget Expenditure Status Report* outlines the forecast variances from budget of the 2025 capital expenditures approved by the Board. The tables on pages 2 to 7 provide additional detail on the capital expenditures for 2025 which were approved in Order No. P.U. 27 (2024) and Order No. P.U. 2 (2024). The additional detail is organized by single-year projects and programs approved for 2025, multi-year projects approved to commence in 2025 and previously approved multi-year projects with expenditures occurring in 2025.

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 *2025 Capital Budget Expenditure Status Report*, there are four programs that meet the criteria for variance explanations. These explanations are contained in Appendix A to the *2025 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.
2025 Capital Budget Expenditure Status Report
Capital Expenditure Overview
($000)

	Annual Budget	Expenditures		Annual Forecast	
		Actual	Forecast		
Asset Class and Project Description	**2025 Budget**	**January to April**	**May to December**	**2025 Forecast**	**Variance**
Distribution	59,464	22,906	44,925	67,831	8,367
Substations	15,952	1,878	14,074	15,952	0
Transmission	18,064	322	19,087	19,409	1,345
Generation - Hydro	7,267	955	6,312	7,267	0
Generation - Thermal	318	240	78	318	0
Information Systems	11,009	2,497	8,512	11,009	0
Telecommunications	994	52	942	994	0
General Property	4,010	522	3,488	4,010	0
Transportation	5,042	63	4,979	5,042	0
Unforeseen Items	750	0	750	750	0
General Expenses Capitalized	5,081	1,630	3,451	5,081	0
Total	**127,951**	**31,065**	**106,598**	**137,663**	**9,712**

Expenditure Type					
Single-Year Projects and Programs Over $750,000	79,468	26,277	62,692	88,969	9,501
Single-Year Projects and Programs $750,000 and Under	10,850	2,985	8,076	11,061	211
Multi-Year Projects Commencing in 2025	18,219	1,209	17,010	18,219	0
Multi-Year Projects Commencing Prior to 2025	19,414	594	18,820	19,414	0
Total	**127,951**	**31,065**	**106,598**	**137,663**	**9,712**

Newfoundland Power Inc.
2025 Capital Budget Expenditure Status Report
Single-Year Projects and Programs Over $750,000[1]
($000)

Asset Class and Project Description	Annual Budget 2025 Budget	Expenditures Actual January to April	Expenditures Forecast May to December	Annual Forecast 2025 Forecast	Variance	Notes
Distribution						
Extensions	13,402	5,706	14,276	19,982	6,580	1
Reconstruction	7,425	2,635	4,790	7,425	0	
Replacement Transformers	6,340	2,535	3,805	6,340	0	
LED Street Lighting Replacement	5,654	3,051	2,603	5,654	0	
New Transformers	5,623	2,247	3,376	5,623	0	
Rebuild Distribution Lines	5,115	2,122	2,993	5,115	0	
Relocate/Replace Distribution Lines for Third Parties	3,528	1,044	2,484	3,528	0	
New Services	3,208	1,308	3,476	4,784	1,576	2
New Street Lighting	2,460	735	1,725	2,460	0	
Distribution Feeder Automation	1,125	244	881	1,125	0	
Feeder Additions for Load Growth	960	27	933	960	0	
Replacement Street Lighting	884	224	660	884	0	
Total Distribution	**55,724**	**21,878**	**42,002**	**63,880**	**8,156**	
Substations						
Substation Replacements Due to In-Service Failures	4,927	579	4,348	4,927	0	
Northwest Brook Substation Refurbishment and Modernization	4,175	501	3,674	4,175	0	
Total Substations	**9,102**	**1,080**	**8,022**	**9,102**	**0**	
Transmission						
Transmission Line Maintenance	2,884	110	4,119	4,229	1,345	4
Total Transmission	**2,884**	**110**	**4,119**	**4,229**	**1,345**	
Generation - Hydro						
Mobile Hydro Plant Penstock Refurbishment	825	34	791	825	0	
Total Generation - Hydro	**825**	**34**	**791**	**825**	**0**	

Newfoundland Power Inc.
2025 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	**2025 Budget**	**January to April**	**May to December**	**2025 Forecast**	**Variance**	**Notes**
Information Systems						
System Upgrades	1,408	277	1,131	1,408	0	
Shared Server Infrastructure	970	578	392	970	0	
Cybersecurity Upgrades	940	340	600	940	0	
Application Enhancements	914	322	592	914	0	
Total Information Systems	**4,232**	**1,517**	**2,715**	**4,232**	**0**	
Telecommunications						
VHF Radio System Replacement	870	28	842	870	0	
Total Telecommunications	**870**	**28**	**842**	**870**	**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	5,081	1,630	3,451	5,081	0	
Total General Expenses Capitalized	**5,081**	**1,630**	**3,451**	**5,081**	**0**	
Total	**79,468**	**26,277**	**62,692**	**88,969**	**9,501**	

[1] Approved in Order No. P.U. 27 (2024).

Newfoundland Power Inc.
2025 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**			
	2025 Budget	**January to April**	**May to December**	**2025 Forecast**	**Variance**	**Notes**
Distribution						
Distribution Feeder PEP-02 Refurbishment	667	12	655	667	0	
Distribution Feeder SMV-01 Refurbishment	654	52	602	654	0	
Replacement Meters	648	329	319	648	0	
New Meters	457	464	204	668	211	3
Replacement Services	445	92	353	445	0	
Allowance for Funds Used During Construction	220	79	141	220	0	
Total Distribution	**3,091**	**1,028**	**2,274**	**3,302**	**211**	
Substations						
Substation Protection and Control Replacements	685	353	332	685	0	
Substation Ground Grid Upgrades	609	10	599	609	0	
Total Substations	**1,294**	**363**	**931**	**1,294**	**0**	
Transmission						
Wood Pole Retreatment	600	1	599	600	0	
Total Transmission	**600**	**1**	**599**	**600**	**0**	
Generation - Hydro						
Hydro Plant Replacements Due to In-Service Failures	731	304	427	731	0	
La Manche Canal Bridge Replacement	530	201	329	530	0	
Total Generation - Hydro	**1,261**	**505**	**756**	**1,261**	**0**	
Generation - Thermal						
Thermal Plant Replacements Due to In-Service Failures	318	240	78	318	0	
Total Generation - Thermal	**318**	**240**	**78**	**318**	**0**	
Information Systems						
Personal Computer Infrastructure	720	269	451	720	0	
Network Infrastructure	470	68	402	470	0	
Total Information Systems	**1,190**	**337**	**853**	**1,190**	**0**	

Newfoundland Power Inc.
2025 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	**2025 Budget**	**January to April**	**May to December**	**2025 Forecast**	**Variance**	**Notes**
Telecommunications						
Communications Equipment Upgrades	124	24	100	124	0	
Total Telecommunications	**124**	**24**	**100**	**124**	**0**	
General Property						
Additions to Real Property	682	38	644	682	0	
Building Accessibility Improvements	650	16	634	650	0	
Specialized Tools and Equipment	595	0	595	595	0	
Tools and Equipment	589	194	395	589	0	
Physical Security Upgrades	456	239	217	456	0	
Total General Property	**2,972**	**487**	**2,485**	**2,972**	**0**	
Total	**10,850**	**2,985**	**8,076**	**11,061**	**211**	

1 Approved in Order No. P.U. 27 (2024).

Newfoundland Power Inc.
2025 Capital Budget Expenditure Status Report
Multi-Year Projects Commencing in 2025[1]
($000)

	2025 Summary					Overall Project Summary				
	Annual Budget	Expenditures		Annual Forecast	Variance	Total Project Budget	Total Project Spend to Date	Total Project Forecast	Variance	Notes
		Actual	Forecast							
Asset Class and Project Description	**2025 Budget**	**January to April**	**May to December**	**2025 Forecast**	**2025 Forecast vs Budget**	**2025 - 2027**	**YTD April 2025**	**2025 - 2027**	**Total Forecast vs Budget**	
Distribution										
Distribution Feeders SCT-01 and BLK-01 Relocation	649	0	649	649	0	1,789	0	1,789	0	
Total Distribution	**649**	**0**	**649**	**649**	**0**	**1,789**	**0**	**1,789**	**0**	
Substations										
Summerville Substation Refurbishment and Modernization	511	104	407	511	0	5,021	104	5,021	0	
Lockston Substation Refurbishment and Modernization	305	55	250	305	0	4,826	55	4,826	0	
Gander Substation Power Transformer Replacement	17	3	14	17	0	4,185	3	4,185	0	
Pulpit Rock Substation Power Transformer Replacement	17	1	16	17	0	2,922	1	2,922	0	
Total Substations	**850**	**163**	**687**	**850**	**0**	**16,954**	**163**	**16,954**	**0**	
Transmission										
New Transmission Line from Lewisporte to Boyd's Cove	1,886	75	1,811	1,886	0	20,722	75	20,722	0	
Transmission Line 94L Rebuild	3,485	93	3,392	3,485	0	12,560	93	12,560	0	
Total Transmission	**5,371**	**168**	**5,203**	**5,371**	**0**	**33,282**	**168**	**33,282**	**0**	
Generation - Hydro										
Mount Carmel Pond Dam Refurbishment	3,608	154	3,454	3,608	0	4,616	154	4,616	0	
Total Generation - Hydro	**3,608**	**154**	**3,454**	**3,608**	**0**	**4,616**	**154**	**4,616**	**0**	
Information Systems										
Asset Management Technology Replacement	3,479	537	2,942	3,479	0	8,013	537	8,013	0	
Outage Management System Upgrade	1,811	106	1,705	1,811	0	3,270	106	3,270	0	
Total Information Systems	**5,290**	**643**	**4,647**	**5,290**	**0**	**11,283**	**643**	**11,283**	**0**	
General Property										
Port Union Building Replacement	278	20	258	278	0	1,281	20	1,281	0	
Total General Property	**278**	**20**	**258**	**278**	**0**	**1,281**	**20**	**1,281**	**0**	
Transportation										
Replace Commercial Vehicles and Aerial Devices 2025-2026	2,173	61	2,112	2,173	0	4,975	61	4,975	0	
Total General Property	**2,173**	**61**	**2,112**	**2,173**	**0**	**4,975**	**61**	**4,975**	**0**	
Total	**18,219**	**1,209**	**17,010**	**18,219**	**0**	**74,180**	**1,209**	**74,180**	**0**	

[1] Approved in Order No. P.U. 27 (2024).

Newfoundland Power Inc.
2025 Capital Budget Expenditure Status Report
Multi-Year Projects Approved in Previous Years[1]
($000)

	2025 Summary					Overall Project Summary				
	Annual Budget	Expenditures		Annual Forecast	Variance	Total Project Budget	Total Project Spend to Date	Total Project Forecast	Variance	Notes
		Actual	Forecast							
Asset Class and Project Description	**2025 Budget**	**January to April**	**May to December**	**2025 Forecast**	**2025 Forecast vs Budget**	**2024 - 2025**	**2024 - April 2025**	**2024 - 2025**	**Total Forecast vs Budget**	
Substations										
Islington Substation Refurbishment and Modernization	4,706	272	4,434	4,706	0	5,014	1,172	5,014	0	
Total Substations	**4,706**	**272**	**4,434**	**4,706**	**0**	**5,014**	**1,172**	**5,014**	**0**	
Transmission										
Transmission Line 146L Rebuild	9,209	43	9,166	9,209	0	11,361	1,639	11,361	0	
Total Transmission	**9,209**	**43**	**9,166**	**9,209**	**0**	**11,361**	**1,639**	**11,361**	**0**	
Generation - Hydro										
Lookout Brook Hydro Plant Refurbishment	1,573	262	1,311	1,573	0	1,935	770	1,935	0	
Total Generation - Hydro	**1,573**	**262**	**1,311**	**1,573**	**0**	**1,935**	**770**	**1,935**	**0**	
Information Systems										
Microsoft Enterprise Agreement	297	0	297	297	0	891	316	891	0	
Total Information Systems	**297**	**0**	**297**	**297**	**0**	**891**	**316**	**891**	**0**	
General Property										
Gander Building Renovation	760	15	745	760	0	935	190	935	0	
Total General Property	**760**	**15**	**745**	**760**	**0**	**935**	**190**	**935**	**0**	
Transportation										
Replace Vehicles and Aerial Devices 2024-2025	2,869	2	2,867	2,869	0	4,809	900	4,809	0	
Total General Property	**2,869**	**2**	**2,867**	**2,869**	**0**	**4,809**	**900**	**4,809**	**0**	
Total	**19,414**	**594**	**18,820**	**19,414**	**0**	**24,945**	**4,987**	**24,945**	**0**	

[1] Approved in Order No. P.U. 2 (2024).

APPENDIX A:

Variance Notes

Distribution

1. Extensions:

   Budget: $13,402,000 Forecast: $19,982,000 Variance: $6,580,000

   The forecast expenditure for *Extensions* is expected to be approximately 49% above the budgeted amount. The increase reflects a 49% increase in anticipated new customer connections. In 2025, the forecast number of new customer connections is expected to increase from 2,220 to 3,310.[1]

2. New Services:

   Budget: $3,208,000 Forecast: $4,784,000 Variance: $1,576,000

   The forecast expenditure for *New Services* is expected to be approximately 49% above the budgeted amount. The increase reflects a 49% increase in anticipated new customer connections. In 2025, the forecast number of new customer connections is expected to increase from 2,220 to 3,310.

3. New Meters:

   Budget: $457,000 Forecast: $668,000 Variance: $211,000

   The forecast expenditure for *New Meters* is expected to be approximately 46% above the budgeted amount. The increase reflects a 49% increase in anticipated new customer connections. In 2025, the forecast number of new customer connections is expected to increase from 2,220 to 3,310.

Transmission

4. Transmission Line Maintenance:

   Budget: $2,884,000 Forecast: $4,229,000 Variance: $1,345,000[2]

   The forecast expenditure for *Transmission Line Maintenance* is expected to be approximately 47% above the budgeted amount. The increase reflects an estimated $1,345,000 cost to relocate sections of Transmission Lines 38L and 39L near Newfoundland and Labrador Hydro's Holyrood Generating Station.[3]

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1 Based on the Conference Board of Canada's medium-term outlook released March 2025.

2 Newfoundland Power anticipates filing a CIAC Application with the Board in the third quarter of 2025 to seek approval for the CIAC associated with this work.

3 See Hydro's *Application for Early Execution Capital Work for Bay d'Espoir Unit 8 and Avalon Combustion Turbine – Refile - Redacted* approved in Order No. P.U. 17 (2025).

June
2025

1.1 Feeder Additions for Load Growth

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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.

Eliminating overload conditions mitigates risks of in-service equipment failures, which can result in significant repair costs and extended customer outages.

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 to eliminate overload conditions.

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") has identified one overload condition to be addressed over the 2026-2027 period by upgrading an existing single-phase section of distribution line to three-phase and completing a load transfer to an alternative source of supply. The overload condition described in this report can be attributed to residential growth in the Company's service territory.

2.0 OVERLOADED CONDUCTORS

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 making contact with other conductors, or the conductor breaking, causing a fault and subsequent customer outage and safety hazard. Overload conditions on conductors 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]

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[1] Feeder balancing involves transferring load from one phase to another on a three-phase distribution feeder to balance the amount of load on each phase. Load transfers involve transferring load from one feeder to an 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 overload conditions on conductors. 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, a 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 the overload condition is not present on all three phases.

(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 of 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 Lines

Heavily loaded single-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 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 lines that may be overloaded.[3] Load measurements were subsequently taken to verify the results of the computer simulation.[4]

The analysis identified one location where a single-phase line is overloaded. Mitigation of this overload condition is required and is described below.

3.2 Distribution Feeder DLK-03 Upgrade

Distribution feeder DLK-03 leaves Deer Lake ("DLK") Substation and supplies customers in the town of Deer Lake, including the Deer Lake Airport, and the communities of Reidville, Cormack and Bonne Bay. This distribution feeder serves approximately 1,490 residential and commercial customers.

Figure 1 illustrates the route of distribution feeder DLK-03.

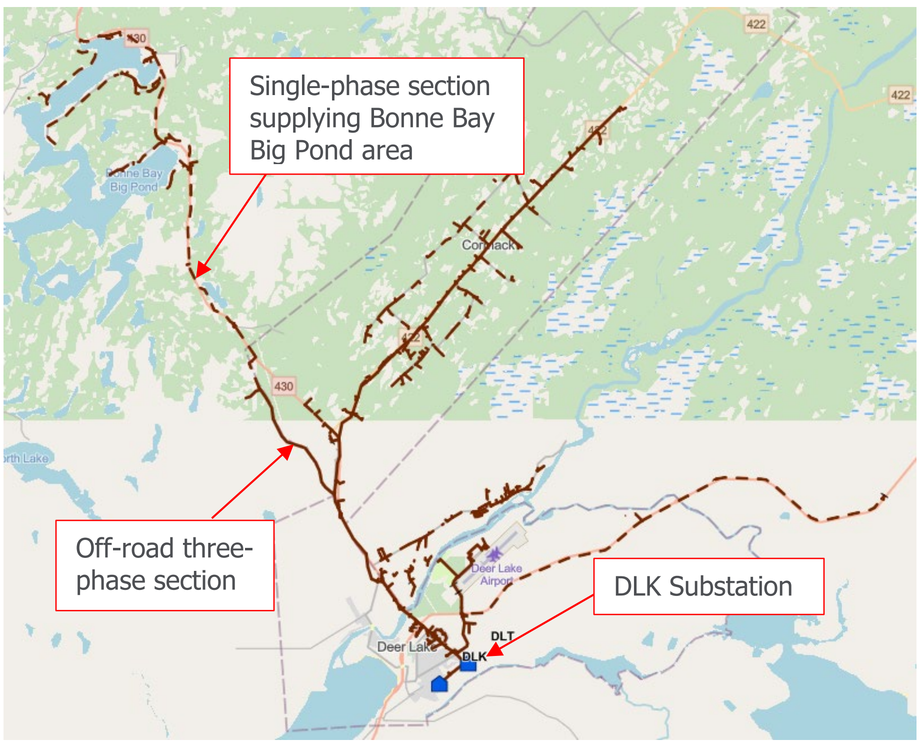

Figure 1 – Distribution Feeder DLK-03.

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. Loading on individual sections of distribution line is approximated by modeling software and must be verified in the field when warranted by operational concerns, such as protection device trips or inquiries regarding new developments.

A 16-kilometre section of the single-phase distribution feeder is overloaded. This section of line extends northwest primarily along the Viking Trail Highway to serve customers in the Bonne Bay Big Pond 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 30% over the last 16 years.[5] Annual increases in customers reflect a shift from what was once a predominantly seasonal cabin area to year-round permanent residences. As a result, new service connections and service upgrades have been requested more frequently.

The overloaded single-phase section is supplied by a remote off-road 5.5-kilometre three-phase section that is difficult to access for maintenance or outage purposes. Furthermore, due to the magnitude of the load being supplied by a long single-phase section, the primary distribution system supplying customers in the Bonne Bay Big Pond area is prone to low-voltage conditions during peak periods.[6]

An analysis of distribution feeder DLK-03 was completed using CYME Power Engineering software and verified using actual load measurements. The analysis showed that the peak load on the identified single-phase section of the feeder is approximately 147 amps, which exceeds the Company's planning criteria for maximum current on a single-phase distribution line.[7]

Three categories of alternatives that are generally available to address overloaded conductor are not applicable to DLK-03. Feeder balancing is not applicable as the identified section of DLK-03 is single phase. A new feeder build from DLK substation is not feasible due to the magnitude of the associated costs. A non-wires alternative, such as a utility-scale battery system, is not feasible due to the prolonged duration of the overload condition.[8]

As a result, the alternatives evaluated for their viability to mitigate the overloaded section of distribution feeder DLK-03 are: (i) upgrading from single-phase to three-phase; and (ii) transferring customer load in the Bonne Bay Big Pond area to Newfoundland and Labrador Hydro's ("Hydro") Wiltondale ("WDL") Terminal Station distribution feeder WDL-L1.

Alternative 1: Upgrade Single-Phase Section to Three-Phase

Alternative 1 would involve upgrading 11-kilometres of the 16-kilometre overloaded single-phase section to three-phase 1/0 AASC conductor to resolve the overload condition. In addition, a 4-kilometre three-phase extension would be required to connect the upgraded section to the main trunk of DLK-03 along the Viking Trail Road.[9]

The total capital cost of this alternative is $3,516,000.

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5 There were 359 customers supplied by this section of line in 2009 and 468 customers in 2025, an increase of 109 customers or 30% (109 / 359 = 0.304, or 30%).

6 Newfoundland Power's planning criteria for primary distribution voltages is 0.95-1.05pu.

7 Newfoundland Power's planning criteria for maximum current on a single-phase distribution line is 85 amps.

8 During the most recent 2024-2025 winter season, the load on the single-phase section of overloaded line was greater than 85A for a continuous one-week period. Considering typical 4-hour battery system pricing as per *Cost Projections for Utility-Scale Battery Storage: 2023 Update* by Cole et al., a battery alternative sized to mitigate a week-long overload condition would be cost-prohibitive.

9 This would involve relocating the 5.5-kilometre off-road section to the 4-kilometre right-of-way that would be roadside along the Viking Trail.

Figure 2 illustrates the route of the three-phase upgrade described in Alternative 1.

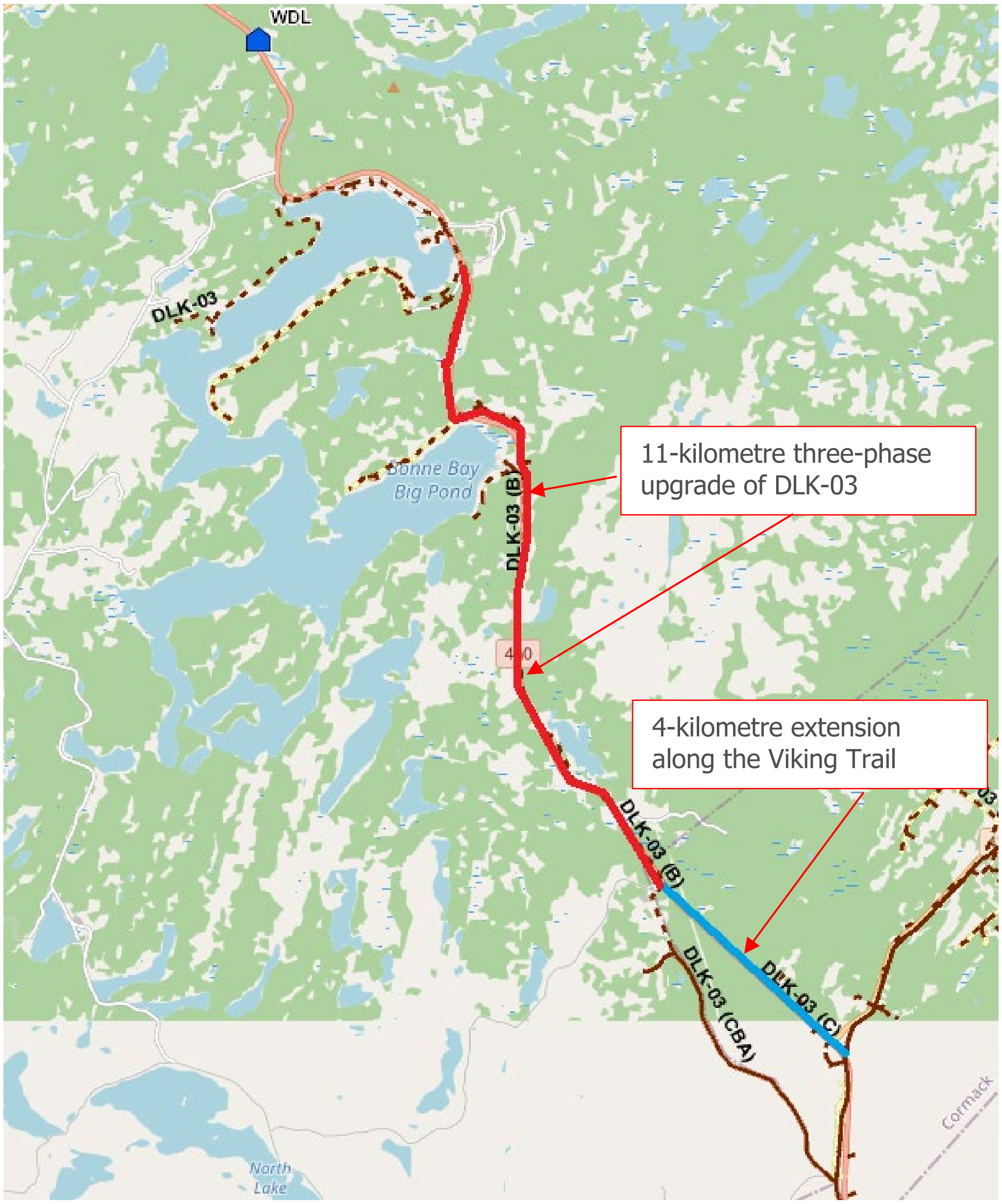

Figure 2 – Three-Phase Upgrade of Distribution Feeder DLK-03.

Costs associated with Alternative 1 are provided in Table 1.

Table 1
Feeder Additions for Load Growth Project
Alternative 1 Project Costs
($000s)

Category	2026	2027	Total
Material	373	1,073	1,446
Labour – Internal	353	657	1,010
Labour - Contract	232	481	713
Engineering	215	77	292
Other	23	32	55
Total	1,196	2,320	3,516

Engineering design work, environmental surveying, brush clearing and preliminary line work for Alternative 1 would be completed in 2026. Construction would continue into the following year and would be completed by the end of 2027.

Alternative 2: Load Transfer to Hydro's WDL-L1

Alternative 2 would involve building a 2.5-kilometre three-phase extension from Hydro's WDL Terminal Station distribution feeder WDL-L1 to supply Newfoundland Power customers in the Bonne Bay Big Pond area. This alternative would also involve upgrading a 3.5-kilometre section of DLK-03 single-phase distribution to three-phase and transferring this section onto WDL-L1.

The WDL Terminal Station is closer to the Bonne Bay Big Pond area than the DLK Substation, and Hydro has confirmed that there is sufficient capacity to supply the load required by customers in the Bonne Bay Big Pond area.

WDL-L1 is a 12.5kV three-phase distribution feeder that exits WDL Terminal Station and heads north along The Viking Trail to supply 35 Hydro customers in the area. Under Alternative 2, Newfoundland Power would construct a 2.5-kilometre three-phase extension that would tap off WDL-L1 outside of WDL Terminal Station. To accommodate this load transfer, Hydro would be required to install a voltage regulator bank, recloser and metering tank at their WDL Terminal Station.[10]

[10] See Hydro's *Upgrade Distribution System (2026-2027) – Wiltondale* report as part of their 2026 Capital Budget Application.

The 2.5-kilometre three-phase extension would extend south to supply 468 Newfoundland Power customers in the Bonne Bay Big Pond area, which would effectively be transferred from DLK-03 onto a newly designated distribution feeder. As a result of this alternative, a new Hydro supply point would be established at WDL Terminal Station.[11]

Transferring the 3.5-kilometre section of DLK-03 onto Hydro's WDL-L1 would resolve the overload and undervoltage conditions that have materialized on the single-phase section of DLK-03. Furthermore, customers in the Bonne Bay Big Pond area would no longer be impacted by the section of off-road line adjacent to the Viking Trail.

The Newfoundland Power capital cost of this alternative is $1,137,000.
Figure 3 illustrates the proposed route described in Alternative 2.

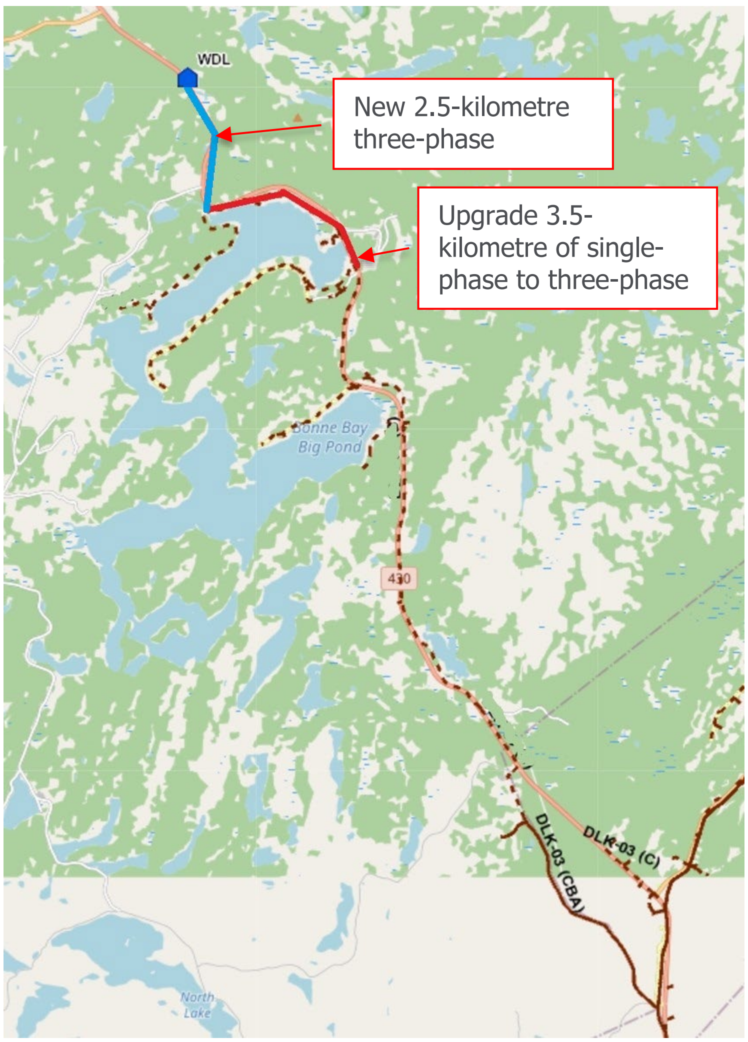

Figure 3 – Distribution Feeder DLK-03 Extension from WDL Terminal Station.

[11] Hydro supplies Newfoundland Power with electricity via 24 supply points located throughout the Company's service territory. This includes large supply points such as those located at Hydro's Oxen Pond, Hardwoods, Holyrood, and Stephenville terminal stations. It also includes smaller supply points such as those serving Monkstown, Bay L'Argent, and Doyles.

Costs associated with Alternative 2 are provided in Table 2.

Table 2 Feeder Additions for Load Growth Project Alternative 2 Project Costs ($000s)			
Category	2026	2027	Total
Material	0	248	248
Labour – Internal	0	401	401
Labour - Contract	200	194	394
Engineering	50	27	77
Other	0	17	17
Total	250	887	1,137

Engineering design work, environmental surveying and brush clearing for Alternative 2 would be completed in 2026. Construction would begin the following year and would be completed by the end of 2027.

Evaluation of Alternatives

Since Alternative 2 requires upgrades to Hydro's WDL distribution system, a net-present value ("NPV") analysis was conducted. This NPV analysis considers Hydro's additional costs as proposed in their *Upgrade Distribution System (2026-2027) – Wiltondale* report as part of their 2026 Capital Budget Application. Specifically, Hydro's costs include $408,700 in 2026 and $952,700 in 2027.

The results of the NPV analysis are provided in Table 3.

Table 3 Feeder Additions for Load Growth Project NPV Analyses of Alternatives ($000s)	
Alternative #	NPV
1	3,897
2	2,756

As shown in Table 3, when accounting for Hydro's required costs to upgrade their WDL distribution system, Alternative 2 remains least-cost.

Recommended Alternative

Of the alternatives considered, transferring customers in the Bonne Bay Big Pond area to a new extension from Hydro's WDL Terminal Station distribution feeder WDL-L1 is the least-cost alternative. This is therefore the recommended alternative to address the identified overload condition.

4.0 PROJECT COST

Table 4 provides the costs of the *Feeder Additions for Load Growth* project to address overload conditions on distribution feeder DLK-03 in 2026 and 2027.

Table 4
Feeder Additions for Load Growth Project
2026-2027 Project Costs
($000s)

Category	2026	2027	Total
Material	0	248	248
Labour – Internal	0	401	401
Labour - Contract	200	194	394
Engineering	50	27	76
Other	0	17	17
Total	250	887	1,137

The total cost of the *Feeder Additions for Load Growth* project is $250,000 in 2026 and $887,000 in 2027.

5.0 CONCLUSION

The *Feeder Additions for Load Growth* project for 2026 includes:

(i) Upgrading a 3.5-kilometre single-phase of distribution feeder DLK-03 to three-phase 1/0 AASC and constructing a new 2.5-kilometre three-phase supply from Hydro's WDL Terminal Station distribution feeder WDL-L1.

This upgrade is the least-cost solution to address overload conditions resulting from customer growth in the Deer Lake area. Completing this work in 2026 and 2027 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

Size and Type	Continuous Winter Rating[1] Amps	Continuous Summer Rating[2] Amps	Planning Ratings[3] CLPU Factor[4] = 2.0 Sectionalizing Factor[5] = 1.33 Amps	MVA 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.

June
2025

2.1
2026 Substation Refurbishment and Modernization

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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 2026, the Company is proposing to commence a two-year project to refurbish and modernize Greenspond ("GPD") Substation near the Town of Greenspond at a cost of $2,952,000. GPD Substation contains a considerable amount of deteriorated and obsolete equipment that poses a risk to reliable operation.

Due to supply chain constraints and procurement lead times for electrical equipment, Newfoundland Power has transitioned to multi-year substation refurbishment and modernization projects where purchases of equipment having long procurement lead times will be necessary.[3] This provides the ability to complete design, procurement and contract approval in year one and construction and commissioning in a subsequent year. This transition continues with the refurbishment and modernization of GPD Substation as a two-year project.

This report provides an update on Newfoundland Power's *Substation Refurbishment and Modernization Plan* and the overall condition of substation assets. The project proposed as part of the *2026 Capital Budget Application* is detailed in the appendix that follows.

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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, switches, 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
2026 to 2030

Substation Designations	Cost Estimates ($000s)				
	2026	2027	2028	2029	2030
LOK	4,521*	-	-	-	-
SMV	4,510*	-	-	-	-
GPD	374	2,578	-	-	-
RBK	-	52	811	-	-
GFS	-	92	1,502	-	-
HAR	-	754	5,074	-	-
SBK	-	206	2,970	-	-
MOP	-	128	1,122	-	-
BLK	-	-	290	2,467	-
GOU	-	-	685	3,267	3,950
RRD	-	-	256	1,980	2,034
PHR	-	-	-	255	1,653
SLA	-	-	-	72	1,460
FRN	-	-	-	-	184†
HWD	-	-	-	-	119†
BCV	-	-	-	-	575†
BIG	-	-	-	-	62†
SJM	-	-	-	-	202†
TOTAL	9,405	3,810	12,710	8,041	10,239

Note: SUB: See the Electrical System Handbook included with the *2006 Capital Budget Application* for three-letter substation designations.

* Year two of multi-year projects in 2025 and 2026.
† Year one of multi-year projects in 2030 and 2031.

Newfoundland Power's current plan includes the refurbishment and modernization of 18 substations over the next five years. The refurbishment and modernization plan during this period 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. However, 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, with a sharp decline for in-service power transformers past 70 years of age.[5, 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.

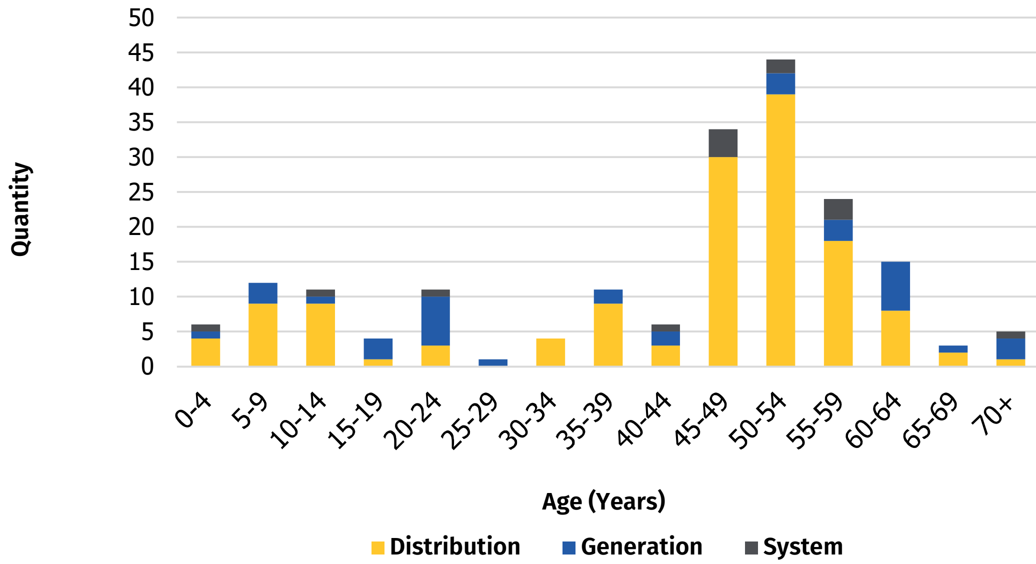
5 Based on information published by the International Council on Large Electric Systems ("CIGRE"). CIGRE is an international association with an objective to develop and facilitate the exchange of engineering knowledge and information in the field of electric power systems. CIGRE published a report on 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 48% 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 ten 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.

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8 The 10 power transformers failures since 2020 include: MUN-T2, BLK-T2, DUN-T1, SLA-T3, SLA-T4, GBS-T1, HUM-T2, HUM-T3, PIT-T1, and TRN-T1. Of the 10 failures experienced over the last five years, three power transformers failed in service and the remaining seven were identified as being at imminent risk of failure through condition monitoring. Four of the 10 power transformers required replacement, while the remaining six were repaired and returned to service.

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.[11] 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. 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 power transformer fleet to manage risks associated with the increasing age of the fleet and potential impacts on the provision of reliable service to customers.[12] 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 376 high voltage circuit breakers in service.[13] 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.[14] A majority of the SF6 type breakers were installed to replace older bulk-oil type breakers. A number of older bulk-oil type breakers remain 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.[15]

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11 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.

12 See the *2026 Capital Budget Application*, report *2.2 Substation Power Transformer Strategy*.

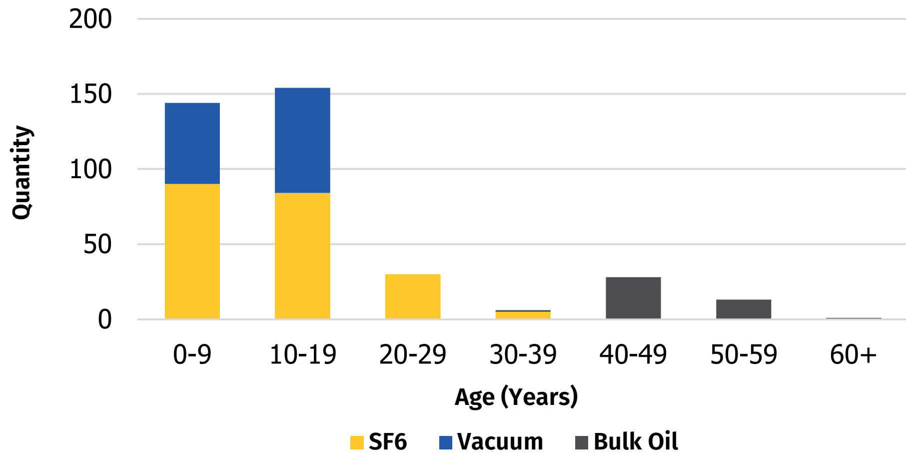
13 There are additional circuit breakers located in switchgear in the Company's substations and generation plants. This quantity of 376 breakers excludes switchgear circuit breakers.

14 Sulfur hexafluoride ("SF6") gas is used in high voltage circuit breaker design to extinguish the electrical arc created when opening energized breaker contacts.

15 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 21 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 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 209 SF6 type breakers in service. The majority of these breakers are less than 20 years old, with an average age of 12 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.[16] These breakers have started to experience issues with excessive SF6 leaks, with 12 of these units having gaskets replaced to address this issue.[17] These breakers are being monitored closely for further leakage issues and will be repaired as required.

There are 43 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 49 years.

The bulk-oil type breakers that remain in service are approaching the end of their useful service lives. GE KSO and GE FKP oil-filled breakers comprise 88% of those in service. GE KSO breakers were manufactured from 1976 to 1991, have an average age of 46 years and can no longer be economically maintained.[18] The GE FKP breakers were manufactured from 1970 to 1982 and have an average age of 49 years. The age and condition of these breakers pose environmental risks as they can contain between 250 and 12,500 liters of oil.

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16 There are 18 66 kV breakers and 26 138 kV breakers.

17 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.

18 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.

Currently, all new breakers being purchased are either SF6 or vacuum type, depending on the required voltage and fault interrupting capability.

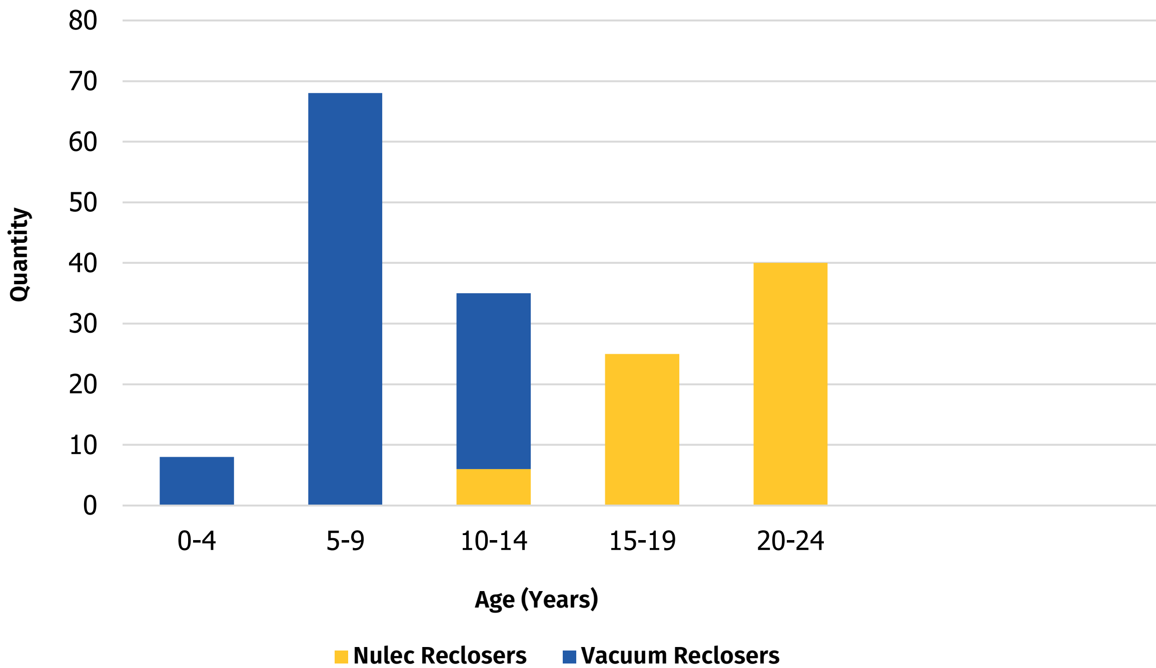
Reclosers

Reclosers are electrical safety devices specifically designed to automatically interrupt and restore power in the event of temporary faults in the electrical distribution system, where low short circuit fault levels are present. Newfoundland Power currently operates 176 substation reclosers.[19] 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.[20]

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



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19 There are additional reclosers located on the Company's distribution feeders. This quantity of 176 reclosers excludes the downline reclosers installed on distribution feeders.

