Whenever. Wherever.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

May 29, 2026

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

Attention: Mike McNiven
Board Secretary

Dear Mr. McNiven:

Re: Newfoundland Power's 2027 Capital Budget Application

Enclosed are the original and 10 copies of Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") *2027 Capital Budget Application* (the "Application").

The Application seeks an order approving the Company's proposed 2027 capital budget and fixing and determining Newfoundland Power's average rate base for 2025.

Subsection 41(3) of the *Public Utilities Act* (the "Act") together with section 3 of the *Public Utilities Regulations,* NLR 40/23 provides 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 for which the Company seeks approval 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 Ms. Adrienne Ding, the Consumer Advocate.

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

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

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

Yours truly,

Dominic Foley
Legal Counsel

Enclosures

cc. Shirley Walsh
Newfoundland and Labrador Hydro

Adrienne Ding
O'Dea Earle

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**

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 2027 Capital Budget; and
(b) fixing and determining its 2025 rate base.

2027 Capital Budget Application

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NEWFOUNDLAND POWER
A FORTIS COMPANY

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 2027 Capital Budget; and
(b) fixing and determining its 2025 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 2027 capital expenditures in the amount of $79,411,000 comprising projects and programs costing in excess of $750,000;

   (b) proposed single-year 2027 capital expenditures of $9,723,000 comprising projects and programs costing $750,000 and under;

   (c) proposed multi-year projects commencing in 2027 with capital expenditures of $9,551,000 in 2027, $23,304,000 in 2028 and $12,867,000 in 2029; and

   (d) ongoing multi-year projects previously approved in Order No. P.U. 38 (2025) and Order No. P.U. 27 (2024) with capital expenditures of $50,664,000 in 2027 and $8,040,000 in 2028 (the "Previously Approved Multi-Year Projects").

3. The proposed 2027 Capital Budget includes contributions toward the cost of improvements or additions to property that Newfoundland Power intends to demand from its customers in 2027 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.

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 2025 of $1,419,718,000.[1]

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 2027 in the amount of $149,349,000 as set out in Schedules A, B and C to this Application comprising:

      i. single-year project and program expenditures in excess of $750,000 in the amount of $79,411,000;
      ii. single-year project and program expenditures $750,000 and under in the amount of $9,723,000;
      iii. multi-year projects with 2027 expenditures of $9,551,000; and
      iv. previously approved multi-year projects with 2027 expenditures of $50,664,000.

   (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 $50,664,000 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 2025 in the amount of $1,419,718,000 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.

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[1] Additional information regarding deferred charges and a reconciliation of average rate base to invested capital is provided in report *4.1 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 29th day of May, 2026.

NEWFOUNDLAND POWER INC.

Douglas Wright
Senior Legal Counsel to Newfoundland Power Inc.
P.O. Box 8910
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 2027 Capital Budget; and
(b) fixing and determining its 2025 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 29th day of May, 2026:

Douglas Wright
Barrister and Solicitor

Byron Chubbs, P.Eng.

Newfoundland Power Inc.
2027 Capital Budget Application

TABLE OF CONTENTS

APPLICATION

SUPPORTING MATERIALS

2027 CAPITAL BUDGET SUMMARY

Expenditure Type	Budget ($000s)
Single-Year Projects and Programs Over $750,000	79,411
Single-Year Projects and Programs $750,000 and Under	9,723
Multi-Year Projects Commencing in 2027	9,551
Multi-Year Projects Approved in Previous Years	50,664
Total	**$ 149,349**

Asset Class	Budget ($000s)
Distribution	59,823
Substations	25,202
Transmission	29,397
Generation - Hydro	2,944
Generation - Thermal	1,033
Information Systems	14,194
Telecommunications	149
General Property	3,629
Transportation	7,228
Unforeseen Allowance	750
General Expenses Capitalized	5,000
Total	**$149,349**

2027 CAPITAL BUDGET
SINGLE-YEAR PROJECTS AND PROGRAMS
OVER $750,000

Projects and Programs	Budget ($000s)
Distribution	
Extensions	13,852
Reconstruction	8,319
Replacement Transformers	5,573
Rebuild Distribution Lines	5,502
New Transformers	4,943
Relocate/Replace Distribution Lines for Third Parties	3,872
New Services	3,520
New Street Lighting	2,496
Distribution Feeder COB-02 Extension	1,828
Feeder Additions for Load Growth	1,284
Distribution Feeder CAB-01 Refurbishment	972
Replacement Street Lighting	936
Distribution Feeder GDL-02 Loop 10 and 20 Refurbishment	789
Total Distribution	**$53,886**
Substations	
Substation Replacements Due to In-Service Failures	4,613
Total Substations	**$4,613**
Transmission	
Transmission Line Maintenance	3,465
Transmission Line 114L Replacement and 142L Relocation	2,341
Total Transmission	**$5,806**
Generation - Hydro	
Hydro Facility Rehabilitation	1,531
Hydro Plant Replacements Due to In-Service Failures	764
Total Generation - Hydro	**$2,295**

2027 CAPITAL BUDGET
SINGLE-YEAR PROJECTS AND PROGRAMS
OVER $750,000

Projects and Programs	**Budget ($000s)**
Information Systems	
Shared Server Infrastructure	1,974
System Upgrades	1,899
Application Enhancements	1,442
Cybersecurity Upgrades	962
Personal Computer Infrastructure	784
Total Information Systems	**$7,061**
Unforeseen Allowance	
Allowance for Unforeseen Items[1]	750
Total Unforeseen Allowance	**$750**
General Expenses Capitalized	
General Expenses Capitalized	5,000
Total General Expenses Capitalized	**$5,000**
Total	**$79,411**

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.

2027 CAPITAL BUDGET
SINGLE-YEAR PROJECTS AND PROGRAMS
$750,000 AND UNDER

Projects and Programs	**Budget ($000s)**
Distribution	
Distribution Feeder MIL-02 Refurbishment	685
Distribution Feeder Automation	662
Replacement Meters	616
New Meters	573
Replacement Services	397
Allowance for Funds Used During Construction	249
Total Distribution	**$3,182**
Substations	
Substation Protection and Control Replacements	743
Substation Ground Grid Upgrades	369
Total Substations	**$1,112**
Transmission	
Transmission Line 59L Relocation	715
Total Transmission	**$715**
Generation - Thermal	
MD3 Refurbishment	705
Thermal Plant Replacements Due to In-Service Failures	328
Total Generation - Thermal	**$1,033**
Information Systems	
Network Infrastructure	465
Total Information Systems	**$465**

**2027 CAPITAL BUDGET
SINGLE-YEAR PROJECTS AND PROGRAMS
$750,000 AND UNDER**

Projects and Programs	Budget ($000s)
Telecommunications	
Communications Equipment Upgrades	149
Total Telecommunications	**$149**
General Property	
Additions to Real Property	731
Tools and Equipment	642
Specialized Tools and Equipment	626
Physical Security Upgrades	568
Building Accessibility Improvements	500
Total General Property	**$3,067**
Total	**$9,723**

2027 CAPITAL BUDGET
MULTI-YEAR PROJECTS

Multi-Year Projects Commencing in 2027

Asset Class	Project Description	2027	2028	2029	Total
Distribution	Distribution Reliability Initiative	871	2,069	-	2,940
Distribution	Distribution Feeder ILC-02 Refurbishment	595	610	-	1,205
Distribution	Distribution Feeder GBY-01 Refurbishment	402	958	-	1,360
Substations	Blaketown Substation Refurbishment and Modernization	528	5,700	-	6,228
Substations	Rattling Brook Substation Refurbishment and Modernization	74	1,426	-	1,500
Substations	Portable Substation	990	3,894	5,049	9,933
Substations	Mobile Plant Substation Refurbishment and Modernization	299	925	-	1,224
Substations	LAU-T1 Power Transformer Replacement	99	3,186	-	3,285
Substations	LBK-T1 Power Transformer Replacement	73	86	2,175	2,334
Substations	HAR-T1 Power Transformer Replacement	75	71	2,758	2,904
Substations	RRD-T3 Power Transformer Replacement	66	64	2,565	2,695
Generation - Hydro	Rose Blanche Hydro Plant Refurbishment	649	1,079	-	1,728
Information Systems	Microsoft Enterprise Agreement	320	320	320	960
Transportation	Replace Vehicles and Aerial Devices 2027-2028	4,510	2,916	-	7,426
	Total	**$9,551**	**$23,304**	**$12,867**	**$45,722**

2027 CAPITAL BUDGET
MULTI-YEAR PROJECTS

Multi-Year Projects Approved in Previous Years

Asset Class	Project Description	2025	2026	2027	2028	Total
Distribution	Feeder Additions for Load Growth[2]	-	250	887	-	1,137
Substations	Greenspond Substation Refurbishment and Modernization[3]	-	374	2,578	-	2,952
Substations	Gander Substation Power Transformer Replacement[4]	17	3,905	263	-	4,185
Substations	Molloy's Lane Substation Power Transformer Replacement[5]	-	12	2,789	-	2,801
Substations	Lewisporte-Boyd's Cove 138 kV Conversion[6]	-	568	7,551	-	8,119
Substations	Substation Spare Power Transformer Inventory[7]	-	13	3,906	-	3,919
Substations	Mobile Plant Substation Power Transformer Replacement[8]	-	12	93	2,522	2,627
Substations	King's Bridge Substation Power Transformer Replacement[9]	-	12	93	2,866	2,971
Transmission	New Transmission Line from Lewisporte to Boyd's Cove[10]	1,886	9,283	9,553	-	20,722
Transmission	Transmission Line 100L Rebuild[11]	-	450	13,323	-	13,773
Information Systems	Geographic Information System Upgrade[12]	-	500	5,173	2,652	8,325
Information Systems	Customer Correspondence Modernization[13]	-	782	1,175	-	1,957
General Property	Summerford Building Replacement[14]	-	155	562	-	717
Transportation	Replace Vehicles and Aerial Devices 2026-2027[15]	-	3,003	2,718	-	5,721
	Total	**$1,903**	**$19,319**	**$50,664**	**$8,040**	**$79,926**

2 Approved in Order No. P.U. 38 (2025). See Newfoundland Power's *2026 Capital Budget Application*, Schedule B, pages 6 to 7.
3 Approved in Order No. P.U. 38 (2025). See Newfoundland Power's *2026 Capital Budget Application*, Schedule B, pages 47 to 50.
4 Approved in Order No. P.U. 27 (2024). See Newfoundland Power's *2025 Capital Budget Application*, Schedule B, pages 63 to 66.
5 Approved in Order No. P.U. 38 (2025). See Newfoundland Power's *2026 Capital Budget Application*, Schedule B, pages 59 to 62.
6 Approved in Order No. P.U. 38 (2025). See Newfoundland Power's *2026 Capital Budget Application*, Schedule B, pages 44 to 46.
7 Approved in Order No. P.U. 38 (2025). See Newfoundland Power's *2026 Capital Budget Application*, Schedule B, pages 63 to 67.
8 Approved in Order No. P.U. 38 (2025). See Newfoundland Power's *2026 Capital Budget Application*, Schedule B, pages 55 to 58.
9 Approved in Order No. P.U. 38 (2025). See Newfoundland Power's *2026 Capital Budget Application*, Schedule B, pages 51 to 54.
10 Approved in Order No. P.U. 27 (2024). See Newfoundland Power's *2025 Capital Budget Application*, Schedule B, pages 77 to 82.
11 Approved in Order No. P.U. 38 (2025). See Newfoundland Power's *2026 Capital Budget Application*, Schedule B, pages 74 to 77.
12 Approved in Order No. P.U. 38 (2025). See Newfoundland Power's *2026 Capital Budget Application*, Schedule B, pages 90 to 92.
13 Approved in Order No. P.U. 38 (2025). See Newfoundland Power's *2026 Capital Budget Application*, Schedule B, pages 87 to 89.
14 Approved in Order No. P.U. 38 (2025). See Newfoundland Power's *2026 Capital Budget Application*, Schedule C, page 8.
15 Approved in Order No. P.U. 38 (2025). See Newfoundland Power's *2026 Capital Budget Application*, Schedule B, pages 106 to 109.

2027 CAPITAL PROJECTS AND PROGRAMS

OVER $750,000

2027 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 2027, 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 continues to evaluate options to meet the information requirements contained in the Provisional Guidelines. The Company is currently undertaking a replacement of its legacy Asset Management Technology with a modern solution which will enable the Company to explore opportunities such as improving analytics and increasing the digitization and utilization of data.

The following provides an overview of the information provided within Schedule B to the Application for each project and program proposed for 2027:

(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 expected to be assessed upon completion of the *Asset Management Technology Replacement* project.

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. Options to gather the data required to calculate risk mitigation or reliability improvement are expected to be assessed upon completion of the *Asset Management Technology Replacement* project. 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 Company expects its approach may evolve going forward as its asset management practices are matured.

Figure 1 shows the risk matrix.

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

Figure 1 - Risk Matrix.

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

A detailed description of the risk matrix methodology is provided in Appendix C to the *2027 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.

2027 CAPITAL BUDGET
SCHEDULE B TABLE OF CONTENTS

DISTRIBUTION

Title:	**Distribution Reliability Initiative**
Asset Class:	**Distribution**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$871,000 in 2027 and $2,069,000 in 2028**

PROJECT DESCRIPTION

The *Distribution Reliability Initiative* targets the replacement of deteriorated poles, conductor and hardware on the worst performing feeders or feeder sections on Newfoundland Power's distribution system. Customers served by these distribution feeders or sections of feeder experience service reliability that is significantly below the Company average.

For 2027, Newfoundland Power is proposing to refurbish two sections of Glovertown ("GLV") Substation distribution feeder GLV-02. The refurbishment of distribution feeder GLV-02 will include rebuilding deteriorated off-road sections of line, identified through detailed condition-based engineering assessments, and relocating them to roadside corridors. This includes a 12-kilometre section between Traytown and Charlottetown that will be rebuilt and relocated to the Trans-Canada Highway, as well as a 5-kilometre section between Traytown and Sandringham that will be rebuilt and relocated to Route 301.

This project is proposed as a multi-year project with design and procurement completed by the end of the fourth quarter of 2027 and construction activities to conclude in the fourth quarter of 2028.

Additional information on this project is included in report *1.1 Distribution Reliability Initiative* filed as part of the Application.

PROJECT BUDGET

The budget for the *Distribution Reliability Initiative* is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2027 and 2028 for the *Distribution Reliability Initiative*.

Table 1
Distribution Reliability Initiative Project
2027 and 2028 Budget
($000s)

Cost Category	2027	2028	Total
Material	415	986	1,401
Labour – Internal	13	31	44
Labour - Contract	433	1,029	1,462
Engineering	3	6	9
Other	7	17	24
Total	$871	$2,069	$2,940

Proposed expenditures for the *Distribution Reliability Initiative* are $871,000 in 2027 and $2,069,000 in 2028 for a total project budget of $2,940,000.

ASSET BACKGROUND

The *Distribution Reliability Initiative* is a longstanding initiative. Projects proposed as part of the *Distribution Reliability Initiative* are determined by: (i) calculating reliability performance indices for all distribution feeders; (ii) analyzing the worst performing feeders and feeder sections to identify the cause of the poor reliability performance; and (iii) completing engineering assessments to determine whether capital improvements would address a feeder's poor reliability performance.

With the implementation of the Company's Outage Management System in 2019, the Company now receives outage data with high granularity and can integrate outage data with other systems such as the Geographic Information System. These systems enable data visualization for outages and reliability metrics, and the ability to correlate these metrics to physical assets and geographic areas. These improvements allow improved analysis and decision making for distribution reliability improvements. The Company's approach to targeting its worst performing feeders for capital improvements is consistent with good utility practice.

Distribution Feeder GLV-02

Distribution feeder GLV-02 extends from GLV Substation running along Route 310 towards Eastport and Sandringham branching to the communities of Malady Head and Charlottetown. This feeder currently serves 1,560 customers. Outage Management System data for distribution feeder GLV-02 shows that the majority of outage minutes on this feeder are associated with two specific off-road and deteriorated sections: a 12-kilometre section between Traytown and Charlottetown near the Trans-Canada Highway, as well as a 5-kilometre section between Traytown and Sandringham near Route 301. Both sections of distribution feeder are within the Terra Nova National Park boundary. The reliability performance experienced by the 1,280 customers served by these sections of distribution feeder GLV-02 has been considerably worse than Newfoundland Power's corporate average over the last five years.

An engineering assessment of the 5-kilometre section toward Sandringham and the 12-kilometre section toward Charlottetown has identified that the factors contributing to poor reliability performance are: (i) deteriorated conductor; (ii) danger tree contacts; (iii) deteriorated poles, crossarms and insulators; and (iv) inaccessibility of the lines. This section of the feeder was originally constructed in the 1960s with #2 Aluminum Conductor Steel Reinforced ("ACSR") conductor. The Company has experienced issues with this particular conductor in the past, as oxidation between the steel core and aluminum outer strands is known to occur. The oxidation is particularly prevalent in coastal environments in which frequent salt spray occurs.

ASSESSMENT OF ALTERNATIVES

Newfoundland Power evaluated two alternatives with respect to distribution feeder GLV-02: (i) rebuild the existing 5-kilometre and 12-kilometre sections of line in their existing rights-of-way; and (ii) rebuild and relocate the existing 5-kilometre section of line to the roadside of Route 301, and rebuild and relocate the existing 12-kilometre section of line to the roadside of the Trans Canada Highway.

The assessment determined that reconstruction and relocation of the identified sections of line is the least cost alternative to address the poor service reliability experienced by customers supplied from these sections of distribution feeder GLV-02. Additionally, relocating these sections of distribution feeder to the roadside will improve access to the line during outage response activities and will improve the efficiency of preventive maintenance and inspection activities.

For additional information on the assessment of alternatives, see section 4 of report *1.1 Distribution Reliability Initiative* filed as part of the Application.

RISK ASSESSMENT

The *Distribution Reliability Initiative* will mitigate risks to the delivery of reliable service to customers on distribution feeder GLV-02.

The 1,280 customers supplied by two off-road sections of distribution feeder GLV-02 are experiencing significantly worse reliability performance than the Company average. The consequence of not completing this project is assessed as Serious (4).

The contribution of these sections of distribution line to the poor service reliability experienced by customers was confirmed through an engineering review, inspection and detailed analysis of outage data and equipment failures. The probability of continued poor reliability performance if this project is not completed is assessed as Near Certain (5).

Table 2 summarizes the risk assessment of the 2027 *Distribution Reliability Initiative*.

Table 2
Distribution Reliability Initiative Project
Risk Assessment Summary

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

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

JUSTIFICATION

The *Distribution Reliability Initiative* is required to provide customers with reliable service at the lowest possible cost. The project will address the poor service reliability currently experienced by customers serviced by distribution feeder GLV-02. Customers in this area currently experience service reliability that is significantly below the Company average. The proposed project to refurbish identified sections of distribution feeder GLV-02 will address deficiencies identified during inspections and improve the service reliability experienced by customers in these areas.

Title:	**Distribution Feeder COB-02 Extension**
Asset Class:	**Distribution**
Category:	**Project**
Investment Classification:	**Renewal**
Budget:	**$1,828,000**

PROJECT DESCRIPTION

The *Distribution Feeder COB-02 Extension* project involves extending Cobbs Pond ("COB") Substation distribution feeder COB-02, a distribution feeder serving the town of Gander and surrounding area. This project proposes to extend the feeder approximately 8 kilometres to serve customers currently served by Jonathan's Pond ("JON") Substation distribution feeder JON-01. JON Substation will be retired along with transmission line 108L as part of the completion of the *New Transmission Line from Lewisporte to Boyd's Cove* project approved in Newfoundland Power's *2025 Capital Budget Application*. The extension of distribution feeder COB-02 was determined to be part of the least-cost alternative to continue serving these customers.[1]

Design work for the *Distribution Feeder COB-02 Extension* project is expected to be completed by the end of the second quarter of 2027. Construction will be completed by the end of the third quarter of 2027.