20 In 2015, as part of the *Substation Refurbishment and Modernization Plan,* the Company initiated a five-year *Substation Feeder Automation* program to modernize its substation reclosers by replacing vintage hydraulic reclosers with reclosers with automation capability.

As a result of the completion of the *Substation Feeder Automation* program in 2019, the age profile of the Company's substation reclosers is favourable.[21] All substation reclosers are currently less than 25 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 64 Nulec reclosers installed between 2001 to 2012 for distribution feeder protection.[22] Since 2021, 12 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 lives.[23]

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 five substations with nine distribution switchgear lineups.[24] The majority of this switchgear is operated at 12.5 kV distribution voltage; however, there are two locations with 4.16 kV switchgear.[25] The Company's substation switchgear consists of a total of 51 individual circuit breakers.[26]

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 86% of the Company's switchgear breakers have been in service for 47 years or more, which is at 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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21 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.

22 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.

23 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.

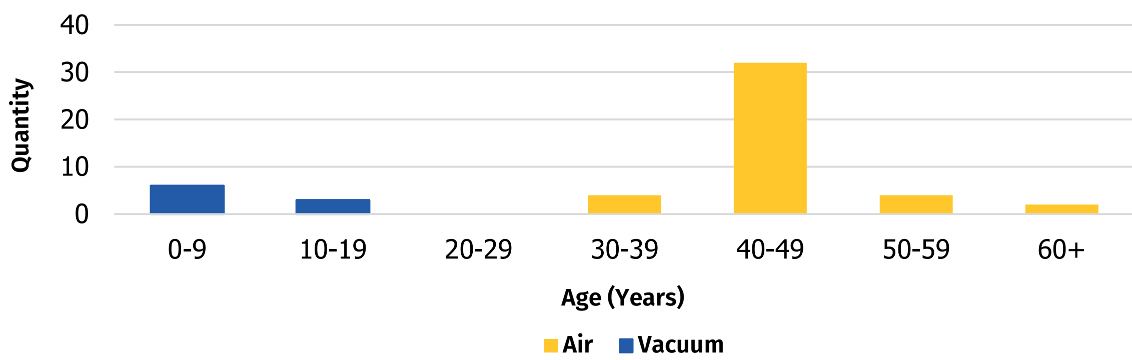
24 There are also 25 switchgear lineups associated with the Company's generation plants.

25 The only 4.16 kV distribution switchgear remaining in service are located at the Company's Grand Falls ("GFS") and Stamps Lane ("SLA") substations.

26 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.[27] Arc flash technologies on newer switchgear mitigate the arc flash hazard to prevent injury to personnel and contain equipment damage.[28] 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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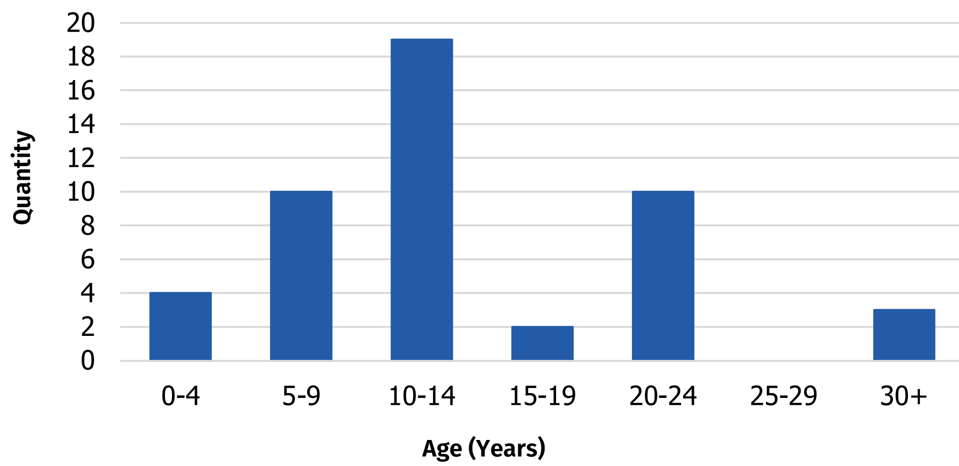
27 Arc resistant switchgear relieves the pressure buildup from severe arcing and exhausts the rapidly expanding air away from operating personnel. Arc flash protective relays can detect the early stage of an arc's development and initiate instantaneous tripping of the associated breakers.

28 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 from the effects of faults on the electricity system. 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.[29] 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.[30]

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[29] 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 replacement practices that conform to industry practice.

[30] 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.

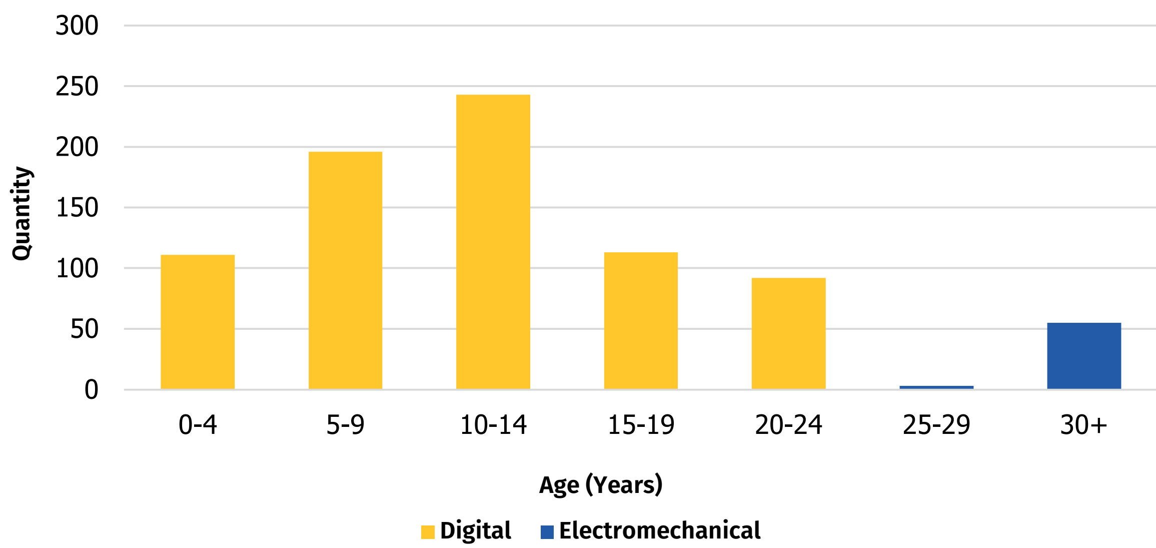
Over the past 20 years, Newfoundland Power has upgraded most of the electromechanical protection devices. However, approximately 8% of the protection devices currently in service are still electromechanical.

Industry experience indicates the expected useful service life is 20 to 30 years for electromechanical relays and 10 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
Electromechanical and Digital Relay Age Distribution



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.[31] There are a number of other in-service relays that will soon reach the end of the expected life for digital relays.[32]

[31] There are currently 93 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 60% of the in-service Micom P142 devices.

[32] These include Micom P632, P442, P543, P941 and Schweitzer SEL-487B type relays.

High Voltage Switches

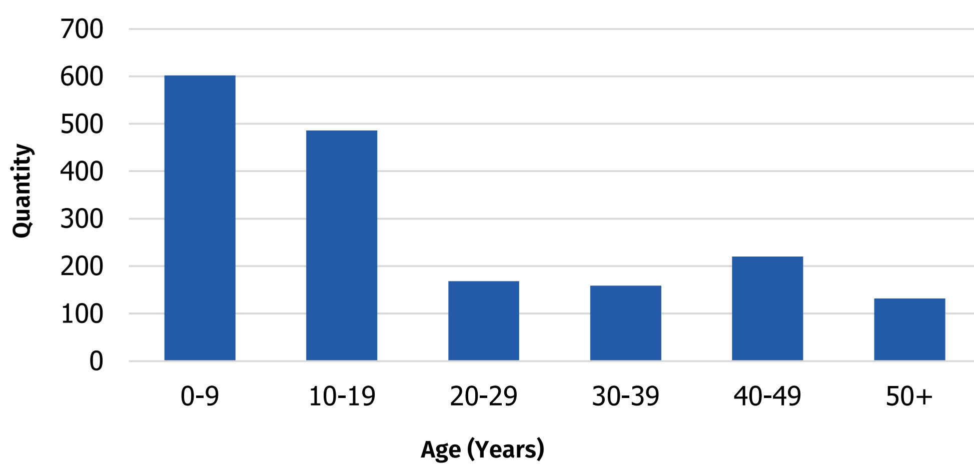
Substation high voltage switches provide isolation for equipment such as power transformers, circuit breakers and reclosers.[33] Newfoundland Power has approximately 1,800 high voltage switches in service.[34]

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.[35]

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.

Figure 7 provides the age distribution of Newfoundland Power's high voltage switches.

Figure 7
Substation Switch Age Distribution



[33] This includes switches of all high voltage classes including 12.5 kV, 25 kV, 66 kV and 138 kV.
[34] This count includes all named switch designations, excluding ground switches, which are considered switch accessories. Fused disconnects have also been excluded.
[35] 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.

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.[36] 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.[37] The high-speed ground switch operates by providing a deliberate single-phase ground fault on the high voltage side of the power transformer.[38] 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.[39]

Newfoundland Power has 17 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.[40]

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.[41] As part of *Substation Refurbishment and Modernization Plan* 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.[42]

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36 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. However, they provide limited protection for internal faults.

37 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.

38 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.

39 The time required for a high-speed ground switch to operate and the upstream circuit breaker to trip is more than what is required for standard circuit breaker operation.

40 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.

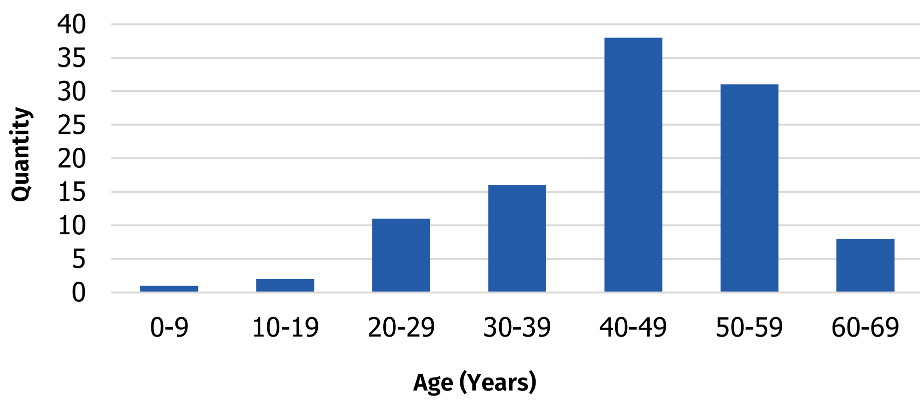
41 Circuit breakers also provide the ability to remotely control the energization of the transformer through the Company's SCADA system.

42 Newfoundland Power has 107 wooden and 154 steel bus structures.

Approximately 72% of the existing wooden bus structures are over 40 years of age, with 36% being 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.[43] 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.

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.[44]

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.

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43 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.

44 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.[45] 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.[46]

Currently, 89 of the 190 in-service power transformers have spill containment installed. Newfoundland Power has 16 substations that contain voltage regulators and four of these currently have spill containment installed.

As part of *Substation Refurbishment and Modernization Plan* projects, Newfoundland Power installs concrete containment foundations for power transformers and voltage regulators inside substations to manage the environmental and safety risks from oil spills.[47]

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; and
(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 Plan* 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 for each substation are necessary 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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45 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/.
46 See IEEE. Standard 979-2012, *IEEE Guide for Substation Fire Protection*. Retrieved June 19, 2024, from https://standards.ieee.org/ieee/979/3665/.
47 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.[48] Other substations that contain digital protection relays for circuit breakers and transformers require a control building to house the associated auxiliary equipment.[49]

Many of Newfoundland Power's existing control buildings are vintage prefabricated buildings which include metal roofs and exterior steel cladding. Maintenance and refurbishment of these prefabricated buildings is limited and would require adapting available construction materials to the prefabricated 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 into 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 2024 there were 54 substation break-ins. A significant increase in substation break-ins has been observed in recent years, with 22 break-ins occurring in 2024. There has been one break-in to date in 2025.

To address this concern, the Company has begun performing security upgrades at its substations as part of the *Physical Security Upgrades* program and *Substation Refurbishment and Modernization Plan* projects. To date, 42 substations have been equipped with surveillance and alarm systems to deter theft and vandalism.

48 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.

49 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. It is not feasible to contain this amount of equipment 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 10 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 indicate 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 2026, the Company has proposed six programs and projects that address component replacements at various substations. The *Molloys Lane Substation Power Transformer Replacement* project addresses the deteriorated MOL-T2 power transformer. This project will mitigate risks to the delivery of reliable service to customers in the west end of St. John's.

The *Kings Bridge Road Substation Power Transformer Replacement* project addresses the deteriorated KBR-T3 power transformer. This project will mitigate risks to the delivery of reliable service to customers in the downtown area of St. John's. The *Mobile Hydro Plant Substation Power Transformer Replacement* project addresses the deteriorated and overloaded MOP-T1. This project will ensure a continuous energy supply remains available from the hydro plant during peak demand conditions. 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.

4.0 PROJECT SCOPE AND COST

4.1 Greenspond Substation Refurbishment and Modernization

Greenspond ("GPD") Substation was constructed in 1981 as a distribution substation. The substation is supplied by a tap from the Newfoundland Power 115L/116L Radial 66 kV Transmission Line system from Trinity ("TRN") Substation. One 2.8 MVA power transformer, GPD-T1, supplies the single 12.5 kV distribution feeder, which is the sole source of supply for approximately 260 customers in the Greenspond area.

An engineering assessment of the substation shows that it contains a significant amount of deteriorated and obsolete equipment.

Appendix A provides a detailed condition assessment and scope of work for the *Greenspond Substation Refurbishment and Modernization* project.

Table 2 provides a detailed breakdown of the *Greenspond Substation Refurbishment and Modernization* multi-year project.

Table 2
Greenspond Substation Refurbishment and Modernization Project
Project Cost Estimate
($000s)

Cost Category	2026	2027	Total
Material	112	1,803	1,915
Labour - Internal	34	214	248
Labour - Contract	-	-	-
Engineering	220	347	567
Other	8	214	222
Total	374	2,578	2,952

The project to refurbish and modernize GPD Substation is estimated to cost $374,000 in 2026 and $2,578,000 in 2027 for a total project cost of $2,952,000.

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 2026, Newfoundland Power is proposing to refurbish and modernize GPD Substation.[50] This substation contains a significant amount of deteriorated and obsolete equipment. Refurbishing and modernizing this substation will ensure the continued provision of safe and reliable service to customers supplied by GPD Substation.

50 The refurbishment of GPD Substation is a two-year project commencing in 2026.

APPENDIX A:

Greenspond Substation Refurbishment and Modernization

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1.0 GREENSPOND SUBSTATION

Greenspond ("GPD") Substation was constructed in 1981 as a distribution substation. The substation is supplied by a tap from the Newfoundland Power 115L/116L Radial 66 kV Transmission Line system from Trinity ("TRN") Substation. One 2.8 MVA power transformer, GPD-T1, supplies the single 12.5 kV distribution feeder which is the sole source of supply for approximately 260 customers in the Greenspond area.

Figure A-1 shows GPD Substation.

Figure A-1: GPD Substation.

2.0 ENGINEERING ASSESSMENT

2.1 66 kV Infrastructure

The 66 kV wooden pole structure was installed in 1981 when the substation was constructed. An inspection and engineering assessment of GPD Substation noted multiple deficiencies of the wood pole structure. The structures were found to have poles with signs of decay and multiple woodpecker holes, and cross arms with various degrees of deterioration, splits and decay. The deteriorated condition of the poles and crossarms compromises the structure's ability to support the weight of critical substation equipment, such as switches and bus supports, 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.

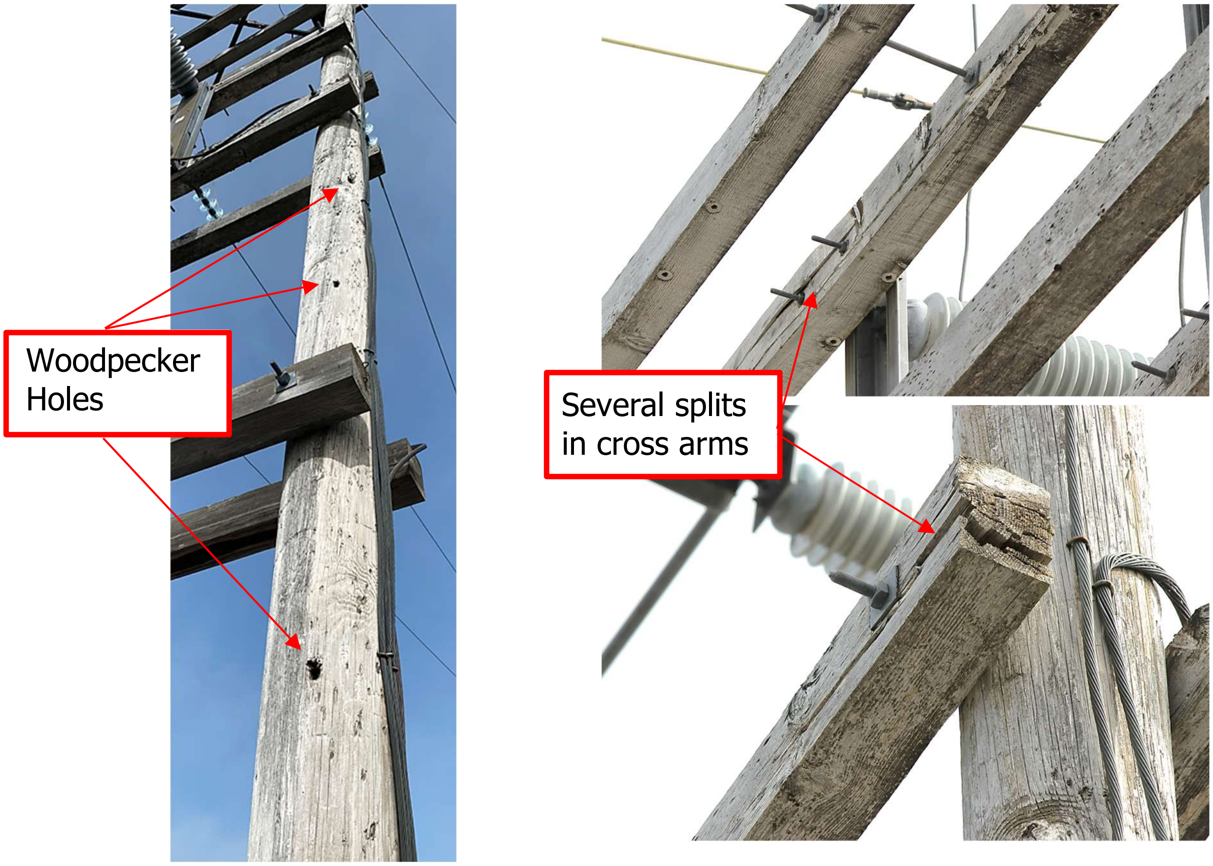

Figure A-2: Deteriorated GPD 66 kV Wood Structure.

The wood pole structure will be removed and replaced with a new galvanized steel structure.

The existing 66 kV switch and 66kV fused disconnect mounted on the existing structure are 44 years old and have deteriorated from exposure to environmental factors and mechanical wear. This deterioration increases the risk of operational failure, necessitating their replacement.

2.2 12.5 kV Infrastructure

The wooden poles in the GPD Substation 12.5 kV bus structure were installed when the substation was first constructed in 1981, and the wooden poles for the voltage regulator support structure were installed in 1990. An inspection and engineering assessment determined that the structures are deteriorated to the point where replacement is required. Similar to the 66 kV structure, multiple poles have woodpecker holes and show signs of decay near the tops. The cross arms exhibit various degrees of deterioration, including splits and decay. The deteriorated condition of the wood structure compromises their ability to support the weight of critical substation equipment, such as switches and bus work, increasing the probability of failure. The wood pole structure is deteriorated to the point where replacement is required.

Figure A-3 shows examples of the deteriorated wood pole structures.

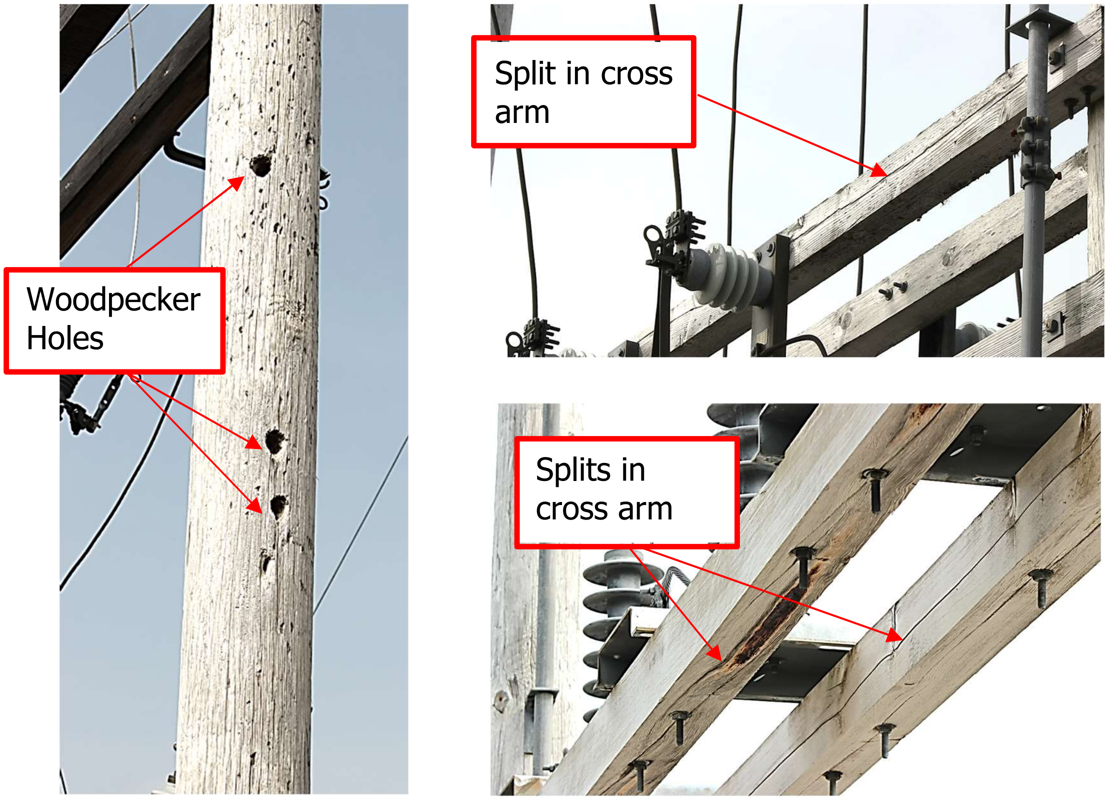

Figure A-3: Deteriorated GPD 12.5 kV Wood Structure.

The wood pole structure will be removed and replaced with a new galvanized steel structure.

The 12.5 kV switches are 44 years old and have deteriorated from exposure to environmental factors and mechanical wear. This deterioration increases the risk of operational failure, necessitating their replacement. One 12.5 kV air break switch, one set of voltage regulator bypass switches, and two sets of 12.5 kV hook-stick operated switches will be replaced.

The 12.5 kV recloser protecting distribution feeder GPD-01 was manufactured by Nulec in 2002.[1] This recloser is at the end of its useful life and will be replaced.

GPD Substation currently utilizes a bank of voltage regulators on the single distribution feeder, GPD-01. One voltage regulator was manufactured by Allis Chalmers in 1974, the second by McGraw Edison in 1994, and the last by Cooper in 2012. 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 and to mitigate the safety risks of a fire.

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1 Since 2021, 12 of these reclosers have required replacement. Three of these 12 failures occurred between January and May of 2025. 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.

2 The GPD Substation voltage regulator bank contains a total oil volume of approximately 1,000 liters.

2.3 Power Transformer

GPD-T1 is a 60-year-old distribution power transformer that was manufactured by Canadian General Electric in 1965. GPD-T1 is a 66 kV to 12.5 kV, 2.8 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 transformer's physical condition show it is in good condition, apart from signs of rusting on the main tank.

Newfoundland Power utilizes the Electric Power Research Institute's Power Transformer Expert software to monitor the health of its power transformer assets. For GPD-T1, the Abnormal Condition Index indicates low short-term risk, and the Normal Degradation Index indicates moderate long-term risk. GPD-T1 is not expected to be replaced within the next five years based on its present risk.

The GPD-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 and to mitigate safety risks.[3]

Figures A-4 shows power transformer GPD-T1.

Figure A-4: GPD-T1 Power Transformer.

[3] Power transformer GPD-T1 contains approximately 3,600 liters of oil.

2.4 Protection and Control

Protection of the power transformer, GPD-T1, is currently provided by a set of fuses. A new set of fuses will be designed to mount on the new 66 kV steel bus structure. The feeder protection is provided by a microprocessor-based digital relay.

The existing communication at GPD Substation includes a cellular modem inside a recloser cabinet. 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 communications gateway will provide a network connection to the SCADA system for all the substation devices that provide monitoring, protection and control of the distribution feeder, and monitoring for the substation power transformer. The modernization will also allow for remote administration of upgraded devices.[4]

The installation of a new 12.5 kV combined potential and current instrument transformer is required to reduce voltages to levels acceptable for metering.

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 GPD Substation in the last five years.

2.5 Building

The GPD Substation does not have an existing control building as the limited number of existing protection and control devices in service are able to fit in small outdoor control cabinets. A new control building is required to allow the installation of network and communication functionality, protection relays, control switches, blocking switches, metering, storage of 66kV fuse refills and other miscellaneous equipment.[5]

2.6 Site Condition

The GPD Substation yard requires an extension to accommodate the increased footprint of the steel structures, the spill containment foundations and a portable substation. Minor improvements to the site such as addressing drainage requirements, removing unsuitable soil and vegetation, and laying structural fill will be completed during the proposed project.
The existing ground grid at GPD Substation has deficiencies that pose a risk to the safe and reliable operation of the electric equipment. Certain areas of the yard have insufficient grounding, and connections between the main ground grid and the substation fence are missing. A grounding study is necessary to assess these issues and upgrade the grid to align with current standards and to cover the expanded substation yard and new equipment.

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4 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 assess fault data.

5 Protection and communication devices housed in panels are required to be kept in a dry environment with temperature control.

3.0 RISK ASSESSMENT

The *Greenspond Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to approximately 260 customers in the Greenspond area. GPD Substation is the sole source of supply to customers in the Greenspond area.

Equipment failure in the substation exposes all customers supplied by GPD Substation to the risk of extended 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.[6]

GPD Substation contains equipment that is deteriorated and at end of life, increasing the probability of outages to customers. The wood pole structures in the substation are deteriorated and require replacement. The majority of the substation switches are deteriorated and require replacement due to their mechanical condition. The 12.5 kV recloser is at the end of its useful life and requires replacement.

The existing power transformer and voltage regulators in GPD 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, thus providing fire protection benefits.

There are deficiencies identified with the ground grid at GPD Substation that pose a risk to safety and reliability. The substation has sections where there is no ground grid, and areas where there is no connection between the main ground grid and the fence grounding. 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.

Overall, refurbishment and modernization of GPD Substation is necessary to ensure the continued delivery of reliable, safe and environmentally responsible service to customers in the Greenspond area.

4.0 ASSESSMENT OF ALTERNATIVES

In the case of GPD Substation, the number of components currently requiring preventative and corrective maintenance justifies the refurbishment and modernization of the substation in 2026 and 2027. The 66 kV and 12.5 kV wood pole structures are deteriorated and require replacement. The 66 kV and 12.5 kV switches are deteriorated and have reached the end of their useful life. The 12.5 kV recloser is at the end of its useful life. The power transformer and voltage regulators do not have a spill containment foundation.

Deferral of the *Greenspond 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

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6 If a wood pole structure were to fail, a portable substation installation may be required to restore service to customers. Typically, a portable substation can be installed within 24 to 36 hours, assuming one is available.

it would increase risks to the delivery of safe and reliable service to customers in the Greenspond area.

5.0 PROJECT SCOPE

The 2026 and 2027 scope of work at GPD Substation includes the following:

(i) Expand the existing yard;
(ii) Construct a new control building;
(iii) Construct new 66 kV and 12.5 kV steel structures to replace deteriorated wood structures;
(iv) Construct new spill containment foundations for existing transformer and voltage regulators;
(v) Install a new set of 66 kV fuses;
(vi) Replace deteriorated 66 kV and 12.5 kV switches;
(vii) Replace one end-of-life 12.5 kV recloser;
(viii) Install 66 kV potential transformer;
(ix) Install new 12.5 kV combined current and potential transformer;
(x) Install new digital relays and the associated communications equipment;
(xi) Upgrade and extend the ground grid;
(xii) Install new security cameras; and
(xiii) Install varmint protection on all 12.5 kV equipment.

Table A-1 summarizes the age and condition of the primary equipment planned to be replaced.

Table A-1
2026/2027 Planned Equipment Replacements
Greenspond Substation

Equipment	Age (Years)	Condition
66 kV Wood Pole Structure	44	Deteriorated
66 kV Air Break Switch	44	Deteriorated
66 kV Fused Disconnect	44	Deteriorated
12.5 kV Wood Pole Structure	34-44	Deteriorated
12.5 kV Hook-Stick Operated Switches	44	Deteriorated
12.5 kV Air Break Switch	20	Replacement due to new structure
12.5 kV Recloser	23	End of Life

Engineering design and procurement of long lead equipment will be completed in 2026. Construction will begin in the second quarter of 2027 and be completed in the fourth quarter of 2027. Commissioning of the substation will be completed during the fourth quarter of 2027.

6.0 PROJECT COST

Table A-2 provides the cost breakdown for the multi-year *Greenspond Substation Refurbishment and Modernization* project.

Table A-2
Greenspond Substation
Refurbishment and Modernization Project
Project Cost
($000s)

Cost Category	2026	2027	Total
Material	112	1,803	1,915
Labour - Internal	34	214	248
Labour - Contract	-	-	-
Engineering	220	347	567
Other	8	214	222
Total	$374	$2,578	$2,952

The *Greenspond Substation Refurbishment and Modernization* project is estimated to cost $374,000 in 2026 and $2,578,000 in 2027 for a total project cost of $2,952,000.

7.0 CONCLUSION

The *Greenspond 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 GPD Substation. New 66 kV and 12.5 kV steel structures will replace the deteriorated wood structures, deteriorated switches will be replaced, the recloser at end of life will be replaced, 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 damage in the case of an oil spill as well as to mitigate safety risks related to fire. The total project cost to complete the *Greenspond Substation Refurbishment and Modernization* project is estimated to be $2,952,000.

June 2025

2.2 Substation Power Transformer Strategy

Prepared by:

Michael Power, P.Eng

NEWFOUNDLAND POWER

A FORTIS COMPANY

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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. To manage this risk, Newfoundland Power is proposing a power transformer strategy to ensure the continued reliability of the electrical system through these assets.

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 approach enables the completion of design, procurement, and contract approval in year one with installation and commissioning being completed in subsequent years.

2.0 POWER TRANSFORMER ASSET MANAGEMENT

2.1 In Service 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 have significant impacts on the electrical system, including extended outages to generation plants, transmission lines, or distribution lines potentially affecting a large number of customers.

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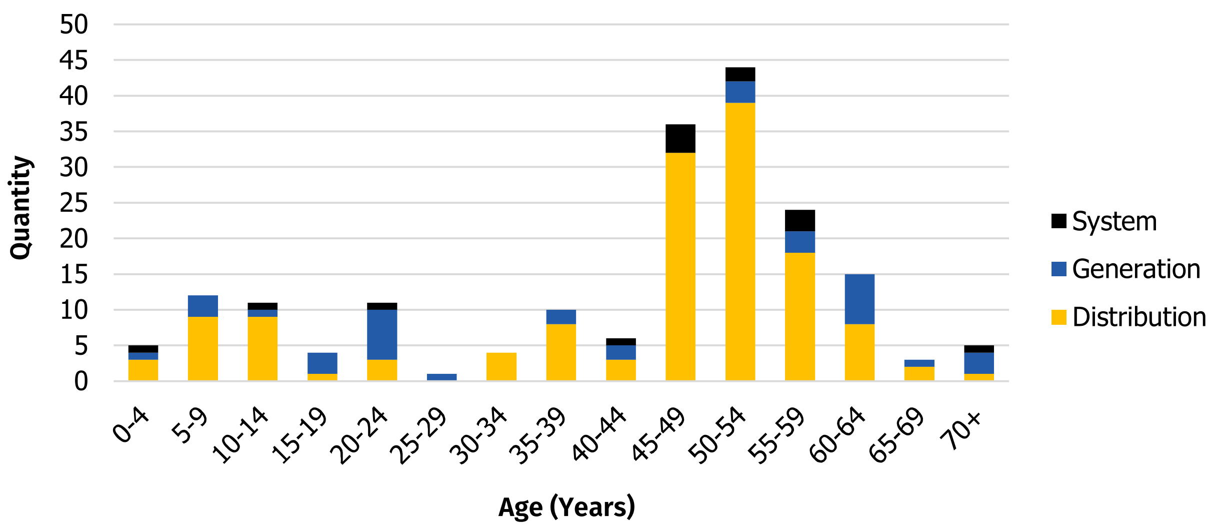
1 Newfoundland Power's substations may serve multiple purposes and can be classified as any combination of the generation, transmission and distribution functions.

2 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] Industry experience also suggests that power transformer failure rates tend to vary based on age, with units aged 60 years or older failing at nearly double the rate of those aged between 40 and 60 years.[5]

Figure 1 shows the age distribution of the Company's power transformers.

Figure 1
Power Transformer Age Distribution



A total of 91 power transformers in the Company's fleet, or approximately 48%, are aged 50 years or older, which is the upper limit of the typical industry experience. This percentage will increase materially over the next five years, as an additional 36, or approximately 19%, of power transformers are currently between the ages of 45 and 49 years.

The service life of the Company's power transformers has historically exceeded the expected life observed in the industry. This performance can be explained by a number of factors including the Company's maintenance program and the favourable load profile in Newfoundland and Labrador, as the highest loads are experienced in the winter when ambient temperatures are

[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] See Centre for Energy Advancement through Technological Innovation ("CEATI"), *Station Equipment: Failure Rates, 2016,* page 3-3.

the lowest.[6] 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.

2.2 Portable Substation Fleet

When maintenance is completed on a power transformer, it often requires the unit to be removed from service for two to four weeks. If the load supplied by the power transformer cannot be transferred to another transformer in the substation or an adjacent substation, a portable substation is installed to maintain service to customers.[7] Portable substations are also installed to maintain service to customers during capital projects and equipment failures in substations. Capital projects at substations typically require the deployment of a portable substation for between two and seven months. Portable substation deployment in response to equipment failures can last substantially longer.

Newfoundland Power currently has a fleet of four portable substations. These portable substations operate at different voltages and are therefore capable of providing emergency backup for different power transformers.[8] The Company also has access to one portable substation from Newfoundland and Labrador Hydro ("Hydro"), P2, through an equipment sharing agreement.[9]

[6] Cold ambient temperatures during peak periods help keep the power transformer cool, mitigating the effects of heat on the insulation inside the transformer. Winding insulation deterioration is a major indicator that a power transformer has reached end of life and is the cause of many transformer failures. While insulation deterioration occurs naturally over time, it is accelerated by exposure to the high temperatures that can be experienced during peak load conditions.

[7] Compared to a standard power transformer, a portable substation transformer is physically smaller, has less mass and is mounted on a trailer with associated cooling system, switches, breakers and protection. These features add significantly to the cost of a portable substation compared to a standard power transformer.

[8] Portable substations each include an air brake switch used for isolation on the high-voltage side, a multiple-winding power transformer, and a breaker on the low-voltage side. The flexibility provided by the multiple-winding transformer allows the portable substations to connect to transmission, generation and distribution systems of different voltages and capacities. However, each portable substation is technically limited to only serving locations corresponding to its capacity and voltage specifications.

[9] Hydro's portable substation is referred to as Portable Substation No. 2 ("P2"). It has a capacity of 15 MVA. P2 can provide coverage for 87 of Newfoundland Power's 191 power transformers. However, all but one of these power transformers is covered by a Newfoundland Power portable substation.

Table 1 provides an overview of the five portable substations.

Table 1
Portable Substation Summary

Portable Substation	Size (MVA)	Primary Voltages (kV)	Secondary Voltages (kV)	Manufacture Date	Date Refurbished
P1	10	66/33/25/12.5	25/14.4/12.5/ 7.2/4.16/2.4	1966	2017
P2[10]	15	138/66	66/33/25/12.5	1973	2022
P3	25	138/66	66/25/14.4/12.5/7.2	1976	2011
P4	50	138/66	66/25/12.5	1992	2015
P5	50	138/66	25/14.4/12.5/7.2	2014	-

The portable substations range in size from 10 MVA to 50 MVA and have been in service for between 11 and 59 years. Combined, these units can provide emergency backup for most power transformers in Newfoundland Power's system.

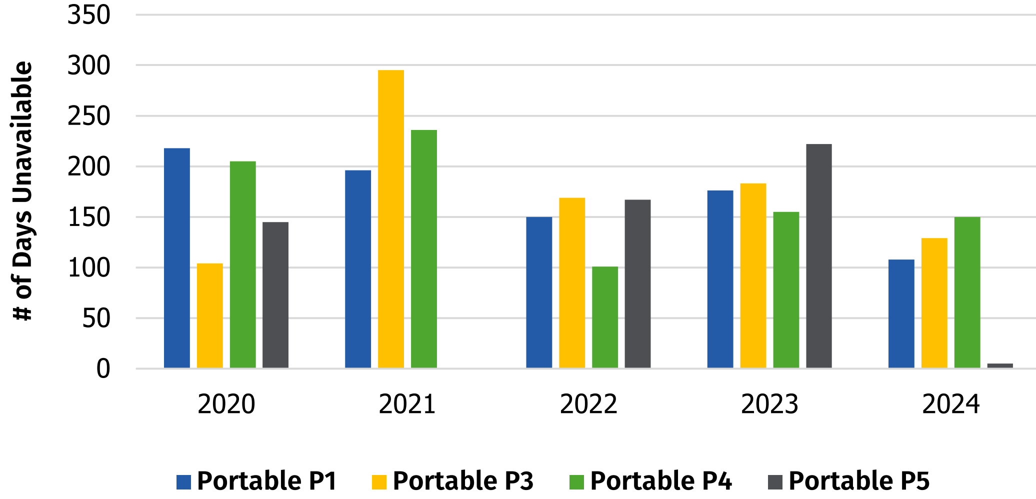
Newfoundland Power does not consider a portable substation to be a spare transformer. Portable substations are typically utilized to support the Company's capital and maintenance programs for substations, as well as to respond to in-service equipment failures. Typically, portable substation installations are intended for short-term usage.

In emergency situations, the Company's focus is on restoring service to customers promptly and safely following equipment failure. Options to restore service to customers during an emergency include load transfers, if the opportunity exists, or the deployment of a portable substation.

10 *Ibid.*

Figure 2 shows the utilization of Newfoundland Power's portable substations from 2020 to 2024.[11]

Figure 2
Portable Substation Utilitization
(2020-2024)



The utilization of individual portable substations varies annually. This variability is attributable to annual requirements related to the Company's capital and maintenance programs for substations, variability of in-service equipment failures, and periodic requirements to remove a portable unit from service for refurbishment.

An increased probability of power transformer failure and diminished supply of spares is expected to put considerable pressure on the availability of portable substations. A portable substation that is deployed in response to a transformer failure can, in certain conditions, be required to remain in service for up to 36 months. Given the age and condition of the Company's transformer fleet, it is reasonable to anticipate multiple transformer failures occurring concurrently which could potentially exceed Newfoundland Power's emergency response capabilities.

Reduced availability of portable substations would pose a risk to the delivery of reliable service to customers from two perspectives.

First, it would expose customers to a risk of even longer duration outages. A readily available portable substation can be deployed to restore service to customers within 24 to 36 hours. However, redeploying a portable substation that is already in service may not be possible or may require four or more days to uninstall, redeploy and restore service to customers.

[11] Figure 2 includes periods during which a portable substation was removed from service for refurbishment or repairs. For example, P1 was removed from service for refurbishment throughout 2018. Figure 2 does not include the three to five weeks during each year when maintenance is completed on each portable substation, as routine maintenance can typically be advanced or delayed to accommodate scheduling requirements.

Second, it would present risks to the execution of the Company's annual capital and maintenance programs for substations. Portable substations are critical to the effective implementation of annual maintenance and capital programs at substations. Anticipated usage of portable substations is expected to remain similar to the past five years as annual substation maintenance and capital programs are not expected to change in the near term. Newfoundland Power prioritizes the restoration of service to customers over maintenance activities. A reduced availability of portable substations could therefore result in the deferral of substation maintenance, which would pose additional risks of equipment failure and customer outages.

2.3 Spare Power Transformer Inventory

Maintaining an adequate inventory of spare power transformers is consistent with current utility practice.

Newfoundland Power has historically relied on power transformers removed from service in response to system load growth for use as spares. The Company has not historically procured power transformers specifically to serve as spares prior to the *Substation Spare Power Transformer Inventory* project approved as part of Newfoundland Power's *2023 Capital Budget Application*.

The availability of a suitable inventory transformer following the failure of a power transformer can significantly reduce the duration that a portable substation is required to be in service. A spare unit can either be permanently installed to return a substation to its normal configuration or temporarily installed while a power transformer is being repaired or a more suitable replacement is being procured.

Table 2 provides details on Newfoundland Power's current inventory of spare power transformers.[12]

Table 2
Spare Transformer Inventory

Equipment ID	Age	Capacity (MVA)	Primary Voltage (kV)	Secondary Voltage (kV)
200385[13]	1 Year	15/20/25	66	12.5/25
200299	49 Years	15/20	138	25
200219	55 Years	10	66	12.5
200328	42 Years	5/6.7/8.3	66	25
200185	57 Years	1.68/2.24	33/66	4.16/12.5
200358	16 Years	0.5	66	7.2/14.4
200220	55 Years	10/13.3	66	4.16/12.5
200352	22 Years	25/33.3/41.6	138	66

Five of the spare power transformers mentioned above were previously removed from service and are immediately available for deployment. Power transformer 200299 is a 15/20 MVA unit that is 49 years old. Power transformer 200219 is a 10 MVA unit that is 55 years old. Power transformer 200328 is a 5/6.67/8.33 unit that is 42 years old. Two other transformers, 200185 and 200358, have limited capacity and provide minimal backup coverage for the Company's existing fleet.

Two of the spare power transformers are in service and can be removed from service in the event of an emergency. Power transformer 200220 is currently serving as Stamp's Lane Substation transformer SLA-T1, however is not needed for capacity. This power transformer is 55 years old. Power transformer 200352 is 22 years old and is currently serving as Salt Pond Substation transformer SPO-T5. This unit could be considered for temporary relocation to address a failure but must be reinstalled on the Burin Peninsula once it is no longer needed for emergency use.[14]

12 Hydro also maintains a fleet of six spare power transformers. They are typically smaller in capacity and/or have voltage configurations that have limited application in Newfoundland Power's system. As a result, they provide minimal backup coverage for Newfoundland Power's transformers.

13 Power transformer 200385 is the new spare transformer that was procured as part of the *Substation Spare Power Transformer Inventory* project approved as part of Newfoundland Power's *2023 Capital Budget Application*.

14 SPO-T5 works in tandem with power transformer SPO-T4 serving approximately 8,500 customers on the Burin Peninsula. These two power transformers provide N-1 redundancy for supplying the 66 kV transmission system. In 2002, an issue with SPO-T4 resulted in an extended outage on the Burin Peninsula and highlighted the critical need for SPO-T5. See *Application for Approval of Capital Expenditures Supplemental to Newfoundland Power Inc.'s 2002 Capital Expenditure Budget approved by Board Order P.U. 21 (2001-2002).*

These eight spare power transformers provide coverage for approximately 67% of Newfoundland Power's fleet.[15] Over 60% of existing spare units are approaching end of life. As a result, coverage provided by the Company's current inventory of spare power transformers will diminish over time as these spares are placed in service or retired.

2.4 Preventative Maintenance and Condition Assessment

As part of the Company's 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.[16] All power transformers undergo annual oil sampling.[17] Additionally, power transformers are scheduled for 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 Electric Power Research Institute's ("EPRI") Power Transformer Expert System ("PTX") to diagnose and assess the condition of its power transformer fleet.[18] 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.

PTX identifies the Insulation Degradation Risk and the Incipient Fault Risk for each unit in the Company's power transformer fleet. The Insulation Degradation Risk is intended to provide an indication of the physical condition of the paper insulating system relative to its initial state. 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. These indices serve as a guide for maintenance efforts on individual units, while also informing overall fleet management decisions.

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[15] See Appendix A for the coverage provided by each of the power transformers included in Table 2.

[16] 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.

[17] 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 transformers age 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.

[18] The EPRI PTX software is also used by other utilities as a tool to aid in the development of transformer condition assessments.

2.5 Current Utility Practice

The risks posed by aging power transformers are not unique to Newfoundland Power. According to EPRI, large customer load growth in the 1970s and 1980s has caused an *asset wall* of transformers in the 35-to-45-year age range that are approaching the end of their nominal design lives.[19]

A 2021 survey conducted through Centre for Energy Advancement through Technological Innovation ("CEATI") indicates that utilities currently manage power transformer failures through a combination of portable substations and spare transformers. A total of 15 transmission and distribution utilities responded to the survey. The average age of the transformer fleets of the surveyed utilities was 35 years, compared to 43 years for Newfoundland Power.

Table 3 summarizes the results of the CEATI survey on utility practices for managing power transformer failure.

Table 3
2021 CEATI Survey
Utility Power Transformer Failure Management [20]

Utility	Average Age of Transformer Fleet	Portable Substations	Spare Transformer Inventory
Utility 1	30	No	Yes
Utility 2	43	Yes	Yes
Utility 3	35	Yes	Yes
Utility 4	29	No	Yes
Utility 5	40	Yes	Yes
Utility 6	35	Yes	Yes
Utility 7	34	Yes	Yes
Utility 8	42	Yes	Yes
Utility 9	35	No	Yes
Utility 10	42	Yes	Yes
Utility 11	25	Yes	Yes
Utility 12	40	Yes	Yes
Utility 13	40	Yes	Yes
Utility 14	23	No	Yes
Utility 15	38	Yes	Yes

[19] See EPRI, *Utilizing Industry-Wide Data to Better Understand Power Transformer Fleet Performance,* pages 1-3.
[20] A portion of the surveyed utilities have systems that are constructed to meet N-1 criteria and therefore have redundant installed transformer capacity. These include Utility 11 and Utility 14. Utility 10 meets N-1 criteria on its transmission power transformers. Utility 15 meets N-1 criteria for transmission power transformers above 161 kV.

The survey showed that all 15 surveyed utilities maintain an inventory of spare transformers. Spare transformers commonly account for between 2% and 5% of a utility's total fleet, ranging as high as 15% to 17%. Similar to Newfoundland Power, 11 of the surveyed utilities have both an inventory of spare transformers and portable substations.

A separate survey on power transformers was conducted through CEATI in 2023. A total of 19 transmission, distribution, and vertically integrated utilities were surveyed. 13 of the 19 utilities indicated that they have a program for planned replacement of power transformers.

3.0 RISK ASSESSMENT

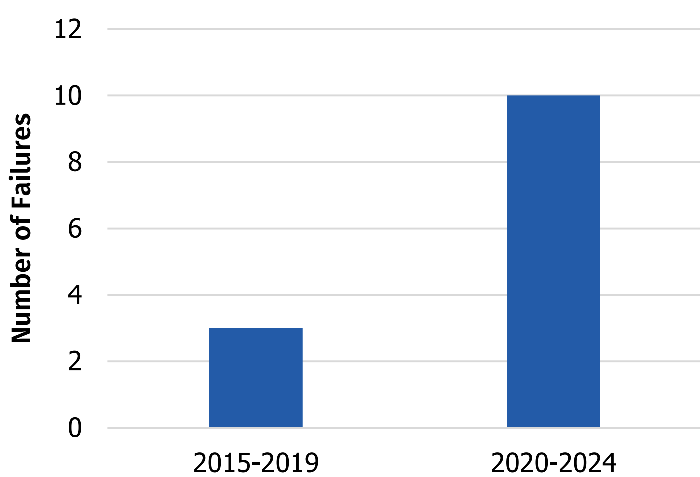
3.1 Probability of Power Transformer Failure

Newfoundland Power conducted a risk assessment of its substation power transformers to assess the current probability and consequences of equipment failures. The assessment included trends in power transformer failures, the age profile of its transformer fleet, and market trends in transformer delivery lead times.

The number of power transformer failures within the Company's fleet has increased over the last decade.

Figure 3 shows the number of power transformer failures experienced from 2015 to 2024.[21]

Figure 3
Power Transformer Failure
(2015-2024)



Newfoundland Power has experienced 13 power transformer failures over the last decade, 10 of which have occurred in the past five years.[22] This compares to three power transformer failures over the previous five-year period.

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21 See Appendix B for the list of substation power transformer failures experienced from 2015 to 2024.
22 See Appendix B for additional information on transformer failures experienced by the Company in the last decade.

Of the 10 failures experienced over the last five years, three power transformers failed in service and the remaining seven were identified as being at imminent risk of failure through condition monitoring. Four of the 10 power transformers required replacement, while the remaining six were repaired and returned to service.

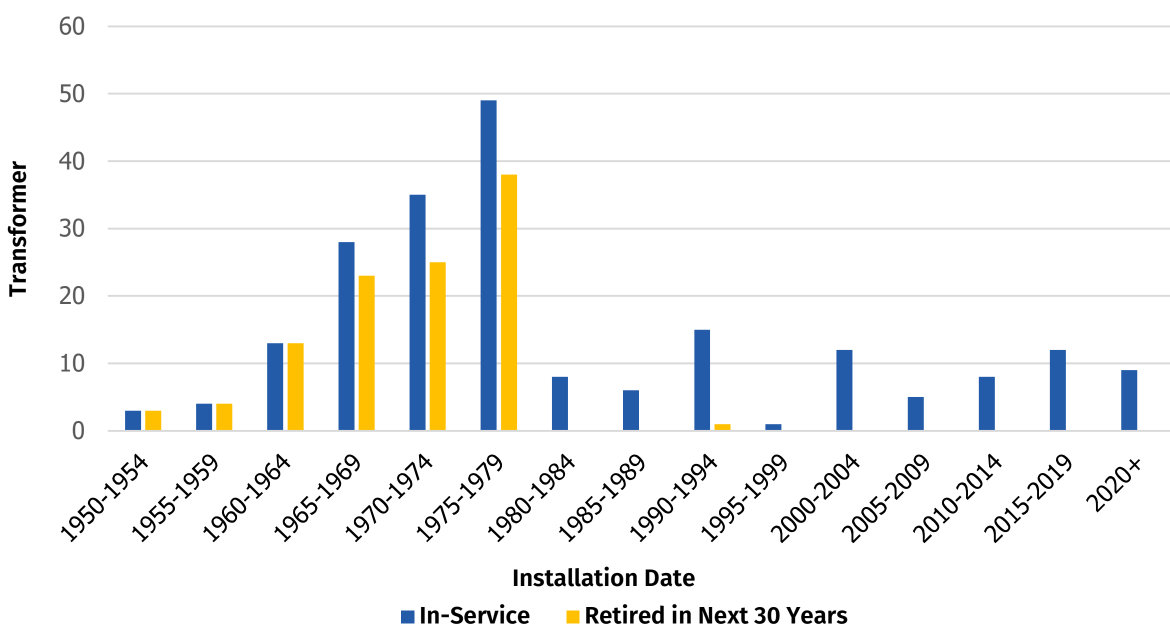
In 2022, Gannett Flemming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a service life study related to the Company's substation power transformers as of December 31, 2022. The study is included in Appendix C. The purpose of this study was to estimate reasonable lives for in-service power transformers and to forecast an expected retirement schedule for each of the units over the next 30 years.

In this report Gannett Fleming stated:

"The 30-year forecast of anticipated power transformer retirements is derived from the expected average service life and the ages of the existing assets. For this study, retirements were calculated using statistical modeling. It is important to acknowledge that the condition of the units was not considered in this analysis, and this statistical approach was intended to provide a high-level outlook. Therefore, these results can be interpreted as providing general view of likely scenarios rather than an exact depiction of future occurrences. As with any projection, uncertainties may exist, and the forecast should be interpreted with the understanding that it offers a broad overview of potential outcomes."

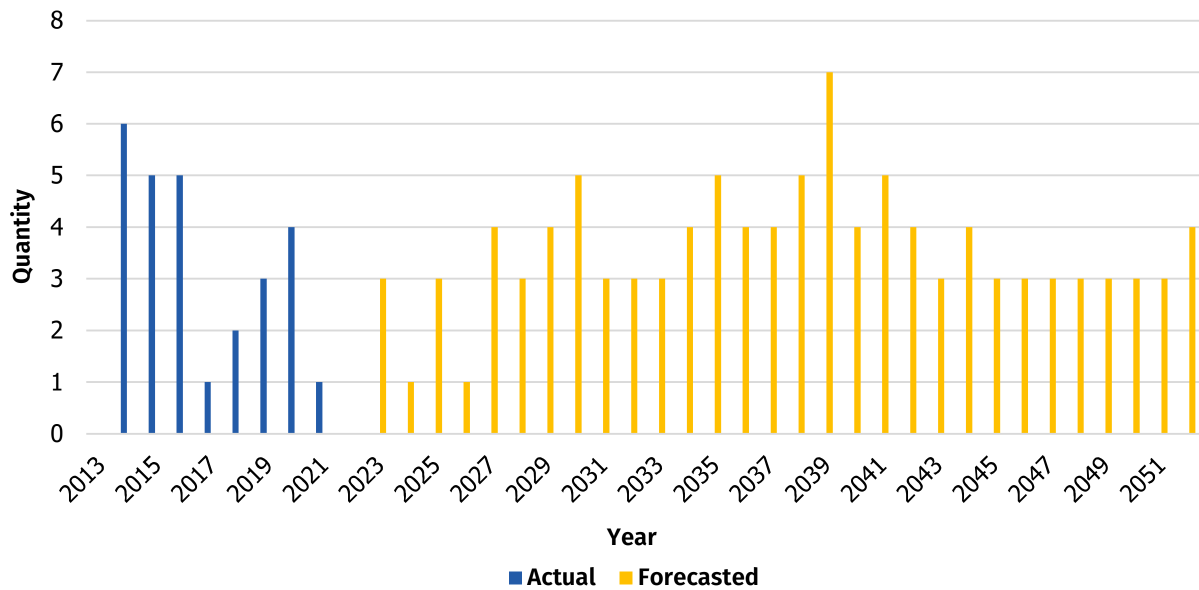
Gannett Fleming's projection of Power Transformer Retirements over the period of 2023 to 2052 is summarized in Figure 4 below. This figure groups the in-service transformers by installation date and indicates the units that are projected to be replaced over this thirty-year period.

Figure 4
Projection of Power Transformer Retirements



The forecasted power transformer retirements by year are summarized in Figure 5 below.

Figure 5
Actual and Forecasted Power Transformer Retirements



As indicated in Figure 5, the Gannett Fleming study states that "*The frequent retirement of power transformers should be expected over the next 30 years. The analysis suggests that the Company will be replacing, on average, three transformers on an annual basis through 2052*."

3.2 Consequence of Power Transformer Failure

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 a proximate substation, as well as the availability and proximity of a portable substation.

Examining whether it is possible to transfer load is the first step in Newfoundland Power's emergency response following transformer failure. A load transfer can typically restore service to customers within a few hours. The ability to transfer load depends on whether there is transformer capacity available at the substation or a proximate substation, and the presence of sufficient distribution tie points. In the Newfoundland Power system, this option is generally limited to highly networked urban areas, such as St. John's, during non-peak periods.[23]

In many instances, a portable substation must be deployed to restore service to customers following a transformer failure. The deployment of a portable substation was required to restore service to customers following seven of the 13 power transformer failures that occurred over

[23] During periods of high customer demand during the winter, there is limited ability to transfer load between power transformers within the Company's urban areas. Additionally, substations supplied by radial transmission and distribution systems are not capable of transferring load to other substations as they have a single connection point to the electrical system.

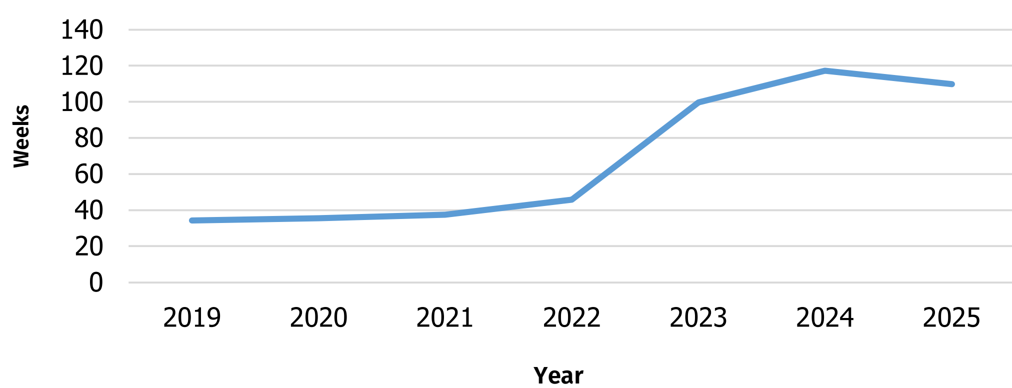
the last decade.[24] If a portable substation is readily available, service can typically be restored to customers within 24 to 36 hours.

The length of time a portable substation must remain in service varies depending on whether the power transformer requires repair or replacement, and whether a suitable spare transformer is available. In some cases, transformers can be repaired on site within days or weeks. In other cases, transformers must be shipped out of province to a third-party repair facility, which can require 18 to 24 months. When replacement of a transformer is necessary, it can require between 24 and 36 months to design, procure, deliver, install and commission the transformer.[25]

Newfoundland Power has typically had a small quantity of spare power transformers available to respond to a transformer failure.[26] A spare power transformer can typically be installed within a month of a transformer failure. A spare unit can be installed on a permanent basis, or as a temporary solution to cease reliance on a portable substation while equipment repairs are completed or an appropriately sized replacement can be procured.[27]

Newfoundland Power uses a competitive tendering process to procure transformers. The Company analyzed market trends in vendors' proposed delivery times for power transformers as part of assessing the consequences of power transformer failures.[28] The analysis showed the average proposed delivery time for power transformers from the time of order has increased significantly, from an average of 34 weeks in 2019 to an average of 110 weeks in 2025. A summary of the average delivery lead time is summarized in Figure 6 below.

Figure 6
Power Transformer Average Delivery Lead Time



24 See Appendix B.
25 These transformer lead time estimates are based on information provided by manufacturers currently utilized by the Company. However, some manufacturers have indicated lead times upwards of 60 months.
26 A spare transformer is assessed to determine its suitability for installation based on various factors, including transformer capacity, voltages, winding configuration, physical size and any space constraints in the substation.
27 Depending on the capacity of the spare transformer and the load requirements of the substation, the permanent, least-cost solution may involve the purchase and installation of a smaller sized power transformer and removal from service of the installed spare transformer.
28 The analysis was based on delivery times proposed by vendors through Newfoundland Power's competitive tendering process for power transformers.

Factoring in the additional time required to obtain approval and procure a new transformer, acquiring a new unit can take up to three years. An increase in delivery times for replacement transformers represents a risk that additional time could be required to respond to transformer failures.

The impact on customers of a power transformer failure can be observed in the failure of Bonavista Substation transformer BVA-T1 in November 2018. At that time, BVA-T1 failed in service, resulting in an outage to approximately 2,600 customers in the Bonavista area. It took approximately 24 hours to deploy a portable substation and fully restore service to customers.[29] The portable substation remained installed at Bonavista Substation for 11 months while the transformer was repaired.[30]

4.0 POWER TRANSFORMER STRATEGY

Newfoundland Power's customers are exposed to an increasing risk of extended outages due to the age and condition of the Company's power transformers. Increasing delivery lead times of power transformers and the increasing probability of transformer failure of the aging fleet each contribute to increased risks to customer reliability with the Company's current emergency response capabilities. In response to these increased risks, Newfoundland Power has adopted a proactive strategy that includes improved monitoring and assessment capabilities to support the planned replacement of power transformers, as well as enhancements to the Company's emergency response capabilities.[31]

Planned transformer replacements are a strategic response to the increased risk posed by Newfoundland Power's aging fleet of substation power transformers. Nearly half of the Company's transformers are already 50 years or older, and a significant portion of the remaining fleet is rapidly approaching this threshold. Without a structured and planned replacement plan, Newfoundland Power would experience an increase in power transformer failures that would likely exceed the Company's current emergency response capabilities. This would lead to extended customer outages and increased costs.

By implementing a planned replacement strategy, Newfoundland Power can strategically manage the retirement and replacement of these critical assets. This approach allows for the scheduling of replacements based on condition assessments, operational priorities, and system needs. Using this approach, the Company can mitigate the increased costs associated with emergency repairs and replacements, extended customer outages, and reactive procurement. This approach also enables Newfoundland Power to schedule replacements during optimal periods, minimizing disruption to customers and ensuring alignment with broader capital planning.

[29] At the time BVA-T1 failed, a portable substation was located nearby in Clarenville and was ready for transport, which enabled a rapid deployment of the unit to Bonavista Substation.

[30] The total cost associated with the emergency response and repair of BVA-T1, a transformer originally manufactured in 1990, was $720,000, in 2019 dollars.

[31] Refer to the *Substation Spare Transformer Inventory* project approved as part of Newfoundland Power's *2023 Capital Budget Application*, and the *Pulpit Rock Substation Power Transformer Replacement* and *Gander Substation Power Transformer Replacement* projects approved as part of Newfoundland Power's *2025 Capital Budget Application*.

By combining planned replacements with enhanced emergency response capabilities, Newfoundland Power can better balance the risk of unexpected failures with the need for suitable backup resources.

Ensuring an adequate inventory of spare transformers is an important element of emergency response. Considering increasing delivery lead times, Newfoundland Power plans to increase its inventory of spare power transformers, while ensuring compatibility with the various system configurations throughout the Company's service territory.[32] This will significantly improve the probability that a power transformer would be available to either temporarily or permanently return a substation to service following a transformer failure, while also alleviating potential pressures on the availability of portable substations by reducing the duration that portable units must be installed in response to a power transformer failure.

Newfoundland Power's fleet of portable substations has historically provided a sufficient level of support for substation maintenance activities, capital projects and short-term emergency response. Looking forward, it is expected that the current fleet will be challenged to provide the same level of support over the medium term, and an additional portable substation may be required. The Company will continually assess the capabilities of its portable substation fleet and any new additions to the fleet will be proposed as required.

5.0 CONCLUSION

A significant number of Newfoundland Power's power transformers are operating beyond or nearing the end of their expected service life. This aging profile, combined with extended procurement lead times and current emergency response resources, presents a risk to customers.

Proactively replacing power transformers while also enhancing emergency response capabilities enables the Company to manage asset replacements in a controlled manner. This approach allows the Company to stay ahead of the aging asset curve, ensuring system reliability while proactively reducing the risk of costly failures and minimizing the potential for customer outages.

Appendix D summarizes the Substation Power Transformer Strategy five-year plan. The plan will be revisited yearly as part of the preparation of the annual capital budget and may change due to changing priorities identified by the most recent inspections, assessments, and operating experience.

Appendix E contains a detailed review of the Substation Power Transformer Strategy scope proposed for 2026.

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[32] A compatible spare must have the same primary and secondary voltages, and the same or larger MVA capabilities as the unit being supported, while also considering the winding configurations. Varying voltage and load conditions throughout the system therefore requires a diverse spare inventory capable of coverage for configurations such as 138-66 kV, 138-25/12.5 kV, 66-25/12.5 kV, et cetera.

APPENDIX A:

Power Transformer Listing – Portable/Spare Capability

Table A-1
Power Transformer Listing – Portable/Spare Capability

		Operating Voltage				NP Portable Compatibility				NP Spare Inventory Compatibility							
Designation	Type	High (kV)	Low (kV)	Size MVA	2025 Forecast MVA	P1	P3	P4	P5	200-299	200-185	200-358	200-219	200-352	200-220	200-328	200-385
ABC-T1	Dist.	66.0	12.5	13.33	6.21	X	X	X	X				X		X		X
APT-T1	Dist.	66.0	25.0	25.00	17.74		X	X	X								X
BCV-T1	Dist.	66.0	25.0	25.00	21.66		X	X	X								X
BFS-T1	Dist.	138.0	25.0	20.00	9.37		X	X	X	X							
BHD-T1	Dist.	66.0	25.0	7.46	4.06	X	X	X	X							X	X
BIG-T1	Dist.	66.0	12.5	11.11	8.88	X	X	X	X				X		X		X
BLA-T1	Dist.	138.0	25.0	6.67	4.69		X	X	X	X							
BLK-T2	Dist.	138.0	25.0	20.00	17.07		X	X	X	X							
BOT-T1	Dist.	138.0	25.0	20.00	14.79		X	X	X	X							
BRB-T1	Dist.	138.0	12.5	20.00	12.55		X	X	X								
BRB-T4	Dist.	138.0	12.5	25.00	14.38		X	X	X								
BVA-T1	Dist.	138.0	12.5	25.00	15.16		X	X	X								
BVJ-T1	Dist.	138.0	25.0	2.67	0.27		X	X	X	X							
BVS-T1	Dist.	66.0	12.5	20.00	17.79		X	X	X								X
BVS-T2	Dist.	66.0	12.5	15.00	11.08		X	X	X						X		X
CAB-T2	Dist.	66.0	25.0	6.67	4.32	X	X	X	X							X	X
CAR-T1	Dist.	66.0	25.0	25.00	20.23		X	X	X								X
CAT-T2	Dist.	138.0	12.5	20.00	6.15		X	X	X								
CHA-T1	Dist.	66.0	25.0	50.00	39.51			X	X								
CHA-T2	Dist.	66.0	25.0	25.00	19.29		X	X	X								X
CLK-T1	Dist.	66.0	12.5	10.00	6.37	X	X	X	X				X		X		X
CLK-T2	Dist.	66.0	12.5	10.00	6.80	X	X	X	X				X		X		X
CLV-T2	Dist.	138.0	12.5	20.00	12.75		X	X	X								
CLV-T3	Dist.	138.0	12.5	25.00	13.47		X	X	X								
COB-T1	Dist.	138.0	12.5	20.00	14.60		X	X	X								

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Power Transformer Listing – Portable/Spare Capability

		Operating Voltage				NP Portable Compatibility				NP Spare Inventory Compatibility							
Designation	Type	High (kV)	Low (kV)	Size MVA	2025 Forecast MVA	P1	P3	P4	P5	200-299	200-185	200-358	200-219	200-352	200-220	200-328	200-385
COB-T3	Dist.	138.0	12.5	25.00	18.25		X	X	X								
COL-T1	Dist.	138.0	12.5	16.67	7.52		X	X	X								
DLK-T1	Dist.	66.0	25.0	25.00	24.74		X	X	X								X
DOY-T2	Dist.	66.0	25.0	6.67	5.01	X	X	X	X							X	X
DUN-T1	Dist.	66.0	25.0	25.0	8.10	X	X	X	X							X	X
FER-T1	Dist.	66.0	12.5	4.00	2.39	X	X	X	X				X		X		X
FRN-T1	Dist.	66.0	25.0	6.67	4.53	X	X	X	X							X	X
GAL-T1	Dist.	66.0	12.5	13.33	11.40		X	X	X						X		X
GAL-T2	Dist.	66.0	12.5	13.33	11.29		X	X	X						X		X
GAM-T1	Dist.	138.0	25.0	6.67	5.39		X	X	X	X							
GAN-T1	Dist.	138.0	12.5	20.00	17.85		X	X	X								
GAR-T1	Dist.	66.0	12.5	3.72	2.22	X	X	X	X		X		X		X		X
GBE-T1	Dist.	66.0	7.2	0.33	0.26	X	X		X			X					
GBS-T1	Dist.	66.0	25.0	25.00	8.38	X	X	X	X								X
GBY-T1	Dist.	66.0	25.0	13.33	8.27	X	X	X	X							X	X
GDL-T1	Dist.	66.0	25.0	25.00	20.27		X	X	X								X
GDL-T2	Dist.	66.0	25.0	25.00	20.58		X	X	X								X
GDL-T3	Dist.	66.0	25.0	25.00	20.89		X	X	X								X
GFS-T2	Dist.	138.0	25.0	20.00	14.05		X	X	X	x							
GFS-T3	Dist.	138.0	25.0	50.00	32.26			X	X								
GFS-T5	Dist.	66.0	4.2	11.17	6.43	X									X		
GIL-T1	Dist.	66.0	25.0	6.67	6.66	X	X	X	X							X	X
GLN-T1	Dist.	138.0	25.0	8.34	3.65		X	X	X	X							
GLV-T1	Dist.	138.0	25.0	20.00	12.30		X	X	X	X							
GOU-T2	Dist.	66.0	12.5	20.00	14.87		X	X	X								X

Table A-1
Power Transformer Listing – Portable/Spare Capability

		Operating Voltage				NP Portable Compatibility				NP Spare Inventory Compatibility							
Designation	Type	High (kV)	Low (kV)	Size MVA	2025 Forecast MVA	P1	P3	P4	P5	200-299	200-185	200-358	200-219	200-352	200-220	200-328	200-385
GOU-T3	Dist.	66.0	12.5	13.33	10.54		X	X	X						X		X
GPD-T1	Dist.	66.0	12.5	2.80	1.03	X	X	X	X		X		X		X		X
GRH-T2	Dist.	138.0	12.5	20.00	13.90		X	X	X								
HAR-T1	Dist.	66.0	12.5	14.90	11.78		X	X	X						X		X
HBS-T1	Dist.	66.0	25.0	6.67	3.73	X	X	X	X							X	X
HCT-T3	Dist.	66.0	12.5	2.24	1.85	X	X	X	X		X		X		X		X
HGR-T1	Dist.	66.0	25.0	25.00	9.97	X	X	X	X								X
HOL-T1	Dist.	138.0	12.5	20.00	16.86		X	X	X								
HOW-T3	Dist.	25.0	4.2	1.00	0.63	X											
HUM-T1	Dist.	66.0	12.5	25.00	18.12		X	X	X								X
HWD-T1	Dist.	66.0	12.5	20.00	18.20		X	X	X								X
HWD-T2	Dist.	66.0	12.5	20.00	18.10		X	X	X								X
HWD-T3	Dist.	66.0	25.0	50.00	52.95			X	X								
ILC-T1	Dist.	66.0	12.5	13.33	8.14	X	X	X	X				X		X		X
ISL-T1	Dist.	66.0	12.5	4.00	4.12	X	X	X	X				X		X		X
JON-T1	Dist.	66.0	7.2	0.33	0.10	X	X		X			X					
KBR-T3	Dist.	66.0	25.0	25.00	21.39		X	X	X								X
KBR-T4	Dist.	66.0	25.0	25.00	22.26		X	X	X								X
KEL-T1	Dist.	66.0	25.0	25.00	23.83		X	X	X								X
KEN-T1	Dist.	66.0	25.0	25.00	20.24		X	X	X								X
KEN-T2	Dist.	66.0	25.0	50.00	42.20			X	X								
LAU-T1	Dist.	66.0	12.5	13.30	4.56	X	X	X	X				X		X		X
LET-T1	Dist.	66.0	25.0	16.67	9.17	X	X	X	X								X
LEW-T1	Dist.	138.0	25.0	25.00	20.59		X	X	X								
LGL-T1	Dist.	66.0	25.0	14.90	6.53	X	X	X	X							X	X

Table A-1
Power Transformer Listing – Portable/Spare Capability

		Operating Voltage				NP Portable Compatibility				NP Spare Inventory Compatibility							
Designation	Type	High (kV)	Low (kV)	Size MVA	2025 Forecast MVA	P1	P3	P4	P5	200-299	200-185	200-358	200-219	200-352	200-220	200-328	200-385
LLK-T1	Dist.	138.0	12.5	20.00	5.67		X	X	X								
LOK-T3	Dist.	66.0	12.5	4.00	3.67	X	X	X	X				X		X		X
LPD-T1	Dist.	66.0	12.5	25.00	18.00		X	X	X								X
LPD-T2	Dist.	66.0	12.5	25.00	18.00		X	X	X								X
MIL-T1	Dist.	66.0	25.0	16.67	13.15		X	X	X								X
MKS-T1	Dist.	138.0	25.0	14.90	8.00		X	X	X	X							
MMT-T1	Dist.	66.0	12.5	6.67	5.35	X	X	X	X				X		X		X
MOB-T2	Dist.	66.0	12.5	16.67	13.73		X	X	X								X
MOL-T1	Dist.	66.0	12.5	25.00	27.58		X	X	X								X
MOL-T2	Dist.	66.0	12.5	25.00	26.07		X	X	X								X
MSY-T1	Dist.	138.0	12.5	20.00	17.61		X	X	X								
MUN-T1	Dist.	66.0	12.5	14.96	3.87	X	X	X	X				X		X		X
MUN-T2	Dist.	66.0	12.5	25.00	6.18	X	X	X	X				X		X		X
NCH-T1	Dist.	66.0	12.5	6.67	3.52	X	X	X	X				X		X		X
NHR-T1	Dist.	66.0	12.5	13.33	7.86	X	X	X	X				X		X		X
NWB-T1	Dist.	138.0	25.0	11.20	6.19		X	X	X	X							
OPL-T1	Dist.	66.0	12.5	15.00	8.76	X	X	X	X				X		X		X
OXP-T1	Dist.	66.0	12.5	13.33	9.86	X	X	X	X				X		X		X
PAB-T5	Dist.	66.0	12.5	13.33	8.99	X	X	X	X				X		X		X
PAS-T1	Dist.	66.0	12.5	13.30	14.48		X	X	X								X
PBD-T1	Dist.	138.0	25.0	16.67	3.14		X	X	X	X							
PEP-T1	Dist.	66.0	25.0	25.00	12.35		X	X	X								X
PEP-T2	Dist.	66.0	25.0	25.00	13.06		X	X	X								X
PHR-T3	Dist.	33.0	4.2	4.00	2.55	X											
PJN-T1	Dist.	66.0	7.2	0.33	0.45	X	X		X			X					

Table A-1
Power Transformer Listing – Portable/Spare Capability

		Operating Voltage				NP Portable Compatibility				NP Spare Inventory Compatibility							
Designation	Type	High (kV)	Low (kV)	Size MVA	2025 Forecast MVA	P1	P3	P4	P5	200-299	200-185	200-358	200-219	200-352	200-220	200-328	200-385
PUL-T1	Dist.	66.0	25.0	25.00	21.42		X	X	X								X
PUL-T2	Dist.	66.0	25.0	25.00	21.94		X	X	X								X
QTZ-T1	Dist.	66.0	4.2	0.75	0.11	X					X				X		
RBK-T2	Dist.	66.0	25.0	6.67	3.40	X	X	X	X							X	X
ROB-T1	Dist.	66.0	25.0	6.67	4.73	X	X	X	X							X	X
RRD-T2	Dist.	66.0	12.5	20.00	17.40		X	X	X								X
RRD-T3	Dist.	66.0	12.5	20.00	19.56		X	X	X								X
RVH-T1	Dist.	66.0	25.0	8.33	3.35	X	X	X	X							X	X
SCR-T1	Dist.	138.0	25.0	8.30	5.94		X	X	X	X							
SCT-T1	Dist.	66.0	25.0	6.67	1.84	X	X	X	X							X	X
SCT-T2	Dist.	25.0	12.5	4.00	1.00	X											
SCV-T2	Dist.	66.0	25.0	11.20	9.49	X	X	X	X								X
SJM-T1	Dist.	66.0	25.0	25.00	16.15		X	X	X								X
SJM-T2	Dist.	66.0	12.5	25.00	17.47		X	X	X								X
SJM-T3	Dist.	66.0	25.0	25.00	11.97		X	X	X								X
SLA-T1	Dist.	66.0	4.2	13.30	4.19	X											
SLA-T2	Dist.	66.0	4.2	10.40	3.72	X									X		
SLA-T3	Dist.	66.0	12.5	25.00	20.13		X	X	X								X
SLA-T4	Dist.	66.0	12.5	25.00	21.69		X	X	X								X
SMV-T1	Dist.	66.0	25.0	4.00	2.95	X	X	X	X							X	X
SPF-T1	Dist.	138.0	12.5	20.00	14.46		X	X	X								
SPO-T1	Dist.	66.0	12.5	15.00	12.19		X	X	X						X		X
SPR-T1	Dist.	138.0	25.0	16.67	12.54		X	X	X	X							
STG-T1	Dist.	66.0	25.0	6.67	4.07	X	X	X	X							X	X
STX-T1	Dist.	66.0	12.5	6.67	5.19	X	X	X	X				X		X		X

Table A-1
Power Transformer Listing – Portable/Spare Capability

		Operating Voltage				NP Portable Compatibility				NP Spare Inventory Compatibility							
Designation	Type	High (kV)	Low (kV)	Size MVA	2025 Forecast MVA	P1	P3	P4	P5	200-299	200-185	200-358	200-219	200-352	200-220	200-328	200-385
SUM-T1	Dist.	66.0	25.0	13.33	7.60	X	X	X	X							X	X
SUN-T5	Dist.	138.0	25.0	25.00	10.38		X	X	X	X							
TNS-T1	Dist.	138.0	14.4	1.00	0.91		X		X								
TRN-T1	Dist.	66.0	25.0	6.67	3.61	X	X	X	X							X	X
TRP-T1	Dist.	66.0	12.5	15.00	2.44	X	X	X	X				X		X		X
TWG-T1	Dist.	66.0	12.5	13.33	9.32	X	X	X	X				X		X		X
VIC-T1	Dist.	66.0	12.5	13.33	9.76	X	X	X	X				X		X		X
VIR-T1	Dist.	66.0	12.5	25.00	22.18		X	X	X								X
VIR-T2	Dist.	66.0	25.0	25.00	24.64		X	X	X								X
VIR-T3	Dist.	66.0	25.0	25.00	11.65		X	X	X								X
WAL-T1	Dist.	66.0	12.5	20.00	22.33		X	X	X								X
WAL-T2	Dist.	66.0	12.5	25.00	22.93		X	X	X								X
WAV-T6	Dist.	66.0	12.5	13.30	6.51	X	X	X	X				X		X		X
WBC-T1	Dist.	66.0	25.0	8.33	3.34	X	X	X	X							X	X
WES-T1	Dist.	66.0	12.5	13.33	9.57	X	X	X	X				X		X		X
CAB-T1	Gen.	66.0	7.2	11.25	N/A	X	X		X								
FPD-T1-A	Gen.	12.5	4.2	0.25	N/A												
FPD-T1-B	Gen.	12.5	4.2	0.25	N/A												
FPD-T1-C	Gen.	12.5	4.2	0.25	N/A												
GRH-T1	Gen.	66.0	13.8	30.00	N/A	X	X		X								
HCP-T1	Gen.	66.0	6.9	12.00	N/A	X	X		X								
HCT-T1	Gen.	66.0	2.4	3.00	N/A	X											
LBK-T1	Gen.	66.0	2.4	10.00	N/A	X											
LOK-T1	Gen.	46.0	6.9	2.50	N/A	X	X		X								
LOK-T2	Gen.	66.0	46.0	7.46	N/A	X	X		X								

Table A-1
Power Transformer Listing – Portable/Spare Capability

		Operating Voltage				NP Portable Compatibility				NP Spare Inventory Compatibility							
Designation	Type	High (kV)	Low (kV)	Size MVA	2025 Forecast MVA	P1	P3	P4	P5	200-299	200-185	200-358	200-219	200-352	200-220	200-328	200-385
LOK-T4	Gen.	46.0	6.9	2.50	N/A	X	X		X								
MOP-T1	Gen.	66.0	6.9	10.00	N/A	X	X		X								
MRP-T1	Gen.	66.0	2.4	1.50	N/A	X											
NCH-T2	Gen.	66.0	6.9	5.33	N/A	X	X		X								
PAB-T3	Gen.	66.0	4.2	4.00	N/A	X											
PBK-T1	Gen.	66.0	6.9	6.67	N/A	X	X		X								
PHR-T1	Gen.	33.00	2.4	6.70	N/A	X											
PIT-T1-A	Gen.	12.5	4.2	0.33	N/A												
PIT-T1-B	Gen.	12.5	4.2	0.33	N/A												
PIT-T1-C	Gen.	12.5	4.2	0.33	N/A												
PUN-T1-A	Gen.	66.0	2.4	0.33	N/A	X											
PUN-T1-B	Gen.	66.0	2.4	0.33	N/A	X											
PUN-T1-C	Gen.	66.0	2.4	0.33	N/A	X											
RBH-T1	Gen.	25.0	6.9	9.30	N/A												
RBK-T1	Gen.	66.0	6.9	23.75	N/A	X	X		X								
ROP-T1	Gen.	66.0	6.9	5.33	N/A	X	X		X								
SBK-T1	Gen.	66.0	6.9	7.00	N/A	X	X		X								
SCV-T1	Gen.	66.0	4.2	3.33	N/A	X											
TCV-T1	Gen.	66.0	6.9	7.50	N/A	X	X		X								
TOP-T1	Gen.	25.0	2.4	0.75	N/A												
TOP-T1	Gen.	25.0	2.4	0.75	N/A												
TOP-T1	Gen.	25.0	2.4	0.75	N/A												
VIC-T2	Gen.	12.5	2.4	0.60	N/A												
WBK-T1	Gen.	12.5	2.4	0.33	N/A												
WBK-T1	Gen.	12.5	2.4	0.33	N/A												

Table A-1
Power Transformer Listing – Portable/Spare Capability

		Operating Voltage				NP Portable Compatibility				NP Spare Inventory Compatibility							
Designation	Type	High (kV)	Low (kV)	Size MVA	2025 Forecast MVA	P1	P3	P4	P5	200-299	200-185	200-358	200-219	200-352	200-220	200-328	200-385
WBK-T1	Gen.	12.5	2.4	0.33	N/A												
WES-T2	Gen.	66.0	13.2	16.00	N/A	X	X		X								
BLK-T3	Tran.	138.0	66.0	41.60	N/A			X						X			
BRB-T2	Tran.	138.0	66.0	41.60	N/A			X						X			
BRB-T3	Tran.	138.0	66.0	41.60	N/A			X						X			
CAT-T1	Tran.	138.0	66.0	16.70	N/A		X	X						X			
CLV-T1	Tran.	138.0	66.0	25.00	N/A		X	X						X			
COB-T2	Tran.	138.0	66.0	41.60	N/A			X						X			
GAM-T2	Tran.	138.0	66.0	41.60	N/A			X						X			
GAN-T2	Tran.	138.0	66.0	21.30	N/A		X	X						X			
GAN-T3	Tran.	66.0	N/A	3.50	N/A												
GFS-T1	Tran.	138.0	66.0	29.70	N/A			X						X			
GOU-T1	Tran.	66.0	33.0	10.00	N/A												
RBK-T3	Tran.	138.0	66.0	25.00	N/A		X	X						X			
SPO-T4	Tran.	138.0	66.0	41.60	N/A			X						X			
SPO-T5	Tran.	138.0	66.0	41.60	N/A			X									

Note: * Generation Plant will require an operational derating when served by the portable substation due to differences in transformer capacity.

APPENDIX B:

Power Transformer Failures: 2015 to 2024

Table B-1 lists Newfoundland Power's actual experience with respect to substation power transformer failures from 2015 to 2024.

Table B-1
Power Transformer Failures
(2015-2024)

Transformer	Voltage	Capacity (MVA)	Year Purchased	Year Failed	Action	Portable Required	Type of Failure
MUN-T2	66 – 12.5	20	1976	2022	Replacement	No	Imminent
BLK-T2	138 - 25	20	1977	2021	Repair	Yes	Imminent
DUN-T1	66 - 25	25	1990	2021	Repair	No	In-Service
SLA-T3	66 - 12.5	24.375	1973	2021	Repair	No	Imminent
SLA-T4	66 - 12.5	25	1988	2021	Replacement	No	In-Service
GBS-T1	66 - 12.5	25	1966	2020	Replacement	Yes	Imminent
HUM-T2[1]	66 - 4.16	7.46	1968	2020	Repair	Yes	Imminent
HUM-T3[2]	66 - 12.5	13.3	1974	2020	Repair	Yes	Imminent
PIT-T1	12.5 - 2.4	3 x 0.333	1983	2020	Replacement	No	Imminent
TRN-T1	66 - 25	6.67	1972	2020	Repair	No	In-Service
BVA-T1	138 - 12.5	25	1990	2018	Repair	Yes	In-Service
PUL-T2	66 - 12.5	25	2011	2019	Replacement	Yes	Imminent
RVH-T1	66 - 12.5	8.33	1968	2017	Replacement	Yes	In-Service

[1] HUM-T2 was subsequently scrapped due to poor test results following its removal from service as part of the *2022 Humber Substation Refurbishment & Modernization* project.
[2] HUM-T3 was subsequently replaced and scrapped as part of the *2022 Humber Substation Refurbishment & Modernization* project.

APPENDIX C:

Gannett Flemming – Service Life Study

NEWFOUNDLAND POWER INC.

ST. JOHN'S, CANADA

SERVICE LIFE STUDY

NEWFOUNDLAND POWER
POWER TRANSFORMERS
AS OF DECEMBER 31, 2022

Prepared by:

GANNETT FLEMING

Excellence Delivered As Promised

NEWFOUNDLAND POWER INC.

ST. JOHN'S, CANADA

SERVICE LIFE STUDY
NEWFOUNDLAND POWER
POWER TRANSFORMERS
AS OF DECEMBER 31, 2022

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Mechanicsburg, Pennsylvania

GANNETT FLEMING

Gannett Fleming
Valuation and Rate Consultants, LLC

Corporate Headquarters
300 Sterling Parkway, Suite 200
Mechanicsburg, PA 17050
717.763.7211

June 24, 2025

Newfoundland Power Inc.
55 Kenmount Road
St. John's, NL A1B 3P6

Ladies and Gentlemen:

Pursuant to your request, we have conducted a service life study related to Newfoundland Power Inc.'s substation power transformers. The attached report presents a description of the methods used in the estimation of power transformer service lives, the statistical support for the service life estimate, and a 30-year forecast of anticipated power transformer retirements.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

John F. Wiedmayer

JOHN WIEDMAYER
Sr. Project Manager – Depreciation Studies

JASON POWERY
Assistant Project Manager

JFW
074887.000

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NEWFOUNDLAND POWER INC.