PROJECT BUDGET

The budget for the *Distribution Feeder COB-02 Extension* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2027 for the *Distribution Feeder COB-02 Extension* project.

Table 1
Distribution Feeder COB-02 Extension
2027 Budget
($000s)

Cost Category	2027
Material	587
Labour – Internal	50
Labour – Contract	1,160
Engineering	10
Other	21
Total	**$1,828**

[1] See report *3.1 Gander- Twillingate Transmission Planning Study* filed in Newfoundland Power's *2025 Capital Budget Application* for further information regarding the work involved as part of the least cost alternative.

Proposed expenditures for the *Distribution Feeder COB-02 Extension* project total $1,828,000 in 2027.

ASSET BACKGROUND

Distribution feeder COB-02 serves 848 customers. Most customers are in the town of Gander, with a small number of customers in cabin areas along the Gander Bay Highway.

The distribution feeder has a three-phase trunk that feeds subdivisions along Rowsell Blvd and Penwell Avenue, with several single phase and two-phase taps providing service to customers. The feeder extends North along the Gander Bay Highway as a single-phase tap to feed nearby cabin areas. The proposed extension will be an addition to the single-phase section.

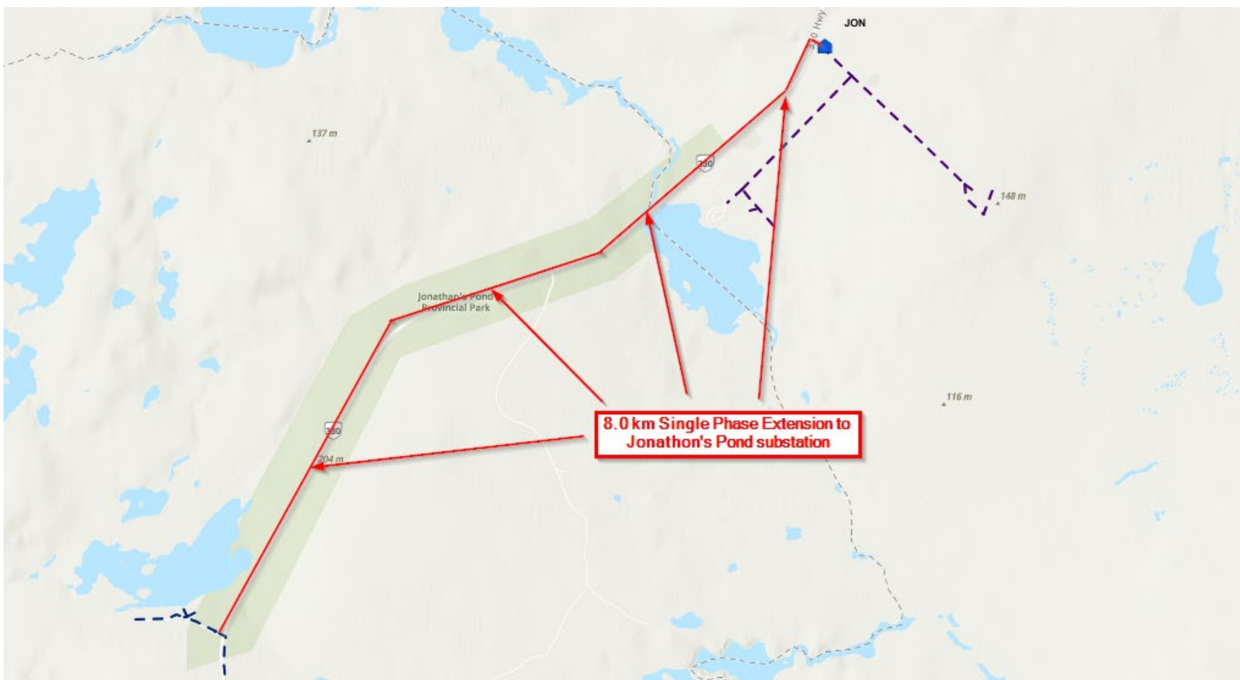

Figure 1 - Distribution Feeder COB-02 Extension Project

ASSESSMENT OF ALTERNATIVES

There are no identified alternatives for this project as retiring Transmission Line 108L was identified as the least cost alternative in the *Gander – Twillingate Transmission System Planning Study*.[2] Failure to complete the necessary extension work on distribution feeder COB-02 would prohibit the retirement of Transmission Line 108L and JON Substation.

The economic analysis as part of the *Gander-Twillingate Transmission System Planning Study* included various sensitivity analyses to consider the impacts of estimated cost increases across different asset classes, including transmission and distribution. The results of the sensitivity

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

analyses concluded that the recommended alternative was least-cost across all sensitivities. The latest estimates for both the *Distribution Feeder COB-02 Extension* and the *Transmission Line 114L Replacement and 142L Relocation* projects are higher than what were initially estimated as part of the original Planning Study. As a result, the original NPV analysis conducted as part of the Planning Study was re-evaluated using the latest costs for both projects. In addition to the noted reliability and transmission-level voltage improvements associated with the recommended alternative, the results of the NPV analysis confirm that the recommended alternative remains least-cost.

RISK ASSESSMENT

The *Distribution Feeder COB-02 Extension* 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 distribution work were identified as part of this project.

Table 2 summarizes the risk assessment of the 2027 *Distribution Feeder COB-02 Extension* project.

Table 2
Distribution Feeder COB-02 Extension
Risk Assessment Summary

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

Overall, failing to complete the *Distribution Feeder COB-02 Extension* project poses a High (20) risk to the delivery of least cost, reliable, safe, and environmentally responsible service to customers. Action is required in 2027 to mitigate these risks for customers.

JUSTIFICATION

The *Distribution Feeder COB-02 Extension* project is necessary to realize the least-cost alternative proposed under the *Gander-Twillingate Transmission Planning Study* filed with Newfoundland Power's *2025 Capital Budget Application*. Completing this project will enable the continued provision of reliable service to customers in the Gander-Twillingate area at least-cost.

Title: **Distribution Feeder GBY-01 Refurbishment**
Asset Class: **Distribution**
Category: **Project**
Investment Classification: **Renewal**
Budget (Multi-Year): **$402,000 in 2027; $958,000 in 2028**

PROJECT DESCRIPTION

The *Distribution Feeder GBY-01 Refurbishment* project involves refurbishing approximately 14 kilometres of Gander Bay ("GBY") Substation distribution feeder GBY-01, a distribution feeder serving the communities of Gander Bay South and onwards to Rodger's Cove. This proposed project includes:

1. Replacing 22 deteriorated and leaning poles along the Route 331 causeway;
2. Replacing deteriorated crossarms, vintage insulators, and hardware; and
3. Replacing deteriorated 2/0 ACSR conductor.

Engineering inspections of this feeder section have indicated advanced deterioration in poles and crossarms as well as non-standard, deteriorated and undersized conductor present on this section of distribution line.

Design work for the *Distribution Feeder GBY-01 Refurbishment* project is expected to be completed by the end of 2027. Construction will be completed by the end of the fourth quarter of 2028.

PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2027 and 2028 for the *Distribution Feeder GBY-01 Refurbishment* project.

Table 1
Distribution Feeder GBY-01 Extension
2027 and 2028 Budget
($000s)

Cost Category	2027	2028	Total
Material	119	283	402
Labour – Internal	7	16	23
Labour – Contract	233	554	787
Engineering	38	93	131
Other	5	12	17
Total	$402	$958	$1,360

Proposed expenditures for the *Distribution Feeder GBY-01 Refurbishment* project include $402,000 in 2027 and $958,000 in 2028, for a total project budget of $1,360,000.

ASSET BACKGROUND

Distribution feeder GBY-01 serves 643 customers in the Gander Bay area including the communities of Rodger's Cove, Victoria Cove and Clarke's Head.

The three-phase trunk of distribution feeder GBY-01 is approximately 15 kilometres in length, beginning at GBY Substation, and is tied to distribution feeder SUM-02 at Rodger's Cove. The feeder includes a coastal section passing along a causeway in Gander Bay North which is approximately 850 metres in length. A bridge located in the middle of the causeway spans approximately 175 metres. Of the feeder's 643 customers, 518 are located on the northern side of Gander Bay. The primary conductor along GBY-01 is predominantly 2/0 ACSR. The causeway portion of distribution feeder GBY-01 has 2/0 AASC primary conductor. Figure 1 shows distribution feeder GBY-01.

Figure 1 – Distribution Feeder GBY-01 Refurbishment Project

Distribution feeder GBY-01 was originally constructed in the 1960s, with a significant portion of original hardware in service. The feeder contains deteriorated poles and crossarms, as well as vintage insulators. There are also several transformers which are rusted and require replacement.

The conductor along distribution feeder GBY-01 is 2/0 ACSR, which is non-standard and has sustained damage due to environmental factors such as salt water, wind, snow and ice. This has led to the conductor corroding along the feeder, creating a reliability and safety hazard for customers and line crews. Corrosion has also caused bird caging, which has been observed in high volume along the primary conductor.[3] At several of these points, bird caging has become extreme to the point where light is visible through the strands of the conductor. Quick sleeves are installed at various points along the conductor which has created hot spots at various points on the feeder.

Near the tie-point with SUM-02 in Rodger's Cove, the span lengths of GBY-01's distribution poles are not in accordance with current standards. This has caused concerns for the poles' structural integrity, as they are leaning and bending. Poles on this segment of the feeder are Class 5 poles and have a span of up to 130 metres.[4]

These issues are exacerbated along the causeway at the beginning of the feeder. The causeway portion of the feeder experiences excessive environmental loading due to its location. The poles along the causeway are severely leaning outwards towards the water due to high winds and the age of the structures. Some poles are also warped and bent and are no longer straight, increasing the possibility of a pole cracking or breaking. As this causeway is located at the beginning of the feeder. Such a breakage would compromise all customers on the feeder in the event of a component failure.

A detailed inspection of the feeder was completed in 2024, with the following deficiencies identified:

- Severely leaning and deteriorated poles located along the causeway that require replacement. Figures 2 and 3 shows a sample of these poles.
- 11 kilometres of the three-phase primary is 2/0 ACSR is non-standard and deteriorated. Figure 4 shows an example of repairs on conductor to address bird caging.

Figure 5 shows miscellaneous deficiencies, including a small sample of deteriorated transformers and insulators.

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3 Bird caging occurs in ACSR conductor when the individual strands separate, causing the conductor to unwrap.

4 Pole classes are proportional to their diameter, with Class 5 being the smallest. Class 5 poles are outdated, with Class 4 and 3 currently used for distribution. Current standards indicate that the maximum span for Class 4 and 3 poles are 99 metres and 88 metres for 1/0 and 4/0 primaries, respectively.

Figure 2 – Leaning Poles on Causeway Section

Figure 3 – Leaning and Deteriorated Poles

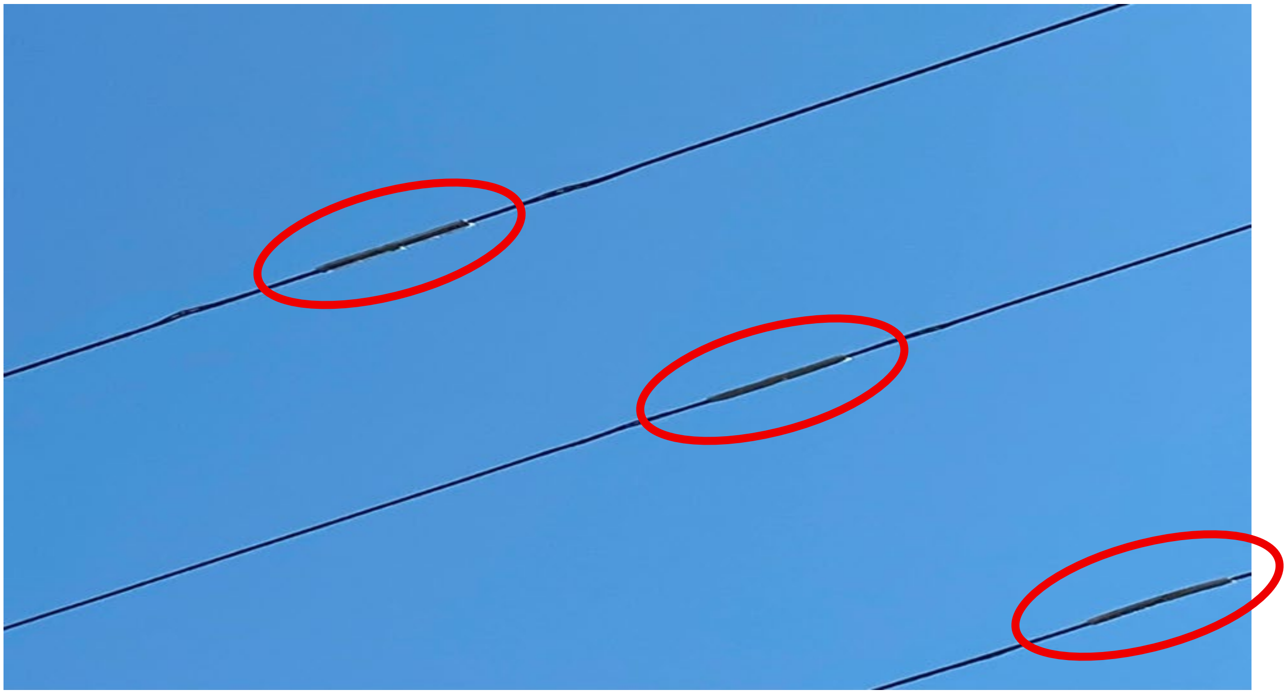


Figure 4 – Conductor Quick Sleeve Repairs

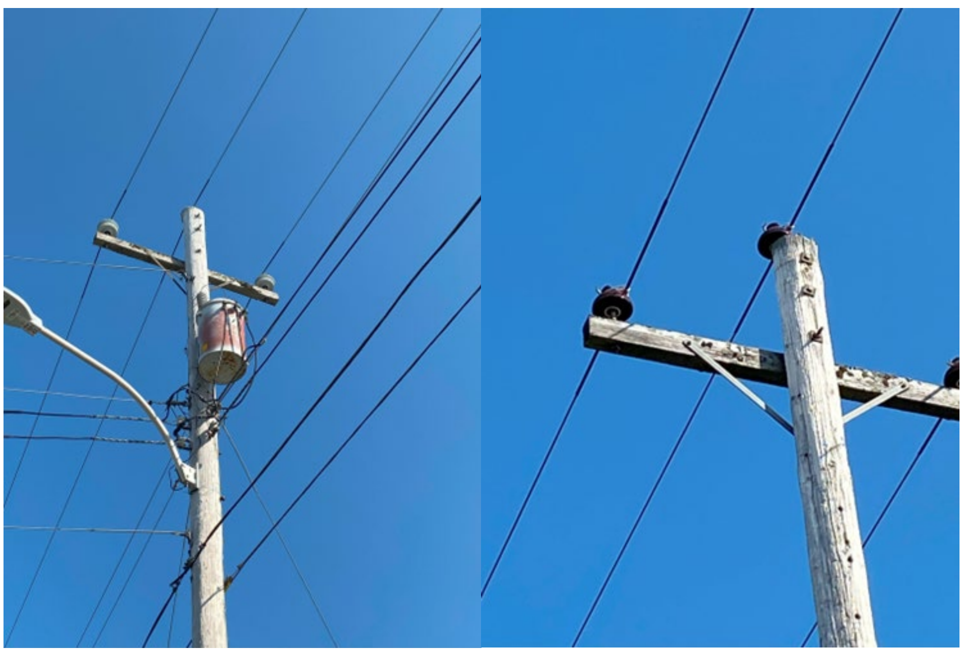


Figure 5 – Deteriorated Transformer and Insulators

ASSESSMENT OF ALTERNATIVES

Newfoundland Power has identified three potential alternatives to address the deteriorated condition of distribution feeder GBY-01. These alternatives include deferral, like-for-like asset replacement, and upgrade/life extension.

Due to the deteriorated condition of this line as identified through inspection and engineering assessment, deferral is not an option. Advanced degradation is present across various components. As such, deferral would increase the risk of equipment failure and customer outages.

Like-for-like replacement is not viable due to the presence of non-standard conductor and equipment along sections of the distribution feeder. These sections require upgrading to meet current standards and will ensure that distribution feeder GBY-01 can effectively pick up load if required, using the existing tie disconnect along Highway 331 to distribution feeder SUM-02.

The only viable alternative is an upgrade and life extension of distribution feeder GBY-01 to address the deteriorated condition of the distribution feeder.

RISK ASSESSMENT

The *Distribution Feeder GBY-01 Refurbishment* project is necessary to address known deterioration and undersized conductor on distribution feeder GBY-01.

The *Distribution Feeder GBY-01 Refurbishment* project addresses reliability and safety risks associated with the deteriorated condition of the feeder affecting the communities of Rodger's Cove, Victoria Cove and Clarke's Head. The feeder supplies 643 customers, with the majority served through the deteriorated main trunk section. This section includes the deteriorated portion along the causeway, which is the beginning of the feeder. If a component failure occurs along the causeway, it would affect all 643 customers, and result in a prolonged outage due to the difficulties of the working location. The consequence of not completing this project is assessed as Moderate (3).

In its current condition, the feeder exposes all connected customers to elevated risks of extended outages, safety hazards associated with equipment failures, and operational challenges for restoration activities. Most customers are being served from non-standard 2/0 ACSR which further increases the probability of failure. The probability of equipment failure on distribution feeder GBY-01 is assessed as Likely (4).

Table 2 summarizes the risk assessment of the 2027 *Distribution Feeder GBY-01 Refurbishment* project.

Table 2
Distribution Feeder GBY-01 Refurbishment
Risk Assessment Summary

Consequence	Probability	Risk
Moderate (3)	Likely (4)	Medium-High (12)

Based on this assessment, not proceeding with the *Distribution Feeder GBY-01 Refurbishment* project would pose a Medium-High (12) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Distribution Feeder GBY-01 Refurbishment* is necessary to address known deterioration of the feeder and ensure customers continue to receive an adequate supply of electricity at least cost.

Title: **Feeder Additions for Load Growth**
Asset Class: **Distribution**
Category: **Project**
Investment Classification: **System Growth**
Budget: **$1,284,000**

PROJECT DESCRIPTION

The *Feeder Additions for Load Growth* project involves addressing overload conditions and providing additional capacity to address system load growth. For 2027, the proposed *Feeder Additions for Load Growth* project addresses:

- An overloaded section of Blaketown ("BLK") Substation distribution feeder BLK-02 in the area of Brigus Junction near Whalen's Pond; and
- An overloaded section of Chamberlains ("CHA") Substation distribution feeder CHA-04 in the area of Paradise near Lanark drive.

Engineering inspections, vegetation management and construction for the *Feeder Additions for Load Growth* project will be completed in 2027. Additional information on this project is included in report *1.2 Feeder Additions for Load Growth* filed as part of the Application.

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 2027 for the *Feeder Additions for Load Growth* project.

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

Cost Category	2027
Material	384
Labour – Internal	333
Labour - Contract	491
Engineering	64
Other	12
Total	$1,284

Proposed expenditures for the *Feeder Additions for Load Growth* project total $1,284,000 in 2027.