SERVICE LIFE STUDY

EXECUTIVE SUMMARY

Pursuant to Newfoundland Power Inc.'s ("Newfoundland" or "Company") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a service life study related to the Company's substation power transformers as of December 31, 2022. The purpose of this study was to estimate reasonable lives for in-service power transformers and to forecast an expected retirement schedule for each of the units over the next 30 years.

Gannett Fleming has nearly thirty years of experience working with Newfoundland on projects involving the Company's service lives and depreciation of its assets. Gannett Fleming has performed several depreciation studies of Newfoundland's transmission and distribution property as part of depreciation studies filed with Newfoundland's rate cases.

The recommended service life for power transformers in this study (55-R3) differs from the Account 342 Substation Equipment estimate (48-R1) that was proposed by the Company in the most recent 2019 Depreciation Study. The account contains a variety of assets, including power transformers, circuit breakers, busbars, switches, capacitor banks, lightning arresters and several other types of substation equipment. The proposed 48-R1 in the 2019 Depreciation Study reflects a composite life for all of these assets. For the purposes of this study, the lives of power transformers were analyzed exclusive of other substation equipment, and the 55-R3 survivor curve was determined to be most reasonable. This recommended service life is consistent with the analysis of available data, comparisons to estimates for comparable utilities, and information from discussions with Newfoundland management regarding the assets.

The 30-year forecast of anticipated power transformer retirements is derived from the expected average service life and the ages of the existing assets. For this study, retirements were calculated using statistical modeling. It is important to acknowledge that the condition of the units was not considered in this analysis, and this statistical approach was intended to provide a high-level outlook. Therefore, these results can be interpreted as providing general view of likely scenarios rather than an exact depiction of future occurrences. As with any projection, uncertainties may exist, and the forecast should be interpreted with the understanding that it offers a broad overview of potential outcomes.

Detailed results of the 30-year forecast of anticipated power transformer retirements are provided in Part V of this report. Statistical support for the service life estimate recommended in this study is provided in Part V of this report. A summary of the expected power transformer retirements at the transaction year level is presented below:

Transaction Year	Power Transformers Retired
2023	3
2024	1
2025	3
2026	1
2027	4
2028	3
2029	4
2030	5
2031	3
2032	3
2033	3
2034	4
2035	5
2036	4
2037	4
2038	5
2039	7
2040	4
2041	5
2042	4
2043	3

Transaction Year	Power Transformers Retired
2044	4
2045	3
2046	3
2047	3
2048	3
2049	3
2050	3
2051	3
2052	4
Total	***107***

PART I. INTRODUCTION

NEWFOUNDLAND POWER INC.
SERVICE LIFE STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the service life study for Newfoundland Power Inc. (“Newfoundland” or “Company”) power transformers as of December 31, 2022. The service life estimates resulting from the study were based on informed judgment which incorporated analyses of historical plant retirement data as recorded through 2022; a review of Company practice and outlook as they relate to changes in technology, plant operation and retirement; and consideration of current practice in the electric industry including knowledge of service life estimates used for other electric companies, including for Newfoundland’s system as a whole. The 30-year forecast of anticipated power transformer retirements is derived from the expected average service life and the ages of the existing assets.

PLAN OF REPORT

Part I, Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II, Estimation of Survivor Curves, presents descriptions of the methods used in the service life study. Part III, Service Life Considerations, presents the factors and judgment utilized in the average service life analysis. Part IV, Forecasted Retirements, presents descriptions of the methods used in the estimation of future power transformer retirements. Part V, Results of Study, presents a summary of expected future power transformer retirements by transaction year and by installation year, and Part VI, Service Life Statistics, presents the statistical analysis of the service life estimate for power transformers.

BASIS OF THE STUDY

Service Life Estimates

The service life estimate proposed in this study was based on informed judgment which incorporated the statistical analyses of the Company's historical data; a review of management's plans, policies and outlook; general knowledge of the property studied; and a general knowledge of the electric utility industry, including the service life estimates from our studies of other electric utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for utility property. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

An understanding of the function of the plant and information with respect to the reasons for past retirements and the expected causes of future retirements was obtained through discussions with operating and management personnel. The supplemental information obtained in this manner was considered in the interpretation and extrapolation of the statistical analyses.

The results of the service life study for power transformers are provided in Part VI of this report. Based on the results of our studies, Gannett Fleming recommends that the asset quantities, ages and service life estimates be used to develop the most reasonable and accurate estimates of accumulated depreciation.

Forecast of Expected Retirements

The 30-year forecast of anticipated power transformer retirements is derived from the expected average service life and the ages of the existing assets. For this study, retirements were calculated using statistical modeling. It is important to acknowledge that the condition of the units was not considered in this analysis, and this statistical approach was intended to provide a high-level outlook. Therefore, these results can be interpreted as providing general view of likely scenarios rather than an exact depiction of future occurrences. As with any projection, uncertainties may exist, and the forecast should be interpreted with the understanding that it offers a broad overview of potential outcomes.

PART II. ESTIMATION OF SURVIVOR CURVES

PART II. ESTIMATION OF SURVIVOR CURVES

SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units or by constructing a survivor curve by plotting the number of units which survive at successive ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements (or the portion of the frequency curve with the highest level of retirements) in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family. A higher number designates a higher mode curve.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.

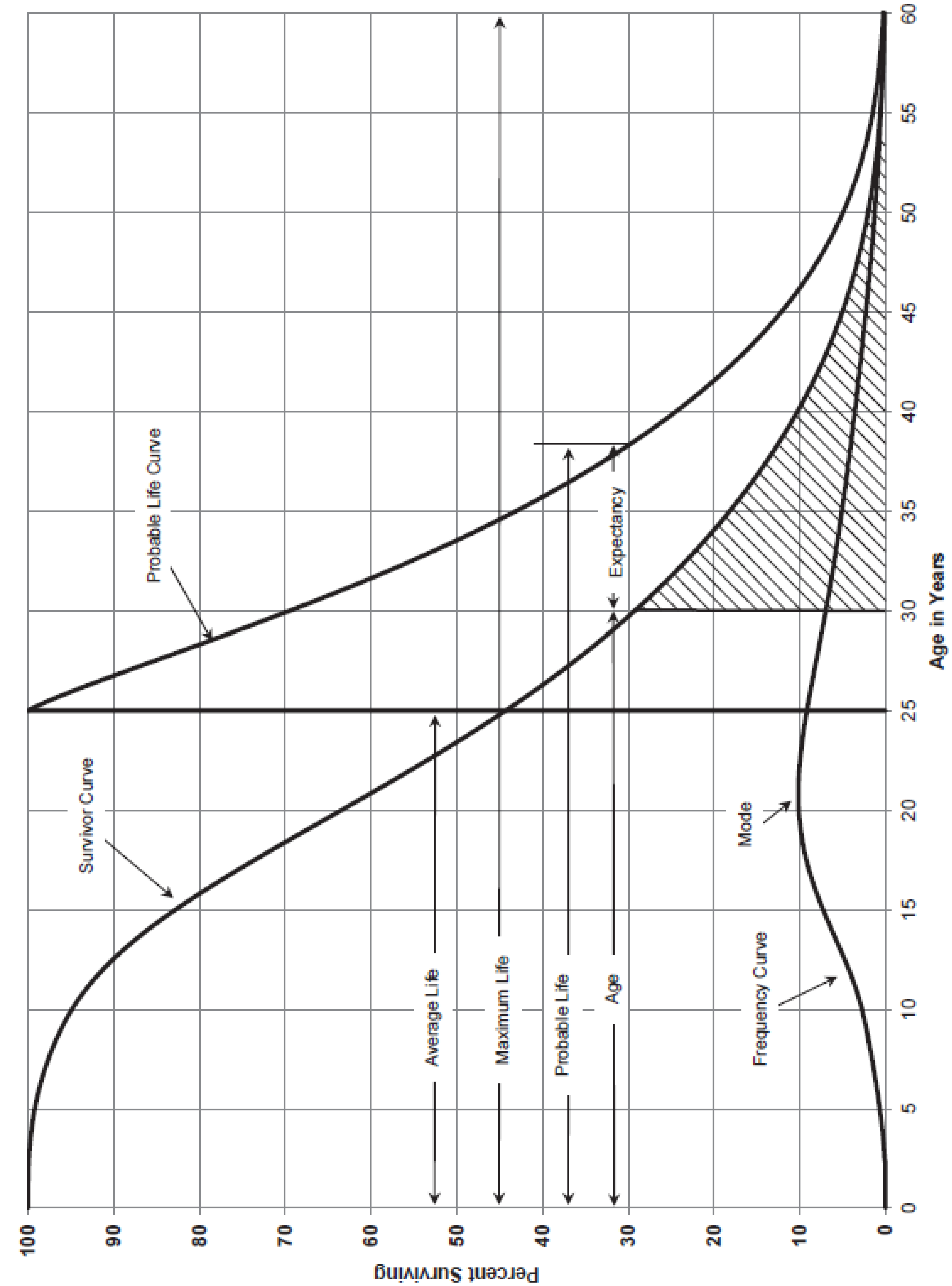

FIGURE 1. TYPICAL SURVIVOR CURVE AND DERIVED CURVES

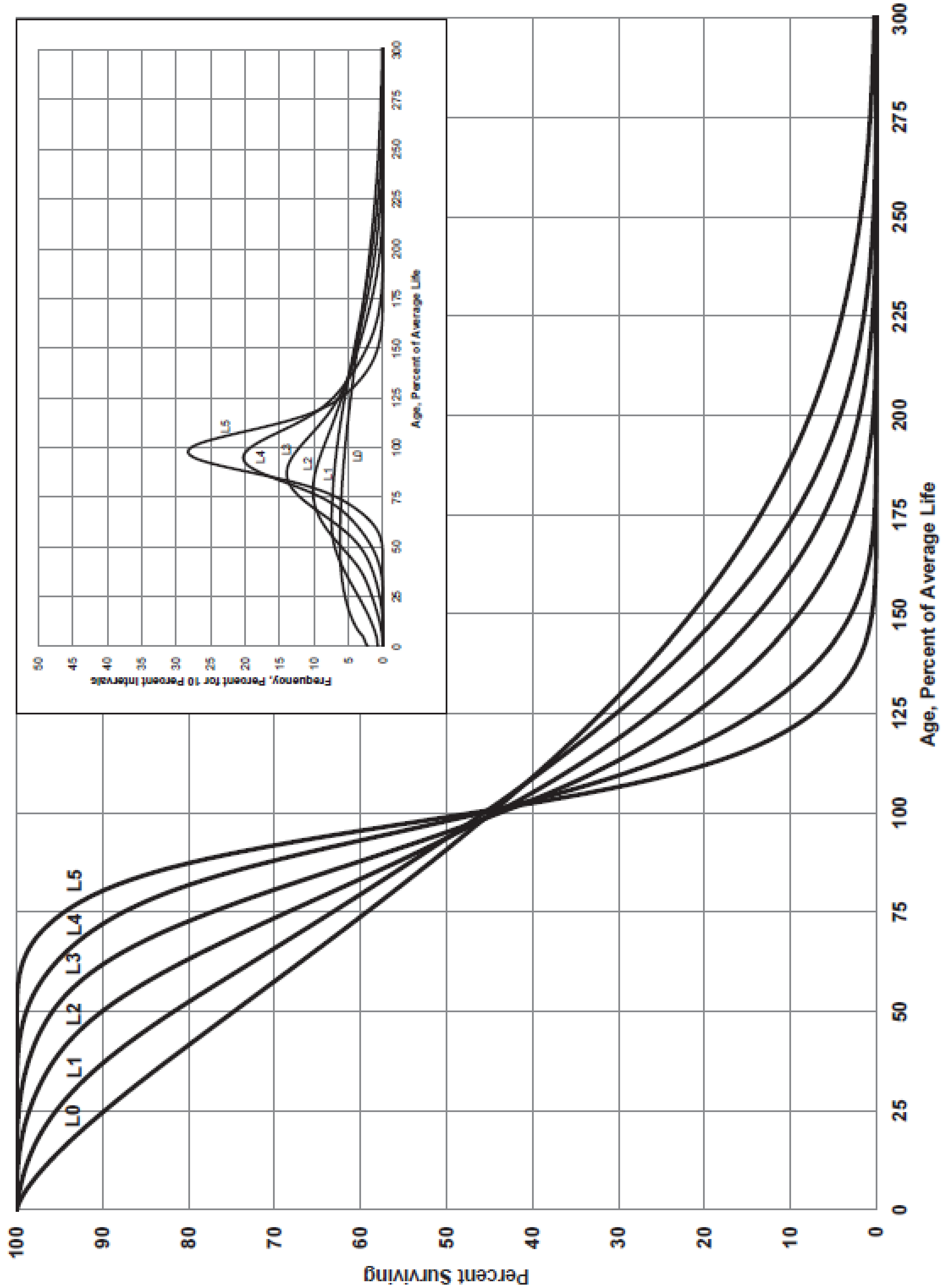

FIGURE 2. LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

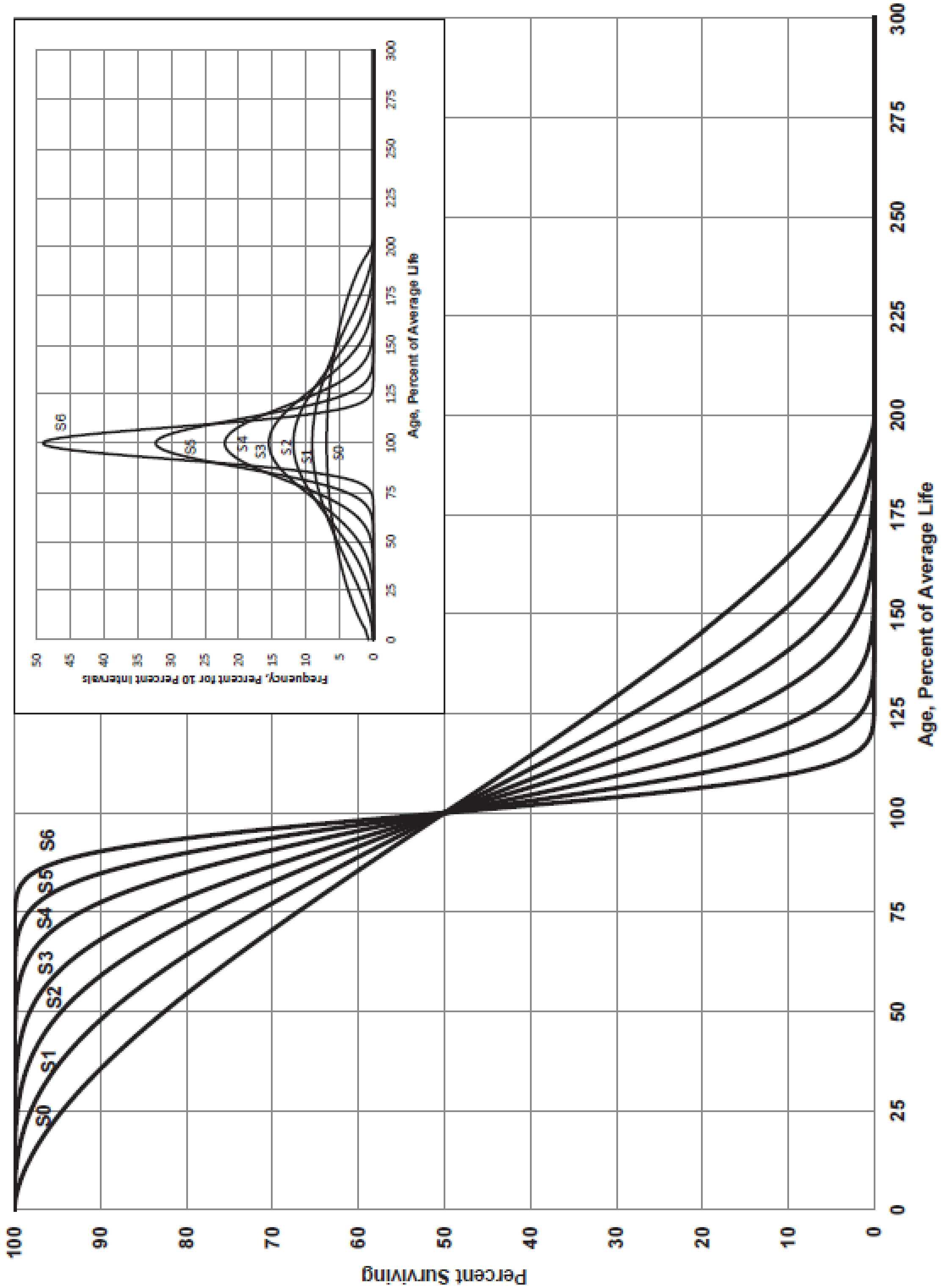

FIGURE 3. SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

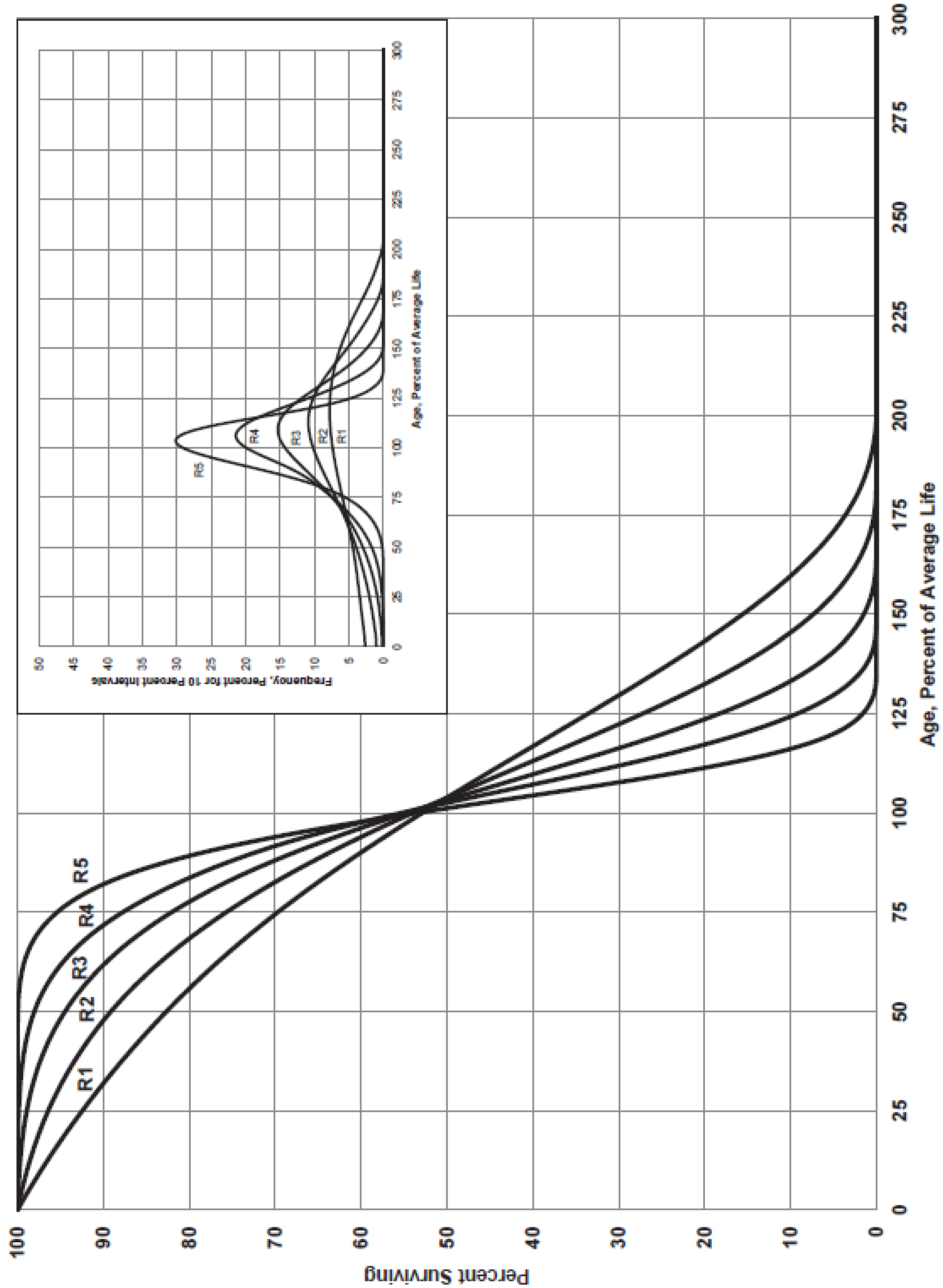

FIGURE 4. RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

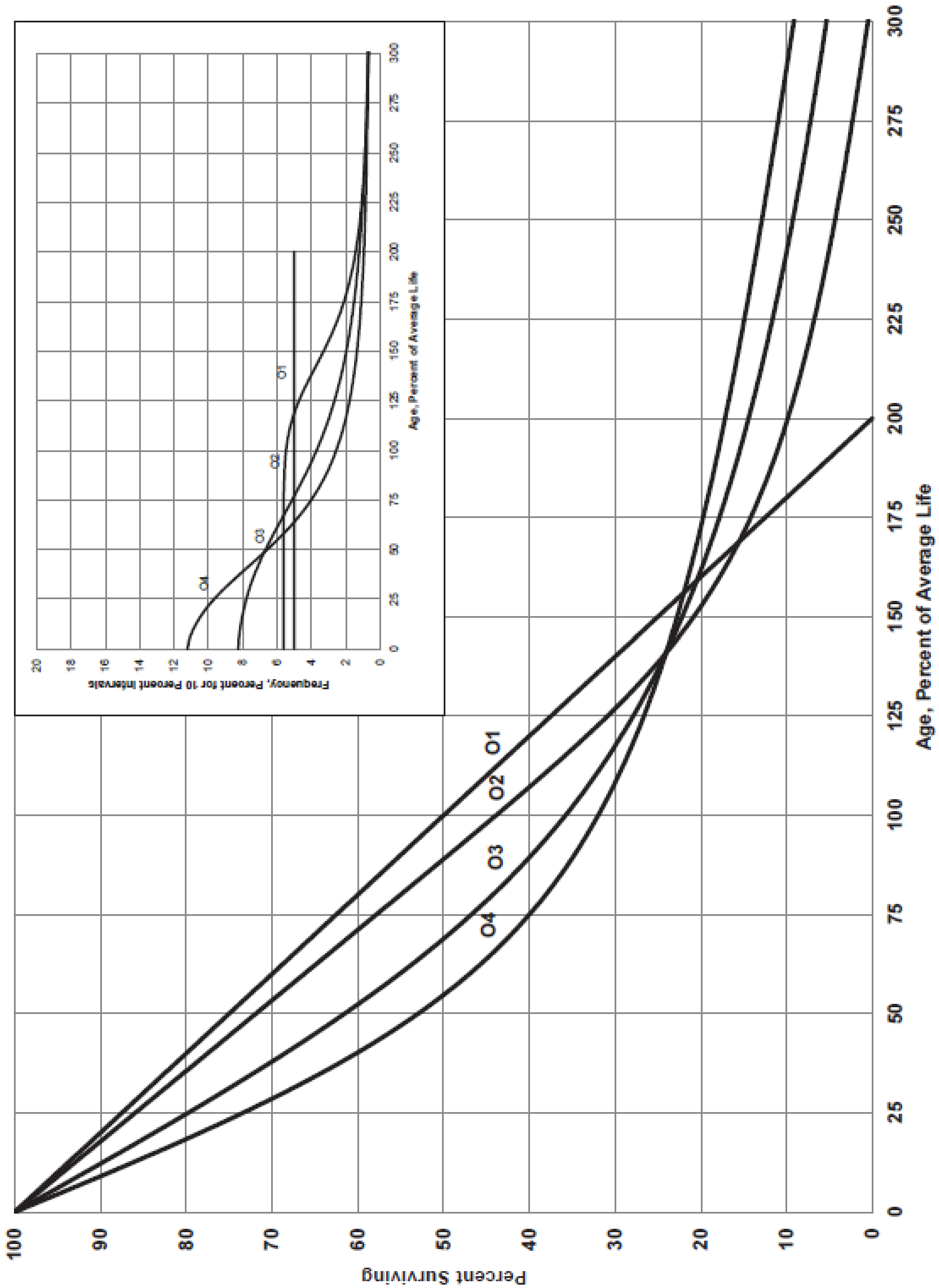

FIGURE 5. ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES

These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."1 In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text and is also explained in several publications including "Statistical Analyses of Industrial Property Retirements,"[2] "Engineering Valuation and Depreciation,"[3] and "Depreciation Systems."[4]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band. The band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

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[1]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[2]Winfrey, Robley, Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

[3]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 1.

[4]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2013-2022 for which there were placements during the years 2008-2022. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2008 were retired in 2013. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2013 retirements of 2008 installations and ending with the 2022 retirements of the 2017 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2013-2022
SUMMARIZED BY AGE INTERVAL

Experience Band 2013-2022 — Placement Band 2008-2022

Year	Retirements, Thousands of Dollars											
	During Year										Total During	Age
Placed	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Age Interval	Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2008	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2009	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2010	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2011	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2012	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2013	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2014		5	11	12	13	14	15	16	18	20	113	7½-8½
2015			6	12	13	15	16	17	19	19	124	6½-7½
2016				6	13	15	16	17	19	19	131	5½-6½
2017					7	14	16	17	19	20	143	4½-5½
2018						8	18	20	22	23	146	3½-4½
2019							9	20	22	25	150	2½-3½
2020								11	23	25	151	1½-2½
2021									11	24	153	½-1½
2022										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2013-2022
SUMMARIZED BY AGE INTERVAL

Experience Band 2013-2022 | Placement Band 2008-2022

Year Placed	Acquisitions, Transfers and Sales, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2008	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2009	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2010	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2011	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2012	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2013	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2014		-	-	-	-	-	-	-	-	-	6	7½-8½
2015			-	-	-	-	-	-	-	-	-	6½-7½
2016				-	-	-	-	(12)[b]	-	-	-	5½-6½
2017					-	-	-	-	22[a]	-	-	4½-5½
2018						-	-	(19)[b]	-	-	10	3½-4½
2019							-	-	-	-	-	2½-3½
2020								-	-	(102)[c]	(121)	1½-2½
2021									-	-	-	½-1½
2022											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2013 through 2022 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2018 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2013-2022
SUMMARIZED BY AGE INTERVAL

Experience Band 2013-2022 | Placement Band 2008-2022

Year	Exposures, Thousands of Dollars										Total at	
	Annual Survivors at the Beginning of the Year										Beginning of	Age
Placed	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Age Interval	Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2008	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2009	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2010	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2011	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2012	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2013	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2014		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2015			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2016				580[a]	574	561	546	530	501	482	3,057	5½-6½
2017					660[a]	653	639	623	628	609	3,789	4½-5½
2018						750[a]	742	724	685	663	4,332	3½-4½
2019							850[a]	841	821	799	4,955	2½-3½
2020								960[a]	949	926	5,719	1½-2½
2021									1,080[a]	1,069	6,579	½-1½
2022										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a]Additions during the year

For the entire experience band 2013-2022, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on page II-16, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

SCHEDULE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2013-2022 Placement Band 2008-2022

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

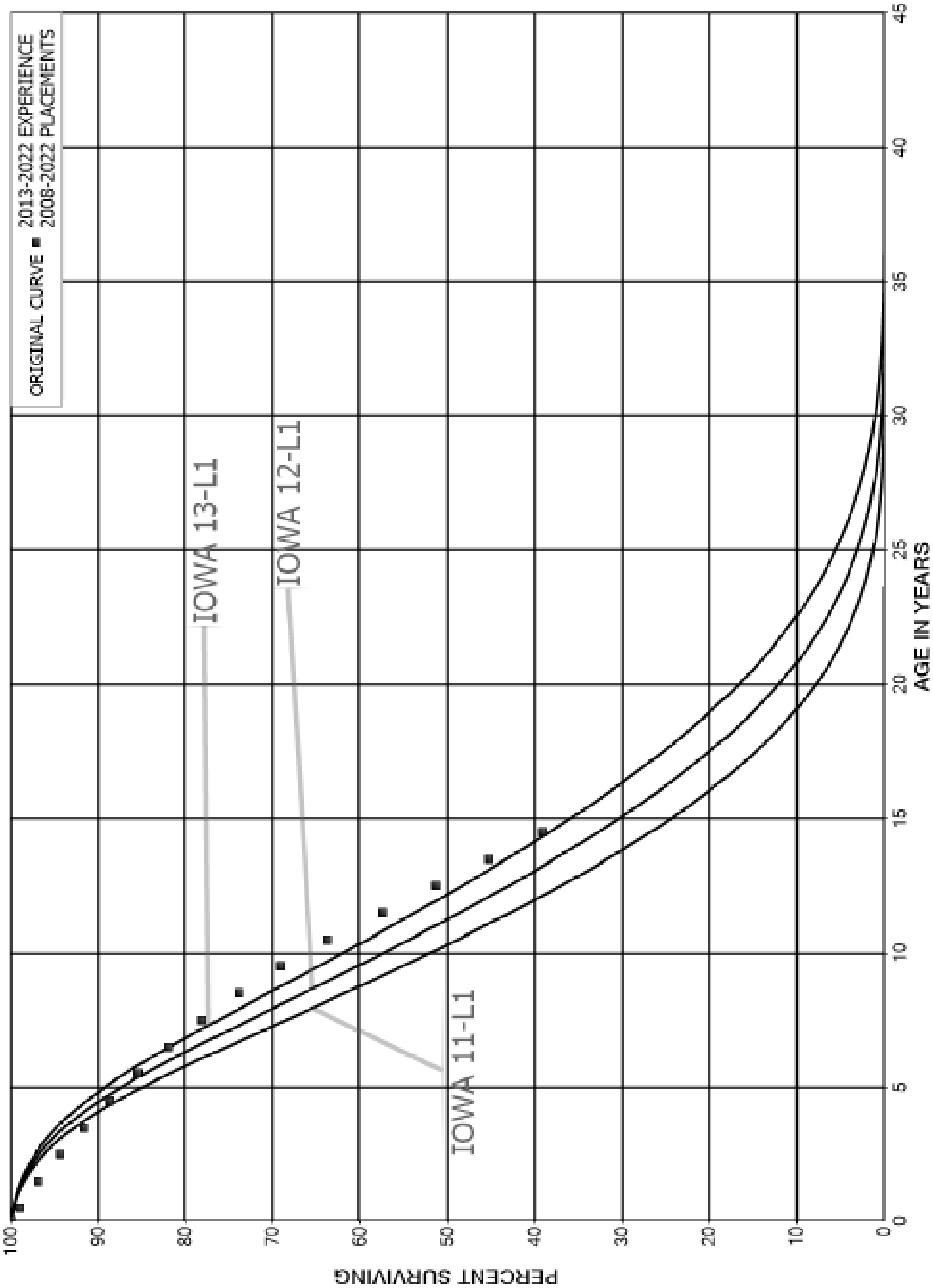


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

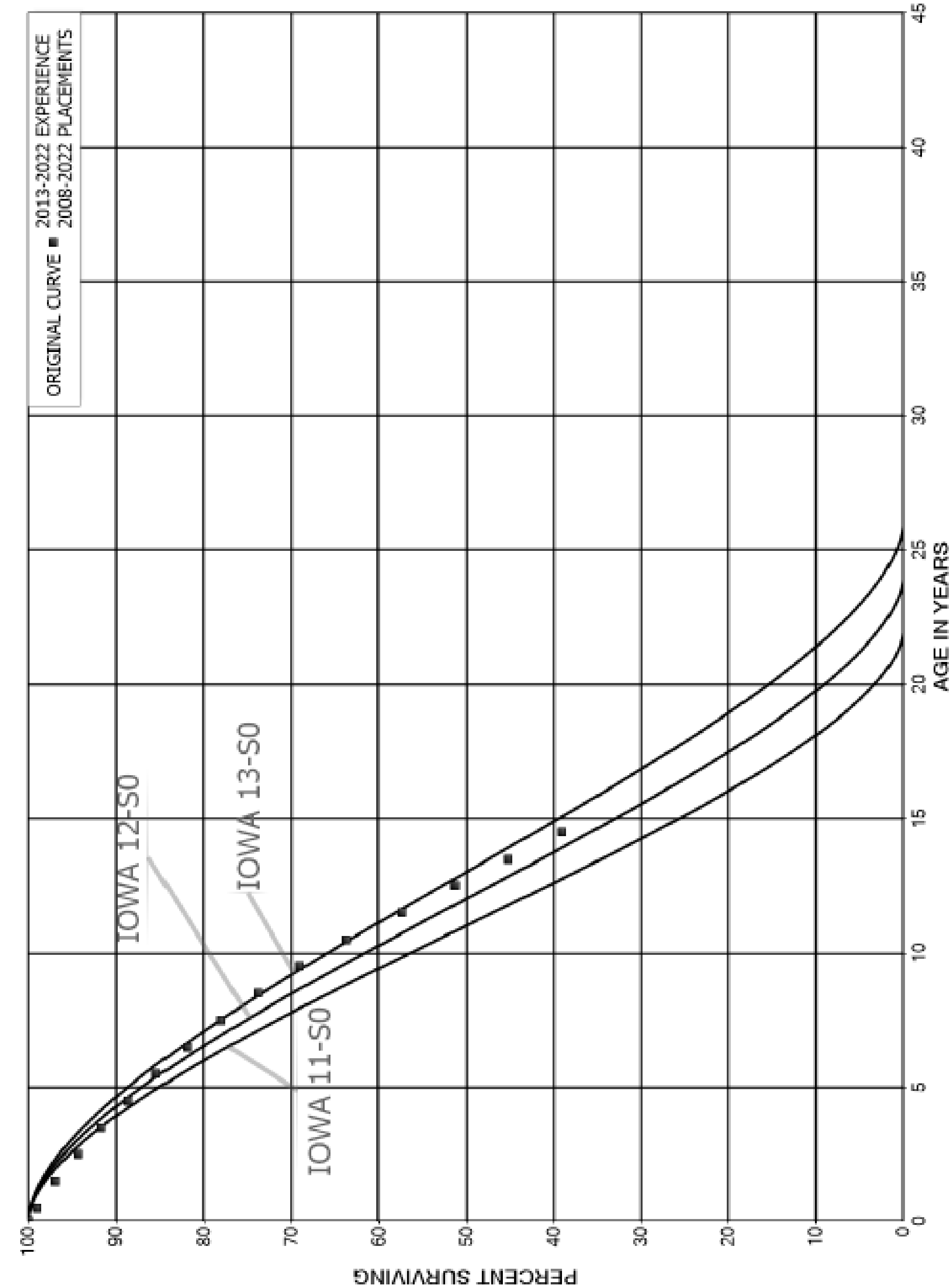


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

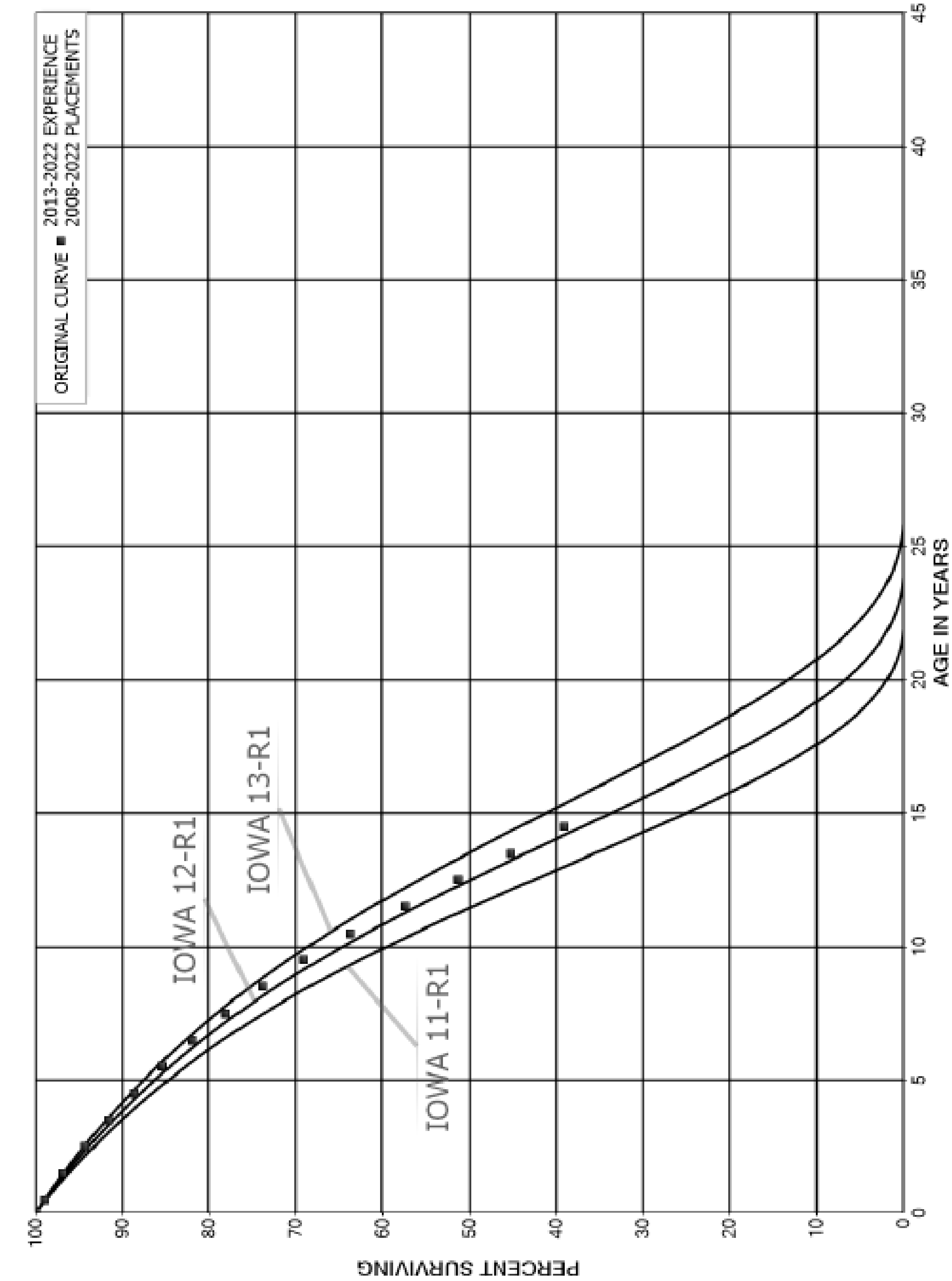
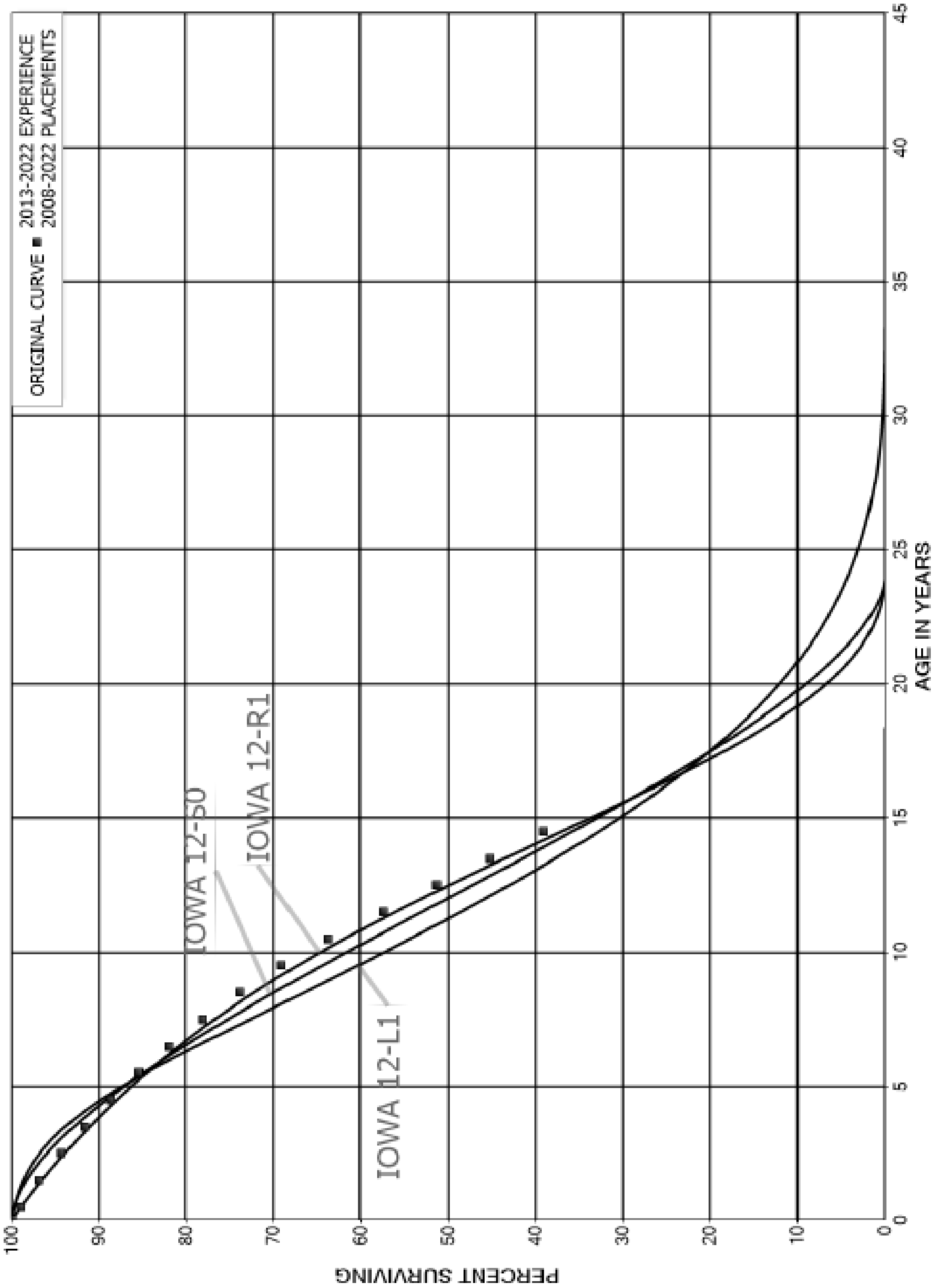


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

The service life estimate for power transformers was based on judgment which considered several factors. The primary factors were the survivor curve estimates from previous studies of this company and other electric utility companies; statistical analyses of data; and the current Company policies and outlook as determined during conversations with management. All of these factors support a service life in the 50-year range.

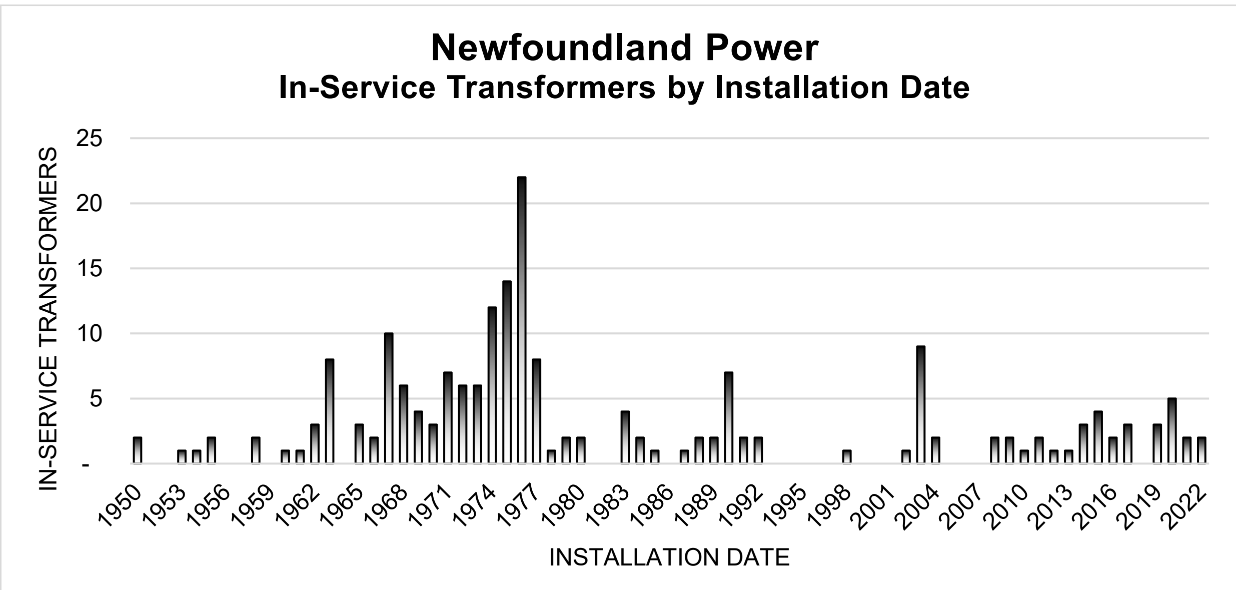
POWER TRANSFORMERS

Substation power transformers are vital components in electrical substations, enabling the efficient transmission and distribution of electricity by transforming voltage levels. They play a key role in stepping up or down voltage to facilitate long-distance transmission while minimizing energy losses. Equipped with protective and monitoring devices, these transformers ensure safe and reliable operation within the electrical grid. Designed to withstand varying loads and environmental conditions, they are robust assets crucial for voltage regulation and power quality maintenance. As essential elements of the transmission and distribution network, substation power transformers facilitate the seamless transfer of electrical power to meet the energy demands of consumers and industries. Their proper functioning and maintenance are critical to ensuring a reliable and uninterrupted supply of electricity to end-users.

The industry average service life expectation for power transformers typically ranges from 45 to 55 years. Power transformers are designed and manufactured to be highly durable and reliable, with the intention of providing long-term operation under normal operating conditions. The service life of a power transformer can be influenced by various factors, including its design, construction quality, maintenance practices, and the operating environment.

Regular maintenance, testing, and monitoring play a crucial role in extending the service life of power transformers. With proper care and maintenance, transformers can often exceed their expected average service life and continue to operate efficiently and reliably for several decades.

As of December 31, 2022, Newfoundland's database consists of 208 in-service transformers and 91 retired transformers. The surviving transformers have installation dates ranging from 1950 through 2022, and the majority of installations occurred in the mid-1960s to late 1970s (see figure below):



EXISTING ESTIMATE

In the most recent 2019 Depreciation Study, the 48-R1 survivor curve was proposed by the Company for Account 342 Substation Equipment. The account contains a variety of assets, including power transformers, circuit breakers, busbars, switches, capacitor banks, lightning arresters and several other types of substation equipment. The proposed 48-R1 in the 2019 Depreciation Study reflects a composite life for all of these assets. Across the industry, breakers and other smaller types of substation equipment typically have lives in the 40-year range. Power transformers are typically expected to have average service lives in the 45 to 55-year range.

ACTUARIAL LIFE ANALYSIS

Data for the actuarial life analysis[5] of power transformers was provided for the years 1997 through 2022. The results of actuarial life analysis for Newfoundland transformers indicate average service lives of somewhat longer than 50 years. Low and mid-mode R curves are most common for this type of equipment. Statistical support for the actuarial life analysis is provided in Part VI of this report.

RECOMMENDATIONS

For the purposes of this study, the 55-R3 survivor curve was determined to be most reasonable. This average service life estimate of 55 years is at the upper end of the typical average service life range for power transformers. From an operating perspective, Newfoundland Power's transformers are typically not overloaded. That is, they are not loaded electrically beyond their maximum nominal load capacity for an extended period. Electrical transformers that operate below the maximum load capacity have a longer lifespan. The recommended service life of 55 years is consistent with the analysis of available data, comparisons to estimates for comparable utilities, and information from discussions with Newfoundland management regarding the assets. This

[5] The actuarial analysis is not dollar-weighted, as is typical for these types of studies. The data provided was at the unit level. Therefore, each power transformer is weighted equally, regardless of the capital dollars spent to purchase or install the unit.

recommended life is a little bit longer than industry expectations, but the operation of Newfoundland’s transformers and the historic level of retirements support a 55-year life.

PART IV. FORECASTED RETIREMENTS

PART IV. FORECASTED RETIREMENTS

OVERVIEW

The primary objective of this analysis was to provide Newfoundland's capital planning team with a high-level expectation of the retirement frequency of in-service power transformers over the next 30 years. A statistical method was employed to perform the analysis, and the condition of individual transformer units was not observed.

METHODOLOGY

Our statistical methodology for forecasting power transformer retirements involved utilizing two main inputs: the age of assets (installation year) and the survivor curve estimate. The survivor curve allows for the mathematical determination of the probability of retirement at a given age. Leveraging proprietary statistical modeling software, we projected the retirement likelihood for each power transformer using the proposed 55-R3 survivor curve. This probability calculation was performed for every power transformer across the transaction years 2023 to 2052, resulting in the most statistically likely outcomes based on asset age and the survivor curve estimate. This robust approach yields a reasonable forecast for power transformer retirements, absent a thorough inspection of all 208 in-service transformers.

For more discussion on the math behind statistically projecting retirements, please refer to Chapter 10, in Depreciation Systems[6] authored by Dr. Frank Wolf and Dr. W. Chester Fitch. Depreciation Systems is an important textbook used by depreciation professionals who are tasked with forecasting and determining the average service lives of utility plant assets.

[6] Depreciation Systems, Iowa State University Press (1994), Dr. Frank K. Wolf and W. Chester Fitch.

RESULTS

The frequent retirement of power transformers should be expected over the next 30 years. The analysis suggests that the Company will be replacing, on average, three transformers on an annual basis through 2052. This rate of retirement is primarily driven by the age of the existing assets. Of the Company's 208 in-service transformers, 129 (62%) were installed in 1977 or earlier, making each of these transformers 46 years or older. With an average service life of 55 years for this account, we would expect to see increased retirement frequency for these assets as these older transformers approach age 55 and beyond.

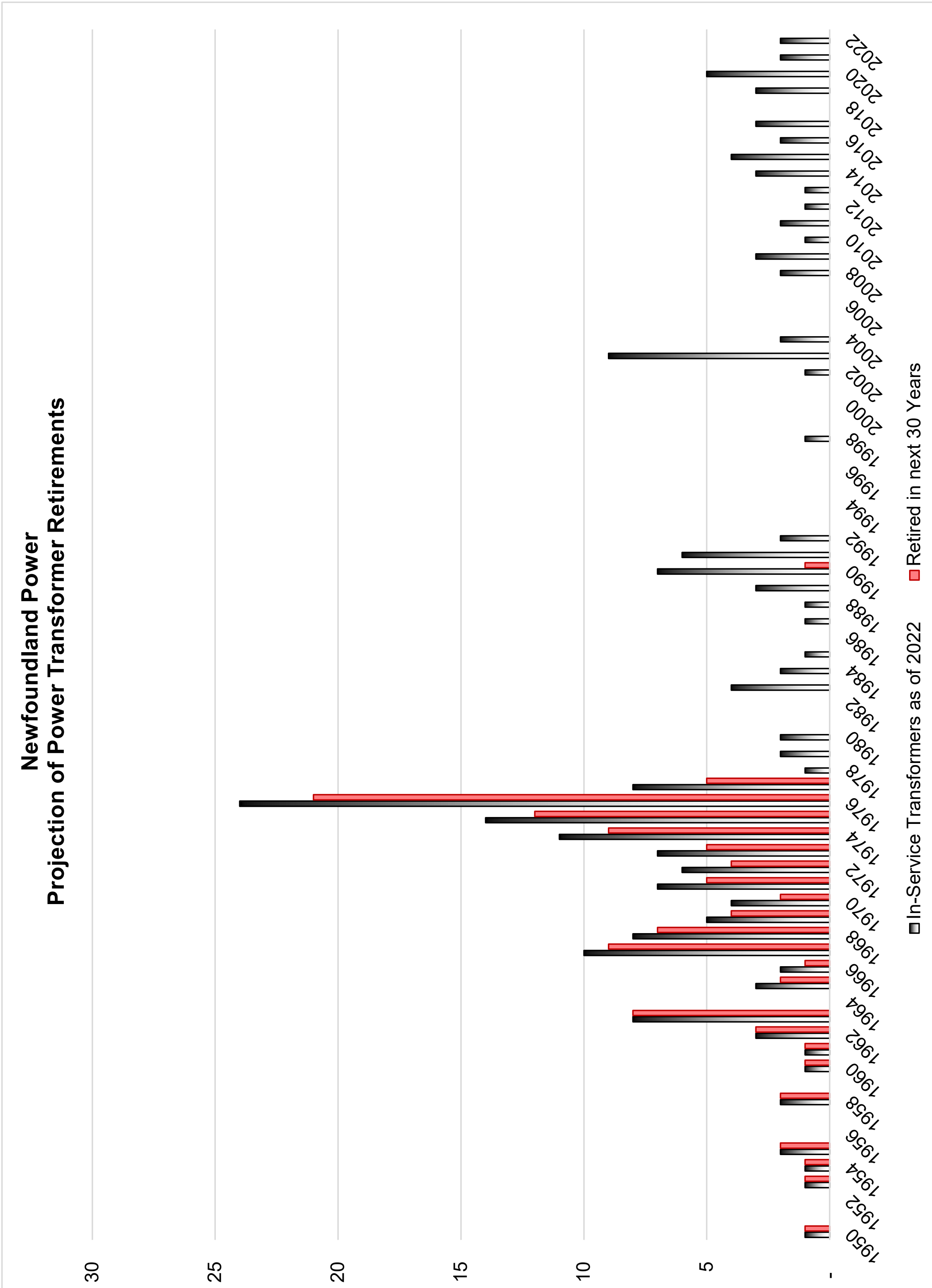
A summary of the projected power transformer retirements is provided in Part V of this report.

PART V.   RESULTS OF STUDY

Newfoundland Power

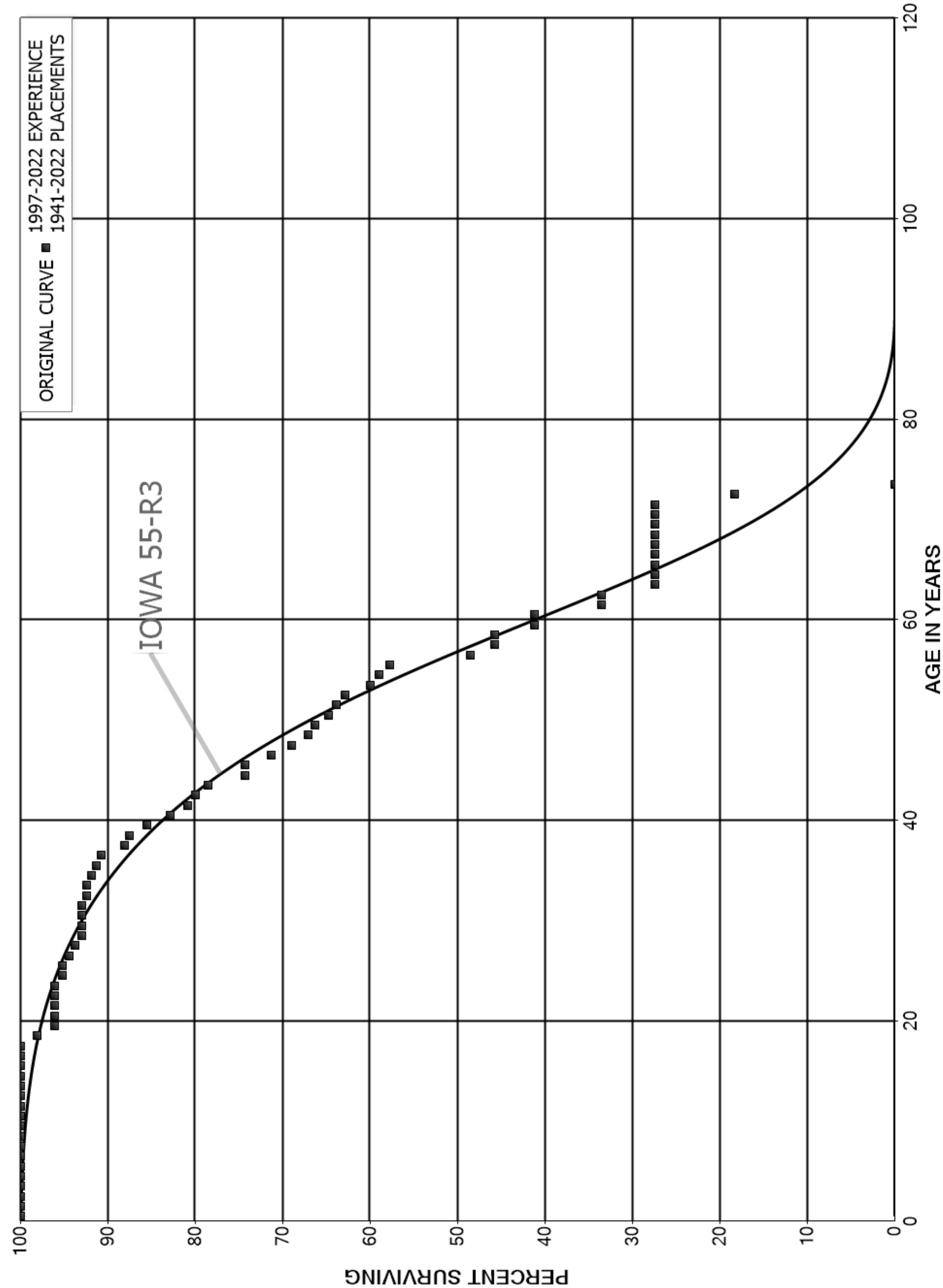
Actual and Forecasted Power Transformer Retirements

Transaction Year	Power Transformers Retired
2013	0
2014	6
2015	5
2016	5
2017	1
2018	2
2019	3
2020	4
2021	1
2022	0
Total Actual	**27**
2023	3
2024	1
2025	3
2026	1
2027	4
2028	3
2029	4
2030	5
2031	3
2032	3
2033	3
2034	4
2035	5
2036	4
2037	4
2038	5
2039	7
2040	4
2041	5
2042	4
2043	3
2044	4
2045	3
2046	3
2047	3
2048	3
2049	3
2050	3
2051	3
2052	4
Total Forecasted	**107**


Newfoundland Power
Projection of Power Transformer Retirements
30
25
20
15
10
5
-
1950
1952
1954
1956
1958
1960
1962
1964
1966
1968
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
In-Service Transformers as of 2022
Retired in next 30 Years

PART VI. SERVICE LIFE STATISTICS

NEWFOUNDLAND POWER
ACCOUNT 342.00 POWER TRANSFORMERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



APPENDIX D:

Substation Power Transformer Strategy Five-Year Plan

Table D-1 Power Transformer Strategy Five-Year Plan				
CBA Approval Year	Planned Transformer Replacements	Spare Power Transformers	Portable Substations	Costs ($000s)[1]
2026[2]	3	1	0	49
2027	3	0	1	6,981
2028	3	0	0	10,988
2029	3	0	0	9,524
2030	3	1	0	6,297

[1] Power transformers are procured, fabricated, and installed over multiple years. Costs shown in the table reflect the actual year in which expenditures are incurred as part of these multi-year projects. These values are subject to change based on updated power transformer condition assessments and changes in emergency response capabilities.

[2] Power Transformer replacements for PUL-T2 as part of the *Pulpit Rock Substation Power Transformer Replacement* project and GAN-T2 as part of the *Gander Substation Power Transformer Replacement* project, both approved in Newfoundland Power's *2025 Capital Budget Application,* Section *2.2 Substation Power Transformer Replacements*, have been excluded from this table.

APPENDIX E:

2026 Substation Power Transformers

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1.0 BACKGROUND

Newfoundland Power is proposing multi-year projects to replace substation power transformers with an increased failure risk and improve emergency response capabilities commencing in 2026 as part of the *Substation Power Transformer Strategy*. A significant number of the Company's power transformers have aged beyond the typical observed service life, thereby increasing the risk of in-service failures. Furthermore, supply chain constraints and procurement lead times have necessitated advanced planning for purchasing new power transformer units.

Beginning in 2026, the Company is proposing capital expenditures for the replacement of: (i) King's Bridge Distribution Power Transformer, KBR-T3 ("200293"), in the City of St. John's at a cost of $2,971,000; (ii) Molloys Lane Distribution Power Transformer, MOL-T2 ("200295"), in the City of St. John's at a cost of $2,801,000; and (iii) Mobile Plant Generation Transformer, MOP-T1 ("200152"), in the Town of Mobile at a cost of $2,627,000. These power transformers are deteriorated and pose a risk to reliable operation. The Company is also proposing the procurement of a spare 138 kV power transformer in 2026 at a cost of $3,919,000.

Table E-1 below provides a cost breakdown of the *2026 Power Transformer Replacement* project.

Table E-1
2026 Power Transformer Replacement
Project Cost
($000s)

Transformer	2026	2027	2028	Total
KBR-T3	12	93	2,866	2,971
MOL-T2	12	2,789	-	2,801
MOP-T1	12	93	2,522	2,627
Spare	13	3,906	-	3,919
Total	$49	$6,881	$5,388	$12,318

2.0 KING'S BRIDGE SUBSTATION POWER TRANSFORMER REPLACEMENT

2.1 Background

King's Bridge Substation

King's Bridge ("KBR") Substation was constructed in 1948 as both a distribution and transmission substation. This substation is supplied by Newfoundland Power 66 kV Transmission Line 12L from Memorial ("MUN") Substation, 66 kV Transmission Line 16L from Pepperrell ("PEP") Substation, and 66 kV Transmission Line 30L from Ridge Road ("RRD") Substation. Two 25 MVA distribution power transformers, KBR-T3 ("200293") and KBR-T4 ("200372"), supply six 12.5 kV distribution feeders, serving approximately 5,740 customers in St. John's.

KBR-T3 Power Transformer

KBR-T3 is a 49-year-old, 15/20/25 MVA, 66-12.5/25 kV power transformer manufactured by Federal Pioneer, and is a sister unit to MOL-T2. This transformer has remained at KBR since its original installation in 1977.

KBR-T3 is deteriorating and an assessment of alternatives determined that it should be replaced.

Figure E-1 shows power transformer KBR-T3.

Figure E-1: Power Transformer KBR-T3.

Newfoundland Power is proposing to replace KBR-T3 over three years commencing in 2026 at an estimated cost of $2,971,000.

2.2 Engineering Assessment

Oil Analysis and Electrical Testing

Power transformer KBR-T3 receives regular maintenance and routine oil sampling in accordance with standard practices. The transformer has undergone annual oil sampling since at least 2009.[1] The transformer last had full maintenance in August 2016.[2]

In October 2024, oil samples were taken from KBR-T3 as part of routine testing. The Transformer Condition Assessments™ ("TCA") completed by TJ|H2b Analytic Services Incorporated ("TJ|H2b")[3], indicated that the mechanical strength of paper for KBR-T3 is reduced to <50% tensile strength. It noted that cellulose degradation is advanced and that the paper insulation may not withstand full fault duty.[4] The estimated degree of polymerization ("DP") is 376-383.[5] This information indicates that the paper insulation inside of the transformer has deteriorated to a point at which it may not have the mechanical strength to withstand a fault on the electrical system.

While the transformer has not shown signs of internal arcing and high temperature heating, the TCAs completed on KBR-T3 have consistently indicated the deterioration of the paper insulation.[6] These are signs of the deteriorating health of the power transformer.

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 KBR-T3 based on information received as of December 31, 2024 is shown in Figure E-2 below.

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1 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 transformers age 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.

2 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.

3 TJ|H2b's laboratory is in Calgary, Alberta. TJ|H2b specializes in diagnostic testing of oil, gas and other insulating materials used in transformers, power circuit breakers and load tap changers.

4 Cellulose refers to the natural polymer derived from plant fibers, which is used to manufacture the insulation paper within a power transformer. This paper is wrapped around the transformer windings to provide electrical insulation and mechanical support. Over time, thermal and electrical stresses degrade the cellulose, reducing the paper's insulating strength and its ability to withstand electrical faults.

5 DP is a measure of transformer insulation mechanical strength and aging. It represents the number of glucose monomers in the paper insulation. New paper insulation has a DP of greater than 1,000. As the insulation ages and/or breaks down from thermal and electrical stresses, the DP value decreases.

6 For comparison, in October 2015, oil samples showed that KBR-T3 was in good health with TJ|H2b indicating that the paper strength was reduced to approximately 50% tensile strength with an estimated DP of 545.

Company:	NP	**Region:**	St. John's
Station:	KBR	**Designation:**	T3
Equipment ID:	200293	**Serial Number:**	64564-1
Manufacturer:	Federal Pioneer	**Manufacture Date:**	3/1/1976
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:**	0.70

PTX Result Summary

Normal Degradation Index:	0.88	**Oil Quality Index:**	0.23
Abnormal Thermal Index:	0.00	**Bushing Index:**	0.00
Abnormal Electrical Index:	0.00	**LTC Index:**	
Abnormal Core Index:	0.00	**Throughfault Failure Index:**	

Diagnosis Summary:

Figure E-2: EPRI KBR-T3 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 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 E-2, the Normal degradation Index of KBR-T3 exceeds the 0.60 threshold.

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 of KBR-T3 disclosed the presence of a leak on the de-energized tap changer. Moisture was found in the oil temperature gauge. The bushings and protection devices were in good condition.

Figure E-3 shows the top of power transformer KBR-T3.

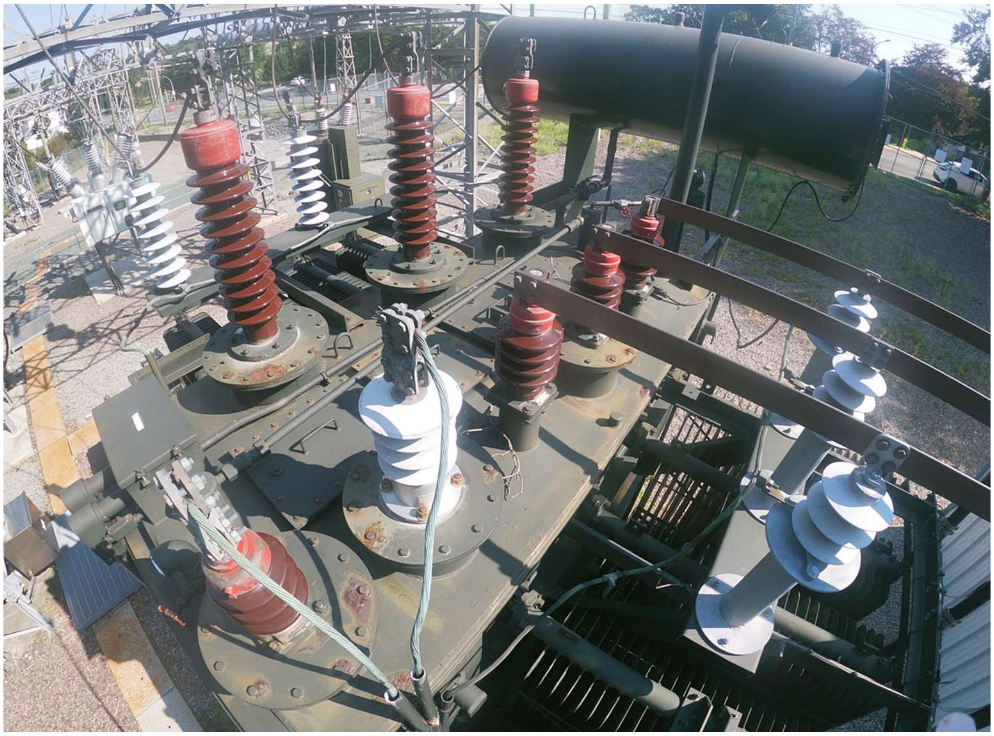

Figure E-3: Top of Power Transformer KBR-T3.

Previously completed corrective maintenance of KBR-T3 includes: (i) oil level gauge replacements in 2006 and 2009; (ii) lightning arrester replacement in 2006; (iii) gas detector relay replacement in 2009; (iv) neutral bushing replacement in 2014; and (v) radiator fan replacements in 2010, 2015, 2016, 2023 and 2024.

Site Conditions

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.[7]

The existing circuit breakers and microprocessor-based digital relays at KBR provide acceptable protection and control for this type of power transformer.

2.3 Risk Assessment

The *King's Bridge Substation Power Transformer Replacement* project will mitigate risks to the delivery of reliable service to approximately 5,740 customers in the St. John's area.

In the case of a KBR-T3 failure, KBR-T4 is unable to supply the existing peak load of the KBR Substation. System load forecasts indicate that up to 13.3 MVA of KBR-T3 load can be transferred to either KBR-T4 or offloaded to adjacent feeders. 8.1 MVA of load would be exposed to an outage.[8] A portable substation or a spare transformer would need to be installed in the event of a KBR-T3 failure.

Newfoundland Power has three portable substations and one spare power transformer that can be used for the emergency response to an in-service failure of KBR-T3. Failure of KBR-T3 would result in an unplanned short-term installation of a portable substation followed by a long-term installation of a spare power transformer when available.[9] 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. Deployment of portable substations in response to transformer failures reduces their availability to respond to other events, increasing the risk of extended outages and hindering the execution of substation maintenance and capital projects.

Based on this assessment, KBR-T3 should be replaced.

7 Power transformer KBR-T3 contains approximately 10,100 liters of oil.
8 A max peak load of 43.7 MVA is being forecasted over the next five years at KBR Substation.
9 Spare transformer 200385 is a suitable medium-term replacement for KBR-T3. While it includes an on-load tap changer that is unnecessary for KBR-T3's operation, it can still serve as a medium-term replacement. However, in Newfoundland Power's view, using transformer 200385 as a long-term solution would not be prudent or cost effective due to the transformer's enhanced capabilities. If it were permanently installed at KBR Substation, a new spare transformer similar to transformer 200385 would need to be procured to maintain a minimally adequate spare transformer inventory.

2.4 Assessment of Alternatives

Newfoundland Power identified and assessed three alternatives to address the deteriorating condition of KBR-T3 power transformer. These are: (i) Condition Based Monitoring; (ii) Remove and Repair; or (iii) Replace and Access. These alternatives are discussed below.

(i) Alternative 1 – Condition Based Monitoring

Long delivery lead times of power transformers, limited emergency response capabilities, and the increased possibility of transformer failures among Newfoundland Power's aging fleet all contribute to increased risks to customer reliability. Newfoundland Power has four portable substations and eight 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 KBR-T3. Following offload, there is one spare transformer available that can then be installed for the medium-term replacement of KBR-T3.[10] By utilizing the only spare transformer available for this voltage rating and capacity, and with power transformer delivery times ranging from 24 to 36 months, there would be limited resources available to respond to future power transformer failures in the short to medium term.

Maintaining the current approach of condition-based monitoring and deferring replacement until failure occurs is not considered a viable long-term strategy for a critical asset like KBR-T3. This approach would significantly increase risks to the delivery of safe and reliable service to approximately 5,740 customers in the St. John's area. Deferral of the *King's Bridge Substation Power Transformer Replacement* project would increase the risk that KBR-T3 will fail in service.

(ii) Alternative 2 – Remove and Repair

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 KBR-T3 would require it to be removed from service for up to 18 to 24 months necessitating 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. The estimated cost to install a portable substation as well as to transport, assess, complete a three-phase rewind, test, and integrate the KBR-T3 transformer back into the system is approximately $1,700,000. This cost could be upwards of $2,000,000 if a spare transformer were installed to allow the portable substation to be removed while waiting for the failed transformer to be repaired. This is approximately 70% of the project cost proposed to purchase and install a new transformer, with no guarantee of extended life comparable to a new transformer.

While repair is sometimes a valid option, it presents several limitations that make it less favourable as a long-term solution for a transformer of this vintage. There are limited facilities that can repair power transformers, resulting in high costs and long lead times. The quality of

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[10] *Ibid.*

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.

The original power transformer tank is not replaced during a typical repair process and would remain in place. The tank would continue to be 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. As a result, refurbished transformers have a service life that is substantially less than that of a new transformer.

The repair of the 49-year-old KBR-T3 is not a viable alternative given that a repair would require the unit to be removed from service for up to 18 to 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.

(iii) Alternative 3 – Replace and Assess

To address the risks outlined above, Newfoundland Power proposes a planned replacement of the deteriorated power transformer based on the condition assessment outlined in this report.

The deteriorated condition of the power transformer justifies replacing it in 2026 to 2028. The TCA from oil samples has shown the deterioration of the strength of the paper insulation inside of the transformer. The PTX System software indicates a high probability that the unit has insulating paper that is no longer capable of providing reliable service.

The planned replacement of KBR-T3 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 unforeseen failures.[11] This will ensure the continued delivery of safe and reliable service to customers served from KBR Substation.

After the transformer has been replaced, it will be assessed and, depending on the condition of the transformer, it may be used for a spare, considered for repair or scrapped.

[11] Unforeseen transformer failures often require the deployment of portable substations and temporary modifications to existing infrastructure to restore service to customers. These emergency deployments are logistically complex and resource intensive. In many cases, the work must be performed outside of regular working hours, incurring overtime labor rates. Additionally, emergency mobilization typically involves accelerated transportation arrangements, specialized equipment handling, and on-site preparation—all of which contribute to significantly higher-than-normal costs.

2.5 Project Cost and Scope

This project involves purchasing a new 15/20/25 MVA, 66-12.5/25 kV power transformer to replace KBR-T3 while the existing unit remains in service. A new spill containment foundation will be installed for the new transformer. The project is proposed to be completed over three years. This would include design and procurement in 2026 and 2027, followed by delivery, installation, testing and commissioning in 2028.

Table E-2 below provides a cost breakdown of the *Kings Bridge Substation Transformer Replacement* project.

Table E-2
King's Bridge Substation Power Transformer Replacement Project
Project Cost
($000s)

Cost Category	2026	2027	2028	Total
Material	-	-	2,660	2,660
Labour - Internal	-	-	13	13
Labour - Contract	-	-	-	-
Engineering	8	34	90	132
Other	4	59	103	166
Total	$12	$93	$2,866	$2,971

The project to replace KBR-T3 is estimated to cost $12,000 in 2026, $93,000 in 2027, and $2,866,000 in 2028 for a total project cost of $2,971,000.

3.0 MOLLOY'S LANE SUBSTATION POWER TRANSFORMER REPLACEMENT

3.1 Background

Molloy's Lane Substation

Molloy's Lane ("MOL") Substation was constructed in 1960 as both a distribution and transmission substation. This substation is supplied by Newfoundland Power 66 kV Transmission Lines 15L from Stamps Lane ("SLA") Substation and 19L from Hardwoods ("HWD") Substation. Two 25 MVA power transformers supply eight 12.5 kV distribution feeders, serving approximately 9,040 customers in the west end area of St. John's.

MOL-T2 Power Transformer

MOL-T2 is a 49-year-old, 15/20/25 MVA, 66-12.5/25 kV power transformer manufactured by Federal Pioneer, and is a sister unit to KBR-T3. This transformer has remained at MOL since its original installation in 1976.

MOL-T2 is deteriorating and an assessment of alternatives determined that it should be replaced.

Figure E-4 shows power transformer MOL-T2.

Figure E-4: Power Transformer MOL-T2.

Newfoundland Power is proposing to replace MOL-T2 over two years commencing in 2026 at an estimated cost of $2,801,000.

3.2 Engineering Assessment

Oil Analysis and Electrical Testing

Power transformer MOL-T2 receives regular maintenance and routine oil sampling in accordance with standard practices. The transformer has undergone annual oil sampling since at least 2002.[12] The transformer last had full maintenance in June 2024.[13]

12 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 transformers age 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.

13 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.

In January 2025, oil samples were taken from MOL-T2 as part of routine testing. The TCA completed by TJ|H2b[14], indicated that the mechanical strength of paper for MOL-T2 is reduced to 50% tensile strength. The estimated DP is 495-508.[15] This information indicates that the paper insulation inside of the transformer has deteriorated and is nearing a point at which it may not have the mechanical strength to withstand a fault on the electrical system.

While the transformer has not shown signs of internal arcing and high temperature heating, the TCAs completed on MOL-T2 have consistently indicated the deterioration of the paper insulation.[16] These are signs of the deteriorating health of the power transformer.

PTX Condition Assessment

Newfoundland Power utilizes EPRI 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 inside the transformer. A summary of the EPRI PTX results for MOL-T2 based on information received as of December 31, 2024 is shown in Figure E-5 below.

Company:	NP	**Region:**	St. John's
Station:	MOL	**Designation:**	T2
Equipment ID:	200295	**Serial Number:**	65044
Manufacturer:	Federal Pioneer	**Manufacture Date:**	3/1/1976
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:**	0.75

PTX Result Summary

Normal Degradation Index:	0.56	**Oil Quality Index:**	0.00
Abnormal Thermal Index:	0.00	**Bushing Index:**	0.00
Abnormal Electrical Index:	0.00	**LTC Index:**	
Abnormal Core Index:	0.00	**Throughfault Failure Index:**	

Diagnosis Summary:

Figure E-5: EPRI MOL-T2 Summary.

14 TJ|H2b's laboratory is in Calgary, Alberta. TJ|H2b specializes in diagnostic testing of oil, gas and other insulating materials used in transformers, power circuit breakers and load tap changers.

15 DP is a measure of transformer insulation mechanical strength and aging. It represents the number of glucose monomers in the paper insulation. New paper insulation has a DP of greater than 1,000. As the insulation ages and/or breaks down from thermal and electrical stresses, the DP value decreases.

16 For comparison, in October 2014, oil samples showed that MOL-T2 was in good health with TJ|H2b indicating that the paper strength was reduced to approximately 70% tensile strength with an estimated DP of 744.

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 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 E-5, the Normal degradation Index of MOL-T2 is approaching the 0.60 threshold.

Physical Condition Assessment

The Company's power transformers are inspected annually to record any exterior physical defects that need to be addressed. The 2022 inspection of MOL-T2 indicated minor signs of rusting or corrosion on the control cabinet, conservators, and piping. Additionally, the inspection noted leaks on the radiators to such an extent that the radiators require replacement.

Previously completed corrective maintenance of MOL-T2 includes: (i) leak repairs on radiator in 2002, 2019 and 2024; (ii) lightning arrestor replacements in 2006 and 2024; (iii) leak repair on top of the transformer and on the radiators in 2009; (iv) low voltage and neutral bushing replacements in 2014; and (v) radiator fan replacements in 2013, 2015, 2016 and 2019.

Site Conditions

The existing spill containment is acceptable, and a new spill containment foundation is not required for the transformer.

The existing circuit breakers and microprocessor-based digital relays at MOL provide acceptable protection and control for this type of power transformer.

3.3 Risk Assessment

The *Molloy's Lane Substation Power Transformer Replacement* project will mitigate risks to the delivery of reliable service to approximately 9,040 customers in the St. John's area.

In the case of a MOL-T2 failure, MOL-T1 is unable to supply the existing peak load of the MOL Substation. System load forecasts indicate that up to 19.2 MVA of MOL-T2 load can be transferred to either MOL-T1 or offloaded to adjacent feeders. 6.9 MVA of load would be exposed to an outage.[17] A portable substation or a spare transformer would need to be installed in the event of a MOL-T2 failure.

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[17] A max peak load of 53.7 MVA is being forecasted over the next five years at MOL Substation.

Newfoundland Power has three portable substations and one spare power transformer that can be used for the emergency response to an in-service failure of MOL-T2. Failure of MOL-T2 would result in an unplanned short-term installation of a portable substation followed by a long-term installation of a spare power transformer when available.[18] 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. Deployment of portable substations in response to transformer failures reduces their availability to respond to other events, increasing the risk of extended outages and hindering the execution of substation maintenance and capital projects.

Based on this assessment, MOL-T2 should be replaced.

3.4 Assessment of Alternatives

Newfoundland Power identified and assessed three alternatives to address the deteriorating condition of MOL-T2 power transformer. These are: (i) Condition Based Monitoring; (ii) Remove and Repair; or (iii) Replace and Assess. These alternatives are discussed below.

(i) Alternative 1 – Condition Based Monitoring

Long delivery lead times of power transformers, limited emergency response capabilities, and the increased possibility of transformer failures among Newfoundland Power's aging fleet all contribute to increased risks to customer reliability. Newfoundland Power has four portable substations and eight 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 MOL-T2. Following offload, there is one spare transformer available that can then be installed for the medium-term replacement of MOL-T2.[19] By utilizing the only spare transformer available for this voltage rating and capacity, and with power transformer delivery times ranging from 24 to 36 months, there would be limited resources available to respond to any additional power transformer failure in the short to medium term.

Maintaining the current approach of condition-based monitoring and deferring replacement until failure occurs is not considered a viable long-term strategy for a critical asset like MOL-T2. This approach would significantly increase risks to the delivery of safe and reliable service to approximately 9,040 customers in the St. John's area. Deferral of the *Molloy's Lane Substation Power Transformer Replacement* project would increase the risk that MOL-T2 will fail in service.

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18 Spare transformer 200385 is a suitable medium-term replacement for MOL-T2. While it includes an on-load tap changer that is unnecessary for MOL-T2's operation, it can still serve as a medium-term replacement. However, in Newfoundland Power's view, using transformer 200385 as a long-term solution would not be prudent or cost effective due to the transformer's enhanced capabilities. If it were permanently installed at MOL Substation, a new spare transformer similar to transformer 200385 would need to be procured to maintain a minimally adequate spare transformer inventory.

19 *Ibid.*

(ii) Alternative 2 – Remove and Repair

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 MOL-T2 would require it to be removed from service for up to 18 to 24 months necessitating 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.

The estimated cost to install a portable substation as well as to transport, assess, complete a three-phase rewind, replace the radiators, test, and integrate the MOL-T2 transformer back into the system is approximately $1,900,000. This cost could be upwards of $2,200,000 if a spare transformer were installed to allow the portable substation to be removed while waiting for the failed transformer to be repaired. This is approximately 80% of the project cost proposed to purchase and install a new transformer, with no guarantee of extended life comparable to a new transformer.

While repair is sometimes a valid option, it presents several limitations that make it less favourable as a long-term solution for a transformer of this vintage. 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.

The original power transformer tank is not replaced during a typical repair process and would remain in place. The tank would continue to be 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. As a result, refurbished transformers have a service life that is substantially less than that of a new transformer.

The repair of the 49-year-old MOL-T2 is not a viable alternative given that a repair would require the unit to be removed from service for up to 18 to 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.

(iii) Alternative 3 – Replace and Assess

To address the risks outlined above, Newfoundland Power proposes the planned replacement of the deteriorated power transformer based on the condition assessment outlined in this report.

The deteriorated condition of the power transformer justifies replacing it in 2026-2027. The TCA from oil samples has shown the deterioration of the strength of the paper insulation inside of the transformer. The PTX System software indicates a moderate probability that the unit has insulating paper that is no longer capable of providing reliable service.

The planned replacement of MOL-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 unforeseen failures.[20] This will ensure the continued delivery of safe and reliable service to customers served from MOL Substation.

After the transformer has been replaced, it will be assessed and, depending on the condition of the transformer, it may be used for a spare, considered for repair or scrapped.

3.5 Project Cost and Scope

This project involves purchasing a new 15/20/25 MVA, 66-12.5/25 kV power transformer to replace MOL-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 2026, followed by delivery, installation, testing and commissioning in 2027.

Table E-3 below provides a cost breakdown of the *Molloy's Lane Substation Transformer Replacement* project.

Table E-3
Molloy's Lane Substation Power Transformer Replacement Project
Project Costs
($000s)

Cost Category	2026	2027	Total
Material	-	2,498	2,498
Labour - Internal	-	13	13
Labour - Contract	-	-	-
Engineering	8	121	129
Other	4	157	161
Total	$12	$2,789	$2,801

The project to replace MOL-T2 is estimated to cost $12,000 in 2026 and $2,789,000 in 2027 for a total project cost of $2,801,000.

[20] Unforeseen transformer failures often require the deployment of portable substations and temporary modifications to existing infrastructure to restore service to customers. These emergency deployments are logistically complex and resource intensive. In many cases, the work must be performed outside of regular working hours, incurring overtime labor rates. Additionally, emergency mobilization typically involves accelerated transportation arrangements, specialized equipment handling, and on-site preparation—all of which contribute to significantly higher-than-normal costs.

4.0 MOBILE PLANT SUBSTATION POWER TRANSFORMER REPLACEMENT

4.1 Background

Mobile Plant Substation

Mobile Plant ("MOP") Substation was constructed in 1950 as a generation substation for the Mobile Hydro Plant ("Plant"). The plant's 11 MVA generator supplies the MOP Substation 10 MVA power transformer that interconnects the generating plant to Newfoundland Power's 66 kV transmission line to Mobile Substation ("MOB") in the Town of Mobile.

MOP-T1 Power Transformer

MOP-T1 is a 75-year-old, 10 MVA, 66-6.9 kV power transformer manufactured by Westinghouse. This transformer has remained at MOP since its original installation in 1951.

MOP-T1 is deteriorating and an assessment of alternatives determined that it should be replaced.

Figure E-6 shows power transformer MOP-T1.

Figure E-6: Power Transformer MOP-T1.

Newfoundland Power is proposing to replace MOP-T1 over three years commencing in 2026 at an estimated cost of $2,627,000.

4.2 Engineering Assessment

Oil Analysis and Electrical Testing

Power transformer MOP-T1 receives regular maintenance and routine oil sampling in accordance with standard practices. The transformer has undergone annual oil sampling since at least 2002.[21] The transformer last had full maintenance in September 2020.[22]

In January 2025, oil samples were taken from MOP-T1 as part of routine testing. The TCA TJ|H2b[23], indicated that the mechanical strength of paper for MOP-T1 is reduced to approximately 70% tensile strength. The estimated DP is 674.[24]

These considerations serve to indicate that the paper insulation inside of the transformer has deteriorated and is nearing a point at which it may not have the mechanical strength to withstand a fault on the electrical system.

While the transformer has not shown signs of internal arcing and high temperature heating, the TCA's completed on MOP-T1 have consistently indicated the deterioration of the paper insulation. These are signs of the deteriorating health of the power transformer.

PTX Condition Assessment

Newfoundland Power utilizes EPRI 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 MOP-T1 based on information received as of December 31, 2024 is shown in Figure E-7 below.

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21 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 transformers age 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.

22 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.

23 TJ|H2b's laboratory is in Calgary, Alberta. TJ|H2b specializes in diagnostic testing of oil, gas and other insulating materials used in transformers, power circuit breakers and load tap changers.

24 DP is a measure of transformer insulation mechanical strength and aging. It represents the number of glucose monomers in the paper insulation. New paper insulation has a DP of greater than 1,000. As the insulation ages and/or breaks down from thermal and electrical stresses, the DP value decreases. Oil processing for MOP-T1 which occurred in 2014 may have also impacted the interpretation of the estimated DP, as dilution can affect the concentration of diagnostic markers such as furans, which are used to estimate insulation aging.

Company:	NP	**Region:**	St. John's
Station:	MOP	**Designation:**	T1
Equipment ID:	200152	**Serial Number:**	207199
Manufacturer:	English Electric	**Manufacture Date:**	3/1/1950
Energize Date:		**Repair Date:**	
Retire Date:		**Voltage Rating:**	66/6.9
Top MVA:	13.333	**Cooling Type:**	ONAF
Number of Phases:	3	**Core Type:**	Core
Is Autotransformer:	False	**Failure Consequence Index:**	0.42

PTX Result Summary

Normal Degradation Index:	0.63	**Oil Quality Index:**	0.01
Abnormal Thermal Index:	0.10	**Bushing Index:**	0.00
Abnormal Electrical Index:	0.00	**LTC Index:**	
Abnormal Core Index:	0.00	**Throughfault Failure Index:**	

Diagnosis Summary:

Figure E-7: EPRI MOP-T1 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 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 E-7, the Normal degradation Index of MOP-T1 exceeds the 0.60 threshold.