ASSET BACKGROUND

Distribution feeder BLK-02 serves 2,295 customers in the Whitbourne and Brigus Junction areas around Ocean's Pond, Whalen's Pond and Middle Gull Pond. A 6-kilometre single-phase section extending southwest along Mill Road near Whalen's Pond is overloaded. Load growth on this section of line can mainly attributed to new customer connections and service upgrades. The number of customers supplied by this single-phase line has increased by 117% over the last 15 years.

Distribution feeder CHA-04 serves 2,683 customers in Paradise. A 1-kilometre single-phase section of line is currently overloaded and is forecast to be substantially overloaded in 2027 due to a planned subdivision development. Peak load on the section of single-phase line was approximately 93 amps in 2025, and the forecasted peak on the single-phase section is expected to reach up to 163 amps in 2027.

ASSESSMENT OF ALTERNATIVES

There are generally five categories of alternatives to address overloaded conductor: feeder balancing, load transfers, feeder upgrades, new 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.

Distribution Feeder BLK-02

Three categories of alternatives that are generally available to address overloaded conductor are not applicable to the overloaded section of BLK-02. Feeder balancing is not applicable as the identified section of BLK-02 is single-phase. A new feeder build from BLK Substation is not feasible due to the magnitude of the associated costs. A load transfer is not applicable since there is no adjacent feeder.

As a result, the alternatives evaluated to mitigate the overloaded section of distribution feeder BLK-02 include: (i) upgrading the tap from single-phase to three-phase; and (ii) a non-wires alternative.

The capital cost of the alternative to upgrade the 6-kilometre section of distribution feeder BLK-02 from single-phase to three-phase to resolve the overload condition is estimated to be $723,000 in 2027. This corresponds to $837,000 on a net present value basis. The capital cost of a non-wires alternative would be $557,000 and would have an expected lifetime of 15 years. This corresponds to $1,029,000 on a net-present value basis.

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

Distribution Feeder CHA-04

Four categories of alternatives that are generally available to address overloaded conductor are not applicable to distribution feeder CHA-04. Feeder balancing is not applicable as the identified section of CHA-04 is single-phase. A new feeder build from CHA 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 forecasted duration of the overload condition. A load transfer was also considered which would involve building extensions from Hardwoods ("HWD") Substation distribution feeders HWD-07 and HWD-09. However, due to a lack of available easements, in conjunction with future load growth on distribution feeder HWD-07 in particular, this option was determined to be not viable.

As a result, only one alternaitve has been identified as being technically and economically viable. The recommended alternative to mitigate the overloaded section of distribution feeder CHA-04 is upgrading the overloaded section from single-phase to three-phase.

The capital cost to upgrade the 1-kilometre section of CHA-04 from single-phase to three-phase to resolve the overload condition is estimated to be $561,000 in 2027.

JUSTIFICATION

The *Feeder Additions for Load Growth* project is required to provide customers equitable access to an adequate supply of power. The project will address overload conditions on two distribution feeders in Newfoundland Power's service area and continue to provide customers with safe and adequate service.

Title:	**Distribution Feeder ILC-02 Refurbishment**
Asset Class:	**Distribution**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$595,000 in 2027 and $610,000 in 2028**

PROJECT DESCRIPTION

The *Distribution Feeder ILC-02 Refurbishment* project involves relocating approximately 1.5 kilometres and refurbishing 4.5 kilometres of Island Cove ("ILC") Substation distribution feeder ILC-02, a distribution feeder serving the communities of Bishop's Cove, Spaniards Bay, and Tilton. The proposed section is located along Bishop's Cove Road in the communities of Spaniards Bay and Bishop's Cove. The proposed project includes:

1. Relocating 1.5 kilometres of two-phase primary to roadside and upgrading to three-phase;
2. Replacing 4.5 kilometres of two-phase primary #4 copper ("Cu") conductor;
3. Replacing deteriorated crossarms, vintage insulators, hardware and transformers; and
4. Replacing deteriorated wooden poles and anchors.

Design work for the *Distribution Feeder ILC-02 Refurbishment* project is expected to be completed by the end of the second quarter of 2027. Construction will begin in 2027 and will be completed by the end of the third quarter of 2028.

PROJECT BUDGET

The budget for the *Distribution Feeder ILC-02 Refurbishment* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2027 and 2028 for the *Distribution Feeder ILC-02 Refurbishment* project.

Table 1
Distribution Feeder ILC-02 Refurbishment
2027 and 2028 Budget
($000s)

Cost Category	2027	2028	Total
Material	286	292	578
Labour – Internal	136	142	278
Labour - Contract	129	132	261
Engineering	26	27	53
Other	18	17	35
Total	$595	$610	$1,205

Proposed expenditures for the *Distribution Feeder ILC-02 Refurbishment* project include $595,000 in 2027 and $610,000 in 2028, for a total project budget of $1,205,000.

ASSET BACKGROUND

Distribution feeder ILC-02 serves 1,166 customers on the Avalon Peninsula in the communities of Bishop's Cove, Spaniards Bay, and Tilton. The two-phase section of distribution line proposed for refurbishment, as shown in Figure 1, serves 316 customers, was constructed in 1971, and is located along Bishop's Cove Road in the communities of Spaniards Bay and Bishops Cove. The tie disconnect (TD-2018) can connect distribution feeder ILC-02 to distribution feeder ILC-01, which serves 953 customers in the communities of Upper Island Cove and Bryant's Cove.

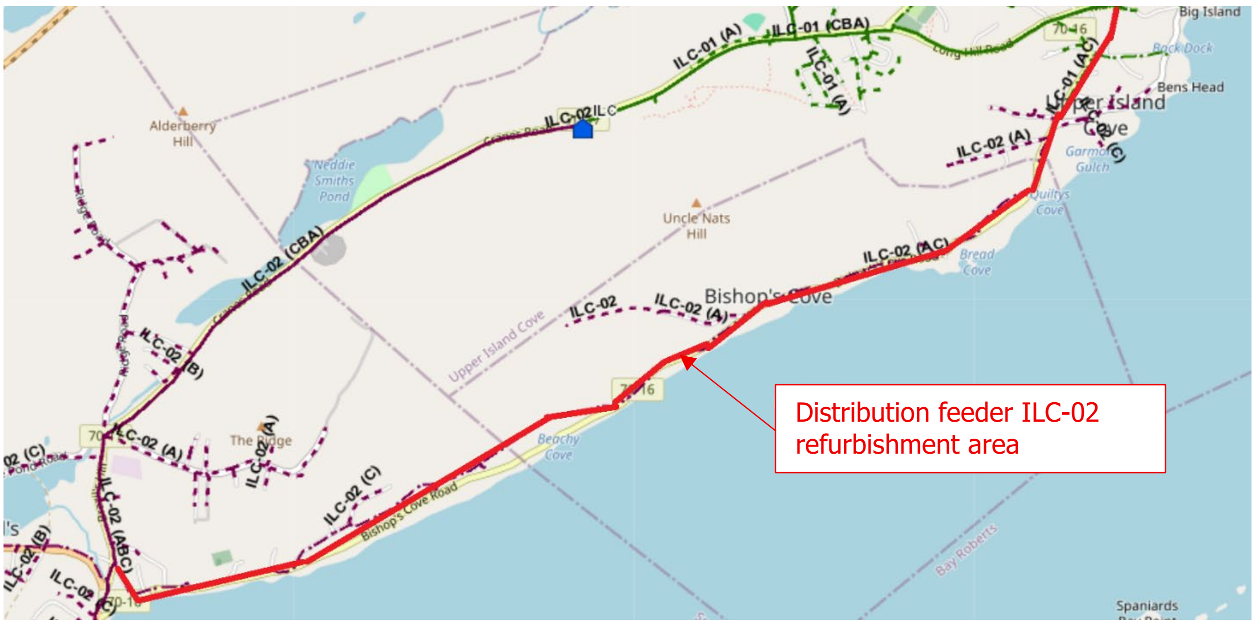


Figure 1 – Location of Distribution Feeder ILC-02 Refurbishment Project

A detailed inspection of the section of line shown in Figure 1 was completed in 2024. The segment has a total of 157 poles. The noted deficiencies include:

- 103 poles, or 66%, requiring replacement due to deep cracks or rot. Figure 2 shows a small sample of deteriorated poles.
- 83 crossarms, or 53%, requiring replacement due to severe splits and deterioration. Figure 3 shows a small sample of deteriorated crossarms.
- Figure 4 shows pictures of miscellaneous deficiencies, including the use of non-standard equipment.
- 6 EPAC, 16 8080 and 4 2-piece insulators require replacement. Figure 5 shows an example of the non-standard insulators.
- Sub-standard #4 Cu conductor installed on the entire section, including 104 #4 Cu Sleeves.

Figure 2 – Cracking and Deteriorated Poles

Figure 3 – Deteriorated Cross Arms

Figure 4 – Non-Standard Sleeve Repair (left) and Leaning Pole (right)

Figure 5 – Non-standard Insulators

Approximately 1.5 kilometres of distribution line shown below in Figure 7 is off-road, and is challenging to access.

Figure 7 – Off-road section of Distribution Feeder ILC-02

In addition to its deteriorated condition, distribution feeder ILC-02 has identified overload conditions. Phase A has a peak load of 96 amps, while phase C has a peak load of 77 amps, resulting in a net average load of 86 amps per phase, and exceeds the Company's planning criteria for maximum single-phase current. Additionally, tie disconnect TD-2018 is largely unusable due to the resulting feeder imbalance on distribution feeders ILC-01 and ILC-02. Transfers of load to distribution feeder ILC-01 are limited to Bishop's Cove Road only.

ASSESSMENT OF ALTERNATIVES

Newfoundland Power has identified three potential alternatives to address the deteriorated condition of distribution feeder ILC-02. These alternatives include deferral, like-for-like asset replacement, and upgrade/life extension.

Due to the deteriorated condition of this line as identified through inspection and engineering assessment, deferral is not an option. Advanced degradation is present across various components. As such, deferral would increase the risk of equipment failure and customer outages.

Like-for-like replacement is not viable due to an identified overload condition in sections of the distribution feeder. These sections require upgrading to meet customer demand in the area and will ensure that distribution feeders ILC-01 and ILC-02 can effectively pick up load if required, using the existing tie disconnect near Bishop's Cove. Additionally, relocating segments of the line roadside offers an opportunity to improve accessibility, outage response, and operational efficiency.

The only viable alternative is an upgrade and life extension of distribution feeder ILC-02 to address both the deteriorated condition and the identified overload condition.

RISK ASSESSMENT

Distribution feeder ILC-02 consists of 4.2 kilometres of main trunk line routed primarily in Bishop's Cove, Tilton, and Spaniard's Bay area and serves 1,166 customers. Inspections identified 104 conductor splices along the proposed 6-kilometre two-phase section of ILC-02, indicating a high incidence of historical conductor failures and material deficiencies. These splices are located within the proposed section, which has legacy equipment dating to the early 1970s, including undersized #4 Cu conductor and pin-type/porcelain and non-standard insulators. These insulators are prone to failure due to separation from the pin, which can cause the conductor to come free from the crossarm or pole. The cumulative number of splices and identified failure modes introduces both reliability and safety risks, as each splice represents a potential point of failure and reflects repeated corrective repairs rather than system renewal. The consequence of not completing the *Distribution Feeder ILC-02 Refurbishment* project is assessed as Serious (4).

Engineering inspections of distribution feeder ILC-02 have identified advanced deterioration, non-standard construction, accessibility concerns, overloaded conditions, undersized #4 Cu conductor, and deficiencies as noted above. The probability of equipment failure is therefore assessed as Likely (4).

Table 2 summarizes the risk assessment of the 2027 *Distribution Feeder ILC-02 Refurbishment* project.

Table 2
Distribution Feeder ILC-02 Refurbishment
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Distribution Feeder ILC-02 Refurbishment* project would pose a Medium-High (16) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Distribution Feeder ILC-02 Refurbishment* is necessary to address identified deterioration of the feeder, address loading and accessibility concerns, and ensure customers continue to receive an adequate supply of electricity at least cost.

Title: **Distribution Feeder CAB-01 Refurbishment**
Asset Class: **Distribution**
Category: **Project**
Investment Classification: **Renewal**
Budget: **$972,000**

PROJECT DESCRIPTION

The *Distribution Feeder CAB-01 Refurbishment* project involves rebuilding a portion of Cape Broyle ("CAB") Substation distribution feeder CAB-01, which serves the community of Cape Broyle and surrounding area. The proposed project includes:

1. Replacing 3.1 kilometres of three-phase primary #4 copper ("Cu") conductor;
2. Replacing deteriorated crossarms, vintage insulators, hardware and transformers; and
3. Replacing deteriorated and overloaded wooden poles and anchors.

Design work for the *Distribution Feeder CAB-01 Refurbishment* project is expected to be completed in the first quarter of 2027. Construction will begin in the second quarter of 2027 and is expected to be completed by the end of the third quarter of 2027.

PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2027 for the *Distribution Feeder CAB-01 Refurbishment* project.

Table 1
Distribution Feeder CAB-01 Refurbishment
2027 Budget
($000s)

Cost Category	2027
Material	300
Labour – Internal	230
Labour – Contract	382
Engineering	45
Other	15
Total	$972

Proposed expenditures for the *Distribution Feeder CAB-01 Refurbishment* project total $972,000 in 2027.

ASSET BACKGROUND

Distribution feeder CAB-01 is the sole 12.5 kV feeder originating from CAB Substation, located adjacent to Route 10 (Southern Shore Highway). The feeder supplies 1,247 customers in the communities of Cape Broyle, La Manche, Calvert, and Ferryland. The substation and distribution feeder were originally constructed in the early 1950s as part of the Cape Broyle Generating Station development. The *Distribution Feeder CAB-01 Refurbishment* project proposes to refurbish a section of the feeder beginning at Station Lane in the community of Cape Broyle, continuing through the community and ending on route 10 as shown in Figure 1.

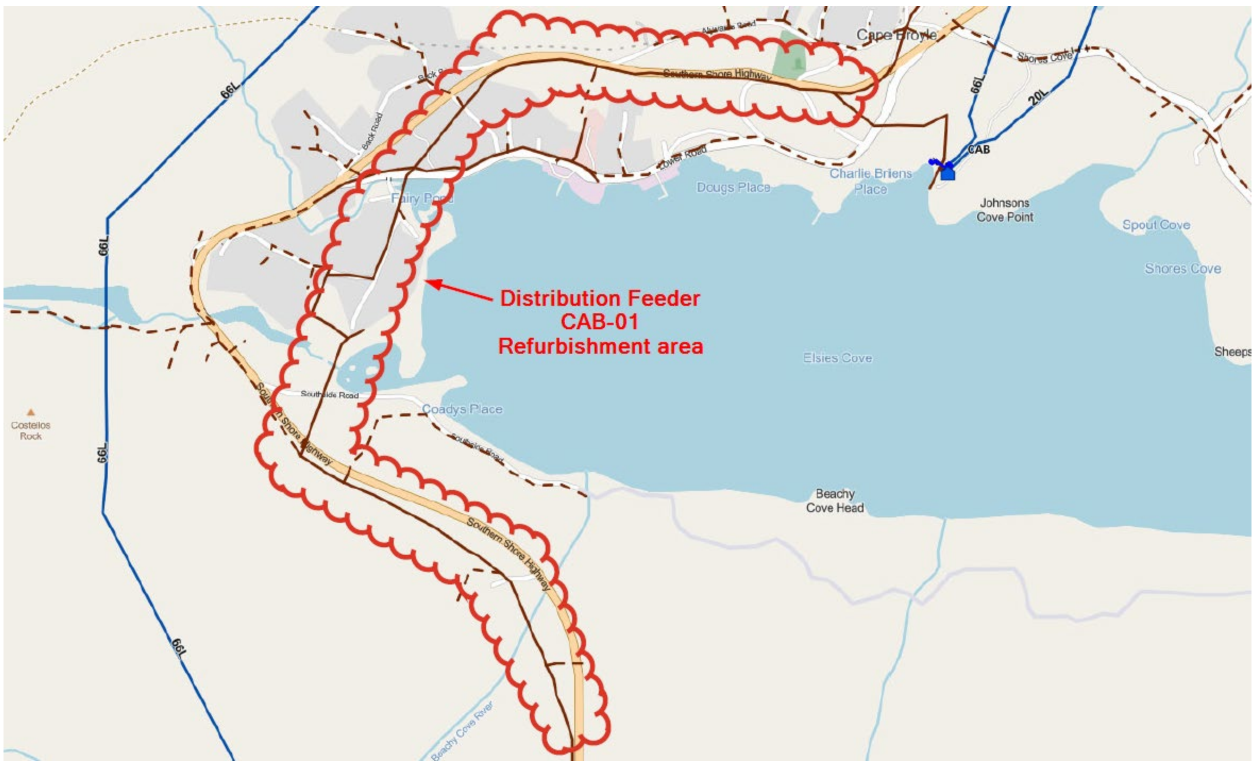


Figure 1 – Location of Distribution Feeder CAB-01 Refurbishment Project

Distribution feeder CAB-01 consists of 13.4 kilometres of main trunk line, routed primarily along the Southern Shore Highway. Inspections have identified a total of 147 conductor splices along the feeder, indicating a high incidence of historical conductor failures and material deficiencies. These splices are predominantly located within sections constructed using legacy infrastructure dating to the early 1950s, including undersized #4 Cu conductor and porcelain insulators. The porcelain insulators are prone to failure due to separation from the pin, which can result in the conductor coming free from the crossarm or pole. The cumulative number of splices and identified failure modes introduce both reliability and safety risks, as each splice represents a potential point of failure and reflects repeated corrective repairs rather than system renewal.

Engineering inspections of distribution feeder CAB-01 have identified advanced deterioration, non-standard construction, 37 deficiency-related work orders, including 30 poles and approximately 3.1 kilometres of undersized #4 Cu conductor requiring replacement.

Several segments of the feeder are not readily accessible by vehicle and are not visible from the roadway, requiring patrols and repairs to be completed on foot. As a result, fault location activities are time consuming, resulting in longer duration outages when they occur. These extended outages contribute to operational challenges, including cold-load pickup and system-stability concerns, negatively affecting reliability for customers. Refurbishing the 3.1-kilometre section of CAB-01 ensures that these non-accessible sections of the main trunk can continue to provide reliable service for the 1,247 customers in the communities of Cape Broyle, La Manche, Calvert, and Ferryland.

Figures 2 to 5 below show examples of deteriorated infrastructure along the 3.1-kilometre section of distribution feeder CAB-01 as well as a portion of the off-road section of distribution line.

Figure 2 - Severe cracks in Feeder Trunk pole

Figure 3 - Deteriorated pole

Figure 4 - Offroad section of Feeder Trunk

Figure 5 - Offroad section of Feeder Trunk

RISK ASSESSMENT

The *Distribution Feeder CAB-01 Refurbishment* project is necessary to address known deterioration and undersized conductors on the distribution feeder.

The *Distribution Feeder CAB-01 Refurbishment* project addresses reliability and safety risks associated with the deteriorated condition of the feeder affecting the communities of Cape Broyle, La Manche, Calvert, and Ferryland. The feeder supplies 1,247 customers, over half of whom are served through the deteriorated main trunk section. This section includes roadside, back-lot, and off-road construction, which is aging and increasingly prone to equipment failure. The consequence of not completing this project is assessed as Serious (4).

In its current condition, the feeder exposes all connected customers to elevated risks of extended outages, safety hazards associated with equipment failures, and operational challenges for restoration activities. The probability of equipment failure on distribution feeder CAB-01 is assessed as Likely (4).

Table 2 summarizes the risk assessment of the 2027 *Distribution Feeder CAB-01 Refurbishment* project.

Table 2
Distribution Feeder CAB-01 Refurbishment
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Distribution Feeder CAB-01 Refurbishment* project would pose a Medium-High (16) risk to customers.

JUSTIFICATION

The *Distribution Feeder CAB-01 Refurbishment* project is necessary to address known deterioration of the feeder and ensure customers continue to receive an adequate supply of electricity at least cost.

Title:	**Distribution Feeder GDL-02 Loop 10 and 20 Refurbishment**
Asset Class:	**Distribution**
Category:	**Project**
Investment Classification:	**Renewal**
Budget:	**$789,000**

PROJECT DESCRIPTION

The *Distribution Feeder GDL-02 Loop 10 and 20 Refurbishment* project involves refurbishing Glendale ("GDL") Substation distribution feeder GDL-02, a distribution feeder serving customers in Mount Pearl. The section proposed for refurbishment includes underground distribution assets along loop 10 and loop 20.

Engineering inspections of this feeder have identified approximately 1.5 kilometres of underground primary conductor requiring replacement, along with secondary conductor and pad mount transformers requiring replacement.

Design work for the *Distribution Feeder GDL-02 Loop 10 and 20 Refurbishment* project is expected to be completed by the end of the first quarter of 2027. Construction will begin in the second quarter of 2027 and will be completed by the end of the third quarter of 2027.

PROJECT BUDGET

The budget for the *Distribution Feeder GDL-02 Loop 10 and 20 Refurbishment* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2027 for the *Distribution Feeder GDL-02 Loop 10 and 20 Refurbishment* project.

Table 1
Distribution Feeder GDL-02 Loop 10 and 20 Refurbishment
2027 Budget
($000s)

Cost Category	2027
Material	356
Labour – Internal	82
Labour – Contract	324
Engineering	27
Other	-
Total	$789

Proposed expenditures for the *Distribution Feeder GDL-02 Loop 10 and 20 Refurbishment* project total $789,000 in 2027.

ASSET BACKGROUND

An engineering assessment of Loops 10 and 20, considering asset age, installation method, configuration, and documented failure history, has determined that the existing underground infrastructure has reached the end of its useful service life. Continued operation without refurbishment is expected to result in ongoing failures and increased risk to customer reliability.

The underground distribution infrastructure for Loop 10 was installed in 1975 and serves 92 residential customers in the Woodford Place, Whitely Drive, Giles Place, Badcock Place, and Jeffers Drive areas of Mount Pearl. Loop 10 consists of approximately 1.2 kilometres of direct-buried Ethylene Propylene Rubber ("EPR") insulated primary conductor arranged in a looped configuration supplying multiple pad-mounted transformers, as illustrated in Figure 1.[5] Loop 10 has experienced increasing reliability issues and equipment failures, with eight documented primary conductor failures since 2010, including two failures since 2022, indicating accelerated asset deterioration and resulting in approximately 70,000 customer outage minutes for customers served by Loop 10.

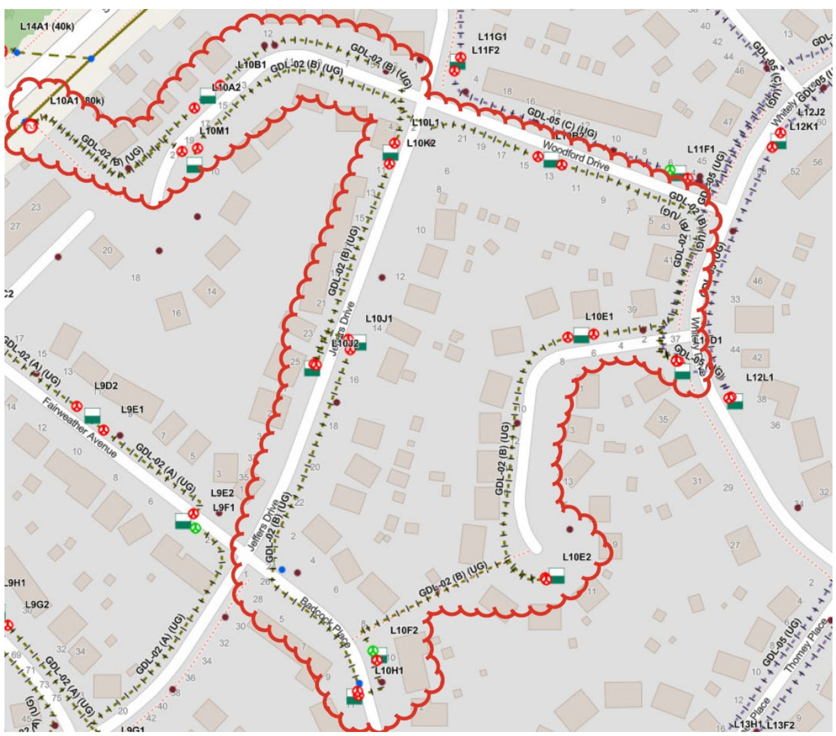


Figure 1 - Distribution Feeder GDL-02, Loop 10

5 Direct-buried refers to cable that is installed directly in the ground without additional protective structures, such as ducts, raceways, or concrete encasement. Direct-buried cables are more prone to damage than cables installed in ducts due to repeated exposure to excavation, backfilling and compacting. Newfoundland Power's current design standard for underground distribution infrastructure does not include direct-buried cables.

The underground infrastructure for Loop 20 was installed in 1976 and serves 80 residential customers in the Munden Drive area of Mount Pearl. Loop 20 consists of approximately 0.3 kilometres of direct-buried EPR-insulated primary conductor in a looped configuration supplying pad-mounted transformers, as shown in Figure 2. Despite its shorter length, Loop 20 has experienced three primary conductor failures since 2014, representing a high failure rate relative to asset size and confirming advanced degradation and resulting in approximately 24,000 customer outage minutes for customers served by Loop 20.

Figure 2 - Distribution Feeder GDL-02, Loop 20

RISK ASSESSMENT

The *Distribution Feeder GDL-02 Loop 10 and 20 Refurbishment* project is necessary to address deteriorated underground infrastructure as identified through an engineering assessment.

Loops 10 and 20 of distribution feeder GDL-02 provide electrical service to a total of 172 residential customers in Mount Pearl. Loop 10 serves 92 customers in the Woodford Place, Whitely Drive, Giles Place, Badcock Place, and Jeffers Drive areas, while Loop 20 serves 80 customers in the Munden Drive area. Both loops are supplied by underground primary conductors that are beyond their useful service life. Customers served by these loops are exposed to increased risk of outages due to the deteriorated condition of the underground conductors. When the conductor fails, customers are without service until a crew is dispatched, the fault is located, and switching is completed to isolate the fault and restore service. The consequence of not completing this project is assessed as Minor (2).

Given the age of the assets, method of installation, and documented failure history, the probability of continued equipment failure is assessed as Near Certain (5). Deferring the project would continue to expose 92 customers on Loop 10 and 80 customers on Loop 20 to an increased likelihood of unplanned outages.

Table 2 summarizes the risk assessment of the 2027 *Distribution Feeder GDL-02 Loop 10 and 20 Refurbishment* project.

Table 2
Distribution Feeder GDL-02 Loop 10 and 20 Refurbishment
Risk Assessment Summary

Consequence	Probability	Risk
Minor (2)	Certain (5)	Medium-High (10)

Based on this assessment, not proceeding with the *Distribution Feeder GDL-02 Loop 10 and 20 Refurbishment* project would pose a Medium-High (10) risk to customers.

JUSTIFICATION

The *Distribution Feeder GDL-02 Loop 10 and 20 Refurbishment* project is necessary to address known deterioration on underground infrastructure and ensure customers continue to receive an adequate supply of electricity at least cost.

Title: **Extensions**
Asset Class: **Distribution**
Category: **Program**
Investment Classification: **Access**
Budget: **$13,852,000**

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 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.[6]

Table 1 provides the cost per customer connection for the *Extensions* program from 2022 to 2027.

Table 1
Extensions Program
Cost per Customer

Year	2022	2023	2024	2025	2026F	2027F
Total ($000s)	12,489	15,145	19,601	18,558	16,747	13,852
Adjusted Costs ($000s)[1]	14,090[2]	15,389[3]	16,371[4]	17,288[5]	16,747	-
New Customers	2,646	2,372	3,052	3,122	3,060	2,342
Cost/Customer[1] ($)	5,325	6,488	5,364	5,537	6,037	5,915

1 2026 dollars.
2 Excludes approximately $343,000 related to the connection of the new Western Memorial Regional Hospital.
3 Excludes approximately $1,117,000 related to several large CIAC projects in 2023.
4 Excludes approximately $4,100,000 associated with large CIAC projects in Joe Batts Pond and Cormack cabin areas.
5 Excludes approximately $1,800,000 associated with large CIAC projects in Joe Batts Pond cabin area and Jonathan's Pond.

6 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 2,342 new customer connections in 2027 at a cost per connection under the *Extensions* program of $5,915.

Table 2 provides a breakdown of expenditures proposed for 2027 for the *Extensions* program.

Table 2
Extensions Program
2027 Budget
($000s)

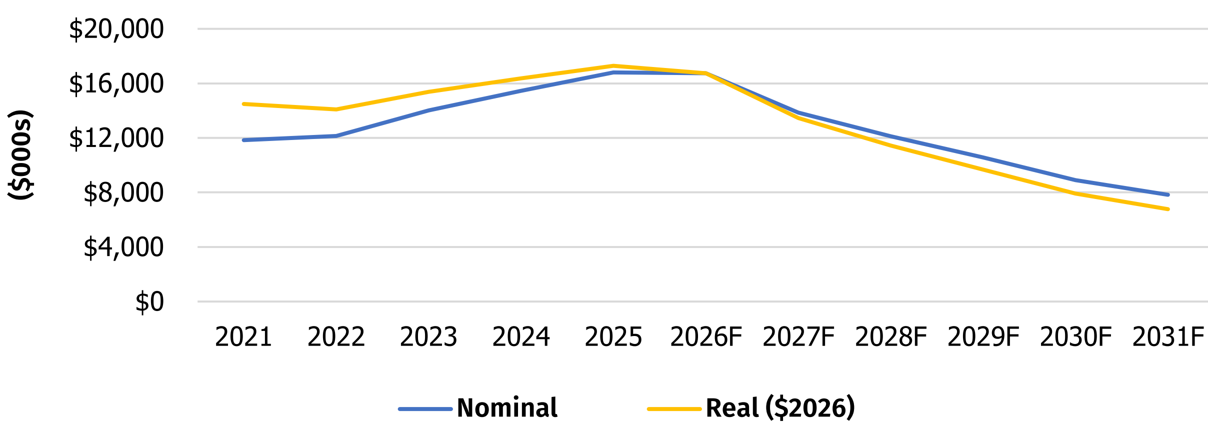
Cost Category	2027
Material	4,298
Labour – Internal	3,883
Labour – Contract	3,128
Engineering	1,748
Other	795
Total	$13,852

Proposed expenditures for the *Extensions* program total $13,852,000 in 2027.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Extensions* program from 2021 to 2031.[7]

Figure 1
Extensions Program Expenditures
(2021-2031F)



[7] For forecast expenditures for the *Extensions* program, see the *2027-2031 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 2027 due to a forecast decline in new customer connections. Annual expenditures under this program averaged approximately $15 million from 2022 to 2026, or approximately $16.0 million when adjusted for inflation as described in Table 1. Annual expenditures under this program are forecast to average approximately $10.7 million over the next five years.

ASSET BACKGROUND

Newfoundland Power operates approximately 9,800 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 vary 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: **$8,319,000**

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.[8]

Table 1 provides the annual expenditures for the *Reconstruction* program from 2022 to 2026.

Table 1
Reconstruction Program
Historical Expenditures
($000s)

Year	2022	2023	2024	2025	2026F
Total	6,179	7,622	8,633	8,488	7,674
Adjusted Costs[1]	6,888[2]	8,416	8,571[3]	8,763	7,674

1 2026 dollars
2 Excludes approximately $314,000 related to Hurricane Earl, Hurricane Fiona and an additional winter storm on February 8th.
3 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 $8.1 million from 2022 to 2026.

8 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 2027 for the *Reconstruction* program.

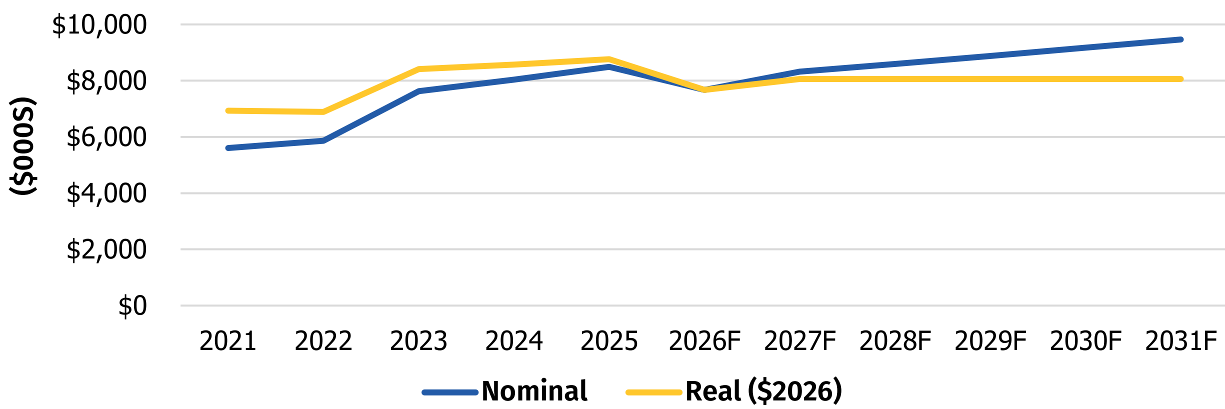
Table 2 Reconstruction Program 2027 Budget ($000s)	
Cost Category	2027
Material	2,025
Labour – Internal	3,591
Labour – Contract	1,610
Engineering	735
Other	358
Total	$8,319

Proposed expenditures for the *Reconstruction* program total $8,319,000 for 2027.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Reconstruction* program from 2021 to 2031.[9]

Figure 1
Reconstruction Program Expenditures
(2021-2031F)



Annual expenditures under this program averaged approximately $7.5 million from 2022 to 2026, or approximately $8.1 million when adjusted as described above. Annual expenditures are forecast to average approximately $8.9 million over the next five years.

[9] For forecast annual expenditures for the *Reconstruction* program, see the *2027-2031 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 227,000 wooden support structures and overhead conductor on approximately 9,800 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 16% of wooden support structures on Newfoundland Power's distribution system have exceeded 54 years in service. Approximately 24% of distribution overhead conductor has exceeded 50 years in service.[10]

The effect of age on Newfoundland Power's electrical system can be observed through its recent experience with equipment failures. Over the period 2021 to 2025, equipment-related failures on the distribution system accounted for an average of over 29,000,000 customer minutes of interruption annually.[11] 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 612 deficiencies were corrected annually under the *Reconstruction* program from 2021 to 2025, ranging from 385 in 2022 to 823 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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10 For more information, see the *2027-2031 Capital Plan,* section *2.4.2 Distribution*.
11 Includes equipment failures resulting in an outage to customers. Excludes transmission equipment failures.

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:	**Replacement Transformers**
Asset Class:	**Distribution**
Category:	**Program**
Investment Classification:	**Renewal**
Budget:	**$5,573,000**

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 2024 to 2026.

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

Year	2024	2025	2026F
Total	5,931	6,529	4,954
Adjusted Costs[1]	6,195	5,281[2]	4,954

[1] 2026 dollars.
[2] Excludes costs related to maintaining transformer inventory levels.

The average annual adjusted cost for the *Replacement Transformers* program was approximately $5.5 million from 2024 to 2026.

Table 2 provides a breakdown of expenditures proposed for 2027 for the *Replacement Transformers* program.

Table 2
Replacement Transformers Program
2027 Budget
($000s)

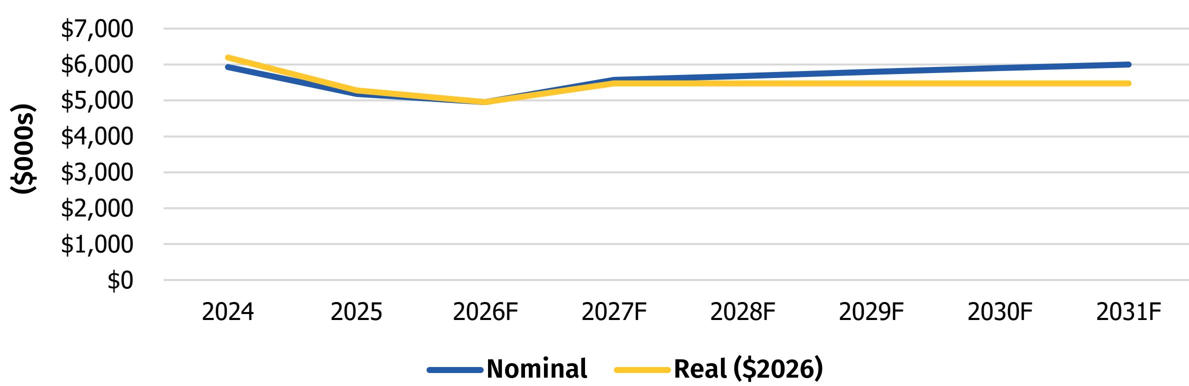
Cost Category	2027
Material	5,573
Labour – Internal	-
Labour – Contract	-
Engineering	-
Other	-
Total	$5,573

Proposed expenditures for the *Replacement Transformers* program total $5,573,000 for 2026.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Replacement Transformers* program from 2024 to 2031.[12]

Figure 1
Replacement Transformers Program Expenditures
(2024-2031F)



Annual expenditures under this program averaged approximately $5.4 million from 2024 to 2026, or approximately $5.5 million when adjusted as described above. Annual expenditures are forecast to average approximately $5.8 million over the next five years.

12 For forecast annual expenditures for the *Replacement Transformers* program, see the *2027-2031 Capital Plan,* Appendix A, page A-2.

ASSET BACKGROUND

There are approximately 58,000 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 21% in service for 20 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 690 transformers were replaced annually from 2021 to 2025, 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:	**Rebuild Distribution Lines**
Asset Class:	**Distribution**
Category:	**Program**
Investment Classification:	**Renewal**
Budget:	**$5,502,000**

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 41 distribution feeders will undergo inspection in 2026 with planned preventative maintenance in 2027:

BCV-03	BVS-04	GFS-06	KBR-09	PUL-02	WES-03
BFS-01	COB-01	HOL-01	KBR-10	QTZ-01	
BLA-01	DLK-03	HOL-03	KBR-15	RRD-05	
BRB-01	DOY-01	HWD-01	KEN-03	SLA-08	
BRB-02	GAL-03	HWD-03	MOL-03	SLA-10	
BRB-03	GBY-01	HWD-04	NHR-02	STG-01	
BRB-05	GDL-04	ILC-01	PHR-01	SUN-01	
BVS-02	GFS-02	ILC-02	PJN-01	TWG-03	

The specific deficiencies to be corrected on these distribution feeders will depend on the outcomes of the inspections completed throughout 2026, 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.[13]

[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 1 shows annual expenditures for the *Rebuild Distribution Lines* program from 2022 to 2026.

Table 1 Rebuild Distribution Lines Historical Expenditures ($000s)					
Year	2022	2023	2024	2025	2026F
Total	3,956	5,085	5,253	5,266	5,263
Adjusted Costs[1]	4,678	5,630	5,623	5,438	5,263

1 2026 dollars.

The average annual adjusted cost for the *Rebuild Distribution Lines* program was approximately $5.3 million from 2022 to 2026.

Table 2 provides a breakdown of expenditures proposed for 2027 for the *Rebuild Distribution Lines* program.