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 of MOP-T1 disclosed the presence of minor signs of rusting or corrosion on the main tank.

Figure E-8 shows the top of power transformer MOP-T1.

Figure E-8: Top of Power Transformer MOP-T1.

Previously completed corrective maintenance of MOP-T1 includes: (i) radiator replacement in 2011; (ii) replace spill pan heat trace in 2013; (iii) H1, H2 bushing replacement in 2014; (iv) oil temperature gauge replacement in 2020; and (v) oil level gauge replacement in 2024

Site Conditions

The spill containment for the transformer is presently a spill pan. This will be upgraded to the current standard of spill containment foundation to protect against environmental damage in the event of an oil spill from the unit.[25]

The existing remote circuit breaker and microprocessor-based digital relays at MOP provide acceptable protection and control for this type of power transformer.

4.3 Risk Assessment

The *Mobile Plant Substation Power Transformer Replacement* project will mitigate risks to the supply of 11 MVA of generation in the Town of Mobile.

In the case of a MOP-T1 failure, the MOP generation plant will be unable to supply any generation into the electrical system. This will decrease the supply of on-island generation by approximately 10 MVA during peak requirements.

Newfoundland Power has three portable substations and no spare power transformer that can be used for the emergency response to an in-service failure of MOP-T1. Failure of MOP-T1

[25] Power transformer MOP-T1 contains approximately 14,400 liters of oil.

would result in an unplanned long-term installation of a portable substation to keep the plant operational, until a replacement can be procured. Present power transformer delivery times are estimated between 24 and 36 months.

The increased probability of power transformer failure, combined with a lack of compatible spare units, has the potential to place considerable pressure on the availability of portable substations. Relying solely on a portable substation in the event of failure may also leave 10 MVA of generation stranded. If a portable substation is unavailable for long-term installation while a replacement transformer is procured, the plant could remain out of service for an extended period. A prolonged plant outage may further stress the electrical system during peak loading, compromising reliability, and increase energy costs.[26] Additionally, extended transformer delivery times could further exacerbate these risks.

Based on this assessment, MOP-T1 should be replaced.

4.4 Assessment of Alternatives

Newfoundland Power identified and assessed three alternatives to address the deteriorating condition of MOP-T1 power transformer. These are: (i) Condition Based Monitoring; (ii) Remove and Repair; or (iii) Replace and Access. These alternatives are discussed below.

(i) Alternative 1 – Condition Based Monitoring

Long delivery lead times of power transformers, limited emergency response capabilities, and the increased possibility of transformer failures among Newfoundland Power's aging fleet all contribute to increased risks to customer reliability. Newfoundland Power has four portable substations and eight 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 MOP-T1. However, there are no spare transformers available that can then be installed for the long-term replacement of MOP-T1. With power transformer delivery times between 24 to 36 months, this would result in either a long-term portable substation installation, or a prolonged plant outage while waiting for a new transformer.

Maintaining the current approach of condition-based monitoring and deferring replacement until failure occurs is not considered a viable long-term strategy for a critical asset like MOP-T1. This approach would significantly increase the risk to the supply of 10 MVA of electricity to the electrical system. Deferral of the *Mobile Plant Substation Power Transformer Replacement* project would increase the risk that MOP-T1 will fail in service.

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[26] With power transformer delivery times upwards of 36 months, it is estimated that a failure of MOP-T1 with no long-term portable substation availability could incur additional energy and capacity costs. Based on the normal hydroelectric generation of the Mobile Plant and the historical average seasonality of generation output, a 36-month Plant outage is predicted to result in approximately $15,000,000 in replacement energy and capacity costs. This estimate is based on the current marginal price of both energy and capacity.

(ii) Alternative 2 – Remove and Repair

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 MOP-T1 would require it to be removed from service for up to 18 to 24 months necessitating the long-term utilization of a portable substation. If a portable substation were not available for the duration of the repair, the plant would be inoperable, placing additional pressure on the electrical system during peak loading. Additional energy costs would also be incurred.

While repair is sometimes a valid option, it presents several limitations that make it less favourable as a long-term solution for a transformer of this vintage. 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.

The original power transformer tank is not replaced during a typical repair process and would remain in place. The tank would continue to be 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. As a result, refurbished transformers have a service life that is substantially less than that of a new transformer.

The repair of the 75-year-old MOP-T1 is not a viable alternative given that a repair would require the unit to be removed from service for up to 18 to 24 months either requiring long-term installation of a portable substation or stranding 10 MVA of generation. This would put additional pressure on the Company's limited emergency response capabilities and the electrical system during peak loading conditions. Furthermore, due to the age of MOP-T1, shipment of the unit to a repair facility risks introducing additional issues beyond the degraded insulation and minor rusting. Years of service and exposure to the elements have likely weakened the integrity of the unit, making it susceptible to damage during transport.

(iii) Alternative 3 – Replace and Assess

To address the risks outlined above, Newfoundland Power proposes the planned replacement of the deteriorated power transformer based on the condition assessment outlined in this report.

The deteriorated condition of the power transformer justifies replacing it in 2026 to 2028. The TCA from oil samples has shown the deterioration of the strength of the paper insulation inside of the transformer. The PTX System software indicates a high probability that the unit has insulating paper that is no longer capable of providing reliable service.

The planned replacement of MOP-T1 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 unforeseen failures.[27] This will ensure the continued delivery of safe and reliable generation to the electrical system.

After the transformer has been replaced, it will be assessed and, depending on the condition of the transformer, it may be used for a spare, considered for repair or scrapped.

4.5 Lifecycle Cost Analysis

The MOP 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 MOP Substation, the replacement of the generation power transformer MOP-T1 as well as the spill containment foundation are only required to serve the Plant. If the Plant was decommissioned and removed, this equipment would no longer be needed.

A lifecycle cost analysis of the Plant including the necessary capital investment required for equipment in MOP Substation related to the Plant was completed in the *2023 Capital Budget Application* report *4.2 Mobile Hydro Plant Refurbishment*. At that time an estimate of $2,356,000 was forecasted for substation work in 2024.[28] This work was deferred, and the proposed work is scheduled for 2026 to 2028. The forecasted cost of the *Mobile Plant Substation Refurbishment and Modernization* project and the MOP-T1 substation power transformer replacement is forecasted to be $3,877,000. The lifecycle cost analysis was revisited to account for the increased substation capital investments, and it was determined that it remains economically viable.

4.6 Project Scope and Costs

This project involves purchasing a new 10/13.3/16.7 MVA, 66-6.9 kV power transformer to replace MOP-T1 while the existing unit remains in service. A new spill containment foundation will be installed for the new transformer. The project is proposed to be completed over three years. This would include design and procurement in 2026 and 2027, followed by delivery, installation, testing and commissioning in 2028.

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27 Unforeseen transformer failures often require the deployment of portable substations and temporary modifications to existing infrastructure to restore service to customers. These emergency deployments are logistically complex and resource intensive. In many cases, the work must be performed outside of regular working hours, incurring overtime labor rates. Additionally, emergency mobilization typically involves accelerated transportation arrangements, specialized equipment handling, and on-site preparation—all of which contribute to significantly higher-than-normal costs.

28 See Newfoundland Power's *2023 Capital Budget Application,* report *4.2 Mobile Hydro Plant Refurbishment, Appendix A: Lifecycle Cost Analysis of the Mobile Plant, Attachment A: Summary of Capital Costs.*

Table E-4 below provides a cost breakdown of the *Mobile Plant Substation Power Transformer Replacement* project.

Table E-4 Mobile Plant Substation Power Transformer Replacement Project Project Costs ($000s)				
Cost Category	2026	2027	2028	Total
Material	-	-	2,323	2,323
Labour - Internal	-	-	13	13
Labour - Contract	-	-	-	-
Engineering	8	34	90	132
Other	4	59	96	159
Total	$12	$93	$2,522	$2,627

The project to replace MOP-T1 is estimated to cost $12,000 in 2026, $93,000 in 2027, and $2,522,000 in 2028 for a total project cost of $2,627,000.

5.0 SUBSTATION SPARE POWER TRANSFORMER INVENTORY

Newfoundland Power is proposing the procurement of a 138-25/12.5 kV, 15/20/25 MVA spare power transformer as a critical enhancement to its emergency response capabilities. This additional transformer is necessary to address a significant gap in the Company's current inventory of spare transformers and to ensure continued system reliability. Maintaining an adequate inventory of spare power transformers is consistent with current utility practices and is essential for managing the risks associated with an aging transformer fleet.

Currently, Newfoundland Power maintains an inventory of eight spare power transformers, which provide coverage for approximately 66% of its fleet. However, there is no spare transformer available for 15 in-service 138-12.5 kV power transformers or for two in-service 138-25 kV, 25 MVA power transformers. The proposed spare transformer will provide backup coverage for these 17 critical units, significantly improving the Company's ability to respond to transformer failures.

Compounding this risk is the significant increase in transformer delivery lead times. In recent years, the average delivery time for power transformers has risen from approximately 34 weeks in 2019 to over 111 weeks in 2025, with some manufacturers quoting lead times of up to 60 months. These extended timelines mean that, in the event of a failure, a replacement transformer may not be available for at least two to three years. Without a suitable spare on hand, Newfoundland Power would be forced to rely on portable substations for prolonged periods, which could severely impact system reliability.

The availability of a compatible spare transformer following a failure significantly reduces the duration that a portable substation must remain in service. Portable substations are essential for short-term emergency response, as well as for supporting substation maintenance activities and capital projects. However, they are not intended for long-term deployment. A transformer failure that necessitates extended use of a portable unit can tie up that resource for up to three years, limiting Newfoundland Power's flexibility to respond to other events and potentially deferring planned maintenance and capital work. This, in turn, increases the risk of additional equipment failures and customer outages.

A spare transformer can be installed either permanently to restore a substation to its normal configuration or temporarily while a failed unit is being repaired or replaced. This flexibility helps to alleviate pressure on the portable substation fleet and ensures that emergency response resources remain available for other critical needs.

Newfoundland Power has determined that procuring power transformers specifically to serve as spares is necessary to mitigate the increasing risk of transformer failure over the near term. The Company plans to maintain an adequate inventory of spare transformers through the strategic procurement of transformers that can be deployed upon the failure of an in-service unit. The proposed procurement of a 138-25/12.5 kV, 15/20/25 MVA power transformer in 2026 is a key component of this strategy.

The procurement of a 138 kV spare power transformer will enhance Newfoundland Power's ability to respond to equipment failures, reduce the risk of prolonged customer outages, and support the continued delivery of safe and reliable service to its customers. This is especially important given the risks associated with an aging transformer fleet and the extended timelines now required to procure replacement transformers.

Table E-5 below provides a cost breakdown of the *Substation Spare Power Transformer Inventory project*.

Table E-5
Substation Spare Power Transformer Inventory Project Costs
($000s)

Cost Category	2026	2027	Total
Material	-	3,730	3,730
Labour - Internal	-	1	1
Labour - Contract	-	-	-
Engineering	9	22	31
Other	4	153	157
Total	$13	$3,906	$3,919

The project to purchase a spare transformer is estimated to cost $13,000 in 2026 and $3,906,000 in 2027 for a total project cost of $3,919,000.

6.0 CONCLUSION

Power transformers KBR-T3, MOL-T2 and MOP-T1 are deteriorated and require replacement. Their replacement is essential to safe and reliable system operation.

In Newfoundland Power's view, commencing the replacements of KBR-T3, MOL-T2 and MOP-T1 in 2026 is necessary to address the deteriorated conditions of the units, and to ensure the continued delivery of safe and reliable service to customers served by KBR, MOL and MOP Substations. The Company will monitor the conditions of KBR-T3, MOL-T2 and MOP-T1 while the projects are ongoing to mitigate any further risks to the delivery of safe and reliable service.

Seventeen in-service power transformers do not currently have a suitable spare transformer that could be utilized upon the failure of one of these units. The purchase of a new transformer is required to maintain an adequate inventory of spare transformers.

Newfoundland Power will assess the condition of its spare transformers and its inventory requirements annually to determine the need for any additional spares. The Company will seek Board approval of any additional spare units through future capital applications.

Attachment A

TJ|H2b Transformer Condition Assessment History – Power Transformer KBR-T3

Table A-1
TJ|H2b Transformer Condition Assessment History - Power Transformer KBR-T3

Date	Estimated DP	Comments
10-02-2014	710	Treat the fluid to remove oxidation products. Continue normal operation. Paper strength is reduced to approximately 70% tensile strength.
10-07-2015	545	Continue normal operation. Paper strength is reduced to approximately 50% tensile strength.
08-08-2016	416	Treat the fluid to remove oxidation products. Continue normal operation. Paper strength is reduced to approximately 40% tensile strength.
09-21-2017	427-433	Treat the fluid to remove oxidation products. Paper condition is normal.
10-04-2018	396	Treat the fluid to remove oxidation products. Mechanical strength of paper is reduced <50% tensile strength. Cellulose degradation is advanced, paper insulation may not withstand full fault duty. No abnormal gas generation is indicated.
10-10-2019	395-398	Treat the fluid to remove oxidation products. Mechanical strength of paper is reduced <50% tensile strength. Cellulose degradation is advanced, paper insulation may not withstand full fault duty. No abnormal gas generation is indicated.
10-27-2020	356-362	Mechanical strength of paper is reduced <50% tensile strength. Cellulose degradation is advanced, paper insulation may not withstand full fault duty.
12-09-2021	384-396	Treat the fluid to remove oxidation products. Paper may not withstand full fault duty.
10-12-2022	407-416	Consider treatment to remove oxidation products. Heating is indicated. Cellulose may be involved. Paper may not withstand full fault duty.
09-20-2023	402-414	Treat the fluid to remove oxidation products. Heating is indicated. Cellulose may be involved. Paper mechanical insulation strength is reduced to approximately 50% tensile strength.
10-11-2024	376-383	No abnormal gas generation is indicated. Mechanical Strength of paper is reduced <50% tensile strength. Cellulose degradation is advanced, paper insulation may not withstand full fault duty.

Attachment B

TJ|H2b Transformer Condition Assessment History – Power Transformer MOL-T2

Table B-1
TJ|H2b Transformer Condition Assessment History - Power Transformer MOL-T2

Date	Estimated DP	Comments
07-10-2014	744	Consider treatment to remove oxidation products. Paper strength is reduced to approximately 70% tensile strength.
07-06-2015	536	Consider treatment to remove oxidation products. Continue normal operation. Paper strength is reduced to approximately 50% tensile strength.
07-04-2016	621-646	Continue normal operation. Paper strength is reduced to approximately 60% tensile strength. Consider treatment to remove oxidation products.
07-18-2017	569-574	Consider treatment to remove oxidation products.
08-29-2018	608-631	Continue normal operation. Paper strength is reduced to approximately 60% tensile strength.
10-07-2019	585	Consider treatment to remove oxidation products. Paper mechanical insulation strength is reduced to approximately 50% tensile strength.
10-13-2020	565	Consider treatment to remove oxidation products. Paper mechanical insulation strength is reduced to approximately 50% tensile strength.
11-24-2021	580	Consider treatment to remove oxidation products.
12-21-2022	561-567	No abnormal gas generation is indicated. Paper condition is normal.
11-14-2023	549-567	No abnormal gas generation is indicated. Paper mechanical insulation strength is reduced to approximately 50% tensile strength.
1-30-2025	495-508	No abnormal gas generation is indicated. Paper mechanical insulation strength is reduced to approximately 50% tensile strength.

Attachment C

TJ|H2b Transformer Condition Assessment History – Power Transformer MOP-T1

Table C-1
TJ|H2b Transformer Condition Assessment History - Power Transformer MOP-T1

Date	Estimated DP	Comments
09-03-2014	838	Continue normal operation. Paper condition is normal.
09-09-2015	569-650	Continue normal operation. Paper strength is reduced to approximately 50% tensile strength.
12-02-2015	831	Continue normal operation. Paper condition is normal.
12-14-2016	775	Continue normal operation. Paper strength is reduced to approximately 70% tensile strength.
12-15-2017	784	Continue normal operation. Paper mechanical condition is reduced to approximately 70 % tensile strength.
06-11-2018	694-764	Continue normal operation. Paper condition is normal.
12-19-2018	733	Continue normal operation. Paper mechanical condition is reduced to approximately 70 % tensile strength.
06-14-2019	695-735	Continue normal operation. Paper mechanical condition is reduced to approximately 70 % tensile strength.
02-26-2020	722	Continue normal operation. Paper mechanical condition is reduced to approximately 70 % tensile strength.
08-20-2020	715	Continue normal operation. Paper mechanical condition is reduced to approximately 70 % tensile strength.
04-14-2021	708	Continue normal operation. Paper mechanical condition is reduced to approximately 70 % tensile strength.
11-01-2021	713	Continue normal operation. Paper mechanical condition is normal.
06-10-2022	705	No abnormal gas generation is indicated. Paper condition is normal.
11-01-2022	703	No abnormal gas generation is indicated. Paper condition is normal.
04-12-2023	698	No abnormal gas generation is indicated. Paper condition is normal.
11-10-2023	692	No abnormal gas generation is indicated. Paper mechanical condition is reduced to approximately 70 % tensile strength.
06-05-2024	676	No abnormal gas generation is indicated. Paper mechanical condition is reduced to approximately 70 % tensile strength.
01-31-2025	674	No abnormal gas generation is indicated. Paper mechanical condition is reduced to approximately 70 % tensile strength.

June
2025

3.1
Transmission Line 100L Rebuild

Prepared by:
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NEWFOUNDLAND POWER
A FORTIS COMPANY

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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 2,000 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.

The *2026 Transmission Line Rebuild* project includes a new multi-year project to rebuild Transmission Line 100L in 2026 and 2027.

2.0 BACKGROUND

Newfoundland Power filed a *Transmission Line Rebuild Strategy* as part of its *2006 Capital Budget Application*. The strategy outlines a long-term plan to rebuild the Company's aging transmission lines. Rebuild projects are prioritized based on physical condition, risk of failure, 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. Appendix A provides the most recent update to the strategy.

A total of 28 transmission lines have been rebuilt under the strategy since 2006. With Transmission Line 146L and Transmission Line 94L currently being rebuilt, approximately 88% of the strategy will be executed by the end of 2026.[1] Newfoundland Power plans to continue implementation of the *Transmission Line Rebuild Strategy* in 2026 and 2027 by rebuilding Transmission Line 100L.

3.0 TRANSMISSION LINE 100L

3.1 General

Transmission Line 100L is a 138 kV line running between Sunnyside ("SUN") Substation and Clarenville ("CLV") Substation. The transmission line serves as a critical element of the Central Newfoundland 138 kV looped transmission system which is supplied primarily from SUN and Stony Brook ("STY") infeed supply points from

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[1] Three transmission lines have been removed from the strategy since 2006. Transmission line 101L and the majority of transmission line 102L have been addressed as part of the Central Newfoundland System Planning Study. Transmission Line 53L is no longer in service. This brings the total number of transmission lines encompassed by the strategy to 34. Transmission lines 146L and 94L are currently being rebuilt and are scheduled for completion by the end of 2025 and 2026 respectively, which will bring the total number of lines rebuilt as part of the strategy to 30 (30 / 34 = 0.88, or 88%). Four of the remaining transmission line rebuilds are included in the schedule provided in Appendix A, all of which are planned for completion by the end of 2029.

Newfoundland and Labrador Hydro's ("Hydro") bulk power system. The SUN-STY loop is a key transmission supply network providing power to 35 Newfoundland Power substations.

Figure 1 is a diagram of the Central Newfoundland 138 kV looped transmission network.

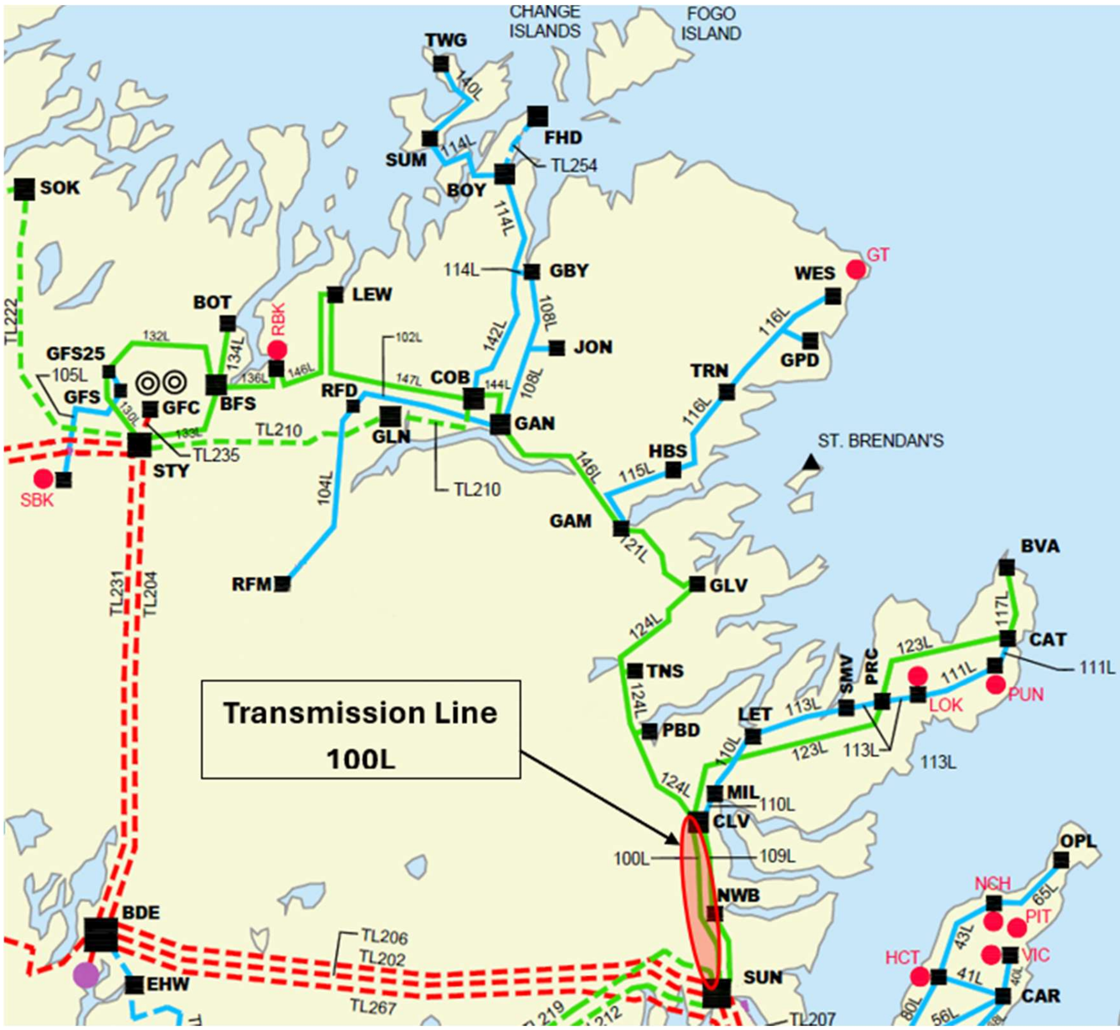

Figure 1 - Central Newfoundland 138 kV Loop.

Transmission Line 100L was originally constructed as a part of a longer transmission line directly connecting SUN Substation and Gander ("GAN") Substation. Over time, this Sunnyside-Gander line was segmented into a number of shorter lines which are currently denoted as Transmission Line 100L, Transmission Line 124L, Transmission Line 121L and Transmission Line 146L. These lines serve as the main 138kV transmission lines making up the eastern portion of the Central Newfoundland 138kV System. Apart from Transmission Line 100L, each of the transmission lines which were originally constructed as part of the long Sunnyside-Gander line have been rebuilt or have a rebuild project currently underway.

Table 1 provides details on the timing of these rebuilds, including their ages at the time the rebuild projects were completed.

Table 1
Sunnyside-Gander Transmission Line Segment Rebuilds

Transmission Line	Original Construction	Rebuild Year	Age at Rebuild
100L[2]	1964	2027	63
124L[3]	1964	2022	58
121L	1964	2022	58
146L	1964	2025	61

Transmission Line 100L is exhibiting a similar deteriorated condition as these other transmission lines at the time of their rebuilds. This is to be expected given they were constructed concurrently as part of a single transmission line.

3.2 Condition Assessment

The bulk of Transmission Line 100L was originally constructed in 1964, with the exception of a two-kilometre section connecting the transmission line to the CLV Substation, which was constructed in 1975. The total line is 34.1 kilometres in length and consists of approximately 148 H-Frame structures with 397.5 ACSR conductor.[4] Having been in service for over 61 years, the conductor is approaching the end of the typical useful service life for transmission line conductor.[5]

Transmission Line 100L does not meet current standards for the construction of overhead lines.[6] The Canadian Standards Association ("CSA") establishes standards for the construction of overhead systems based on local climatic conditions. At the time of construction in 1964, Transmission Line 100L was designed to withstand sustained winds of 90 km/h. Current CSA standards require that overhead lines be constructed based on actual historical climate data.

Based on this parameter and actual historical wind speed data provided in the standard, Transmission Line 100L should be designed to withstand winds upwards of 120 km/h, which is

2 This is the proposed year for completion of the Transmission Line 100L Rebuild Project.

3 Partial rebuilds of this line occurred from 2001-2005 and again in 2012 due to storm damage and clearance issues, however the majority of the line was rebuilt as a part of *Transmission Line 124L Rebuild Project* in 2021 and 2022.

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

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

6 As noted in Newfoundland Power's *2006 Transmission Line Rebuild Strategy*, 37 of Newfoundland Power's transmission lines constructed between the 1940s and 1960s were not built to adequate design and construction standards by present day criteria. For example, the current version of *CSA standard C22.3 – Overhead Systems* includes design criteria for maximum wind load conditions which were not considered in the original design of 100L.

over 33% higher than its current design.[7] The design of this line means it is not built to withstand local climatic conditions, which increases its probability of failure.

In 2024, Newfoundland Power initiated an engineering assessment of Transmission Line 100L. A detailed inspection of the line was completed in accordance with the Company's *Transmission Line Inspection and Maintenance Practices* to quantify the transmission line's overall condition. The inspection determined that 135 of 148, or 91% of H-Frame structures on Transmission Line 100L have deficiencies.

Wood Poles

A total of 122 of 148, or 82% of H-Frame structures have deteriorated poles, with the majority of these structures having both poles deteriorated. In total, there are 251 poles that require replacement. The deteriorated condition of these poles is to be expected given they have exceeded the typical useful service life of a transmission line wood pole.[8]

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 the pole exposed to moisture and fungus, which accelerates wood rot, compromising its strength over time and increasing the probability of failure.

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[7] *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."*

[8] Transmission Line 100L has been in service for 61 years. Industry experience indicates the typical useful service life of a transmission wood pole is 58 years. See Newfoundland Power's *2026-2030 Capital Plan,* page 9.

Many of the poles on Transmission Line 100L have significant shell separation, as shown in Figure 2.

Figure 2 – Shell Separation and Woodpecker hole on 100L.

The original poles installed on the line are primarily Class 4, which are no longer used by Newfoundland Power to construct transmission lines. Additionally, considerable narrowing and decay has occurred at the top of many poles along the line as seen in Figure 3 below. This level of deterioration can cause hardware to disconnect from the pole.

Figure 3 – Pole top Narrowing and Decay.

The poles that make up Transmission Line 100L are also experiencing severe splits and woodpecker holes as shown in Figure 4. 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.[9]

Figure 4 –Poles with Numerous Woodpecker Holes on 100L.

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9 A sounding test is conducted using a flat faced hammer to sound the pole surface at regular intervals on all quadrants of the pole. If a hollow sound is detected, it indicates that decay is present. If a sounding test indicates a potential problem, a core sampling test may be completed by drilling through the centerline of the pole to observe the decay.

Cross Arms and Cross Braces

A significant number of cross arms and cross braces on Transmission Line 100L have deteriorated. The cross arms on this transmission line are wooden horizontal members which are attached near the top of the structure's wood poles to both support and provide adequate spacing to the conductors. Cross braces are wooden support members attached in an "x" configuration to the wood poles that form most H-frame structures. Cross braces are integral to the overall strength and stability of the transmission structure. The detailed inspection conducted on Transmission Line 100L identified 118 cross arms or cross braces as requiring replacement.

In addition to the deteriorated wood components, the condition assessment identified the deterioration of numerous other components across the transmission line as outlined below.

Insulators

Transmission Line 100L has structures using porcelain insulators manufactured by Canadian Ohio Brass (COB). These insulators were installed when the line was originally constructed. Failure of these insulators due to cement growth and radial cracking is a known problem.[10] The presence of COB insulators on Transmission Line 100L increases the line's risk of failing due to the known deterioration issues with this component.

Timber Cribs

Timber cribs are installed around structures that are located in bog or other areas with soil conditions that otherwise would not provide adequate support for the wood pole. Timber cribs along Transmission Line 100L have been identified as having rotted, missing, or cracked crib members. These deficiencies compromise the overall strength of cribbed structures and increase the likelihood of a failure on the line.

Appendix B provides additional photos of the deterioration present on Transmission Line 100L.

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[10] Cement growth is the expansion of the material that holds in place the pin supporting the connection of the insulator to the pole and conductor. Cement growth causes hairline cracks in the porcelain, weakening the insulator leading to electrical and mechanical failure. The Company's new standard insulator is a toughened glass insulator.

3.3 Risk Assessment

Due to their criticality in serving customers, Newfoundland Power's transmission lines must be maintained to operate to a high standard of reliability.[11] All transmission lines, including Transmission Line 100L, are maintained in accordance with the Company's *Transmission Inspection and Maintenance Practices*.[12]

The historical reliability performance of Transmission Line 100L has been reasonable. There have been thirteen outage events since 2013 due to the need to undertake preventative and corrective maintenance.

Table 2 provides the list of all planned and unplanned outages for Transmission Line 100L from 2013 to 2024.

Table 2
100L Outage Events and Durations
(2013-2024)

Date	Planned/ Unplanned	Outage Cause	Duration (Hours)
February 2013	Unplanned	Severe Weather	22.8
August 2014	Planned	Preventative Maintenance	101.7
March 2015	Planned	Preventative Maintenance	7.8
April 2015	Unplanned	Severe Weather	0.5
May 2015	Planned	Preventative Maintenance	99.5
November 2016	Unplanned	Severe Weather	23.0
November 2018	Unplanned	Severe Weather	5.0
June 2019	Planned	Preventative Maintenance	169.6
October 2021	Planned	Preventative Maintenance	99.0
July 2022	Planned	Preventive Maintenance	81.7
April 2023	Planned	Preventative Maintenance	4.5
October 2023	Planned	Preventative Maintenance	24.0
December 2023	Unplanned	Equipment Failure	29.1

[11] 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.

[12] Since 2019, approximately $375,000 has been spent on completing corrective and preventative maintenance on Transmission Line 100L.

While the historical reliability performance of Transmission Line 100L has been reasonable, the line's sub-standard design and deteriorated condition exposes it to an increased probability of failure going forward.[13]

Failures on Transmission Line 100L can cause the line to be out of service for extended periods of time. Since 2013, the average duration of an unplanned outage event on 100L is approximately 16.1 hours.

Transmission Line 100L plays a critical role in the Central Newfoundland 138 kV transmission system. An outage to Transmission Line 100L results in a significant weakening of the Central Newfoundland 138 kV transmission system. During an outage to the line, all substations on the Bonavista Peninsula, as well as Terra Nova, Port Blandford, Northwest Brook ("NWB") and CLV Substations become supplied by Transmission Line 109L and Transmission Line 124L only. However, a further loss of either of these lines would result in a substantial undervoltage condition within the Central Newfoundland 138kV transmission system and would result in outages to all customers served by these substations. This means that any single failure on Transmission Line 109L or Transmission Line 124L could result in an outage to approximately 16,000 customers. During an outage to Transmission Line 124L, customers could be restored with switching procedures and the dispatch of thermal generation at Wesleyville. During an outage to Transmission Line 109L, the system would be unable to support the Bonavista Peninsula, which would result in approximately 15,200 customers experiencing a prolonged outage event and remaining without service until the cause of the failure is identified and corrected.

Having Transmission Line 100L in service during such an outage to Transmission Line 109L or Transmission Line 124L would allow for the continued supply of electricity to all customers served by the Central Newfoundland 138 kV transmission system, thus avoiding a prolonged service interruption to over 15,000 Newfoundland Power customers.

Overall, the criticality of Transmission Line 100L and its increased probability of failure create a high risk to the delivery of reliable service to approximately 16,000 of Newfoundland Power's customers. Transmission Line 100L was originally scheduled for rebuild in 2012 as part of the 2006 *Transmission Line Rebuild Strategy*. The rebuild of this line has been deferred for 14 years as a result of regular maintenance. Due it its deteriorated condition and increased risks to customers, a capital project is required to address the deficiencies present on the line.

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13 For example, the Newfoundland and Labrador Board of Commissioners of Public Utilities stated in relation to the *Transmission Line 55L Rebuild* project included in Newfoundland Power's *2023 Capital Budget Application*, that it "does not take past reliability performance as evidence of future reliability performance, especially in light of the evidence showing the deteriorated condition of the line." See Order No. P.U. 38 (2022).

4.0 ASSESSMENT OF ALTERNATIVES

4.1 General

Newfoundland Power evaluated three alternatives to address the deteriorated condition of Transmission Line 100L to mitigate risks to the delivery of reliable service to customers. These are: (i) replace the deteriorated structures in place and defer the rebuild of the remainder of the line; (ii) rebuild the existing line in a new, parallel right-of-way; and (iii) rebuild the existing line in a new, partially re-routed right-of-way. These alternatives are discussed below.

4.2 Alternative 1 – Replace Deteriorated Structures and Defer Rebuild

Alternative 1 involves addressing the identified deficiencies on Transmission Line 100L by performing like-for-like replacements of the deteriorated structures across the line in 2026 and deferring work on the remaining structures for an additional 5 years, until 2031.

The focus of the 2026 maintenance work would be to construct new structures immediately next to existing structures which have been identified as containing poles requiring replacement. Additional mid-span structures would also be installed during this work in areas with long span lengths. These mid-span structures are required for two purposes: (i) reducing the loading experienced by the existing structures not planned for replacement in 2026 by shortening the span lengths, reducing the risk of failure on these original vintage poles; and (ii) ensuring the future rebuild of remaining components of the line, which includes the installation of a larger conductor, will adhere to CSA standard requirements.[14]

Under this alternative, the replacement of the remaining existing structures on Transmission Line 100L would be completed in 2031. At that point, these remaining line components would be in service for 67 years. Because the remaining components have exceeded their expected useful service life, an increased risk of equipment failure is expected.

Table 3 provides the capital costs associated with Alternative 1.

Table 3
Alternative 1 Capital Costs
($000)

Year	Item	Cost
2026	Engineering, Brush Clearing and Address Existing Deficiencies with Maintenance	10,942
2031	Address Deferred Structures	4,173
Total		15,115

14 New conductor installed on Transmission Line 100L during the 2031 work will be 559.5 AASC "Darien" conductor which has a larger diameter than the existing conductor on Transmission Line 100L.

Alternative 1 introduces a number of costly inefficiencies to the rebuild of Transmission Line 100L. The deteriorated structures identified for replacement in the initial scope of work are located across the entire 34-kilometre length of the line. As a result, additional time will be required to access selected structures as construction crews move along the line, increasing the difficulty of moving resources and materials during the work. Additionally, in order to ensure the future rebuild of this line adheres to current design standards, the new poles being installed may need to be higher than the existing poles that are being replaced. Installing a large number of poles of greater height will require additional conductor to be spliced onto the existing conductor.[15] The conductor will also have to be re-sagged when the poles are replaced.

Similar issues will exist when the remaining structures are replaced in 2031. During the completion of this scope, the remaining structures to be replaced will also be spread across the entire length of the line and will cause inefficiencies in construction. Additionally, once all structures have been replaced, the existing conductor will have to be removed and replaced.

Alternative 1 presents additional reliability risks to the Central Newfoundland 138 kV looped transmission system. To complete this alternative, Transmission Line 100L will have to be taken out of service for approximately eight months while construction is ongoing as previously described. During this planned work, customers would be exposed to an increased risk of outages. The terrain and routing of the transmission lines in this area of the province can result in lengthy restoration times for outages as described above. To complete Alternative 1, up to 16,000 customers would be put at an increased risk of an outage while Transmission Line 100L is out of service for construction.

Overall, Alternative 1 causes unnecessary inefficiencies and duplication of work throughout the execution of the project. It also exposes customers to increased risks of outages during the completion of the work due to the existing line being offline for prolonged periods each year.

4.3 Alternative 2 – Rebuild in a Parallel Right-of-Way

Alternative 2 involves rebuilding Transmission Line 100L in a new right-of-way immediately parallel to the existing corridor. Under this alternative, the existing line would remain energized throughout the project while a new line is constructed in a transmission right-of-way parallel to the existing line. Once completed, the original line would be de-energized and removed. Figure 5 shows the proposed routing of Alternative 2.

[15] The additional conductor will be required at the transition from the shorter poles to the taller poles, and from the taller poles to the shorter poles.

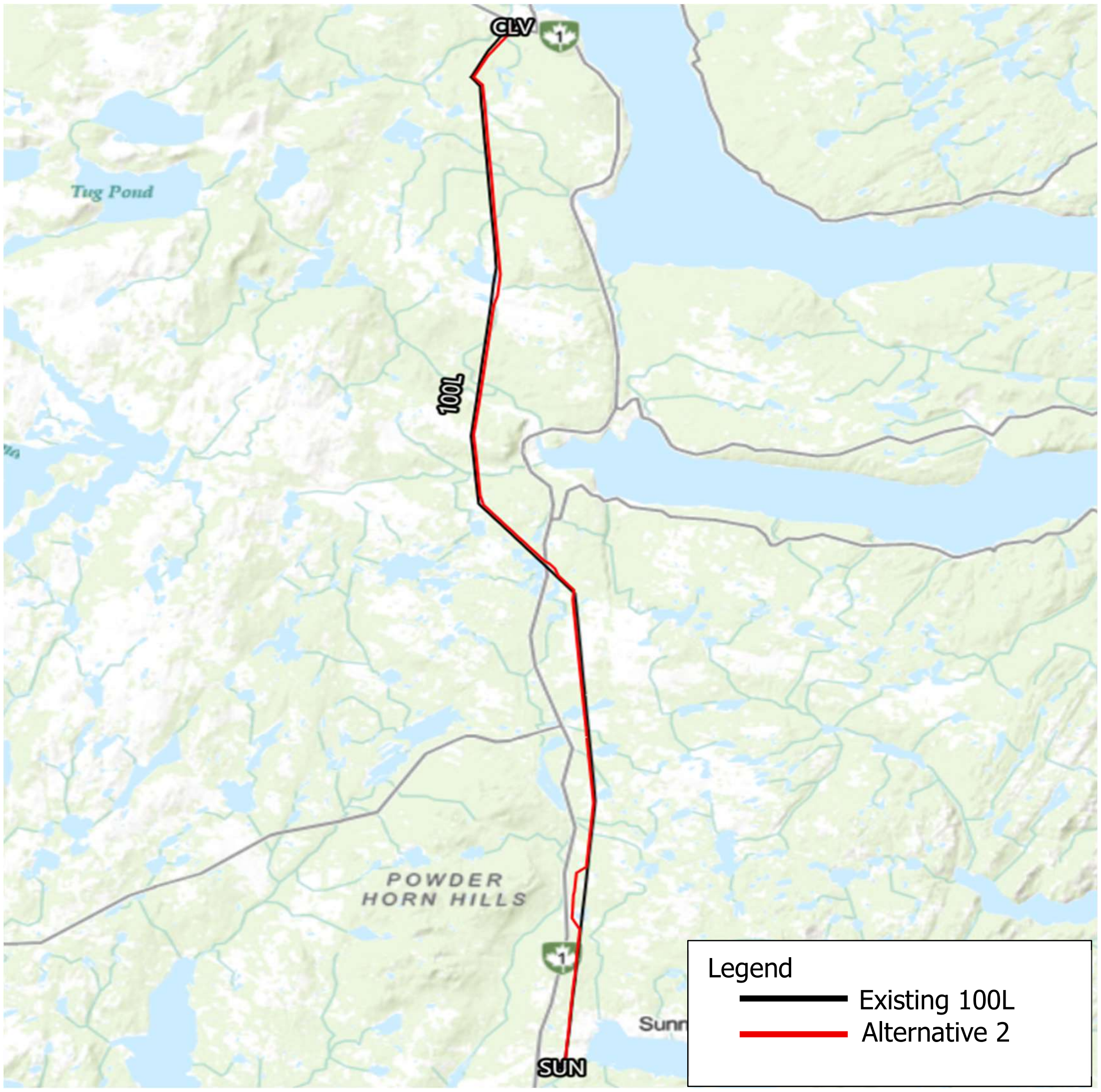

Figure 5 –Map of Alternative 2.

Alternative 2 ensures the continued reliability of the Central Newfoundland 138 kV looped transmission system during the execution of the project. Since the existing line will remain in service during the construction of the new line, it would avoid exposing thousands of customers to the increased risk of outages.

Additionally, rebuilding the entire line at once in a linear fashion allows for the efficient execution of the project. It avoids the duplication of work related to mobilization and travel during construction and removes many of the inefficiencies that come with having to work at locations spread across the entire length of the line, as is required with Alternative 1.

However, the current route of Transmission Line 100L traverses a large quantity of bogs and wetlands. If the entirety of the new line is constructed parallel to the existing transmission line as proposed in Alternative 2, these undesirable site conditions will influence the overall cost of the Project. Newfoundland Power has recently experienced large capital costs on other transmission line rebuild projects due to similar site conditions. These costs are driven by two main factors: (i) providing safe and environmentally responsible access across wetland areas;

and (ii) installing bog structures to ensure structures are adequately supported.[16] Access across wetland areas becomes particularly expensive due to the increased use of bog mats, while the installation of bog structures are more expensive than the installation of a direct bury pole in suitable soil. The additional bog-related costs associated with this option are substantial and together they increase the overall cost of Alternative 2.

Table 4 includes the capital costs associated with Alternative 2.

Table 4
Alternative 2 Capital Costs
($000)

Year	Item	Cost
2026	Engineering, permitting and brush clearing	450
2027	Rebuild 34km of Transmission Line 100L	14,271
Total		14,721

4.4 Alternative 3 – Rebuild in a Partially Re-Routed Right-of-Way

Alternative 3 involves rebuilding a portion of Transmission Line 100L in a new, re-routed right-of-way. Under this alternative, the existing line would remain energized throughout the project, like in Alternative 2. However, the new route would deviate away from the existing right-of-way in areas of known heavy bog and would follow the Trans-Canada Highway instead.

[16] Bog structures are timber cribs backfilled with rock material constructed around the base of a pole to provide adequate support to the structure.

Figure 6 below shows the proposed right-of-way changes of Alternative 3.