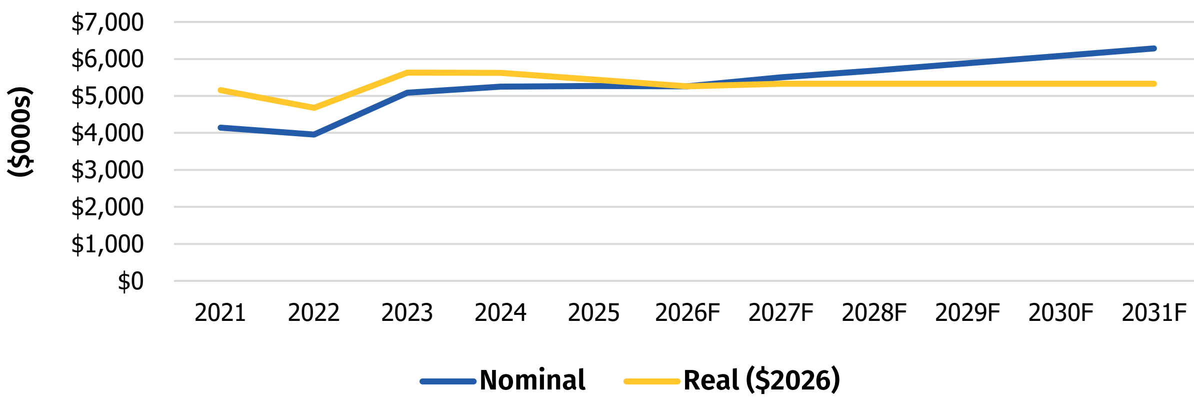
Table 2 Rebuild Distribution Lines 2027 Budget ($000s)	
Cost Category	2027
Material	1,325
Labour – Internal	2,696
Labour – Contract	1,048
Engineering	297
Other	136
Total	$5,502

Proposed expenditures for the *Rebuild Distribution Lines* program total $5,502,000 for 2026.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Rebuild Distribution Lines* program from 2021 to 2031.[14]

Figure 1
Rebuild Distribution Lines Program Expenditures
(2021-2031F)



Annual expenditures under this program averaged approximately $5.0 million from 2022 to 2026, or approximately $5.3 million when adjusted for inflation. Annual expenditures are forecast to average approximately $5.9 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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14 For forecast annual expenditures for the *Rebuild Distribution Lines* program, see the *2027-2031 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 227,000 wooden support structures and overhead conductor on approximately 9,800 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 16% of wooden support structures on Newfoundland Power's distribution system have exceeded 54 years in service. Approximately 24% of distribution overhead conductor has exceeded 50 years in service.[15]

An average of 1,868 deficiencies were corrected annually under the *Rebuild Distribution Lines* program from 2021 to 2025, ranging from 1,468 in 2022 to 2,436 in 2021. These deficiencies were corrected through a combination of rebuilding sections of distribution feeders and the selective replacement of line components.

15 For more information, see the *2027-2031 Capital Plan,* section *2.4.2 Distribution*.

The *Rebuild Distribution Lines* program will address deficiencies on 41 distribution feeders in 2027. These feeders serve an average of approximately 980 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:	**New Transformers**
Asset Class:	**Distribution**
Category:	**Program**
Investment Classification:	**Access**
Budget:	**$4,943,000**

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 2024 to 2026.

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

Year	2024	2025	2026F
Total	5,260	5,789	4,394
Adjusted Costs[1]	5,494	4,684[2]	4,394

1 2026 dollars.
2 Excludes costs related to maintaining transformer inventory.

The average annual adjusted cost for the *New Transformers* program was approximately $4.9 million from 2024 to 2026.

Table 2 provides a breakdown of expenditures proposed for 2027 for the *New Transformers* program.

Table 2
New Transformers Program
2027 Budget
($000s)

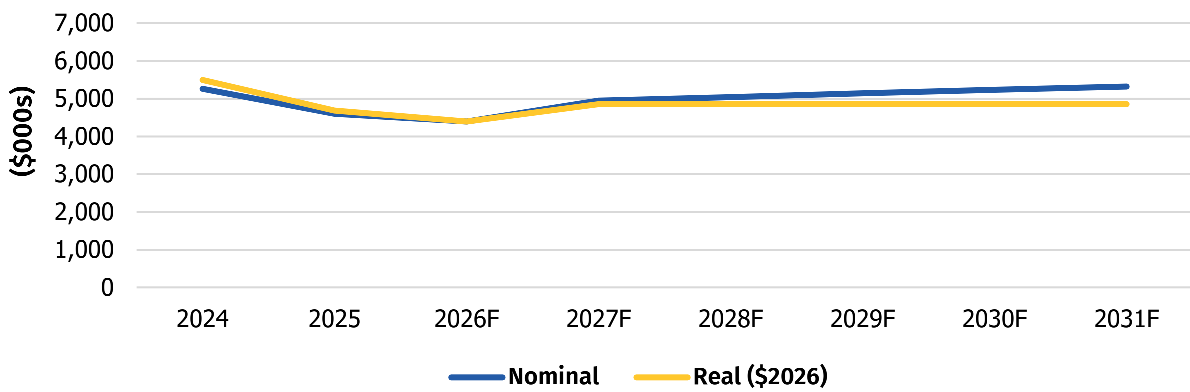
Cost Category	2027
Material	4,943
Labour – Internal	-
Labour – Contract	-
Engineering	-
Other	-
Total	$4,943

Proposed expenditures for the *New Transformers* program total $4,943,000 for 2027.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *New Transformers* program from 2024 to 2031.[16]

Figure 1
New Transformers Program Expenditures
(2024-2031F)



Annual expenditures under this program averaged approximately $4.3 million from 2024 to 2026, or $4.9 million when adjusted as described above. Annual expenditures under this program are forecast to average approximately $5.1 million over the next five years.

16 For forecast annual expenditures for the *New Transformers* program, see the *2027-2031 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 1,136 new transformers were installed annually from 2021 to 2025.

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:	**Relocate/Replace Distribution Lines for Third Parties**
Asset Class:	**Distribution**
Category:	**Program**
Investment Classification:	**Access**
Budget:	**$3,872,000**

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.[17]

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.

[17] 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 2022 to 2026.

Table 1 Relocate/Replace Distribution Lines for Third Parties Program Historical Expenditures ($000s)					
Year	2022	2023	2024	2025	2026F
Total	3,055	3,109	3,905	3,814	3,702
Adjusted Costs[1]	3,559	3,429	4,158	3,937	3,702

[1] 2026 dollars.

The average annual adjusted cost for the *Relocate/Replace Distribution Lines for Third Parties* program was approximately $3.8 million from 2022 to 2026.

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

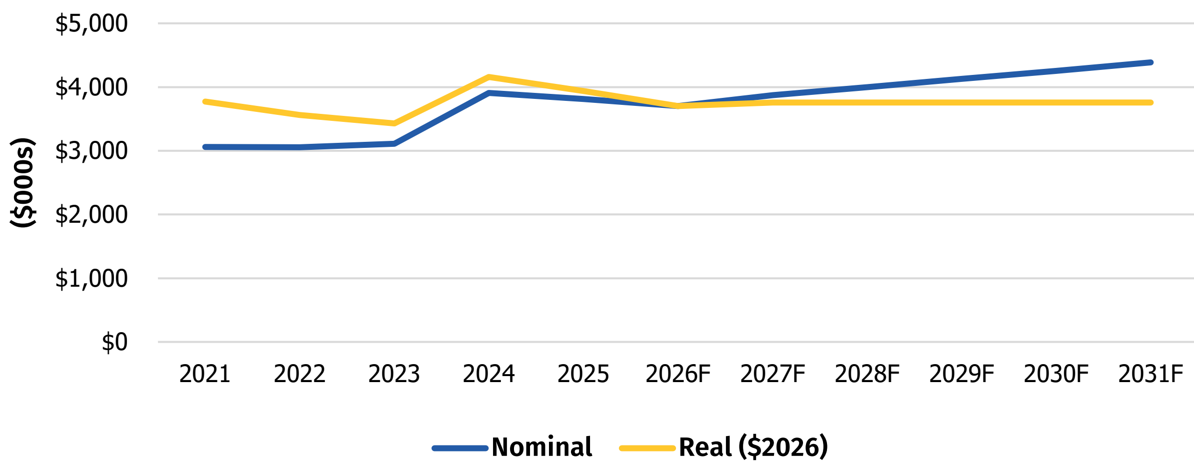
Table 2 Relocate/Replace Distribution Lines for Third Parties Program 2027 Budget ($000s)	
Cost Category	2027
Material	888
Labour – Internal	1,313
Labour – Contract	788
Engineering	623
Other	260
Total	$3,872

Proposed expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program total $3,872,000 for 2027.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program from 2021 to 2031.[18]

Figure 1
Relocate/Replace Distribution for Third Parties Program Expenditures
(2021-2031F)



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 $3.5 million from 2022 to 2026, or approximately $3.8 million when adjusted for inflation. Annual expenditures are forecast to average approximately $4.1 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 281 requests from third parties were received under the *Relocate/Replace Distribution Lines for Third Parties* program from 2021 to 2025.

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.

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18 For forecast annual expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program, see the *2027-2031 Capital Plan,* Appendix A, page A-2.

Title:	**New Services**
Asset Class:	**Distribution**
Category:	**Program**
Investment Classification:	**Access**
Budget:	**$3,520,000**

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 2022 to 2027.

Table 1
New Services Program
Cost per Customer

Year	2022	2023	2024	2025	2026F	2027F
Total ($000s)	3,469	3,260	3,661	4,308	4,218	3,520
Adjusted Costs ($000s)[1]	4,146	3,623	3,934	4,461	4,218	-
New Customers	2,646	2,372	3,052	3,122	3,060	2,342
Cost/Customer[1] ($)	1,567	1,527	1,289	1,429	1,445	1,503

[1] 2026 dollars.

Newfoundland Power is forecasting 2,342 new customer connections in 2027 at a cost per connection of $1,503.

Table 2 provides a breakdown of expenditures proposed for 2027 for the *New Services* program.

Table 2
New Services Program
2027 Budget
($000s)

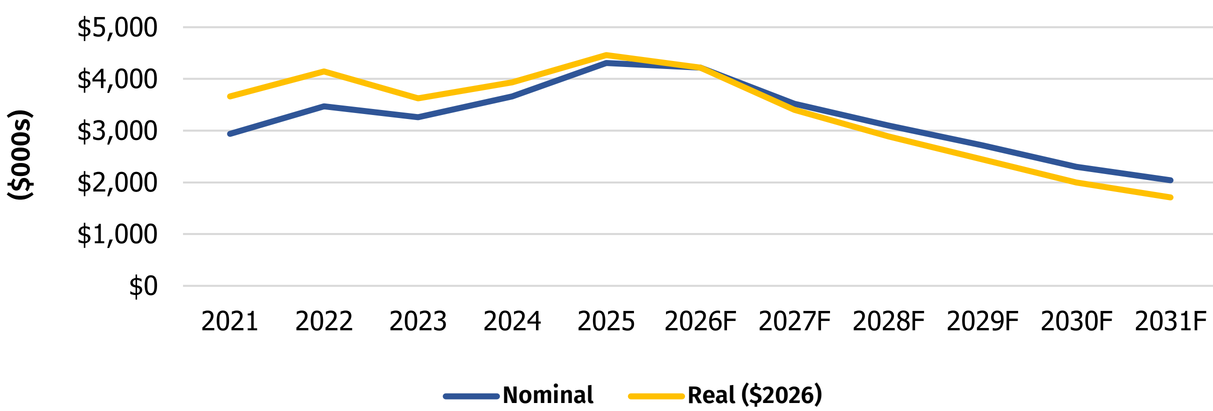
Cost Category	2027
Material	1,009
Labour – Internal	2,009
Labour – Contract	196
Engineering	242
Other	64
Total	3,520

Proposed expenditures for the *New Services* program total $3,520,000 for 2027.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *New Services* program from 2021 to 2031.[19]

Figure 1
New Services Program Expenditures
(2021-2031F)



Annual expenditures under this program averaged approximately $3.8 million from 2022 to 2026, or $4.1 million when adjusted for inflation. Annual expenditures under this program are forecast to average approximately $2.7 million over the next five years.

[19] For forecast annual expenditures for the *New Services* program, see the *2027-2031 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 vary 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: **$2,496,000**

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 2022 to 2026.

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

Year	2022	2023	2024	2025	2026F
Total	$2,209	$2,267	$2,666	$1,856	$2,425
Adjusted Costs[1]	$2,534	$2,475	$2,815	$1,905	$2,425

[1] 2026 dollars.

The average annual adjusted cost for the *New Street Lighting* program was approximately $2.4 million from 2022 to 2026.

Table 2 provides a breakdown of expenditures proposed for 2027 for the *New Street Lighting* program.

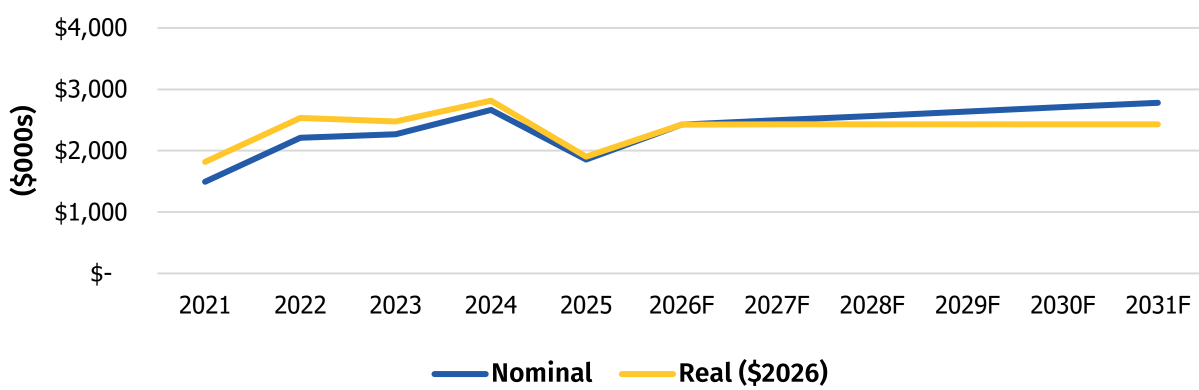
Table 2 New Street Lighting Program 2027 Budget ($000s)	
Cost Category	2027
Material	1,403
Labour – Internal	638
Labour – Contract	330
Engineering	74
Other	51
Total	$2,496

Proposed expenditures for the *New Street Lighting* program total $2,496,000 for 2027.

PROGRAM TREND

Figure 1 shows historical and forecast annual expenditures for the *New Street Lighting* program from 2021 to 2031.[20]

Figure 1
New Street Lighting Program Expenditures
(2021-2031F)



Annual expenditures for the *New Street Lighting* program vary depending upon the number and scope of requests received from customers. Annual expenditures under this program averaged approximately $2.3 million from 2022 to 2026, or approximately $2.4 million when adjusted for inflation. Annual expenditures under this program are forecast to average approximately $2.6 million over the next five years.

20 For forecast annual expenditures for the *New Street Lighting* program, see *2027-2031 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 931 new street lights were installed annually from 2021 to 2025, ranging from a low of 696 in 2025 to a high of 1109 in 2022.

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:	**$936,000**

PROGRAM DESCRIPTION

The *Replacement Street Lighting* program involves the replacement of failed street lighting components including fixtures, 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 2022 to 2026.

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

Year	2022	2023	2024	2025	2026F
Total	$937	$774	$890	$847	$914
Adjusted Costs[1]	$1,036	$835	$933	$867	$914

[1] 2026 dollars.

The average annual adjusted cost for the *Replacement Street Lighting* program was approximately $917,000 from 2022 to 2026.

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

Table 2
Replacement Street Lighting Program
2027 Budget
($000s)

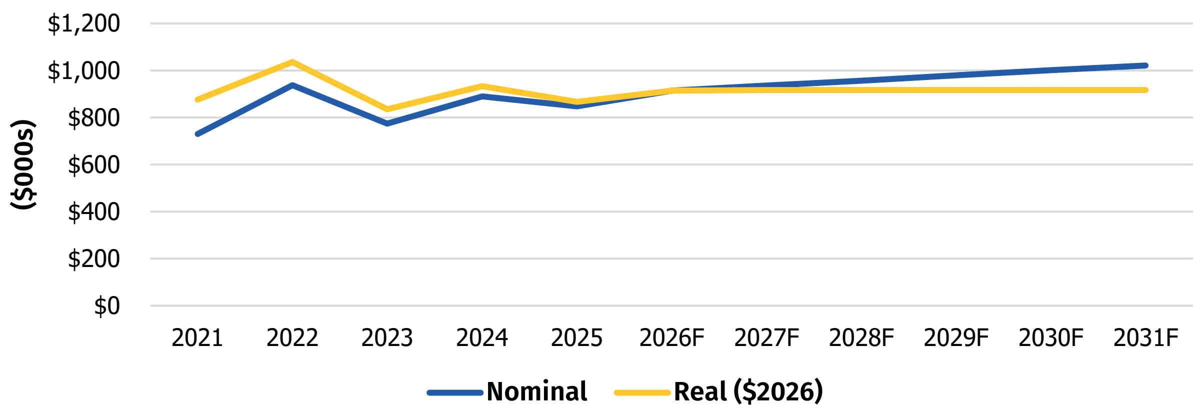
Cost Category	2027
Material	614
Labour – Internal	152
Labour – Contract	153
Engineering	10
Other	7
Total	$936

Proposed expenditures for the *Replacement Street Lighting* program total $936,000 for 2027.

PROGRAM TREND

Figure 1 shows historical and forecast annual expenditures for the *Replacement Street Lighting* program from 2021 to 2031.[21]

Figure 1
Replacement Street Lighting Program Expenditures
(2021-2031F)



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 $872,000 from 2022 to 2026, or approximately $917,000 when adjusted for inflation. Annual expenditures under this program are forecast to average approximately $979,000 over the next five years.

21 For forecast annual expenditures for the *Replacement Street Lighting* program, see *2027-2031 Capital Plan,* Appendix A, page A-2.

ASSET BACKGROUND

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

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. Following completion of the *LED Street Lighting Replacement* project in 2026, the *Replacement Street Lighting* program will address the replacement of street light fixtures and the replacement of other hardware and dedicated street light poles. Newfoundland Power will continue to monitor actual expenditures under this program to determine if adjustments may be needed.

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 street lighting components.

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.

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: **Portable Substation**
Asset Class: **Substations**
Category: **Project**
Investment Classification: **Renewal**
Budget (Multi-Year): **$990,000 in 2027; $3,894,000 in 2028; $5,049,000 in 2029**

PROJECT DESCRIPTION

The *Portable Substation* project involves the purchase of a portable substation designed to temporarily replace the functionality of a substation. Newfoundland Power has assessed the adequacy of its portable substation fleet and determined that the procurement of an additional portable substation is required to support system reliability over the long term.

The proposed unit will include the following equipment mounted on a transportable trailer:

(i) 25 MVA, 138/66 kV to 12.5/25 kV multi-winding power transformer with an On-Load Tap Changer;
(ii) 138 kV isolation equipment;
(iii) 25 kV circuit breaker;
(iv) Instrument transformers;
(v) Auxiliary power;
(vi) Protection, control and metering systems; and
(vii) An integrated cooling system.

Due to the long lead time associated with the procurement of the portable substation, this project is being proposed as a three-year multi-year project. Engineering design and procurement will be completed by the end of 2028, with delivery, installation, testing and commissioning of the new unit to be completed in 2029.

Additional information on this project is provided in report *2.3 Portable Substation* filed with the Application.

PROJECT BUDGET

The budget for the *Portable Substation* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed from 2027 to 2029 for the *Portable Substation* project.

Table 1 Portable Substation Project Cost ($000s)				
Cost Category	2027	2028	2029	Total
Material	918	3,744	4,775	9,437
Labour - Internal	-	-	52	52
Labour – Contract	-	-	-	-
Engineering	52	68	118	238
Other	20	82	104	206
Total	$990	$3,894	$5,049	$9,933

Proposed expenditures for the *Portable Substation* project are $990,000 in 2027, $3,894,000 in 2028, and $5,049,000 in 2029 for a total project budget of $9,933,000.

ASSET BACKGROUND

Newfoundland Power relies on portable substations as a critical component of emergency response, substation maintenance, and substation capital project execution. Portable substations enable the Company to maintain service to customers when substation equipment such as power transformers are removed from service for planned maintenance, capital projects, or following in-service equipment failures.

Newfoundland Power currently has an inventory of four portable substations. These portable substations operate at different voltages and are therefore capable of providing emergency backup for different power transformers. The Company also has access to one portable substation from Newfoundland and Labrador Hydro through an equipment sharing agreement.

Increasing usage of the Company's portable substation inventory is forecast as a result of an aging power transformer fleet, extended deployment durations following in-service failures, and growing demands associated with planned maintenance and capital programs. Collectively, these factors have increased the likelihood that portable substations will be deployed for planned and unplanned purposes. This reduces portable inventory availability and constrains the Company's ability to respond effectively to emergency events.

In response to these risks, Newfoundland Power has assessed the adequacy of its existing portable substation inventory of four portable substations and determined that the procurement of an additional portable substation is required to support system reliability over the long term.

ASSESSMENT OF ALTERNATIVES

Three alternatives were assessed to respond to the increased risk to the adequacy of Newfoundland Power's portable substation fleet: (i) maintain existing portable substation inventory; (ii) increase spare transformer inventory; (iii) procure an additional portable substation. The alternatives were assessed from the perspective of risk mitigation.

The procurement of an additional portable substation will address the increased probability of insufficient emergency response capacity. This alternative directly mitigates the risks associated with an aging transformer fleet, increasing transformer failure frequency, extended procurement lead times, and increasing demands placed on portable substations by planned maintenance and capital programs. Maintaining the existing portable substation inventory without additional investment would require the Company to accept an increasing level of operational and reliability risk. Increasing the spare transformer inventory provides a medium to long term solution following a transformer failure but does not eliminate the need for a portable substation during the initial emergency response period.

The addition of a new portable substation is therefore the recommended alternative. For additional information on the assessment of alternatives completed, see report *2.3 Portable Substation,* section *5.0 Assessment of Alternatives* filed with the Application.

RISK ASSESSMENT

The *Portable Substation* project will mitigate risks to the delivery of reliable service to customers.

The primary risk associated with Newfoundland Power's existing portable substation inventory is the potential for insufficient emergency response capability resulting from limited portable substation availability. Increasing system pressures on the Company's portable substation inventory are caused by an aging power transformer fleet, extended deployment durations following in-service failures, and growing demands associated with planned maintenance and capital programs. Collectively, these factors have increased the likelihood that portable substations will be deployed for planned and unplanned purposes. This reduces portable inventory availability and constrains the Company's ability to respond effectively to additional emergency events.

Portable substations are a critical component of the Company's emergency response to transformer failures. When a portable substation is readily available, service can typically be restored within 24 to 36 hours. However, where a suitable portable substation is not immediately available, restoration may be delayed by several days due to the time required to uninstall, transport, and commission a unit that is in service at another site or because no technically compatible unit is available.

The likelihood of insufficient emergency response capacity is further increased by the duration that a portable substation may remain deployed following a transformer failure. Where a spare power transformer is not immediately available, or where repairs or replacement are delayed due to extended procurement lead times, a portable substation may be required to remain in service for extended periods. In some cases, deployments may last as long as 18 to 36 months.

Extended deployments materially reduce the number of portable substations available out of the Company's existing inventory of four units to respond to subsequent failures.

Maintaining an adequate portable substation inventory reduces exposure to prolonged customer outages and mitigates the risk associated with deferred maintenance and capital work. By limiting outage durations and supporting execution of planned programs, this contributes to the delivery of reliable service to customers.

Table 2 summarizes the risk assessment for the *Portable Substation* project.

Table 2
Portable Substation Project Risk Assessment Summary

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

Overall, failing to complete the *Portable Substation project* poses a High (20) risk to the delivery of least cost, reliable, safe, and environmentally responsible service to customers. Action is required beginning in 2027 to mitigate these risks for customers.

JUSTIFICATION

The *Portable Substation* project is required to provide reliable service to customers at the lowest possible cost. Purchasing an additional portable substation will enhance Newfoundland Power's ability to respond to equipment failures, reduces 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 with an aging transformer fleet and the extended timelines now required to procure replacement transformers.

Title:	**Blaketown Substation Refurbishment and Modernization**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$528,000 in 2027; $5,700,000 in 2028**

PROJECT DESCRIPTION

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

The proposed 2027 and 2028 scope of work for the *Blaketown Substation Refurbishment and Modernization* project includes:

(i) Constructing a new control building to replace existing building;
(ii) Constructing new spill containment foundations for existing transformers;
(iii) Replacing deteriorated 138 kV and 66 kV switches;
(iv) Replacing one oil-filled 25 kV breaker;
(v) Replacing obsolete electromechanical relays with new digital relays;
(vi) Installing new security cameras; and
(vii) Replacing the deteriorated cable trench.

Engineering design and procurement of long lead time equipment will be completed in 2027. Construction will begin in the second quarter of 2028 and will be completed in the fourth quarter of 2028. Commissioning of the substation will be completed during the fourth quarter of 2028.

Additional information on this project is provided in Appendix A of report *2.1 2027 Substation Refurbishment and Modernization* filed with the Application.

PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2027 and 2028 for the Blaketown *Substation Refurbishment and Modernization* project.

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

Cost Category	2027	2028	Total
Material	123	4,561	4,684
Labour – Internal	51	380	431
Labour - Contract	-	-	-
Engineering	340	539	879
Other	14	220	234
Total	$528	$5,700	$6,228

Proposed expenditures for the *Blaketown Substation Refurbishment and Modernization* project are $528,000 in 2027 and $5,700,000 in 2028 for a total project budget of $6,228,000.

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 14 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.[22] Continued execution of the *Substation Refurbishment and Modernization Plan* is therefore necessary to replace obsolete and deteriorated equipment and infrastructure.

In 2027, Newfoundland Power is proposing to refurbish and modernize BLK Substation. The substation was constructed in 1967 as a transmission and 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) a 25 kV oil

[22] For details of the assessment, see the *2027 Capital Budget Application,* report *2.1 2027 Substation Refurbishment and Modernization,* section *2.2*.

filled breaker; (ii) 138 kV and 66kV switches; (iii) protection and control relays; and (iv) the control building and cable trench. Additionally, two transformer spill containment foundations 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 BLK Substation, the number of components requiring preventative and corrective maintenance at this time justifies the requirement to refurbish and modernize the substation in 2027 and 2028. Deferral of the *Blaketown Substation Refurbishment and Modernization* project would increase the risk that some components will fail in service, which would result in outages to approximately 4,090 customers in the Blaketown area and approximately 5,970 customers serviced from radial transmission lines 55L and 94L. Deferring this project is therefore not a viable alternative.

RISK ASSESSMENT

The *Blaketown Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to customers in the Blaketown and surrounding areas.

BLK Substation provides service to approximately 4,090 customers in the Blaketown area and 5,970 customers serviced from radial transmission lines 55L and 94L. Equipment failure in the BLK Substation exposes all customers supplied by BLK 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.

One circuit breaker and 12 switches require replacement based on their age and mechanical condition.[23] The protection and control system includes obsolete equipment that is no longer industry standard and requires replacement. Modernization of these systems is required to reduce operational risk and support reliable fault detection, isolation, and restoration.

Both power transformers in BLK 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.

The existing control building, constructed in 1967, is in a deteriorated condition and no longer provides a suitable environment for housing critical protection, control, and communications equipment. The condition of the building increases the risk of equipment exposure to moisture

[23] Due to the four 66 kV transmission lines terminating in the 66 kV structure, replacement of the switches is a complex activity, and undertaking this work in coordination with the project allows for improved efficiency and reduced operational disruption.

and environmental conditions, which could result in equipment damage or failure. The cable trench infrastructure at BLK Substation is in advanced deteriorated condition. The trench covers exhibit widespread corrosion, section thinning, and misalignment, reducing mechanical protection for critical power, protection, control, and communications cables. Failure of the cable trench system could result in damage to critical cables and extended outage durations.

Given the condition assessment of BLK Substation, the probability of failure is likely. Table 2 summarizes the risk assessment for the *Blaketown Substation Refurbishment and Modernization* project.

Table 2
Blaketown Substation Refurbishment and Modernization
Project Risk Assessment Summary

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

Overall, the condition of BLK Substation poses a High (20) risk to the delivery of reliable, safe, and environmentally responsible service to customers. Action is required in 2027 and 2028 to mitigate these risks for customers.

JUSTIFICATION

The *Blaketown 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 Blaketown and surrounding area.

Title:	**LAU-T1 Power Transformer Replacement**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$99,000 in 2027; $3,186,000 in 2028**

PROJECT DESCRIPTION

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

The proposed 2027 and 2028 scope of work for the *LAU-T1 Power Transformer Replacement* project includes:

(i) Remove existing power transformer LAU-T1; and
(ii) Install and commission new 10/13.3/16.6 MVA, 66-12.5/25 kV power transformer including new spill containment foundation.

LAU Substation was constructed in 1975 as both a distribution and transmission substation. This substation is supplied by Newfoundland Power 66kV Transmission Lines 302L from Salt Pond ("SPO") Substation and 305L from Webber's Cove ("WBC") Substation. LAU is also the 66kV interconnection point to Newind's 66kV Transmission Line 901E to Ryan's Hill Substation and Wind Generation Site. One 13.3 MVA distribution power transformer, LAU-T1, supplies two 12.5kV distribution feeders, serving approximately 700 customers in the Town of St. Lawrence.

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

For additional details, see the *2027 Capital Budget Application,* report *2.2 Substation Power Transformer Strategy*.

PROJECT BUDGET

The budget of the *LAU-T1 Power Transformer replacement* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2027 and 2028 for the *LAU-T1 Power Transformer replacement* project.

Table 1
LAU-T1 Power Transformer Replacement
Project Budget
($000s)

Cost Category	2027	2028	Total
Material	-	2,854	2,854
Labour - Internal	-	105	105
Labour - Contract	-	-	-
Engineering	91	124	215
Other	8	103	111
Total	$99	$3,186	$3,285

Proposed expenditures for the *LAU-T1 Power Transformer replacement* project are $99,000 in 2027, and $3,186,000 in 2028 for a total project budget of $3,285,000.

ASSET BACKGROUND

LAU-T1 is a 50-year-old, 13.3 MVA 66-12.5kV power transformer manufactured by Federal Pioneer. This transformer has remained at LAU since its original installation in 1976.

All power transformers undergo regular maintenance on a 12-year cycle. LAU-T1 has undergone annual oil sampling since at least 2002. The transformer last had full maintenance in October 2025.

Results of oil samples from the on-load tap changer of LAU-T1 have indicated deterioration of tap changer condition. Tap changer Activity Signature Analysis™ ("TASA") completed in October 2024 produced a Code 3 assessment score, indicating moderately abnormal dissipation of energy associated with partial discharge, heating, and abnormal arcing.[24] While subsequent oil sampling in November 2025 showed no abnormal dissipation of energy following refurbishment and oil replacement, this result is not considered indicative of sustained improvement due to the age of the unit and the absence of a major tap changer overhaul since 2017.

ASSESSMENT OF ALTERNATIVES

Three alternatives were assessed to address the condition of power transformer LAU-T1: (i) Condition Based Monitoring; (ii) Remove and Repair; and (iii) Replace Power Transformer.

[24] Results of oil sampling are presented as Tapchanger Activity Signature AnalysisTM ("TASA") provided by TJ/H2b Analytic Services Incorporated ("T2/H2b"). For details, see the *2027 Capital Budget Application*, report *2.2 Substation Power Transformer Strategy*, Appendix A.

The assessment of alternatives determined that Alternative 3, Replace Power Transformer is the only viable alternative to address risks associated with the failure of power transformer LAU-T1 as a result of its condition and age.

For additional information on the assessment of alternatives, see report *2.2 Substation Power Transformer Strategy*, Appendix A, filed with the Application.

RISK ASSESSMENT

The *LAU-T1 Power Transformer Replacement* project will mitigate risks to the delivery of reliable service to approximately 700 customers in the St. Lawrence area.

In the case of a LAU-T1 failure there are no offloading capabilities available to supply the existing peak load of LAU Substation. System load forecasts indicate that 7.56 MVA would be exposed to an outage.[25] A portable substation or a spare transformer would need to be installed in the event of a LAU-T1 failure.

Newfoundland Power has three portable substations and three spare power transformers that can be used for emergency response to an in-service failure of LAU-T1. Failure of LAU-T1 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. Current power transformer delivery times are estimated between 24 and 36 months.

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

Table 2 summarizes the risk assessment for the *LAU-T1 Power Transformer replacement* project.

Table 2
LAU-T1 Power Transformer Replacement Project
Risk Assessment Summary

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

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

[25] A max peak load of 7.56 MVA is being forecasted over the next five years at LAU Substation.

JUSTIFICATION

The *LAU-T1 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 approximately 700 customers in the Town of St. Lawrence.

Title:	**HAR-T1 Power Transformer Replacement**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$75,000 in 2027; $71,000 in 2028; $2,758,000 in 2029**

PROJECT DESCRIPTION

The *HAR-T1 Power Transformer Replacement* project involves the replacement of the Harmon ("HAR") Substation power transformer HAR-T1.

The proposed 2027, 2028, and 2029 scope of work for the *HAR-T1 Power Transformer Replacement* project includes:

(i) Remove existing power transformer HAR-T1; and
(ii) Install and commission new 15/20/25 MVA, 66-12.5/25 kV power transformer including new spill containment foundation.

HAR Substation was constructed in 1968 as both a distribution and transmission substation. This substation is supplied by Newfoundland Power 66kV Transmission Lines 405L from Stephenville Gas Turbine ("STV") Substation and 406L from Gallants ("GAL") Substation. One 11.125 MVA distribution power transformer, HAR-T1, supplies two 12.5kV distribution feeders, serving approximately 1,400 customers in the Stephenville area.

Engineering design and procurement of the new power transformer will be completed in 2027 and 2028. Delivery, installation, testing, and commissioning of the new power transformer will be completed in 2029.

For additional details, see the *2027 Capital Budget Application,* report *2.2 Substation Power Transformer Strategy*.

PROJECT BUDGET

The budget of the *HAR-T1 Power Transformer Replacement* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2027, 2028, and 2029 for the *HAR-T1 Power Transformer Replacement* project.

Table 1
HAR-T1 Power Transformer Replacement
Project Budget
($000s)

Cost Category	2027	2028	2029	Total
Material	-	-	2,468	2,468
Labour - Internal	-	-	108	108
Labour - Contract	-	-	-	-
Engineering	69	39	115	223
Other	6	31	67	104
Total	$75	$71	$2,758	$2,904

Proposed expenditures for the *HAR-T1 Power Transformer Replacement* project are $75,000 in 2027, $71,000 in 2028, and $2,758,000 for a total project budget of $2,904,000.

ASSET BACKGROUND

HAR-T1 is a 57-year-old, 11.125 MVA, 66-12.5 kV power transformer manufactured by General Electric. This transformer has remained at HAR since its original installation in 1969.

All power transformers undergo regular maintenance on a 12-year cycle. HAR-T1 has undergone annual oil sampling since at least 2003. The transformer last had full maintenance in September 2010.

In November 2025, oil samples were taken from HAR-T1 as part of routine testing. The Transformer Condition Assessments™ ("TCA") completed by TJ|H2b Analytic Services Incorporated ("TJ|H2b"), produced a Code 2 assessment score in which heating is indicated. This is a sign of the deteriorating health of the power transformer. The Electric Power Research Institute ("EPRI") Power Transformer Expert System ("PTX") software indicates that the Normal Degradation Index of HAR-T1 exceeds the 0.60 threshold, which highly correlates with units that have insulating paper no longer capable of providing reliable service.[26]

ASSESSMENT OF ALTERNATIVES

Three alternatives were assessed to address the condition of power transformer HAR-T1: (i) Condition-Based Monitoring; (ii) Remove and Repair; and (iii) Replace Power Transformer.

[26] For details, see the *2027 Capital Budget Application*, report *2.2 Substation Power Transformer Strategy*, Appendix C.

The assessment of alternatives determined that Alternative 3, Replace Power Transformer is the only viable alternative to address risks associated with the failure of power transformer HAR-T1 as a result of its condition and age.

For additional information on the assessment of alternatives, see report *2.2 Substation Power Transformer Strategy*, Appendix C, filed with the Application.

RISK ASSESSMENT

The *HAR-T1 Power Transformer Replacement* project will mitigate risks to the supply of reliable power to approximately 1,400 customers in the Stephenville area.

In the case of a HAR-T1 failure, offloading capabilities can partially supply the existing peak load of HAR Substation. System load forecasts indicate that 6.28 MVA would be exposed to an outage.[27] A portable substation or a spare transformer would need to be installed in the event of a HAR-T1 failure.

Newfoundland Power has three portable substations and two spare power transformers that can be used for emergency response to an in-service failure of HAR-T1. Failure of HAR-T1 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. Current power transformer delivery times are estimated between 24 and 36 months.

Overall, an increased probability of power transformer failures, 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 power transformers 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 *HAR-T1 Power Transformer Replacement* project.

Table 2
HAR-T1 Power Transformer Replacement Project
Risk Assessment Summary

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

Overall, the condition of power transformer HAR-T1 poses a Medium-High (16) risk to the delivery of reliable, safe, and environmentally responsible service to customers. Action is required in 2027, 2028, and 2029 to mitigate these risks.

[27] A maximum peak load of 15.9 MVA is being forecasted over the next ten years at HAR Substation.

JUSTIFICATION

The *HAR-T1 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 approximately 1,400 customers in the Stephenville area.

Title:	**RRD-T3 Power Transformer Replacement**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$66,000 in 2027; $64,000 in 2028; $2,565,000**

PROJECT DESCRIPTION

The *RRD-T3 Power Transformer Replacement* project involves the replacement of the Ridge Road ("RRD") Substation power transformer RRD-T3.

The proposed 2027, 2028, and 2029 scope of work for the *RRD-T3 Power Transformer Replacement* project includes:

(i) Remove existing power transformer RRD-T3; and
(ii) Install and commission new 20 MVA, 66-12.5 kV power transformer including new spill containment foundation.

RRD Substation was constructed in 1960 as both a distribution and transmission substation. This substation is supplied by Newfoundland Power 66kV Transmission Lines 30L from King's Bridge ("KBR") Substation, 32L from Oxen Pond ("OXP") Substation and 67L from OXP Substation. Two 20 MVA distribution power transformers, RRD-T2 and RRD-T3, supply eight 12.5kV distribution feeders, serving over 4,400 customers in the City of St. John's.

Engineering design and procurement of the new power transformer will be completed in 2027 and 2028. Delivery, installation, testing, and commissioning of the new power transformer will be completed in 2029.

For additional details, see the *2027 Capital Budget Application,* report *2.2 Substation Power Transformer Strategy*.

PROJECT BUDGET

The budget of the *RRD-T3 Power Transformer Replacement* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2027, 2028 and 2029 for the *RRD-T3 Power Transformer Replacement* project.