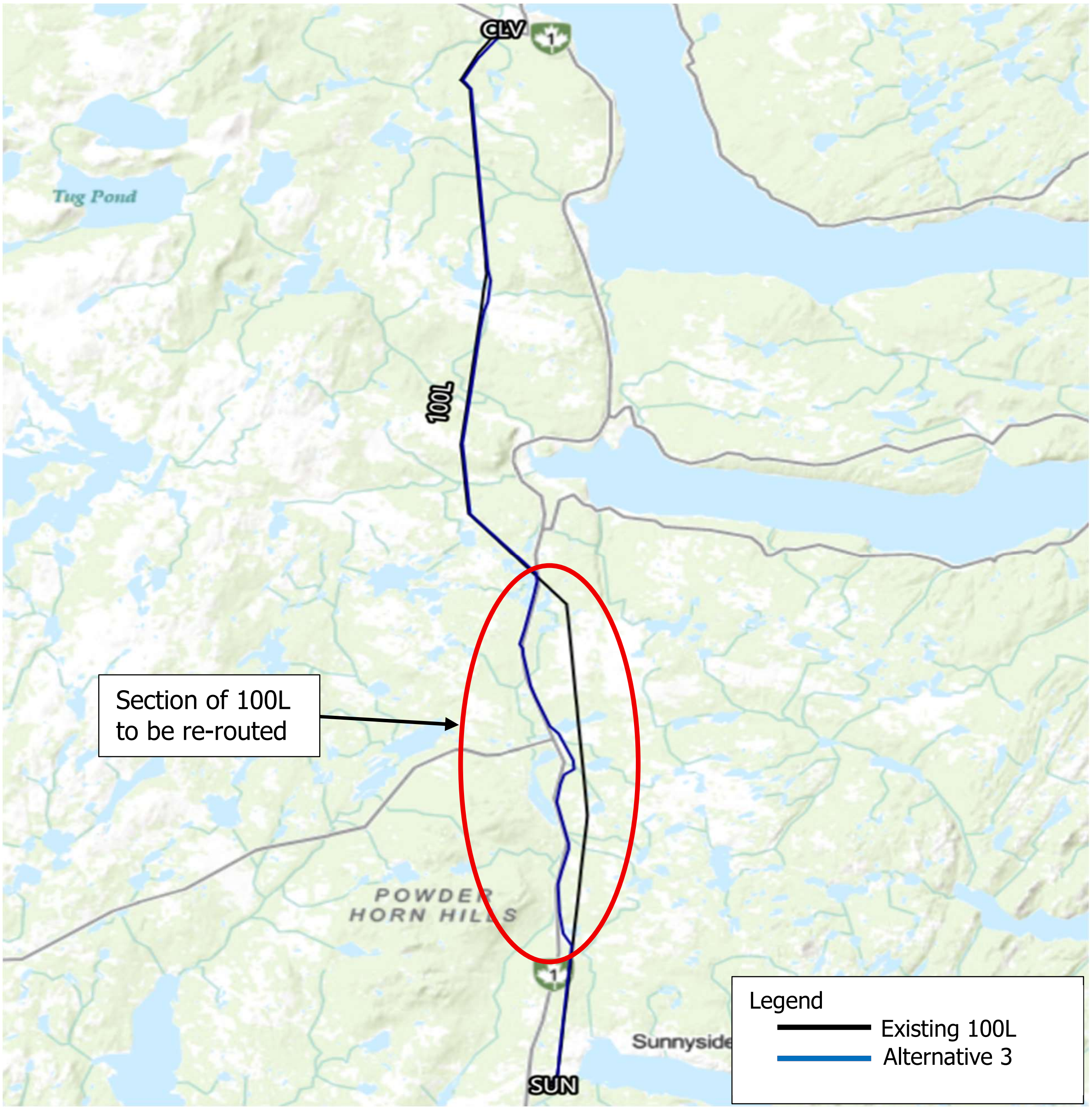

Figure 6 –Map of Alternative 3.

Moving the identified section of the Transmission Line 100L right-of-way to avoid the known wetland areas between SUN and NWB Substations eliminates the need for a substantial number of bog structures and several kilometres of new bog access from the project scope. Additionally, moving the transmission line closer to the Trans-Canada Highway between SUN and NWB Substations will allow for more efficient inspection and maintenance on the line in the future.

Overall, this alternative would provide the greatest value in terms of construction efficiency and eliminates the required re-work from Alternative 1, while also using lessons learned from recent transmission line rebuild projects by avoiding construction through areas with large wetlands.

Table 5 includes the capital costs associated with Alternative 3.

Table 5
Alternative 3 Capital Costs
($000)

Year	Item	Cost
2026	Engineering, permitting and brush clearing	450
2027	Rebuild 34km of Transmission Line 100L	13,323
Total		13,773

4.5 Net Present Value Analysis of Alternatives

A net present value ("NPV") calculation of customer revenue requirement was completed for the assessed 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 6 includes the results of the NPV analysis for the three alternatives.

Table 6
Net Present Value Analysis
($000)

Alternative	NPV
1 – Address Existing Deficiencies and Defer Rebuild	16,527
2 – Rebuild in Parallel Right-of-Way	16,032
3 – Rebuild in Partially Re-routed Right-of-Way	15,002

The NPV analysis determined that Alternative 3, which involves rebuilding Transmission Line 100L in a partially re-routed right-of-way, is the lowest cost alternative.

5.0 PROJECT SCOPE AND COST

Transmission Line 100L is proposed to be rebuilt as a multi-year project. In 2026, the work consists of 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 design, and ordering materials. In 2027, the work consists of establishing construction contracts and completing the construction of the new line.

Table 7 provides a breakdown of the cost to rebuild Transmission Line 100L.

Table 7 Transmission Line 100L Rebuild Project Cost ($000s)			
Description	2026	2027	Total
Engineering	188	35	223
Labour - Contract	-	6,970	6,970
Labour - Internal	-	195	195
Material	-	4,535	4,535
Other	262	1,588	1,850
Total	$450	$13,323	$13,773

The cost of rebuilding Transmission Line 100L is estimated at $13,773,000, including $450,000 in 2026 and $13,323,000 in 2027.

6.0 CONCLUSION

Transmission Line 100L forms an integral part of the Central Newfoundland 138 kV transmission system that is critical to the delivery of reliable service to customers in Central Newfoundland. The line was constructed in 1964, is not built to current engineering standards, and has become deteriorated. The line's design and deteriorated condition increase the probability of failure. This, in turn, increases the risk of customer outages.

At the proposed time of construction, the rebuilding of Transmission Line 100L will have been deferred over 14 years. An assessment of alternatives determined that rebuilding Transmission Line 100L in a partially re-routed right-of-way is the least-cost alternative to mitigate risks to the delivery of reliable service to customers. The proposed project will address deficiencies identified during inspection, eliminate non-standard equipment and ensure Transmission Line 100L is constructed to meet current engineering standards. This will enable the continued delivery of reliable service to customers served by the Central Newfoundland 138 kV transmission system.

APPENDIX A :

Transmission Line Rebuild Schedule: 2026-2030

Table A-1 Transmission Line Rebuild Schedule 2026-2030 ($000s)						
Line	Year Built	2026	2027	2028	2029	2030
94L BLK-RVH	1969	9,075				
148L LEW-BOY	-	9,283	9,553			
100L SUN-CLV	1964	450	13,323			
142L Ext.	1978		1,520			
95L RVH-TRP	1969		2,100	9,600	9,400	
105L SBK-GFS	1963		853	5,187		
35L OXP-APT	1965			850		
109L SUN-CLV	1976				1,750	9,780
12L/14L MUN	1966					700
48L BLK-BRB	1967					1,480
Total		18,808	27,349	15,637	11,150	11,960

APPENDIX B:

Photographs of Transmission Line 100L

Figure B-1 – Void in Pole Top, Hollow Pole.

Figure B-2 – Cracked Pole Top and Splits through Cross Brace Bolts.

Figure B-3 – Severe Splits in Pole through Cross-Arm Bolt Locations.

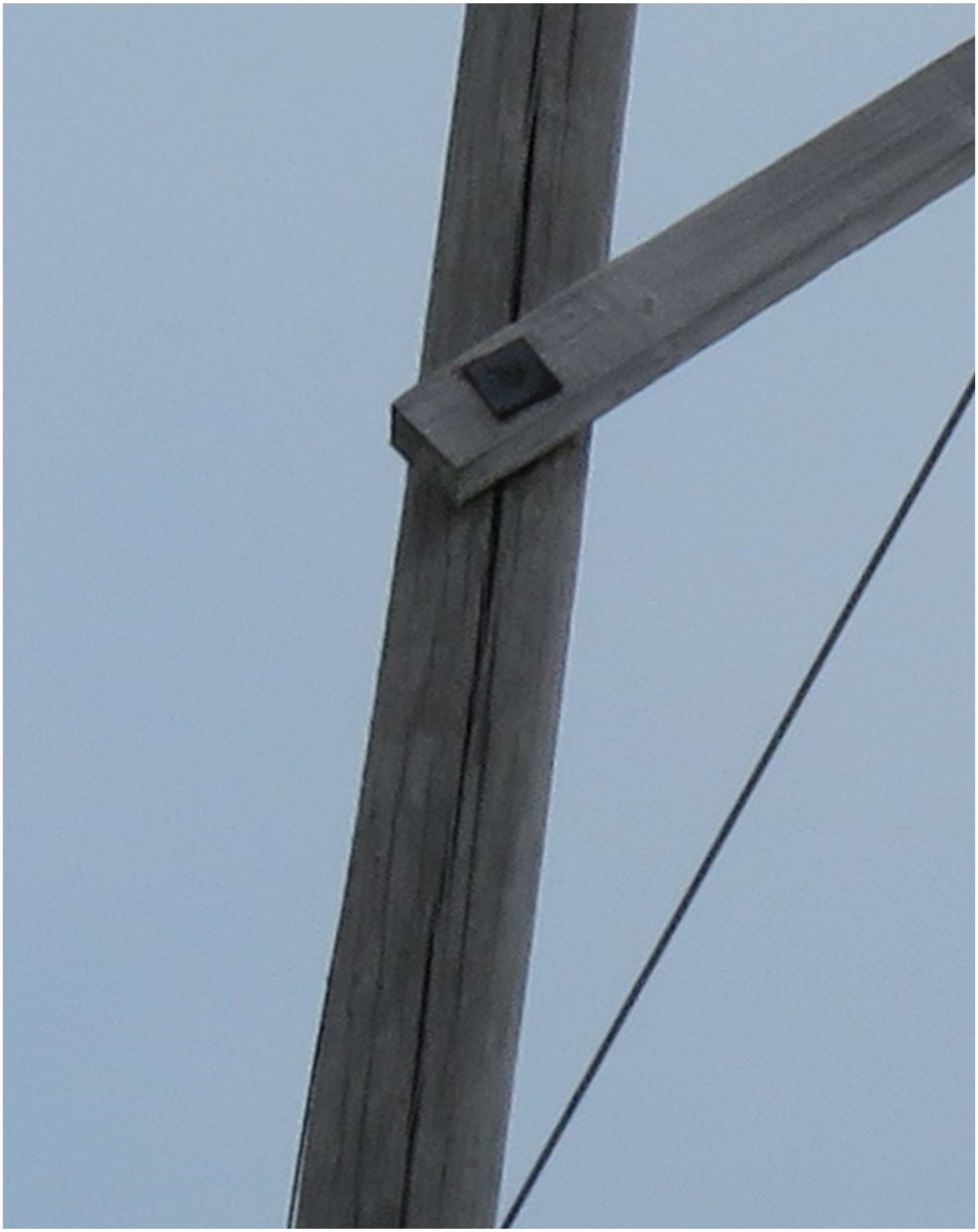

Figure B-4 – Large Split through Cross-Brace Bolt Locations.

Figure B-5 – Splits through Cross Arm.

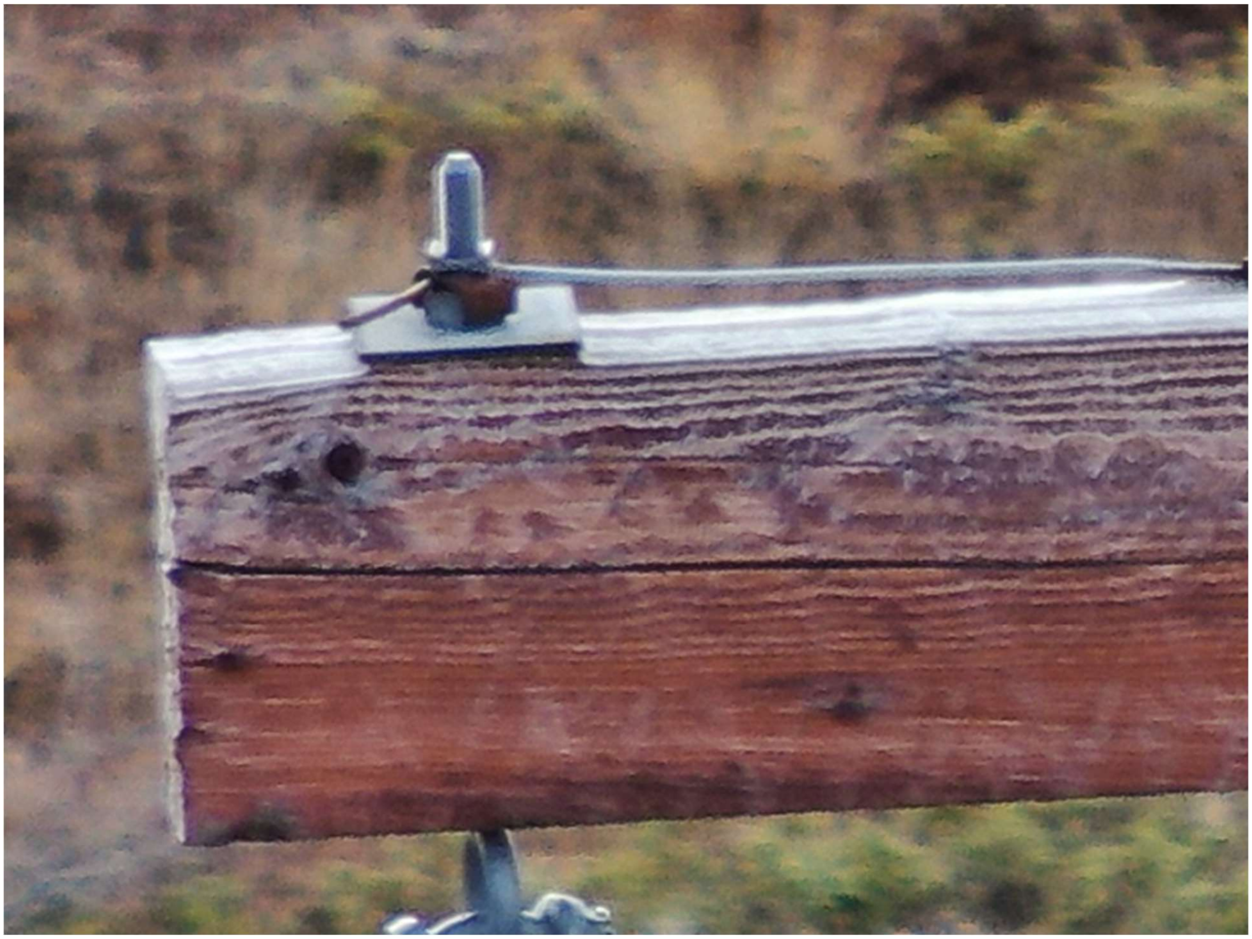

Figure B-6 – Split through Cross Arm.

Figure B-7 – Large Split through Pole, Hollow.

Figure B-8 – Woodpecker Holes, Hollow Pole.

Figure B-9 – Shell Separation.

Figure B-10 – Damaged Cross Brace.

June 2025

4.1 Customer Correspondence Modernization

Prepared by:
Chris Acreman

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 INTRODUCTION

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") current customer correspondence solution for generating and distributing customer billing information has been in use for over two decades. The customer correspondence solution is used to deliver over three million bills annually and more than 70 thousand letters and notifications; the customer correspondence solution is critical to providing accurate and timely information to customers in a secure, least-cost, reliable, and environmentally responsible manner.

Since its implementation in 2004, the customer correspondence solution has had a number of enhancements to support changes in customer billing including the addition of new programs, rates and information sharing to customers.[1] The cumulative effect of these changes has required the Company to implement various manual processes that have introduced inefficiencies in daily operations for new programs.

Customer information requests continue to evolve. The current solution cannot be enhanced to meet increasing customer expectations for more detailed billing information and efforts to support accessibility and inclusiveness for all customers. In addition, there are several business deficiencies that cannot be addressed due to technological limitations.

The effect of incremental changes and modifications introduced over time mean that the current solution is no longer the least cost-cost method of delivering customer billing and communications. Inefficiencies associated with the current system can be addressed with the implementation of modern technology and updated processes. Migration to a modern solution would also result in improved customer service, support for the delivery of complex rate structures, continuing to ensure cybersecurity requirements are met, addressing known deficiencies and addressing accessibility and inclusion considerations. The proposed solution would provide operational efficiencies and, as a result, is least-cost for customers on a net present value ("NPV") basis.

The proposed Customer Correspondence Modernization (CCM) project (the "CCM Project") is estimated to take approximately 15 months including post implementation. The overall cost to complete this migration in 2026 through 2027 is $1,957,000.

[1] Examples include the introduction of the Net Metering Rate, TakeCharge Rebate Programs, and the execution of the 2016 RSP Refund. Limitations in the current solution have required the Company to customize the solution in various ways and necessitate ongoing manual efforts for programs like the Net Metering Service Option bill production.

2.0 BACKGROUND

The primary and most consistent means of communication between Newfoundland Power and its customers is through their monthly bill. This interaction is vital in maintaining strong customer relationships and ensuring that customer service expectations and needs are met.

Newfoundland Power's current customer correspondence solution has dependably communicated customer billing information for more than two decades. However, the technology supporting the production of bills and letters, as well as their design, lacks the ability to effectively manage current and future business requirements.

Through continued modification and extension efforts, Newfoundland Power has maximized the value and useful life of the current platform. The decades of changes have resulted in a custom application that has a number of limitations, including:

(i) requiring manual intervention and processes that create business inefficiencies;
(ii) known and unresolvable deficiencies;
(iii) lack of support for bill delivery of complex rate structures; and
(iv) inability to remove barriers to diversity, equity and inclusion for customers with diverse backgrounds, literacy levels or mental and/or physical disabilities.

In 2023, the Company replaced its legacy Customer Service System, creating an opportunity to evaluate a modernized customer correspondence solution. The CCM Project will address multiple aspects of customer communications, focusing on modernizing bill production. There are over three million pieces of customer correspondence generated annually; this modern solution will enhance the value of each communication and support delivery of customer engagement in the least-cost manner.

2.1 Customer Service

Newfoundland Power conducts regular Customer Satisfaction Surveys to gather customer feedback on various service interactions. Feedback from these surveys has indicated that customers feel the current bill lacks clarity and functionality in several key areas. This includes understanding individual energy usage, how weather affects consumption and costs, awareness of available services, simplification of payment options and the presentation of complex billing calculations. Customers also indicate that the readability and overall comprehension of the current bill is unclear and lacks certain key information. As a result, customers with billing questions or concerns often reach out to the Customer Contact Centre. Bill-related contacts account for over 20 percent of the total volume of calls, emails, and webchats received by the Company's Contact Centre each year.[2]

Newfoundland Power's electronic bill ("ebill") delivery has grown to over 65 percent adoption, yet customer satisfaction with the ebill presentation and delivery is lower than that of paper delivery customers. This can be attributed to the current ebill design being based primarily on a paper bill format.[3] Electronic users expect a more modern, interactive and digital-first experience. This

[2] Bill related contacts account for more than 65,000 annual contacts.
[3] A survey conducted among Newfoundland Power customers in 2024 found satisfaction within the ebill segment was 20 percentage points lower than paper delivery customers.

would include such features as integrated payment processing, customizable downloads, visual annual summaries, notifications and seamless integration with My Account self-service tools.[4] A seamless integration of ebills with My Account self-service would also result in a significant enhancement to cybersecurity for customers. Customers also expect a consistent experience across web and mobile. Additionally, by offering timely and personalized notifications on weather trends and potential impacts on energy use, a more responsive and supportive service can be offered to Newfoundland Power's customers. This is evidenced by recent customer feedback and associated outreach to the Company regarding winter season electricity bills.[5]

2.2 Accessibility and Personalization

The current bill presentation does not provide options to address individual accessibility requirements. For example, customers who experience visual impairments cannot choose an alternate format for their bill. A redesign would provide customers with options for the delivery of billing information that would meet specialized needs. In consultation with InclusionNL, a redesign would provide the opportunity to focus on elements as suggested by such organizations as Accessibility Standards Canada.[6] This would allow for the appropriate use of color, contrast, print size, font type and clarity, spacing, column alignment, information organization and simplicity.

Additionally, there is a need to meet the personalized requirements of various customer groups. For example, the needs of a homeowner differ from those of a residential tenant, a small business owner, a landlord managing multiple properties, a large commercial institution or Government agency. The individual requirements and information needs for customer groups vary. However, the existing bill design is restricted to a single, common delivery format. This prevents delivery of simplified or important information that may only be relevant to a specific customer group.

[4] My Account is Newfoundland Power's online Self Service Portal where customers can retrieve account information such as their bill and complete account related changes such as signing up for new service.

[5] As stated in the 2025 Customer Billing Review, from February 17 to March 7, 2025, approximately 5% of the 11,000 customer calls were specifically about high bills, up from 2% during the same period in 2024.

[6] InclusionNL is a corporate program of The Disability Resource Centre that provides supports, services, and information to businesses in Newfoundland and Labrador. Accessibility Standards Canada was established under the Accessible Canada Act and is responsible for developing national accessibility standards.

2.3 Known Deficiencies

The current bill and letter design has several deficiencies that would be addressed by the CCM Project. These deficiencies result in hours of daily effort to manually review, correct, and redistribute billing correspondences or to answer customer calls and emails to explain or correct information previously distributed. Some examples include:

i. **Residential tenant interactions:** Move outs and move ins for residential tenants is a common customer transaction that is difficult to display clearly within the current bill format.[7]

ii. **Expansion of Summary Billing:** Summary Billing is currently only offered to Consolidated Bill customers.[8] The current bill format is not transferable to residential customers.

iii. **Bill corrections:** The current ability to display detailed information regarding adjustments on a customer bill is limited. Providing additional content on the bill would help inform customers, reducing the need for follow-up contacts.

iv. **Multiple billing periods on one bill:** Multiple billing periods are currently sent to customers individually rather than combined in one comprehensive bill due to limitations of the current solution. Enabling this would result in reduced costs and make it easier for customers to understand any changes to their bills.

v. **Dynamic formatting:** Current formatting does not allow for changes based on type of customer, time of year, weather conditions, or other relevant factors that could alleviate customer inquiries.

vi. **Targeted promotion:** Segmenting bill messages or program promotions based on customer type or scenario is not possible without laborious customizations.[9]

2.4 Obsolescence

Newfoundland Power's bills are currently produced using legacy technology components that have been heavily customized over the past two decades. The skills required to support the application are not commonplace in the market and can only be supported by a limited number of Newfoundland Power staff with detailed knowledge of the program. While the vendor has routinely upgraded the underlying technology, efforts to enhance and upgrade core functionality for these specialized components are becoming increasingly difficult due to functional and technical limitations. As a result, changes to address future functional enhancements and to remediate known deficiencies cannot be feasibly accomplished with the current solution.

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7 Currently, to display details of both the move out and move in service agreements, separate bills must be produced. This results in additional effort on the call taker as well as a doubling of the production costs, including mailing costs for paper delivery.

8 Summary Billing is when two or more service addresses are billed on the same account.

9 Developing targeted email, bill or letter promotions requires the involvement of technical developers to identify the target population and execute the delivery of the promotion. A modern solution would allow internal business users to produce targeted bill messages and promotional programs without the need for technical assistance, resulting in a more efficient process.

In 2024, a survey of Canadian utilities was conducted by the Company in partnership with Electricity Canada. The survey revealed that Newfoundland Power's planned approach to bill design and delivery aligns with industry best practice. Of the utilities surveyed, 80 percent had either replaced their bill design solution in the past five years or were planning to do so within the next two to three years. Obsolescence of technology and the supportability of existing solutions were common reasons cited for replacement. Results of the survey can be found in Appendix B: Electricity Canada Utility Summary Results.

3.0 ASSESSMENT OF ALTERNATIVES

Newfoundland Power assessed alternatives to identify the most viable and least-cost solution to ensure continuity of its customer correspondence solution. The Company identified two potential alternatives: (i) Maintain the existing solution; and (ii) Re-platform and redesign.

3.1 Description of Alternatives

(i) Alternative 1: Maintaining the Existing Solution
Alternative 1 involves maintaining the existing bill format and legacy technology to render, present and print bills. This alternative would continue to delay efficiency gains, limit enhancements and significantly reduce the Company's ability to address evolving customer needs.

(ii) Alternative 2: Re-platform and Redesign
Alternative 2 involves a complete re-platforming of the existing solution to progress Newfoundland Power's bill delivery solution to be an interactive and digital first solution. This would include evaluation and selection of new software as well as a bill redesign to ensure continuity of least cost and secure customer service delivery well into the future.

3.2 Evaluation of Alternatives

Alternative 1: Maintaining the Existing Solution involves retaining the current bill formatting software and associated business operations without modification. While this approach does not require immediate capital investment, it presents several significant long-term risks and limitations.

The primary concern is the increasing risk of obsolescence and reduced supportability. As the existing technology continues to age, vendor support will diminish, leading to higher maintenance costs, greater operational risk, and potential service disruptions. This aging infrastructure also limits the Company's ability to integrate with its modern Customer Service Systems or adopt emerging technologies.

This alternative does not deliver any operational efficiency gains. Manual processes and outdated workflows will persist, resulting in continued resource inefficiencies and higher operating costs over time. Further, it fails to address known deficiencies and customer-driven enhancements. This alternative would also require the Company to forgo an opportunity to enhance cybersecurity for customers.

Alternative 1 exposes the Company and its customers to escalating risks, limits future adaptability, and does not align with strategic goals for least cost customer service, operational efficiency, or cybersecurity hardening.

Alternative 2: Re-platform and Redesign proposes a full replacement of the underlying systems responsible for bill and letter production, printing and distribution. It also includes a comprehensive redesign of the customer bill and its delivery channels. This modernized solution directly addresses the functional obsolescence of the current technology, resolves supportability concerns, and introduces the enhancements required to meet evolving customer expectations. Additionally, it strengthens the Company's ability to manage cybersecurity risks through improved system architecture and compliance with current standards.

A Net Present Value (NPV) analysis was conducted to assess the cost-effectiveness of this alternative. The analysis compares Alternative 2 against the status quo (Alternative 1), evaluating the capital investment required for implementation against projected efficiency gains. These gains include labour savings in Contact Centre operations, reduced manual processing in bill production, increased customer self-service, avoided future capital expenditures, and improved long-term system supportability.

The results, detailed in Appendix A: Net Present Value Analysis, demonstrate that Alternative 2 delivers significant net cost savings over the evaluation period. These findings confirm that Alternative 2 is the least cost solution when compared to maintaining the existing system, offering the greatest value to customers while enhancing operational efficiency and communication capabilities.

Implementation of Alternative 2 is justified based on the requirement to deliver service to customers in a manner that is the least cost and results in more efficient and effective customer service delivery. It would allow Newfoundland Power to continue to ensure the supported, secure and reliable operation of information systems. It addresses known deficiencies, ensures compliance with industry standards and improves operating efficiencies. A modern customer correspondence solution positions the Company to explore new customer engagement opportunities through modernized correspondence tools.

4.0 PROJECT SCOPE AND COSTS

Newfoundland Power proposes conducting a Customer Correspondence Modernization project over the 2026 and 2027 budget years at a total cost of $1.96 million.

The scope of work for the CCM Project encompasses the evaluation of its bill print services, bill and letter generation software; a customer bill redesign; electronic bill presentation and delivery; digital communications and notifications advancements; and secure electronic delivery of sensitive customer information. The CCM Project is necessary to address the documented risks, known deficiencies and evolving customer requirements. The complexity of this project requires resources and expertise above the Company's day-to-day operational capability. Third party consulting assistance will therefore be required throughout the CCM Project if it is approved.

4.1 Project Cost

Table 1 provides a breakdown of project costs by year.

Table 1
CCM Project
2026-2027 Budget
($000s)

Cost Category	2026	2027	Total
Material	638	738	1,376
Labour – Internal	133	398	531
Labour - Contract	-	-	-
Engineering	-	-	-
Other	11	39	50
Total	782	1,175	1,957

Material costs in 2026 include the procurement of the required hardware and software which provide the technological architecture for effective delivery of the proposed new solution. Material costs in 2027 include the services of the selected consultant to design, deliver and implement the solution in a manner that meets Newfoundland Power's requirements and remains least cost for customers.

Internal labour costs include resources from Newfoundland Power's Customer Relations and Technology Departments. Internal labour costs in 2026 reflect the resources required to manage, procure and design a replacement solution. Internal labour costs in 2027 reflect the resources required to manage, configure, test, train employees in serving customers using the new technology and to deploy the solution.

4.2 Project Schedule

The CCM Project is scheduled to commence in Q1 2026, following Board approval. The new solution is expected to be implemented by Q2 2027.

Table 2 provides the schedule for implementing the proposed CCM Project.

Table 2
CCM Project
Project Schedule 2026-2027

Stage/Phase	Timeframe
Pre-Implementation	Q1 2026 - Q2 2026
Procurement	4 months
Implementation	Q3 2026 – Q2 2027
Plan/Initialization	1 month
Foundational Design/Solutioning	2 months
Prototyping	1 month
Detailed Configuration	2 months
Testing and Training	3 months
Deployment	1 month
Post Implementation	Q3 - 2027
Stabilization	1 months

5.0 CONCLUSION

The CCM Project for 2026-2027 would replace the existing, legacy solution that supports the production, distribution and notification of bills, letters and other customer communications. The CCM Project will ensure the bill format offers choice and meets changing customer needs, while ensuring the continued, secure delivery of information.

The CCM Project will provide improved customer service and is the least cost option for customers.

APPENDIX A:

Net Present Value Analysis

NEWFOUNDLAND POWER

Customer Correspondence Modernization Project

		Capital Impacts						Operating Cost Impacts						
		Capital Additions		CCA Tax Deductions				Cost Increases		Cost Benefits				
	YEAR	New Software A	New System Software B	Software	System Hardware	Residual CCA C	Total	Labour D	Non-Lab	Labour E	Non-Lab	Net Operating Savings F	Income Tax G	After-Tax Cash Flow H
0	2026	($782,000)	$0	$782,000	$0	$0	$782,000	$0	$0	$0	$0	$0	$234,600	($547,400)
1	2027	($1,202,614)	$0	$1,202,614	$0	$0	$1,202,614	$0	$0	$0	$0	$0	$360,784	($841,830)
2	2028	$0	$0	$0	$0	$0	$0	$0	($1,665,021)	$222,311	$1,881,557	$438,847	($131,654)	$307,193
3	2029	$0	$0	$0	$0	$0	$0	$0	($1,693,846)	$230,092	$1,914,129	$450,376	($135,113)	$315,263
4	2030	$0	$0	$0	$0	$0	$0	$0	($1,723,010)	$238,145	$1,947,087	$462,222	($138,667)	$323,556
5	2031	$0	$0	$0	$0	$0	$0	$0	($1,753,354)	$246,481	$1,981,377	$474,503	($142,351)	$332,152
6	2032	$0	$0	$0	$0	$0	$0	$0	($1,784,168)	$255,107	$2,016,199	$487,138	($146,141)	$340,996
7	2033	$0	$0	$0	$0	$0	$0	$0	($1,815,356)	$264,036	$2,051,442	$500,122	($150,037)	$350,086
7 Yr	Present Value (See Note I)	@		5.84%										$183,045

NOTES:

A is the sum of the software additions by year.
B is the sum of the computer network hardware additions by year.
C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.
D is any software maintenance fees and internal support costs associated with the project. The non-labour costs are escalated to current year using the GDP Deflator Index. The labour cost estimates are escalated to current year using Newfoundland Power's Labour Escalation Rates.
E is the reduced operating costs. The non-labour cost estimates are escalated to current year using the GDP Deflator Index. The labour costs are escalated to current year using Newfoundland Power's Labour Escalation Rates.
F is the sum of columns D and E.
G is the impact on taxes from the CCA and operating cost deductions. It is equal to column C (total) less column F times the tax rate.
H is the after tax cash flow which is the sum of the capital expenditure (columns A + B) plus operating expenditures (column F) plus income tax (column G).
I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

APPENDIX B:

Electricity Canada Utility Summary Results

Table B-1
Electricity Canada Utility Bill Redesign Summary Results – Within last 5 years

Respondent	Last Bill Redesign	Project Duration	Top Challenges
Utility 1	February 2023	2.5 Years	Working with multiple vendors, underestimating the time & effort, and magnitude of the change, resourcing capacity and project team turnover.
Utility 2	2018	-	The biggest challenges were regulatory and ensuring all regulated items included while keeping the bill simple, we are unique in that we also bill in addition to electricity on the same bill.
Utility 3	2021	1 – 1.5 years (Delays due to CIS Merge Project)	Redesign was initiated due to a merger, however improvements included: clarity in calculation/balance details, modernized look, enhancements to graph
Utility 4	2018	18 Months	• Outdated software / lack of consistency between online and paper billing that made changes difficult and costly; • Bill was 20 years old, in black & white and on non-standard paper sizes that didn't allow enough space to use bills as an effective communication tool; • Inability to enable paperless billing for consolidated accounts
Utility 5	2022-2023	2018-2023	• Our old bills didn't engage customers and empower them to make informed energy choices. • The old bills used overly formal language, and customers were often confused about their charges/credits. • We had a one-bill-fits-all approach, there was only one bill design regardless of the customer category.

Table B-2
Electricity Canada Utility Bill Redesign Summary Results – Changes not within the last 5 years

Respondent	Top Challenges	Redesign Planned
Utility 6	n/a	At least 2 years
Utility 7	• The solution is dated making it difficult to add any new features, • making content/layout changes would require a lot of effort, • Due to the complexity and the age of our solution we do not have many with the background / knowledge to make changes.	Yes – 3 years

Utility 8	• Limited space for bill messages – only have 256 characters that wraps on 4 lines with no formatting/line breaks
	• Lack of colour to bring out specific elements of the bill. E.g. we are unable to highlight or bring out important information
	• No dynamic/targeted content(graphics) other than text messages. E.g. we are unable to include inserts or dynamic messages
	• We would potentially like to recommend to specific customers
	  o To consider other rates. E.g. for EV customers depending on their profile
	  o Payment plans if in arrears
	  o Equal billing or bank draft if not already on those plans
	  o Possible future demand response programs	

Utility 9	• No major updates or improvements to software; • hosted on outdated windows server that needs to be updated; • conflicts with Microsoft patching.	Planning
Utility 10	Customer challenges in understanding the bill	In Progress

June
2025

4.2 Geographic Information System Upgrade

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NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 INTRODUCTION

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") has used Geographic Information System ("GIS") technology to manage its electrical infrastructure since 2013. GIS is integral to Newfoundland Power's operations. It plays a crucial role in maintaining safety compliance by providing accurate real-time mapping of utility infrastructure, allowing for better planning, maintenance and risk mitigation. This real-time model of the electrical system includes the status and location of infrastructure that delivers electricity to customers. GIS is used by the majority of the Company's employees to support numerous business functions and is connected to many critical operational systems, such as outage management, Customer Service System, and asset management.[1] Use of GIS allows Company employees to obtain real time access to grid operations and status. Newfoundland Power utilizes GIS as a central component in its business processes to ensure safe, reliable electricity service to customers in an environmentally responsible manner.

The Company's commercial GIS was implemented in 2013.[2] Prior to the deployment of GIS, the design and layout of the electrical distribution system was completed using a combination of manual and digital processes facilitated by paper drawings, multiple databases and computer programs developed in-house.[3] The implementation of GIS was consistent with utility best practices in effectively managing distribution and transmission assets.[4]

GIS is the central repository of the Company's geographic information. It maintains information on over 1 million features, including approximately:

(i) 267,000 customer service locations and their electrical connectivity;
(ii) 375,000 poles;
(iii) 68,000 streetlights;
(iv) 58,000 distribution transformers;
(v) 9,500 km of primary distribution line; and
(vi) 2,000 km of transmission line.

The GIS technology currently in use is at the end of its useful life and requires a major upgrade. The existing underlying GIS database and modeling structure is being discontinued by its commercial vendor on February 28, 2028.[5] To maintain support and security, the GIS database must be migrated to the current vendor's newer modeling structure prior to this date.[6] The majority of other utilities that utilize the same GIS technology as Newfoundland Power are

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1 Over 90% of Newfoundland Power staff utilize GIS either directly in the system tools or indirectly through integrated systems.

2 See Newfoundland Power's *2013 Capital Budget Application*, report *7.1 Application Enhancements,* section *2.1 Distribution System Information Management Improvements.*

3 Such programs include the Company's previous Customer Service System ("CSS"), replaced in 2023, and previous Outage Management System ("OMS"), replaced in 2019.

4 A jurisdictional scan of 19 Canadian electrical utilities has shown that 100% utilize GIS technology to support company operations.

5 The current GIS technology was first released in late 1999.

6 The new GIS technology was first released on January 22, 2018, and allowed advanced network capabilities for utilities. It is designed to model all components that make up the electric network, how features and objects in the network are connected, trace how resources flow through the network, and analyze how the network is affected by real-world events such as storms, outages, or equipment failure.

currently in various stages of migrating to the latest version of GIS.[7] Failing to complete this migration could result in widespread disruption to Company operations with the loss of geographic tools and integrations. Given the criticality of the Company's GIS technology, as well as integrations to critical business systems, continuing to operate the technology without vendor support is an unacceptable risk to Newfoundland Power and is not a viable option.

Newfoundland Power is proposing a three-year capital project to migrate the Company's GIS technology to the new standard. It is estimated the proposed project will take approximately 30 months, including post implementation and stabilization, beginning in 2026 and concluding in 2028. The total estimated cost to complete the migration is $8,325,000.

2.0 BACKGROUND

2.1 Geographic Information Systems

GIS is a technology that allows for the collection, storage, analysis and visualization of geographical data. GIS integrates various types of data, including maps, satellite images, and demographic information, to create comprehensive and interactive visualizations of geographic areas. While GIS technology initially served as a basic mapping tool, continuous advancements have transformed it into an enterprise-level spatial data system. Today, GIS plays a critical role in decision-making, emergency response, and resource management, offering enhanced capabilities and functionalities.

Figure 1 – GIS and Integrating Systems.

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7 Of the 19 Canadian electrical utilities assessed as part of a jurisdictional scan, three are currently active in their GIS upgrade implementations and 10 are in the planning stages.

GIS is an essential resource for electrical utilities in managing and optimizing infrastructure as well as operational response to issues in the field. It is used to map and monitor the physical location of electrical components, such as transformers, power lines, and customer locations. By providing a detailed and dynamic visual representation of the electrical grid, GIS helps utilities to efficiently plan maintenance activities, manage outages, and respond to emergencies.

GIS facilitates the integration of various data streams, such as customer information, outage incidents, and asset conditions into a single platform. This integration streamlines operations, allowing utility companies to make informed decisions regarding resource allocation, load distribution, and network enhancements. The ability to analyze spatial data in real-time further enhances the operational efficiency and reliability of the electrical grid.

The GIS technology used by Newfoundland Power is supplied by a major vendor in the GIS industry.[8] The current technology on which the present GIS version is based was released in the late 1990s and was built on Microsoft technology that is also nearing end of life and entering mature support as of 2025. The Company's current GIS vendor has invested development into its own products to preempt issues with failing architecture.

The GIS market is currently undergoing a significant upgrade and replacement phase. GIS vendors are currently providing new product versions and technologies that have been developed in advance of technology obsolescence. This includes platform offerings that facilitate the sharing of data between organizations and enable new use cases. Upgrading the Company's GIS to the newest offering would allow the continued evolution and spatial integration of the Company's business processes.

2.2 Geographic Information at Newfoundland Power Prior to GIS

Prior to the deployment of GIS technology at Newfoundland Power, the Company maintained multiple applications and utilized manual processes to manage geographic location and electrical connectivity information. Customer premises and account information, streetlight location and asset data, work management processes and asset management systems were largely text-based database structures and relied on street addresses and descriptive landmarks to define location information. Updates were made to each of these systems individually. As a result, multiple versions of documentation existed, and this duplication made it difficult to identify original source data or to assess the accuracy and currency of information.

8 Of the 19 Canadian electrical utilities assessed as part of a jurisdictional scan, 16 (or 84%) utilize the same GIS technology as Newfoundland Power.

Single Line Diagrams

Single Line Diagrams ("SLDs") are a crucial component in providing a comprehensive visual representation of the electrical system for maintenance, troubleshooting and grid operations. Prior to GIS, approximately 300 distribution circuits were maintained as bound paper copies. These binders were distributed to employees as controlled documents.[9] As the electrical distribution network was modified, for example due to the construction of new lines or the permanent transfer of load between feeders, new pages were drafted for the SLD binders and distributed to employees, requiring old pages to be removed and destroyed. Additionally, these paper documents were not drawn to scale and only represented a general geographic area, making them difficult to use when patrolling feeders during outages. Engineering models of the Company's electrical distribution grid were separately maintained in load flow software, which required information on conductor length and location of loads such as distribution transformers. This layout was maintained separately from the SLDs and had to be updated manually to reflect changes.

Customer Information and Outage Management

During outage events of varying severity, from isolated outages to major events, individual outage tickets were created from customer calls using a homegrown outage management database. Employees would then manually sort these tickets by address to identify common problems to manage outage restoration as efficiently as possible. Similar processes existed for streetlight outages, maintenance work orders and customer-requested field work. These manual workflows often resulted in inefficient dispatch of field resources for duplicate requests.

Asset Information

Geographic information on assets such as transmission lines were maintained as paper drawings or digital file structure lists. Text descriptions indicating geographic landmarks were used to help identify assets in the field. Any changes again necessitated manual updates of documents and required a process to ensure out-of-date copies were destroyed.

In 2013, the Company purchased and installed a commercial GIS system to streamline manual processes used to maintain and distribute information associated with the Company's various distribution assets.[10] As detailed above, prior to the introduction of the GIS, there was significant duplication of effort, an increased risk of errors with manual data entry, and complexity in ensuring multiple versions of documentation were updated and distributed properly.

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[9] Each SLD binder in circulation was individually numbered and tracked. An employee was required to document the update of each of these binders triggered by distribution system changes, to ensure out-of-date information was removed from the Company's records.

[10] See Newfoundland Power's *2013 Capital Budget Application*, report *7.1 Application Enhancements,* section *2.1 Distribution System Information Management Improvements ($572,000)*.

2.3 Use of GIS at Newfoundland Power

GIS technology provides benefits to many business functions at Newfoundland Power, including transmission, distribution and generation of electricity, outage management, work dispatch and response, and sharing of information with customers. GIS is also used for infrastructure design, asset management, and customer support.[11]

GIS is the central repository for geographic information for the Company's assets and customers and is integrated into multiple core business systems. GIS is also a collaborative platform, used to exchange data with other organizations such as other utilities, telecommunications providers and government agencies.[12] It has been continually upgraded since the initial deployment in 2013 to allow continued vendor support and data security.[13] Enhancements, including integrations into other applications, were implemented to improve efficiency of operations and data collection.[14]

2.3.1 Customer Benefits

The use of GIS has provided direct value to Newfoundland Power's customers. This can be seen through numerous operational efficiencies and improved customer service offerings enabled by using GIS. Details of some of these customer benefits are discussed below.

Customer Outage Communication

Newfoundland Power's OMS relies on the GIS electrical system model to trace electrical connectivity from the substation feeder breaker to the customer's service location. This enables direct automated customer outreach when outages occur or are planned for maintenance. It also provides specific customer-based outage information to Customer Service Representatives or Power System Operators who field calls during outage events.