Table 1
RRD-T3 Power Transformer Replacement
Project Budget
($000s)

Cost Category	2027	2028	2029	Total
Material	-	-	2,404	2,404
Labour - Internal	-	-	5	5
Labour - Contract	-	-	-	-
Engineering	61	33	95	189
Other	5	31	61	97
Total	$66	$64	$2,565	$2,695

Proposed expenditures for the *RRD-T3 Power Transformer Replacement* project are $66,000 in 2027, $64,000 in 2028, and $2,565,000 in 2029 for a total project budget of $2,695,000.

ASSET BACKGROUND

RRD-T3 is a 51-year-old, 20 MVA, 66-12.5 kV power transformer manufactured by Ferranti Packard. This transformer has remained at RRD since its original installation in 1977.

All power transformers undergo regular maintenance on a 12-year cycle. RRD-T3 has undergone annual oil sampling since at least 2002. The transformer last had full maintenance in November 2020.

In January 2025, oil samples were taken from RRD-T3 as part of routine testing. The Transformer Condition Assessments™ ("TCA") completed by TJ|H2b Analytic Services Incorporated, indicated that the mechanical strength of paper for RRD-T3 is reduced to 70% tensile strength. The estimated degree of polymerization ("DP") is 661.[28] This information indicates that the paper insulation inside of the transformer is deteriorating. While the transformer has not shown signs of internal arcing and high temperature heating, the TCAs completed on RRD-T3 have consistently indicated the deterioration of the paper insulation. These are signs of the deteriorating health of the power transformer.

28 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.

ASSESSMENT OF ALTERNATIVES

Three alternatives were assessed to address the condition of power transformer RRD-T3: (i) Condition-Based Monitoring; (ii) Remove and Repair; and (iii) Replace Power Transformer.

The assessment of alternatives determined that Alternative 3, Replace Power Transformer is the only viable alternative to address risks associated with the failure of power transformer RRD-T3 as a result of its condition and age.

For additional information on the assessment of alternatives, see report *2.2 Substation Power Transformer Strategy*, Appendix D, filed with the Application.

RISK ASSESSMENT

The *RRD-T3 Power Transformer Replacement* project will mitigate risks to the supply of reliable power to over 4,400 customers in the City of St. John's.

In the event of a RRD-T3 failure, offloading capabilities can partially supply the existing peak load of RRD-T3, while 3.1 MVA of load would be exposed to an outage. There is one spare transformer available that can be installed for the medium-term replacement of RRD-T3. 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.

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

Table 2 summarizes the risk assessment for the *RRD-T3 Power Transformer Replacement* project.

Table 2
RRD-T3 Power Transformer Replacement Project
Risk Assessment Summary

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

Overall, the condition of power transformer RRB-T3 poses a Medium-High (16) risk to the delivery of reliable, safe, and environmentally responsible service to customers. Action is required in 2027, 2028 and 2029 to mitigate these risks.

JUSTIFICATION

The *RRD-T3 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 over 4,400 customers in the City of St. John's.

Title:	**LBK-T1 Power Transformer Replacement**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$73,000 in 2027; $86,000 in 2028; $2,175,000 in 2029**

PROJECT DESCRIPTION

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

The proposed 2027, 2028 and 2029 scope of work for the *LBK-T1 Power Transformer Replacement* project includes:

(i) Remove existing power transformer LBK-T1; and,
(ii) Install and commission new 5/6.7/8.3 MVA 66-2.4kV power transformer at LBK Substation including new spill containment foundation.

LBK Substation was constructed in 1966 as a generation substation for the Lookout Brook Hydro Plant (the "Plant"). The Plant's 3 MVA generator G3 and 2.889 MVA generator G4 supply the LBK Substation. A 7.5 MVA generation power transformer interconnects the generating plant to Newfoundland Power's 66kV Transmission Line 403L to Robinsons ("ROB") Substation.

Engineering design and procurement of the new power transformer will be completed in 2027 and 2028. Delivery, installation, testing, and commissioning of the new power transformer will be completed in 2029.

For additional details, see the *2027 Capital Budget Application,* report *2.2 Substation Power Transformer Strategy*.

PROJECT BUDGET

The budget of the *LBK-T1 Power Transformer Replacement* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2027, 2028 and 2029 for the *LBK-T1 Power Transformer Replacement* project.

Table 1
LBK-T1 Power Transformer Replacement
Project Budget
($000s)

Cost Category	2027	2028	2029	Total
Material	-	-	2,025	2,025
Labour – Internal	-	-	5	5
Labour - Contract	-	-	-	-
Engineering	68	36	107	211
Other	5	50	38	93
Total	$73	$86	$2,175	$2,334

Proposed expenditures for the *LBK-T1 Power Transformer Replacement* project are $73,000 in 2027, $86,000 in 2028, and $2,175,000 in 2028 for a total project budget of $2,334,000.

ASSET BACKGROUND

LBK-T1 is a 64-year-old, 7.5 MVA 66/33-2.4kV power transformer manufactured by English Electric. This transformer was installed in LBK Substation in 1997 after being relocated from Grand Falls Substation.

All power transformers undergo regular maintenance on a 12-year cycle. LBK-T1 has undergone annual oil sampling since at least 2002. The transformer last had full maintenance in August 2009.

In November 2025, oil samples were taken from LBK-T1 as part of routine testing. The Transformer Condition Assessments™ ("TCA") completed by TJ|H2b Analytic Services Incorporated, produced a Code 3 assessment in which arcing was indicated. This is a sign of the deteriorating health of the power transformer. The Electrical Power Research Institute ("EPRI") Power Transformer Expert System ("PTX") software indicates a Normal Degradation Index greater than 0.25, which warrants further scrutiny.[29]

ASSESSMENT OF ALTERNATIVES

Three alternatives were assessed to address the condition of power transformer LBK-T1: (i) Condition Based Monitoring; (ii) Remove and Repair; and (iii) Replace Power Transformer.

The assessment of alternatives determined that Alternative 3, Replace Power Transformer is the only viable alternative to address risks associated with the failure of power transformer LBK-T1 as a result of its condition and age.

29 For details, see the *2027 Capital Budget Application, report 2.2 Substation Power Transformer Strategy*, Appendix B.

As part of the assessment of alternatives, Newfoundland Power revisited the lifecycle cost analysis completed for the Plant as part of the *2024 Capital Budget Application*.[30] The updated lifecycle cost analysis to account for the advancement of substation capital investment determined that it remains economically viable to complete the work.

For additional information on the assessment of alternatives, see report *2.2 Substation Power Transformer Strategy*, Appendix B, filed with the Application.

RISK ASSESSMENT

The *LBK-T1 Power Transformer Replacement* project will mitigate risks to the supply of 5.889 MVA of generation to customers on the island integrated electricity system. Failure of LBK-T1 would result in an unplanned, long-term installation of a portable substation to keep the Plant operational until a replacement can be procured. There are no spare power transformers that can be used. Current power transformer delivery times are estimated to be between 24 and 36 months.

Overall, an increased probability of power transformer failure due to the transformer's condition, 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 could also leave 5.889 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. Additionally, extended transformer delivery times could further exacerbate these risks.

Table 2 summarizes the risk assessment for the *LBK-T1 Power Transformer Replacement* project.

Table 2
LBK-T1 Power Transformer Replacement Project
Risk Assessment Summary

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

Overall, the condition of power transformer LBK-T1 poses a Medium-High (16) risk to the delivery of reliable, safe, and environmentally responsible service to customers. Action is required in 2027, 2028 and 2029 to mitigate these risks.

JUSTIFICATION

The *LBK-T1 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 7.5 MVA of generation from the Lookout Brook Hydro Plant.

30 See report *4.1 Lookout Brook Hydro Plant Refurbishment* filed as part of Newfoundland Power's *2024 Capital Budget Application*.

Title:	**Rattling Brook Substation Refurbishment & Modernization**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$74,000 in 2027; $1,426,000 in 2028**

PROJECT DESCRIPTION

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

The proposed 2027 and 2028 scope of work for the *Rattling Brook Substation Refurbishment and Modernization* project includes:

(i) Remove existing deteriorating 66 kV wood pole bus arrangement and construct a new 66 kV steel pole bus structure as replacement;
(ii) Remove existing 6.9 kV deteriorated wooden crossarms and install fiberglass crossarms in their place on the new steel pole structures;
(iii) Remove existing disconnect switches and install new disconnect switches as replacement;
(iv) Remove existing 12.5 kV obsolete Nulec recloser and install a modern recloser as replacement.

Engineering design and procurement of long lead time equipment will be completed in 2027. Construction will begin in the second quarter of 2028 and will be completed in the fourth quarter of 2028. Commissioning will be completed during the fourth quarter of 2028.

Additional information on this project is provided in Appendix B of report *2.1 2027 Substation Refurbishment and Modernization* filed with the Application.

PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2027 and 2028 for the *Rattling Brook Substation Refurbishment and Modernization* project.

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

Cost Category	2027	2028	Total
Material	11	1,066	1,077
Labour – Internal	-	157	157
Labour - Contract	-	-	-
Engineering	59	112	171
Other	4	91	95
Total	$74	$1,426	$1,500

Proposed expenditures for the *Rattling Brook Substation Refurbishment and Modernization* project are $74,000 in 2027 and $1,426,000 in 2028 for a total project budget of $1,500,000.

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 14 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 2027, Newfoundland Power is proposing to refurbish and modernize RBK Substation. The substation was constructed in 1959 as a generation, transmission, and distribution substation. A condition assessment determined the substation contains deteriorated and obsolete equipment.

31 For details of the assessment, see the *2027 Capital Budget Application,* report *2.1 2027 Substation Refurbishment and Modernization,* section *2.2*.

Several pieces of equipment are at end of life, including: (i) the 66 kV wood pole structure; (ii) disconnect switches; and (iii) a 12.5 kV recloser.

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 RBK Substation, the number of components requiring preventative and corrective maintenance at this time justifies the requirement to refurbish and modernize the substation in 2027 and 2028. Deferral of the RBK Substation refurbishment and modernization project would increase the risk that some components will fail in service, which could result in outages to approximately 780 customers in the Norris Arm area. Deferring this project is therefore not a viable alternative.

RISK ASSESSMENT

The *Rattling Brook Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to customers in the Norris Arm area and support continued delivery of generation from the Rattling Brook Hydro Plant.

Failure of equipment on the 66 kV bus could result in loss of supply from the plant generators and expose approximately 780 customers in the Norris Arm area to prolonged outages. Outage duration would depend on the nature of the failure and restoration requirements.

RBK Substation contains infrastructure that is deteriorating, obsolete, or approaching the end of its expected service life. Condition assessments identified deterioration of the existing 66 kV wood pole bus structures, including deep splits and checks, which increase the likelihood of structural failure and associated outages.

The existing 66 kV disconnect switches associated with RBK-T1 and RBK-T2 were installed approximately 28 years ago and are approaching the typical service life for this equipment. Replacement of these switches as part of the proposed work will reduce the risk of equipment failure and support continued reliable operation of the substation.

In addition, the existing 12.5 kV Nulec recloser installed on the RBK-01 feeder is obsolete and no longer supported by the manufacturer. Similar units have demonstrated increased failure risk due to age and limited parts availability.

Given the condition assessment of RBK Substation, the probability of failure is likely.

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

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

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

JUSTIFICATION

The *Rattling Brook Substation Refurbishment and Modernization* project is required to provide reliable service to customers at the lowest possible cost. Addressing deteriorated and obsolete equipment identified through an engineering assessment will support the continued delivery of reliable service to approximately 780 customers in the Norris Arm area.

Title:	**Mobile Plant Substation Refurbishment & Modernization**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$299,000 in 2027; $925,000 in 2028**

PROJECT DESCRIPTION

The *Mobile Plant Substation Refurbishment and Modernization* project involves the replacement and modernization of deteriorated equipment at Mobile Plant ("MOP") Substation located along the southern shore. The equipment requiring replacement was identified through inspections, engineering assessments and operating experience.

The proposed 2027 and 2028 scope of work for the *Mobile Plant Substation Refurbishment and Modernization* project includes:

(i) Expand the existing yard;
(ii) Upgrade and extend the ground grid;
(iii) Remove existing non-standard 66 kV wood pole bus arrangement and construct a standard steel pole bus;
(iv) Remove existing 6.9 kV wood pole structures and deteriorated crossarms and install steel pole structures aligned with new MOP-T1 replacement transformer footprint;
(v) Install new disconnect switches on the 66 kV and 6.9 kV systems;
(vi) Install 66 kV fused protection for MOP-T1; and
(vii) Install a new substation fence, access gate, and safety signage.

Engineering design and procurement of long lead time equipment will be completed in 2027. Construction will begin in the second quarter of 2028 and will be completed in the fourth quarter of 2028. Commissioning will be completed during the fourth quarter of 2028.

Additional information on this project is provided in Appendix C of report *2.1 2027 Substation Refurbishment and Modernization* filed with the Application.

PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2027 and 2028 for the *Mobile Plant Substation Refurbishment and Modernization* project.

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

Cost Category	2027	2028	Total
Material	166	555	721
Labour – Internal	8	99	107
Labour - Contract	-	-	-
Engineering	121	175	296
Other	4	96	100
Total	$299	$925	$1,224

Proposed expenditures for the *Mobile Plant Substation Refurbishment and Modernization* project are $299,000 in 2027 and $925,000 in 2028 for a total project budget of $1,224,000.

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 14 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.[32] Continued execution of the *Substation Refurbishment and Modernization Plan* is therefore necessary to replace obsolete and deteriorated equipment and infrastructure.

In 2027, Newfoundland Power is proposing to refurbish and modernize MOP Substation. The substation was constructed in 1951 as a generation substation. The replacement of MOP-T1 was approved as part of Newfoundland Power's *2026 Capital Budget Application*.[33] The

32 For details of the assessment, see the *2027 Capital Budget Application,* report *2.1 2027 Substation Refurbishment and Modernization,* section *2.2*.

33 For details, see Newfoundland Power's *2026 Capital Budget Application* report *2.2 Substation Power Transformer Strategy,* Appendix E, section 4.0.

refurbishment of MOP Substation was incorporated in the updated lifecycle cost analysis for the replacement of MOP-T1, and it was determined that it remains economically viable.

The new power transformer has a larger physical footprint than the existing unit and cannot be accommodated within the existing yard configuration. As a result, modifications to the existing 66 kV and 6.9 kV infrastructure are required to accommodate installation of the replacement transformer. Upgrades to the transformer containment foundation, bus structures, grounding grid, and yard configuration are also required to align the installation with current Newfoundland Power practices.

ASSESSMENT OF ALTERNATIVES

The modifications proposed at MOP Substation are required to support installation of the approved replacement of power transformer MOP-T1.

Alternative options, including retaining existing infrastructure and deferring the required modifications, were considered. However, the existing infrastructure cannot accommodate the larger physical footprint of the approved MOP-T1 replacement power transformer within current yard limits.

Deferral of the *Mobile Plant Substation Refurbishment and Modernization* project would prevent the installation of the approved MOP-T1 replacement power transformer and increase the risk of a potential loss of supply from the MOP generators due to a failure of the deteriorated power transformer MOP-T1. This project will facilitate installation of the approved MOP-T1 replacement power transformer and support continued reliable plant and grid operations.

RISK ASSESSMENT

The *Mobile Plant Substation Refurbishment and Modernization* project will mitigate risks to the continued delivery of approximately 11 MVA of generation from the Mobile Plant to Newfoundland Power's transmission system. Replacement of MOP-T1 power transformer was approved as part of Newfoundland Power's *2026 Capital Budget Application*. The proposed *Mobile Plant Substation Refurbishment and Modernization* project represents the remaining infrastructure work required to enable installation of the approved replacement of MOP-T1.

The approved MOP-T1 replacement transformer has a larger physical footprint than the existing unit and cannot be accommodated within existing yard clearances. As a result, the existing 66 kV wood pole bus arrangement and 6.9 kV infrastructure must be reconstructed to maintain required electrical clearances and support installation of the replacement transformer.

Retaining the existing bus structures would result in reduced phase-to-phase and phase-to-ground clearances, increasing the risk of flashover and potential personnel exposure during construction, maintenance, and emergency response activities. These conditions would not align with Newfoundland Power standards and could delay installation and commissioning of the approved MOP-T1 replacement transformer.

In addition, prolonged outages of the Mobile Hydro Plant resulting from substation infrastructure limitations could increase reliance on alternative generation sources and place additional stress on the electrical system during periods of peak demand.

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

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

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

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

JUSTIFICATION

The *Mobile Plant Substation Refurbishment and Modernization* project is required to enable installation of the MOP-T1 replacement power transformer approved as part of Newfoundland Power's *2026 Capital Budget Application*. These upgrades will support continued delivery of approximately 11 MVA of generation from the Mobile Hydro Plant while maintaining safe and reliable operation of the substation.

Title:	**Substation Replacements Due to In-Service Failures**
Asset Class:	**Substations**
Category:	**Program**
Investment Classification:	**Renewal**
Budget:	**$4,613,000**

PROGRAM DESCRIPTION

The *Substation Replacements Due to In-Service Failures* program involves replacing substation equipment that has failed for example, as a result of storm damage, lightning strikes, vandalism, electrical or mechanical failure, corrosion damage, technical obsolescence or failure during maintenance testing, or equipment that is at risk of imminent failure. 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.[34]

Table 1 provides the annual expenditures for the *Substation Replacements Due to In-Service Failures* program from 2022 to 2026.

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

Year	2022	2023	2024	2025	2026F
Total	4,562	5,101	5,841	3,914	4,733
Adjusted Cost[1]	5,190	4,467[2]	4,054[3]	4,036	4,733

1 2026 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.

34 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 $4.5 million from 2022 to 2026 when adjusted as described above.

Table 2 provides a breakdown of expenditures proposed for 2027 for the *Substation Replacements Due to In-Service Failures* program.

Table 2
Substation Replacements Due to In-Service Failures Program
2027 Budget
($000s)

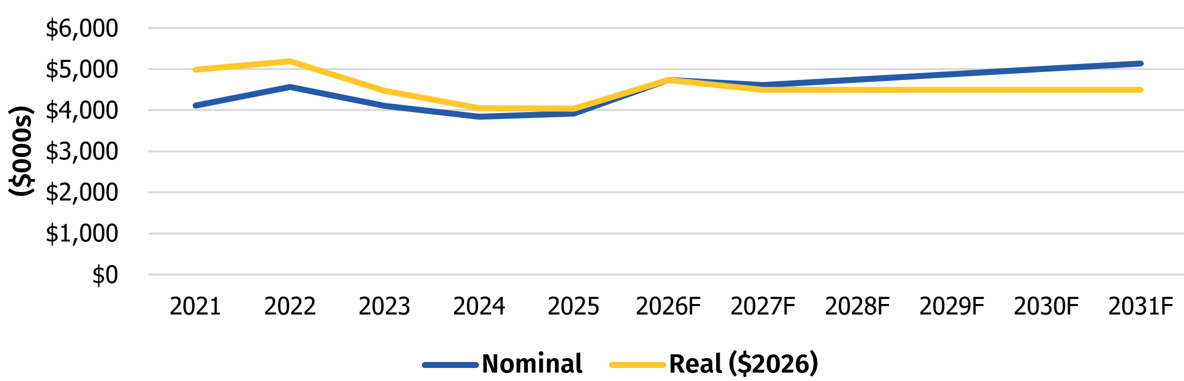
Cost Category	2027
Material	2,558
Labour – Internal	1,342
Labour – Contract	4
Engineering	418
Other	291
Total	$4,613

Proposed expenditures for the *Substation Replacements Due to In-Service Failures* program total $4,613,000 for 2027.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Substation Replacements Due to In-Service Failures* program from 2021 to 2031.[35]

Figure 1
Substation Replacements Due to In-Service Failures
Program Expenditures
(2021-2031F)



[35] For forecast annual expenditures for the *Substation Replacements Due to In-Service Failures* program, see the *2027-2031 Capital Plan,* Appendix A, page A-3. Historical expenditures have been adjusted for the purchases described in Table 1.