Customers can be contacted via text, email or automated phone calls when an outage occurs, or 48 hours in advance of a planned outage, depending on their communication preferences. Customers visiting Newfoundland Power's website are offered a map-based view of upcoming planned outages as well as ongoing unplanned or planned outages.[15]

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11 Current projects to replace and upgrade the Company's Asset Management and Outage Management systems are utilizing GIS as a common platform to allow spatial analysis and improve efficiency.

12 As an example, the Canadian Wildland Fire Information System (CWFIS) publishes data on ongoing wildfires. This data can be mapped in GIS to show proximity of fires to Newfoundland Power infrastructure.

13 The GIS was upgraded in 2018 and 2021 to remain in vendor support. See Newfoundland Power's *2021 Capital Budget Application*, Volume 2, report *6.2 2021 System Upgrades*, page 3 of 6 for the most recent upgrade.

14 See Newfoundland Power's *2015 Capital Budget Application,* report *6.5 Geographic Information System Improvements*. Enhancements were made to the GIS to collect customer connectivity and allow field staff to view GIS data on mobile devices.

15 Newfoundland Power managed an average of 4,712 outage incidents per year and received 739,447 views on its outage center page annually between 2022 and 2024.

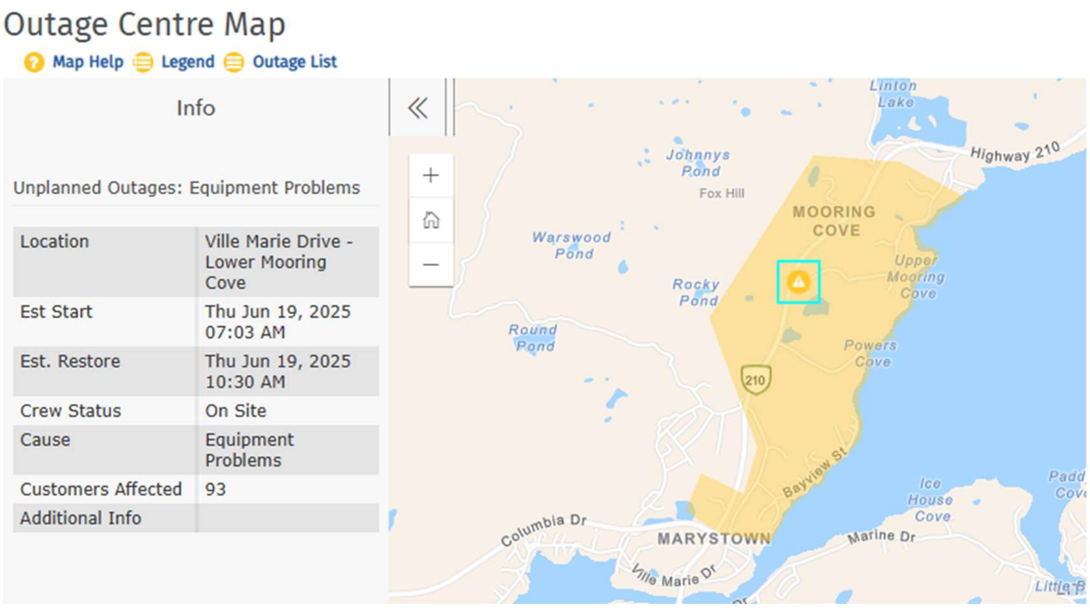

Figure 2 – Newfoundland Power's Outage Centre website, showing an example of an unplanned outage, associated map and details.

Map-Based Streetlight Outage Reporting

GIS permits Newfoundland Power's customers to view a map of the Company's streetlights. This allows customers to more easily identify and report a streetlight outage, as well as access information on outages already reported. Use of GIS has also improved Newfoundland Power's streetlight repair performance by reducing duplicate outage reports and site visits related to lights off for maintenance reasons.[16]

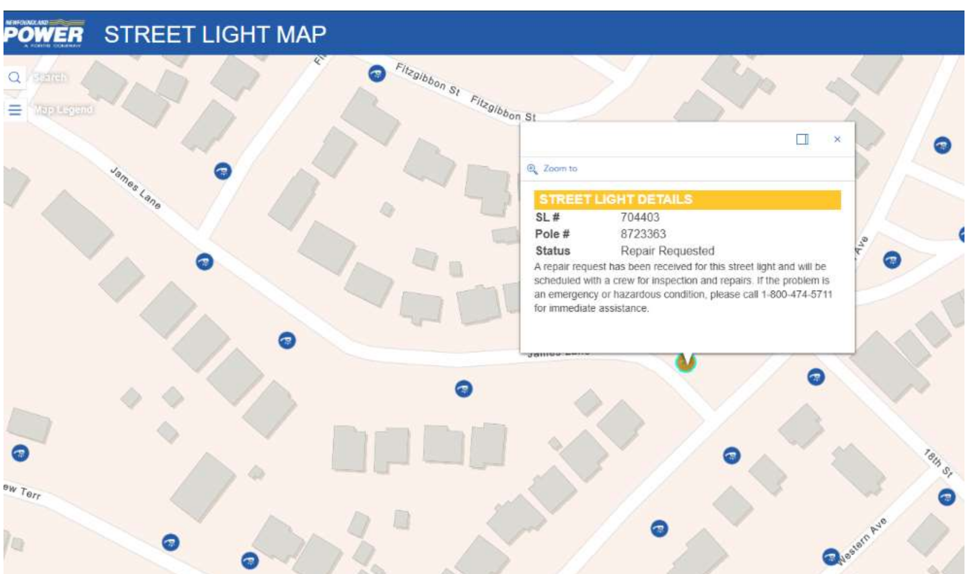

Figure 3 – Customer Streetlight Outage Reporting Map.

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16 Newfoundland Power has reduced its average time to repair for streetlights from 4.3 days in 2020 prior to use of GIS, to 3.5 days in 2024.

Improved Field Response

GIS mapping capabilities, in conjunction with the Workforce Management ("WFMS") and Automatic Vehicle Location ("AVL") systems, allows efficient dispatching of field staff. As an example, when an outage occurs, the Company can identify field crews in close proximity to the location of the outage on a map. This allows assignment of outages to the closest appropriate resource to minimize response time to customers.[17]

2.3.2 Functionality

Asset Geolocation

The GIS maintains geolocation information on over 1 million features, including poles, service locations, transformers, streetlights, buildings, and more. Each feature is uniquely identified and tracked via GPS coordinate. Features are added to GIS upon construction, and specific attributes are collected depending on the feature type.[18] This information was collected over time through various methods. This includes pole data from Bell Aliant's GIS system.[19] Streetlight locations were taken from the former Streetlight Management System, which was subsequently retired. Other features were captured from design and construction drawings, and field surveys were completed to verify data and fill in gaps. Processes have been developed since the deployment of GIS to ensure continued improvement in the accuracy of data.

Electrical Connectivity

GIS maintains electrical connectivity data from the substation feeder breaker to the distribution transformer to the customer's service location. The original source of connectivity information from feeder breaker to distribution transformer was the Company's distribution modeling software.[20] Connectivity from the distribution transformer to the customer service location was collected manually from the field.[21]

Operational Map Views

GIS provides tools to produce map views of the features and data in the GIS database. This allows the Company's users to view and analyze data spatially – for example, to identify the locations of distribution transformers of a specific vintage or construction. Different features may be added, removed or filtered on map views using on-board GIS analysis tools. These map views enabled the retirement of hard-copy feeder map binders and reduced manual updates of multiple independent systems.

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17 Newfoundland Power has an average response time of 1 hour and 52 minutes to emergency calls in the period 2020-2024. This encompasses over 28,500 individual emergency calls.

18 For example, a 'Pole' feature would include attributes for height, class, and installation date amongst other data.

19 Pole locations and specification information was collected in a survey completed as part of the Bell Aliant pole sale in 2012. As part of the Joint Use Agreement, Bell Aliant is responsible for storing and maintaining the pole information inside its own GIS.

20 This software is used to complete network modeling and load flow analysis on the electrical system.

21 See Newfoundland Power's *2015 Capital Budget Application,* report *6.5 Geographic Information System Improvements*.

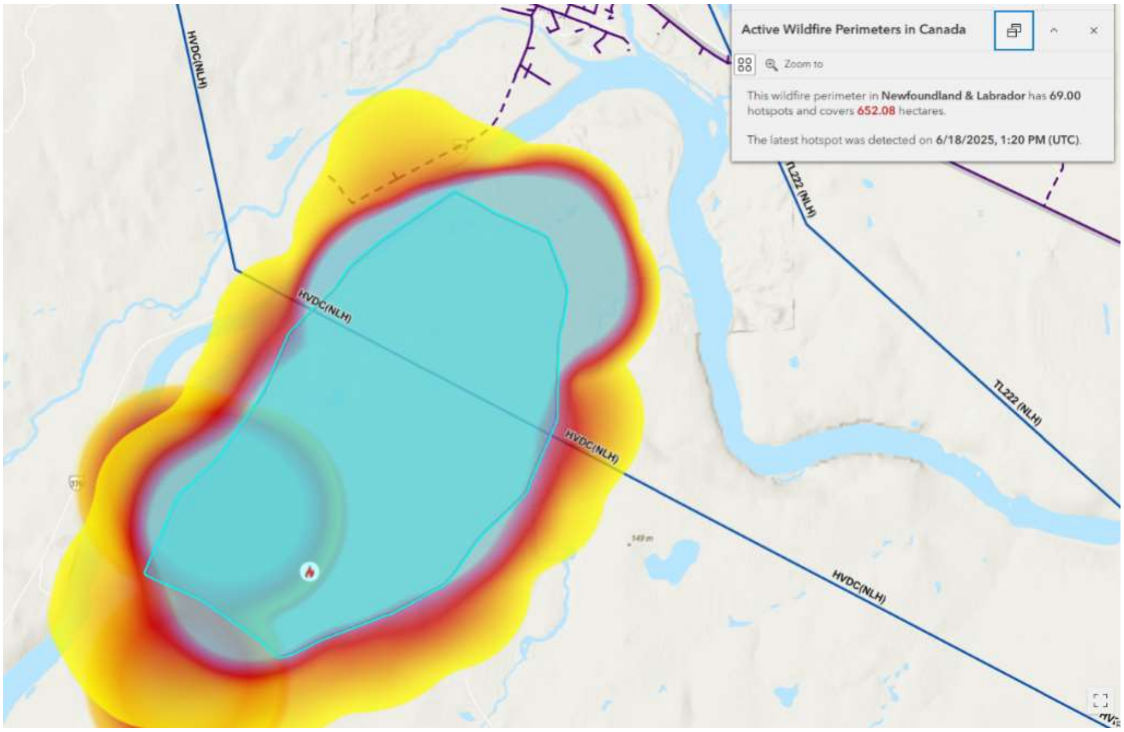

Figure 4 – Operational Map View showing footprint of Badger wildfire in June 2025 and proximity to electrical infrastructure.

2.3.3 Integrations

There are many integrations between GIS and other business systems that have enabled centralization and spatial analysis of data from various functions. In addition to application integrations, there are also scripts, services and automated routines that run on servers. These jobs facilitate the transfer of data between GIS and other systems to ensure appropriate data flow and serve to eliminate the duplication of labour required to keep multiple systems updated when information changes. Some critical application integrations are described in detail below.

Outage Management System ("OMS")

Information on customer outage reports was originally integrated into GIS from the Company's internally developed OMS in 2013. The integration allowed staff to view outage calls geographically, based on customer address. It also improved isolation of root cause locations and reduced duplicate trouble reports. In 2019, the Company installed a new Commercial Off-The-Shelf ("COTS") outage management system that directly integrated with GIS utilizing electrical connectivity information to automatically predict outage locations and improve efficiency both of office staff and field staff outage response.

Customer Information System ("CIS")

Specific customer data, including meter number, account number, and contact information are integrated into GIS from the CIS. This aids in the planning of scheduled outages, allowing targeted customer outreach.

Supervisory Control and Data Acquisition ("SCADA")

Information on the state of electrical equipment on the grid is fed from SCADA into GIS. This connectivity allows employees a real-time view of electrical equipment status and power flow. In conjunction with the OMS, SCADA integration improves outage response by highlighting possible system reconfiguration. This also improves job safety planning and efficiency by providing visual information on temporary or abnormal conditions as verified through the SCADA system.

Workforce Management System ("WFMS") / Automatic Vehicle Location ("AVL")

Work tasks from a variety of host systems are dispatched through the WFMS. The current location and status of fleet vehicles is provided by the AVL system. Both systems are integrated into GIS, providing dispatchers and field staff with map views showing the location of work tasks and current vehicles. As a result, GIS provides a comprehensive, real-time view not only of system conditions, but also of the current distribution of field personnel and resources. This complete, real-time view promotes optimal efficiency by ensuring tasks are assigned to the nearest available resource and enabling the optimal routing of field crews between assigned tasks.

Asset Management System ("AMS")

Asset information, work requests, and work orders from the AMS are integrated into GIS, which also enables improved job planning. Engineering staff can see these items on a map, allowing efficient packaging of work into a single job plan. It also allows geographic analysis of identified deficiencies and equipment in poor condition to support capital planning and help identify possible environmental factors contributing to poor equipment performance or degradation.

Mobile GIS Applications

GIS information is made available to field employees through integrated mobile GIS applications. This allows field employees to 'red-line' incorrect information, providing a method to feed proper information to GIS staff in the office in real-time, allowing continual improvement of the GIS data. This also supports damage assessment workflows, whereby assessors can identify changes on a map to indicate damaged equipment, areas for vegetation management, or other storm response information.

Technical Work Request System ("TWR")

The TWR system is used to track work requests from customers or internal operations and engineering departments related to line extensions, new services, upgrades and relocations of infrastructure. As jobs are designed in TWR, information is provided to GIS to enable users to see proposed or 'in-design' poles and infrastructure prior to actual installation. As jobs in TWR are completed, this infrastructure is then updated to 'as-built', ensuring timeliness and accuracy in the GIS data.

Dashboards and Reporting

GIS information is fed to external reporting and dashboarding systems to permit quick access and analysis to georeferenced data. Dashboards include tools for managing power outages, identified vegetation management activities, and reliability data including SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) on a geographic basis.

Figure 5 – Dashboard showing current power outages and associated map and data.

Streetlight Asset Management System ("SLAMS")

In 2021, the Company enhanced its SLAMS to integrate to GIS. This allowed customers to report streetlight outages or other streetlight problems by selecting an individual streetlight from a map view. Prior to this integration, customers were required to provide a text streetlight location or address. Manual effort was required to screen customer reports for duplicate entries, and it was possible for a light to be reported and dispatched for repair multiple times. Since the integration with GIS, customers can definitively identify the required lights for repair and the system prevents duplicate repair requests. This has improved efficiency and reduced costs for customers by eliminating duplicate dispatch of repairs.

Digital Forms Application

Digital forms utilize GIS data to add geolocation information. For instance, the digital tailboard application uses GIS data to link a tailboard to the location of work. Digital forms also interact with GIS data to complete tasks such as condition assessments and inspections.

3.0 RISK ASSESSMENT

GIS is a critical business application for Newfoundland Power. It is the central repository for the Company's geolocation information and provides crucial tools for managing assets, optimizing operations, and facilitating informed decisions. Spatial analysis capabilities provided through the GIS have enabled efficiency gains and improved service offerings across virtually all customer operations business functions. The accurate real-time mapping provided by GIS allows for improved maintenance and capital planning while ensuring safety compliance. Employees in the engineering, operations, technology, planning and customer service departments all rely on GIS to effectively and efficiently complete their tasks daily in a safe manner.

As detailed above, GIS has allowed the Company to improve customer service offerings and operational efficiency. Should a failure occur, processes that currently depend on GIS would require additional manual effort, reducing employee efficiency.[22] Users would not have direct access to geographic information necessary to support the Company's operations, including current system state and temporary system conditions. GIS, once unavailable, will no longer accommodate data storage. This will cause a disconnect as field changes occur and employees no longer have tools to keep records up to date. Employees would have to rely on paper notes, emails and phone calls to communicate changes, presenting higher risk of human error. The efficiencies gained through GIS would be lost and business operations would be disrupted while processes reliant on GIS are reworked.

The vendor has indicated that the current technology will no longer be supported as of February 28, 2028. Vendor support ensures that critical applications operate reliably and securely. Unsupported applications are more prone to failure and are at risk of cybersecurity breaches. To maintain vendor support, GIS will need to be migrated to the newest version prior to this date. Given the criticality of the Company's GIS technology, as well as integrations to other critical business systems, continuing to operate GIS without vendor support is an unacceptable risk and not a viable option.

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[22] For example, outage prediction and call consolidation are reliant on GIS. If GIS were unavailable, employees would have to manually create and analyze outage reports and associate calls to determine location of likely issues.

4.0 ASSESSMENT OF ALTERNATIVES

The Company identified and assessed three alternatives to migrating its geographic information system: (i) do nothing; (ii) upgrade GIS technology; and (iii) replace GIS technology. 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 GIS technology after it has reached its end of life. This GIS technology would be unsupported by the vendor and the risk of "run-to-failure" would have to be accepted. Introducing a 'run-to-failure' approach could significantly impact critical business processes and integrations if the software fails and will open the Company to cybersecurity risks and threats.

(ii) Alternative 2: Upgrade GIS Technology

Alternative 2 involves a major upgrade of the existing GIS technology to the next release of GIS. The upgraded GIS technology will support the Company's current business functions and integrate with existing technology. As the current GIS vendor holds a large market share of GIS installations, they have worked closely with the vendors of other software applications to develop streamlined methods of integrating functionality into the upgraded GIS system.

(iii) Alternative 3: Replace GIS Technology

Alternative 3 involves replacing the current GIS platform with a new solution from a different vendor. Such a transition would be a significant undertaking, as all existing developments including mobile applications, dashboards, and reporting tools would need to be redeveloped to function on the new platform. Additionally, the internal knowledge base and user training accumulated since the system's implementation in 2013 would not be transferable to the new software, resulting in a substantial loss of organizational expertise and requiring extensive retraining.

4.2 Evaluation of Alternatives

Alternative 1: Do Nothing introduces risk to the Company's operations. The current technology will no longer be supported by the vendor as of February 28, 2028. There is a risk the unsupported technology will fail as surrounding IT infrastructure and operating system patches continue to evolve. This will cause a disruption to Company operations as GIS is an integral solution to most major systems including outage management, asset management, work management and customer service. The unavailability of GIS would impact a significant number of Newfoundland Power staff, including office and field workers, and would expose the Company to an increased risk of cybersecurity breaches.[23] *Alternative 1: Do Nothing* is not an acceptable option due to its associated risks.

Alternative 2: Upgrade GIS Technology involves a major system upgrade to eliminate the risk to Company's operations, work management and customer service. This includes updating existing system integrations, data migration and change management activities. Existing reporting and dashboarding relying on GIS data will also be updated to work with the upgraded GIS technology. Newfoundland Power's current GIS system natively integrates with many of the Company's critical systems that other GIS systems do not. For example, pre-built integrations are included for the WFMS, load and power flow estimating system, OMS and the Company's new asset management software.

The upgraded technology will maintain current business processes that utilize GIS. Upgrading GIS technology will leverage existing processes, components and integrations and as a result, will be less complex as opposed to implementing an alternative GIS technology. In addition, upgrading GIS technology will not require the purchase and licensing of new software.[24] The upgraded technology will ensure ongoing vendor support to help mitigate risk of failure or cybersecurity threats. *Alternative 2: Upgrade GIS Technology* is an acceptable option as it aligns with industry best practices and will enable continued growth and development of GIS capabilities.

Alternative 3: Replace GIS Technology involves replacing the current GIS platform with a solution from a different vendor. It would require redesigning the system architecture, rebuilding all integrations and functionalities, redeveloping dashboards and reports and purchasing new software and licenses. The transition would also result in the loss of established vendor relationships and internal expertise developed since 2013. The unfamiliarity with the new system introduces additional risk and complexity.

While the foundational project tasks, such as project management, data migration and deployment, are estimated at $8.325 million for both Alternatives 2 and 3, Alternative 3 incurs additional costs including more complex system integration (estimated at approximately 20% more than Alternative 2), dashboarding and reporting redevelopment and new software and

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23 The GIS handles customer personal information. Newfoundland Power has a statutory obligation pursuant to the *Personal Information Protection and Electronic Documents Act*, SC 2000, c. 5, to maintain security safeguards for personal information in its possession.

24 Newfoundland Power is currently in an Enterprise-level agreement with the existing GIS vendor. As a result, software licenses from the existing GIS will be migrated to the new GIS at no additional cost.

licensing.[25] These additional costs are estimated at $3.3 million, bringing the total project cost for Alternative 3 to approximately $11.6 million. Alternative 3 is more expensive and is higher risk than Alternative 2, with no clear operational advantage.

Although Alternatives 2 and 3 share foundational project tasks, the additional costs and risks associated with integration, redevelopment, and licensing in Alternative 3 are avoided in Alternative 2. Therefore, Alternative 2: Upgrade GIS Technology is the least cost option.

The Company's current GIS vendor has the largest penetration within Canadian utilities and provides industry leading features, functionality and integration capabilities with other utility-based software. In a recent jurisdictional scan of 19 Canadian electrical utilities, 84% of respondents including major Atlantic Canada electric utilities (Nova Scotia Power, New Brunswick Power, Saint John Energy, and Maritime Electric) utilize the same GIS provider as Newfoundland Power. The results of this jurisdictional scan are outlined in Appendix A: Canadian Utility GIS Survey Results. Moving to a different GIS solution would require a full re-implementation of GIS technology, including data mapping and conversion, business process review and changes, development of new integrations and additional change management in the training of technical resources and system users.

Implementing Alternative 2 avoids the risks of continuing to operate unsupported GIS technology while ensuring the upgraded GIS technology maintains Newfoundland Power's business operations and meets the Company's requirements of running vendor-supported technologies. This will avoid interruptions to the Company's operations and enable the Company to continue using GIS technology. Upgrading GIS technology will mitigate increased risks and costs involved with changing GIS technology. Alternative 2 is the recommended course of action, as it will maintain current functionality and capability at least cost to the customer.

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25 The existing vendor has partnered with many other vendors of operational applications used at Newfoundland Power and provides tools and interfaces to simplify common integrations. These tools do not exist for competing vendor solutions and therefore would require additional effort to replicate. In addition, Newfoundland Power has created approximately 650 electronic forms, dashboards and reports within the current GIS portfolio of tools. Moving to a new system would mean redesigning and redeveloping these components.

5.0 PROJECT SCOPE AND COST

5.1 Project Overview

Newfoundland Power proposes to upgrade its GIS starting in 2026 at an overall cost of approximately $8,325,000. The upgraded GIS will be fully implemented in 2028.

The Company has been working closely with its current GIS provider along with other integration partners to understand the scope and effort associated with the upgrade of GIS technology.

The replacement technology will support the functionality of the current technology with enhancements that are native to the new solution, including more modern underlying technology components to allow supported, secure technology moving forward.

5.2 Project Planning

Newfoundland Power has been preparing for the GIS upgrade over the past number of years. In 2023, the Company installed GIS Enterprise and migrated certain functionality to the GIS Enterprise platform as a pre-requisite for the GIS Upgrade.[26] In 2024, the Company engaged the GIS vendor to complete an upgrade readiness assessment for GIS. The vendor conducted workshops with GIS users and provided technical and cybersecurity support to determine migration complexity, data readiness and integration planning to upgrade GIS. Newfoundland Power undertook a detailed planning exercise outlining the requirements of the major upgrade including integrations, expected length of project, required resources and required vendor engagement. From this exercise, the Company was able to identify integrating vendors who also had to be contacted to determine scope of work. This assessment reviewed data and data structure, integrations, and any reporting components of the current environment.

In 2025, the Company completed a jurisdictional scan of GIS usage for 19 Canadian electrical utilities. This scan gathered information such as the GIS technology vendor and GIS upgrade status. Sixteen of the utilities reviewed currently utilize the same GIS technology as Newfoundland Power. Of the 16, three are currently in the implementation phase of their GIS upgrade, 10 are in the planning phases, and three are unknown. Upgrading GIS prior to the obsolescence date has been a critical target for the majority of the 19 Canadian electrical utilities.

Through various GIS and other integrating vendor engagements, cost estimates, as well as knowledge from previously completed projects, Newfoundland Power was able to develop a project cost and schedule estimate of $8,325,000.

Upgrades of this nature are standard practice within the GIS environment, and therefore many vendors have already developed or are in the process of developing integrations to support the newest version of GIS.

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[26] See Newfoundland Power's *2023 Capital Budget Application*, report *5.1 Application Enhancements*, pages 3 to 4.

5.3 Project Cost

Table 1 provides a breakdown of the costs for implementing the GIS technology upgrade.

Table 1
Geographic Information System Upgrade
2026-2028 Budget
($000s)

Cost Category	2026	2027	2028	Total
Material	142	2,880	671	3,693
Labour – Internal	355	1,703	1,249	3,307
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	3	590	732	1,325
Total	$500	$5,173	$2,652	$8,325

5.4 Project Schedule

Table 2 provides the schedule for implementing the GIS technology upgrade.

Table 2
GIS Technology Upgrade
Project Schedule 2026-2028

Stage/Phase	Timeframe
Pre-Implementation	Q1 2026
Procurement	3 months
Design and Configuration	Q2 2026 to Q4 2027
Design	2 months
Configuration and Integrations	14 months
Data Conversion	4 months
Testing and Training	Q4 2027 – Q1 2028
Testing and Training	5 months
Implementation	Q1 2028
Deployment	2 months
System Stabilization Complete	September 2028

The project is scheduled to commence in Q1 2026, following Board approval. A replacement solution is expected to be implemented in Q1 2028 followed by a system stabilization period.

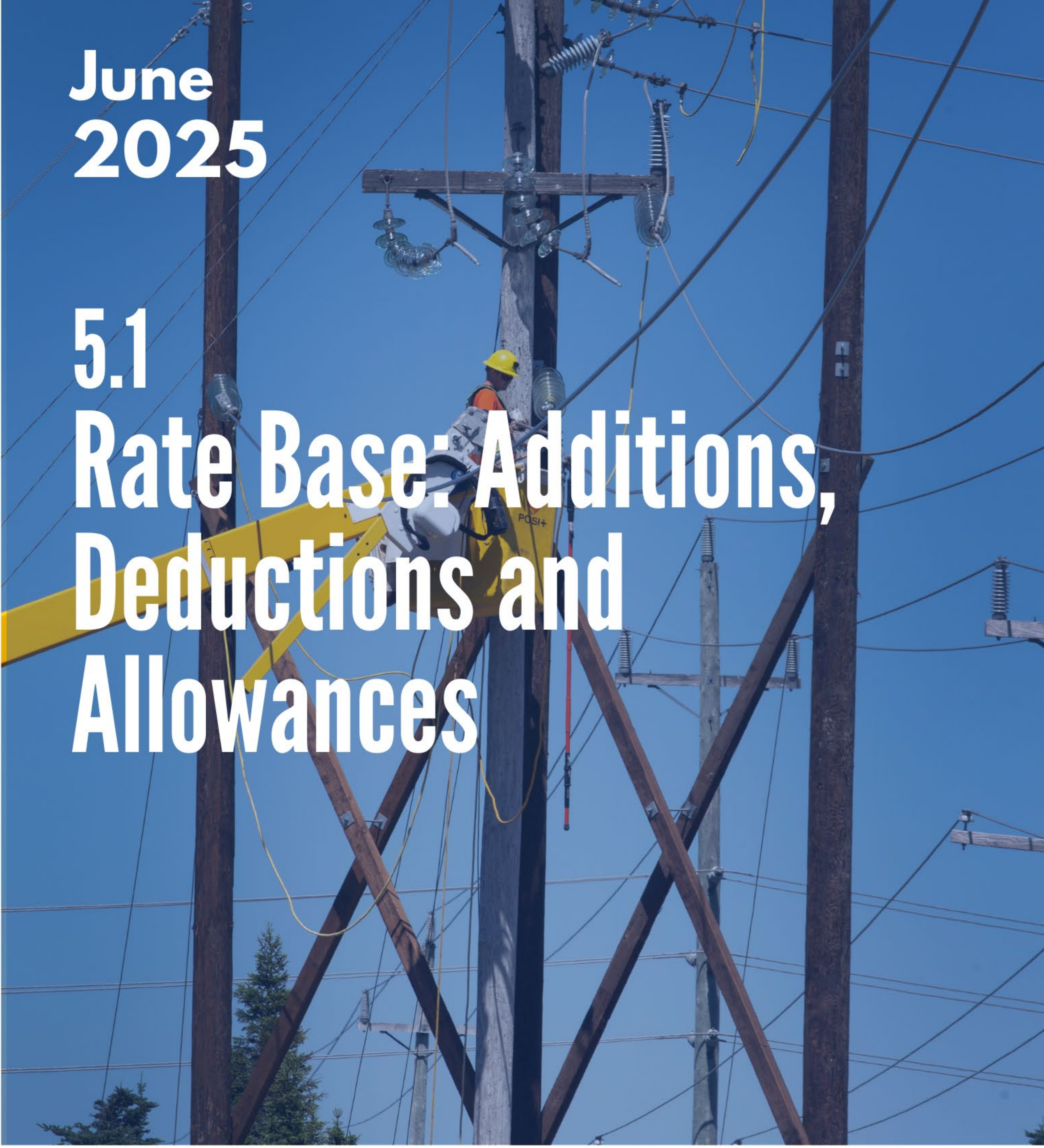
6.0 CONCLUSION

Newfoundland Power's current GIS technology will no longer be supported by the vendor as of February 28, 2028. The Company will perform a major upgrade of the GIS system commencing in 2026. Upgrading technology is in alignment with the industry best practice of running supported software and will allow the Company to continue developing and refining GIS practices while also providing a foundation for GIS maturity.

APPENDIX A

Canadian Utility GIS Survey Results

Table A-1 Utility Geographic Information System Usage			
Utility	# Customers	Utilize GIS Technology	Alternative 2 Vendor
Hydro-Québec	4,316,914	YES	YES
BC Hydro	2,049,322	YES	YES
Hydro One	1,333,601	YES	YES
Alectra Utilities	991,102	YES	NO
Toronto Hydro	772,624	YES	YES
ENMAX Corporation	674,800	YES	YES
Manitoba Hydro	586,795	YES	YES
Fortis Alberta	563,000	YES	YES
SaskPower	537,714	YES	YES
Nova Scotia Power Incorporated	520,000	YES	YES
New Brunswick Power	405,466	YES	YES
EPCOR	369,000	YES	YES
Hydro Ottawa	335,320	YES	NO
ATCO	227,000	YES	YES
FortisBC	175,900	YES	YES
London Hydro	159,039	YES	NO
Veridian Connections Inc.	121,826	YES	YES
Saskatoon Light & Power	117,200	YES	YES
Kitchener-Wilmot Hydro Inc.	96,827	YES	YES



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2025

5.1
Rate Base: Additions, Deductions and Allowances

NEWFOUNDLAND POWER
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1.0 INTRODUCTION

In the *2026 Capital Budget Application* (the "Application"), Newfoundland Power Inc. ("Newfoundland Power" or the "Company") seeks final approval of its 2024 average rate base. This is consistent with current regulatory practice before the Board.

Newfoundland Power's 2024 average rate base of $1,357,191,000 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 2024 annual returns, this report provides a review of the 2023 and 2024 additions, deductions and allowances to support the Company's 2024 average rate base set out in Schedule D to the Application.

[1] Newfoundland Power's 2024 annual returns are provided in its *2024 Annual Report to the Board* which was filed with the Board on March 31, 2025. Return 3 provides the calculation of the Company's 2024 average rate base.

2.0 ADDITIONS TO RATE BASE

2.1 Summary

Table 1 summarizes Newfoundland Power's additions to rate base for 2023 and 2024.

Table 1
Additions to Rate Base
2023-2024
($000s)

	2023	2024
Deferred Pension Costs	101,430	108,293
Credit Facility Costs	105	167
Cost Recovery Deferral – Conservation	20,708	21,280
Cost Recovery Deferral – Revenue Shortfall	229	-
Cost Recovery Deferral – Load Research and Retail Rate Design Review	189	635
Cost Recovery Deferral – Hearing Costs	-	874
Cost Recovery Deferral – Pension Capitalization	799	1,198
Customer Finance Programs	1,199	1,049
Total Additions	$124,659	$133,496

Additions to rate base were approximately $133.5 million in 2024. This is approximately $8.8 million higher than 2023. The higher additions to rate base in 2024 primarily reflect: (i) increases in deferred pension costs;[2] ii) the addition of a regulatory amortization for hearing costs associated with the Company's *2025/2026 General Rate Application*; and, iii) increases in deferred recovery of annual customer energy conservation program costs.

This section outlines the additions to rate base in further detail.

[2] The increase is reflective of the defined benefit pension costs which were a credit for rate setting purposes for 2024.

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]

Table 2 provides details of changes in Newfoundland Power's deferred pension costs for 2023 and 2024.

Table 2
Deferred Pension Costs
2023-2024
($000s)

	2023	2024
Deferred Pension Costs, January 1st	95,095	101,430
Pension Plan Funding	1,515	1,269
Pension Plan Expense	4,820	5,594
Deferred Pension Costs, December 31st	$101,430	$108,293

2.3 Deferred 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, 2023 includes the unamortized credit facility issue costs related to the 2021 and 2022 amendments.[4]

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.

In August 2024, the committed credit facility was renegotiated to extend its maturity date to August 2029 and increase the amount from $100 million to $130 million as approved in Order No. P.U. 23 (2024). Costs related to this amendment totalled $101,000 and are being amortized over the five-year life of the agreement, beginning in 2024.

The unamortized credit facility issue costs associated with the 2021 through 2024 credit facility amendments are included in rate base for 2023 and 2024 as these costs have not yet been reflected in the Company's revenue requirement.

[3] Deferred pension costs were approved for inclusion in average rate base in Order No. P.U. 19 (2003).
[4] 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. In August 2022, the maturity date of the committed credit facility was extended to August 2027 at a cost of $38,000 to be amortized over the five-year life of the agreement, beginning in 2022.

Table 3 provides details of Newfoundland Power's amortization of deferred credit facility issue costs for 2023 and 2024.

Table 3 Credit Facility Costs 2023-2024 ($000s)		
	2023	2024
Balance, January 1st	87	105
Cost – Reduction	-	-
Cost – Addition	44	101
Amortization	(26)	(39)
Balance, December 31st	**$105**	**$167**

2.4 Cost Recovery Deferral – Conservation

In Order No. P.U. 13 (2013), the Board approved the deferred recovery 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 2023 and 2024.

Table 4 Cost Recovery Deferral – Conservation 2023-2024 ($000s)		
	2023	2024
Balance, January 1st	19,359	20,708
Cost	4,311	3,966
Amortization	(2,962)	(3,394)
Balance, December 31st	**$20,708**	**$21,280**

2.5 Cost Recovery Deferral – 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 Order approved the recovery of this shortfall through a regulatory amortization beginning on March 1, 2022 and ending December 31, 2024.

In Order No. P.U. 24 (2024), the Board approved (i) the deferred cost recovery of a forecast revenue shortfall for 2024 of $9.0 million ($6.3 million after-tax) resulting from the Company's *2024 Rate of Return on Rate Base Application* and (ii) the subsequent transfer of the forecast revenue shortfall to the RSA on December 31, 2024.

Table 5 provides details of the changes to the deferred cost recovery related to revenue shortfalls for 2023 and 2024.

Table 5
Cost Recovery Deferral – Revenue Shortfall
2023-2024
($000s)

	2023	2024
Balance, January 1st	459	229
Cost	-	6,300
Transfer to the RSA	-	(6,300)
Amortization	(230)	(229)
Balance, December 31st	**$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 2023 and 2024.

Table 6
Cost Recovery Deferral – Load Research and Retail Rate Design Review
2023-2024
($000s)

	2023	2024
Balance, January 1st	20	189
Cost	169	446
Balance, December 31st	$189	$635

2.7 Cost Recovery Deferral – Hearing Costs

In Order No. P.U. 3 (2025), the Board accepted the Settlement Agreement recommendation for forecast hearing costs of up to $1.0 million related to the Company's *2025/2026 General Rate Application* to be recovered in customer rates over the period July 1, 2025 to December 31, 2027.[5]

Table 7 provides details of the changes in Newfoundland Power's deferred hearing costs for 2023 and 2024.[6]

Table 7
Cost Recovery Deferral – Hearing Costs
2023-2024
($000s)

	2023	2024
Balance, January 1st	-	-
Cost	-	874
Balance, December 31st	-	$874

[5] In Order No. P.U. 3 (2025), the Board directed that any differences between actual and estimated hearing costs would be reflected in the RSA.

[6] Deferred hearing cost balances are included in rate base on an after-tax basis consistent with the treatment of other regulatory assets and liabilities.

2.8 Cost Recovery Deferral – Pension Capitalization

In Order No. P.U. 3 (2022), the Board approved (i) the deferral of annual amounts related to income tax impacts of pension capitalization and (ii) the amortization of these costs over a five-year period, both commencing in January 2023. The corresponding annual increases to revenue requirement for 2023 and 2024 were $1,427,000 and 1,069,000, respectively.

Table 8 provides details of the amortizations of the deferred cost recovery related to pension capitalization for 2023 and 2024.

Table 8
Cost Recovery Deferral – Pension Capitalization
2023-2024
($000s)

	2023	2024
Balance, January 1st	-	799
Cost	999	748
Amortization	(200)	(349)
Balance, December 31st	$799	$1,198

2.9 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 9 provides details of changes to balances related to customer finance programs for 2023 and 2024.

Table 9
Customer Finance Programs
2023-2024
($000s)

	2023	2024
Balance, January 1st	1,472	1,199
Change	(273)	(150)
Balance, December 31st	$1,199	$1,049

3.0 DEDUCTIONS FROM RATE BASE

3.1 Summary

Table 10 summarizes Newfoundland Power's deductions from rate base for 2023 and 2024.

Table 10 Deductions from Rate Base 2023-2024 ($000s)		
	2023	2024
Other Post-Employment Benefits	84,357	86,308
Customer Security Deposits	653	618
Accrued Pension Obligation	5,397	5,512
Accumulated Deferred Income Taxes	30,609	33,287
Weather Normalization Reserve	(6,321)	2,896
Demand Management Incentive Account	(978)	(1,545)
Refundable Investment Tax Credits	292	294
Excess Earnings Account	3,714	-
Total Deductions	$117,723	$127,370

Deductions from rate base were approximately $127.4 million in 2024. Newfoundland Power's total deductions from rate base in 2024 were approximately $9.6 million higher than 2023.

The increased deductions from rate base were primarily due to: (i) activity in the weather normalization reserve; (ii) an increase in accumulated deferred income taxes reflecting timing differences associated with the Company's employee future benefits and continued investment in the electricity system; and, (iii) an increase in the Other Post-Employment Benefits ("OPEBs") liability which reflects the amortization of the OPEBs regulatory asset.[7] Increases were partially offset by the transfer of the balance in the Excess Earnings Account to the RSA on December 31, 2024.

This section outlines the deductions from rate base in further detail.

[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 11 provides details of the changes related to the net OPEBs liability for 2023 and 2024.

Table 11
Other Post-Employment Benefits
2023-2024
($000s)

	2023	2024
Regulatory Asset	7,008	3,504
OPEBs Liability	91,365	89,812
Net OPEBs Liability	$84,357	$86,308

3.3 Customer Security Deposits

Customer security deposits are provided by customers in accordance with the *Schedule of Rates, Rules and Regulations*.

Table 12 provides details on the changes in customer security deposits for 2023 and 2024.

Table 12
Customer Security Deposits
2023-2024
($000s)

	2023	2024
Balance, January 1st	1,270	653
Change	(617)	(35)
Balance, December 31st	$653	$618

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 13 provides details of changes related to the accrued pension obligation for 2023 and 2024.

Table 13
Accrued Pension Obligation
2023-2024
($000s)

	2023	2024
Balance, January 1st	5,300	5,397
Change	97	115
Balance, December 31st	$5,397	$5,512

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]

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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 14 provides details of changes in the accumulated deferred income taxes for 2023 and 2024.

Table 14
Accumulated Deferred Income Taxes
2023-2024
($000s)

	2023	2024
Balance, January 1st	18,076	30,609
Change	12,533	2,678
Balance, December 31st	$30,609	$33,287

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 15 provides details of changes in the balance of the Weather Normalization Reserve for 2023 and 2024.

Table 15
Weather Normalization Reserve
2023-2024
($000s)

	2023	2024
Balance, January 1st	6,576	(6,321)
Operation of the reserve	(6,321)	2,896
Transfers to the RSA	(6,576)	6,321
Balance, December 31st	($6,321)	$2,896

The disposition of the December 31, 2024 balance in the Weather Normalization Reserve account to the RSA as of March 31, 2025 was approved by the Board in Order No. P.U. 15 (2025).

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 16 provides details of the DMI Account for 2023 and 2024.

Table 16 DMI Account 2023-2024 ($000s)		
	2023	2024
Balance, January 1st	107	(978)
Transfers to the RSA	(107)	978
Operation of DMI	(978)	(1,545)
Balance, December 31st	($978)	($1,545)

The disposition of the December 31, 2024 balance in the DMI Account to the RSA as of March 31, 2025 was approved in Order No. P.U. 14 (2025).

3.8 Refundable Investment Tax Credits

Refundable Investment Tax Credits relate to provincial income tax credits for investment and in certain research and development activities. Refundable ITCs related to expenditures that qualify for these tax credits and have been capitalized for accounting purposes are deferred and recognized into income in a manner that is consistent with the amortization of the capital assets to which they relate.

Table 17 provides details on the Refundable Investment Tax Credits for 2023 and 2024.

Table 17 Refundable Investment Tax Credits 2023-2024 ($000s)		
	2023	2024
Balance, January 1st	-	292
Change	292	2
Balance, December 31st	$292	$294

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.

In Order No. P.U. 24 (2024), the Board approved the transfer of the balance in the Excess Earnings Account as of December 31, 2023 to the RSA on December 31, 2024.

Table 18 provides details of the Excess Earnings Account for 2023 and 2024.

Table 18
Excess Earnings Account
2023-2024
($000s)

	2023	2024
Balance, January 1st	-	3,714
Change	3,714	(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.

Table 19 on the following page provides details on changes in the cash working capital allowance for 2023 and 2024.

[11] For 2023, the allowed regulated earnings were 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 19 Rate Base Allowances Cash Working Capital Allowance[12] 2023-2024 ($000s)		
	2023	2024
Gross Operating Costs	594,981	595,523
Income Taxes	(3,484)	15,863
Municipal Taxes Paid	18,398	19,652
Non-Regulated Expenses	(2,091)	(2,511)
Total Operating Expenses	$607,804	$628,527
Cash Working Capital Factor	1.199%	1.199%
	$7,289	$7,536
HST Adjustment	15	15
Cash Working Capital Allowance	$7,304	$7,551

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]

Table 20 provides details on changes in the materials and supplies allowance for 2023 and 2024.

Table 20 Rate Base Allowances Materials and Supplies Allowance 2023-2024 ($000s)		
	2023	2024
Average Materials and Supplies	18,262	18,219
Expansion Factor[14]	19.08%	19.08%
Expansion	3,484	3,476
Materials and Supplies Allowance	$14,778	$14,743

[12] The cash working capital allowance for 2023 and 2024 is calculated based on the methodology used in the calculation of the 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.

[14] The expansion factor is based on a review of actual inventories used for expansion projects. The calculation of the 2023 and 2024 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).