Annual expenditures under the *Substation Replacements Due to In-Service Failures* program averaged approximately $4.2 million from 2022 to 2026, or approximately $4.5 million when adjusted for inflation. Annual expenditures are forecast to average approximately $4.9 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. Four power transformers were replaced or repaired under this program from 2021 to 2025.[36] 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 additional information on the age and condition of substation assets, see report *2.1 2027 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 risk of imminent 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.

[36] 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.

Individual substations provide service to an average of approximately 2,400 customers, with the largest substation providing service to over 11,000 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 Bonavista Substation in 2018 resulted in 3.7 million customer outage minutes. Equipment replaced under the *Substation Replacements Due to In-Service Failures* program has either failed or is at risk of imminent 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)

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 114L Replacement and 142L Relocation**
Asset Class:	**Transmission**
Category:	**Project**
Investment Classification:	**Renewal**
Budget:	**$2,341,000**

PROJECT DESCRIPTION

The *Transmission Line 114L Replacement and 142L Relocation* project involves replacing a section of Transmission Line 114L across the Gander Bay causeway and relocating a section of Transmission Line 142L to connect with the existing Transmission Line 108L.

The *Transmission Line 114L Replacement and 142L Relocation* project is scheduled as a single-year project to be completed in 2027. Engineering and pre-construction activities will be carried out early in the year, including obtaining environmental and development permits and approvals, acquiring necessary property rights, clearing brush, collecting topographic data, finalizing engineering and design work, and ordering materials. Followed by establishing construction contracts, procuring materials, and construction of the new line to be completed by the end of 2027.

PROJECT BUDGET

The budget for the *Transmission Line 114L Replacement and 142L Relocation* project is based on detailed engineering estimates.

Table 1 provides a breakdown of planned expenditures for 2027 required to complete the execution of the *Transmission Line 114L Replacement and 142L Relocation* project.

Table 1
Transmission Line 114L Replacement and 142L Relocation Project
2027 Budget

Description	2027
Material	735
Labour – Internal	66
Labour - Contract	1,169
Engineering	49
Other	322
Total	$2,341

The cost of the *Transmission Line 114L Replacement and 142L Relocation* project is approximately $2,341,000 in 2027.

ASSET BACKGROUND

Transmission Line 142L is a 66 kV H-Frame looped line supplied from Cobbs Pond ("COB") Substation. It travels backcountry for approximately 39 kilometres until it taps into Transmission Line 114L at a junction near Clarke's Head. Transmission Line 114L is a 66 kV H-Frame and single pole radial transmission line which serves Boyd's Cove ("BOY") and Summerford ("SUM") substations. Together, transmission lines 142L and 114L form the primary source of supply to Newfoundland Power's SUM and Twillingate ("TWG") substations and Newfoundland and Labrador Hydro's ("Hydro") Farewell Head ("FHD") Terminal Station.

The current configuration of the Clarke's Head junction between Transmission Line 114L and Transmission Line 142L includes a tap which feeds an additional 1.7-kilometre segment of 114L. This segment of line is primarily constructed across the Gander Bay causeway to a normally open point at Gander Bay ("GBY") Substation. This normally open point can be closed to provide an alternative source of supply to GBY Substation should an outage occur on Transmission Line 108L. Figure 1 below illustrated the current configuration of the transmission system.

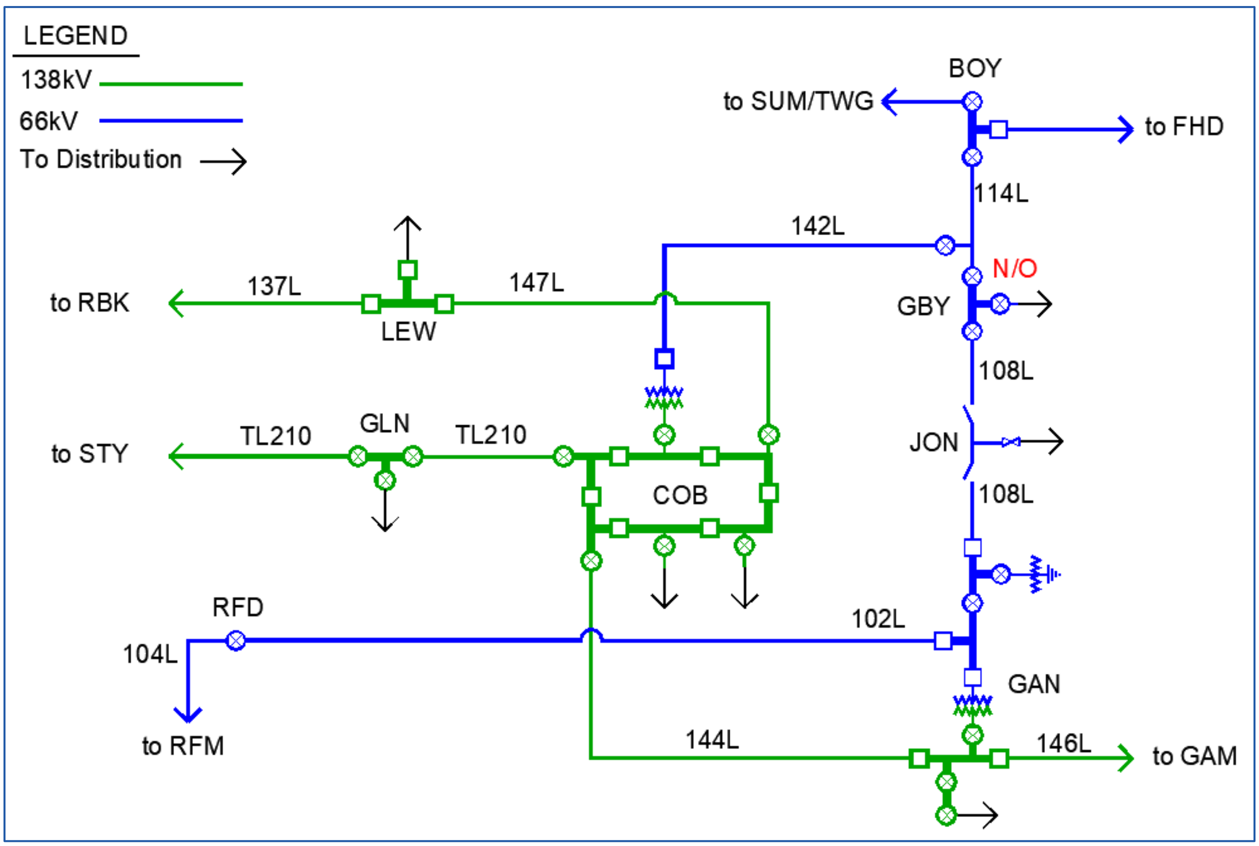


Figure 1 - Existing Configuration of Gander-Twillingate Transmission System

Newfoundland Power submitted the *Gander-Twillingate Transmission System Planning Study* (the "Planning Study") as a part of its *2025 Capital Budget Application*. The Planning Study identified long-standing 66 kV undervoltage conditions in this area of the electrical system and confirmed a need to reconfigure the 66 kV network to ensure long-term reliable service.

The Planning Study recommended the electrical system in the area be reconfigured with the installation of a new 138kV transmission line (now denoted as Transmission Line 148L) between the Lewisporte ("LEW") and BOY substations. In addition to the new transmission line, a number of related activities including 138kV conversion work at the LEW and BOY substations and additional transmission line work on Transmission Line 114L and 142L were identified as being required.

Newfoundland Power received Board approval for the construction of Transmission Line 148L and the conversion of LEW and BOY substations in 2025 and 2026 respectively.

ASSESSMENT OF ALTERNATIVES

The recommended alternative from the Planning Study identified the need to complete additional line work on Transmission Line 114L and 142L in 2027. This scope included replacing the section of Transmission Line 114L across the Gander Bay causeway with new, double circuited structures which would have both Transmission Line 114L and 142L attached, shown in Figure 2 below. Additionally, a new tie between Transmission Line 142L and Transmission Line 108L would be constructed near COB Substation.

Figure 2 – Planning Study Recommended Alternative - Transmission Line 114L and 142L Double Circuit

Throughout the planning process of this project, Newfoundland Power completed an assessment of alternatives to confirm the originally proposed scope remained the least-cost option. This assessment included a review of route feasibility, constructability, reliability risks, and alignment with the system configuration requirements identified in the Planning Study. While the originally proposed alternative remained technically viable within the broader system planning objectives outlined in the Planning Study, Newfoundland Power identified that the estimated cost had increased by approximately $841,000 from the original $1,500,000 estimate in the Planning Study. As a result, Newfoundland Power decided to review a second alternative to ensure the least-cost option was proposed.

The second alternative (the "New Alternative") identified involves the replacement of Transmission Line 114L across the Gander Bay causeway, however this would be a like-for-like replacement and would not include double-circuited structures, as seen below in Figure 3.

Figure 3 – New Alternative -
Transmission Line 114L and 142L, No Double Circuit

Additionally, a new tie immediately south of the Gander River would be constructed between Transmission Lines 142L and 108L, shown in Figure 4.[37]

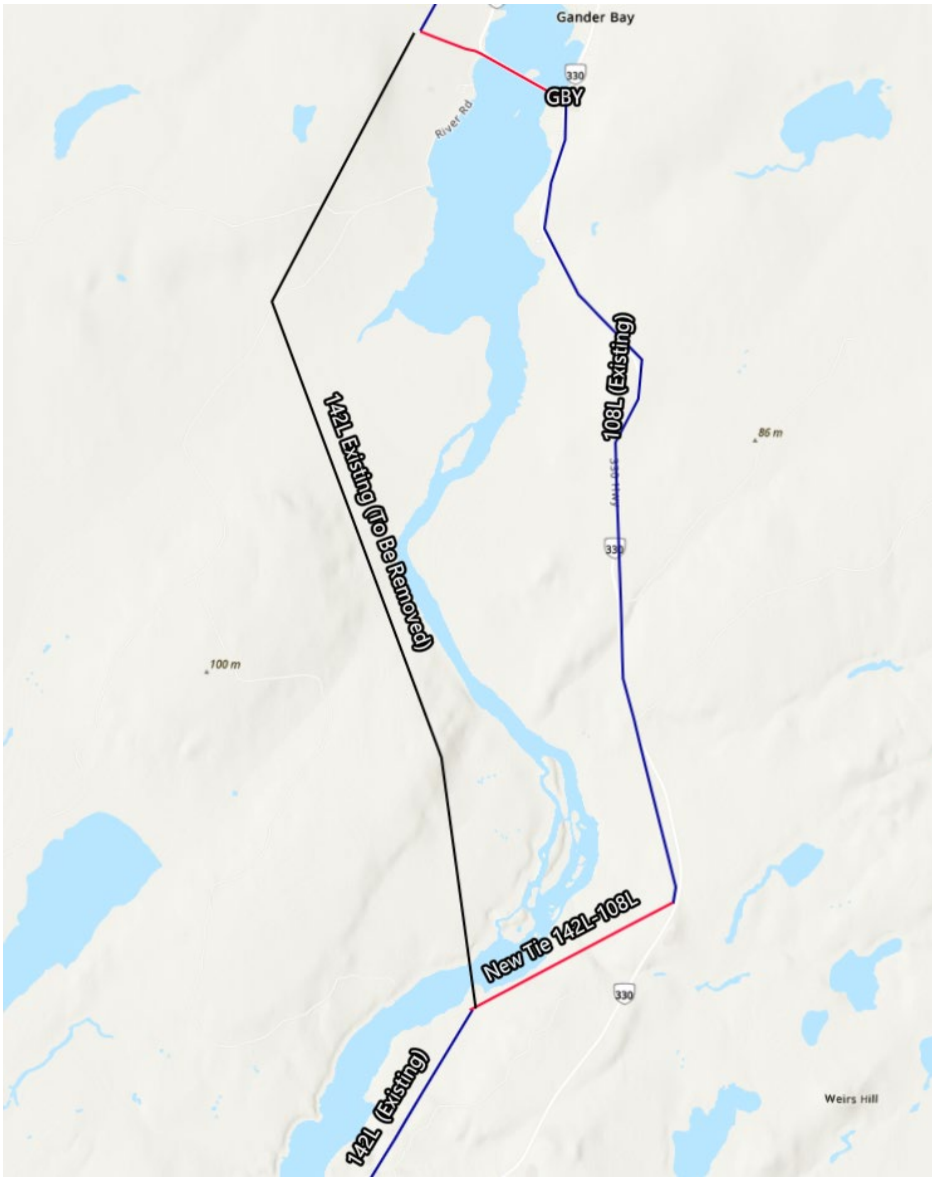


Figure 4 – New Alternative – Transmission Line 142L and 108L Tie

The New Alternative achieves the same system planning objectives as Alternative 1 while removing the requirement of double-circuited structures across the Gander Bay causeway. While technically feasible, the double circuited structures pose a potential reliability risk in that they present a single point of failure across the two transmission lines available to supply GBY Substation. If a double circuit structure across the Gander Bay causeway were to fail, GBY Substation would experience a prolonged outage until a full structure replacement could be completed. Under the New Alternative, in the event of a failure along the segment of 114L

[37] The Planning Study justified the retirement of Transmission Line 108L. Under Alternative 2, a portion of the transmission line would remain in service.

constructed along the causeway, GBY could be fed via Transmission Line 142L. It was determined that Alternative 2 could be completed in one year at an estimated cost of $2,341,000. The assessment of alternatives determined that the New Alternative – Replace Transmission Line 114L tap with a like-for-like replacement and tie Transmission Line 142L into Transmission Line 108L was the least-cost alternative. It also removes the known reliability risk that is present in the original scope of the alternative from the Planning Study. Based on this, it is recommended to proceed with the proposed execution of the New Alternative.

The economic analysis as part of the Planning Study included various sensitivity analyses to consider the impacts of estimated cost increases across different asset classes, including transmission and distribution. The results of the sensitivity analyses concluded that the recommended Planning Study alternative was least-cost across all sensitivities. The latest estimates for both the *Distribution Feeder COB-02 Extension* and the *Transmission Line 114L Replacement and 142L Relocation* projects are higher than what were initially estimated as part of the Planning Study. The original NPV analysis conducted as part of the Planning Study was re-evaluated using the latest costs for both projects. In addition to the noted reliability and transmission-level voltage improvements associated with the recommended alternative, the results of the NPV analysis confirm that the recommended alternative remains least-cost.

RISK ASSESSMENT

The *Transmission Line 114L Replacement and 142L Relocation* project is necessary to permit the completion of the recommended alternative from the *Gander–Twillingate Transmission System Planning Study* approved in the Company's *2025 Capital Budget Application*.

Table 2 summarizes the risk assessment of the *Transmission Line 114L Replacement and 142L Relocation* project.

Table 2
Transmission Line 114L Replacement and 142L Relocation Project
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Transmission Line 114L Replacement and 142L Relocation* project would pose a High (20) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Transmission Line 114L Replacement and 142L Relocation* project is required to support the transmission system modifications identified in the *Gander–Twillingate Transmission System Planning Study* and approved in the Company's *2025 Capital Budget Application*. Completion of the project will ensure customers receive reliable service at least cost consistent with the analysis in the *Gander–Twillingate Transmission System Planning Study.*

Title:	**Transmission Line Maintenance**
Asset Class:	**Transmission**
Category:	**Program**
Investment Classification:	**Renewal**
Budget:	**$3,465,000**

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.[38]

Table 1 provides the annual expenditures for the *Transmission Line Maintenance* program from 2022 to 2026.

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

Year	2022	2023	2024	2025	2026F
Total	2,488	3,449	2,826	3,753	3,306
Adjusted Cost[1]	2,779	3,748	2,977	2,909[2]	3,306

1 2026 dollars.
2 Excludes approximately $913,000 associated with a Contribution in Aid of Construction for the relocation of transmission lines 38L and 39L.

The average annual adjusted cost for the *Transmission Line Maintenance* program was approximately $3.1 million from 2022 to 2026.

38 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 2027 for the *Transmission Line Maintenance* program.

Table 2
Transmission Line Maintenance Program
2027 Budget
($000s)

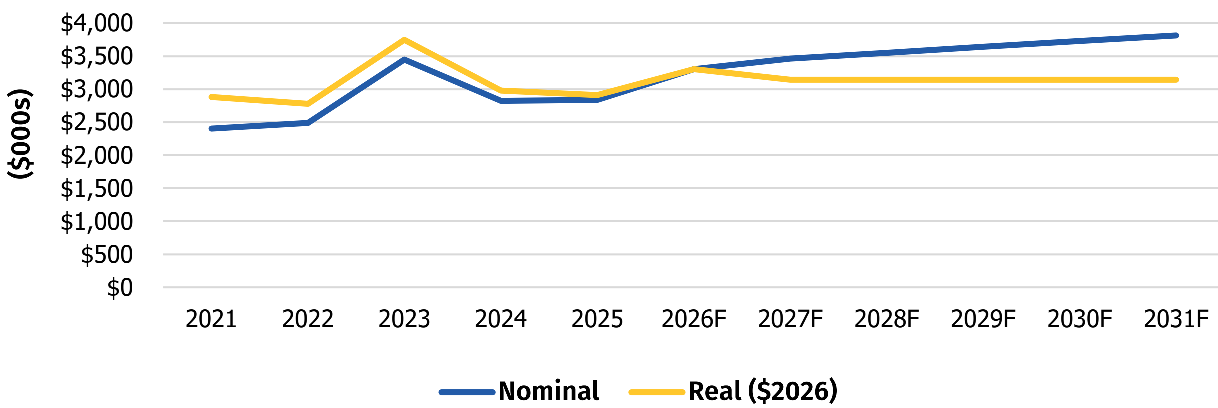
Cost Category	2027
Material	1,104
Labour – Internal	586
Labour – Contract	1,356
Engineering	119
Other	300
Total	$3,465

Proposed expenditures for the *Transmission Line Maintenance* program total $3,465,000 for 2027.

PROGRAM TREND

Figure 1 provides historical and forecast costs for the *Transmission Line Maintenance* program from 2021 to 2031.[39]

Figure 1
Transmisson Line Maintenance
Program Expenditures
(2021-2031F)



Annual expenditures under this program averaged approximately $3.0 million from 2022 to 2026, or approximately $3.1 million when adjusted as described above. Annual expenditures are forecast to average approximately $3.6 million over the next five years.

39 For forecast annual expenditures for the *Transmission Line Maintenance* program, see the *2027-2031 Capital Plan,* Appendix A, page A-4.

ASSET BACKGROUND

Newfoundland Power owns and operates 109 transmission lines, which span approximately 2,000 kilometres. Virtually all of the Company's transmission lines operate at 66 kV or 138 kV.[40] 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. As of 2026, corrective maintenance under this program also includes retreatment of selected transmission poles with wood preservative.

The number of deficiencies addressed under the *Transmission Line Maintenance* program varies annually. From 2021 to 2025, an average of 115 poles, 235 framing structures and 1,076 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.

[40] 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	301	240	188	109	584	470	116	**2,008**
Percentage of Total	15%	12%	9%	6%	29%	23%	6%	**100%**

As shown in Table 3, 29% of Newfoundland Power's transmission lines have been in service for over 50 years. An additional 29% 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 risk of imminent failure or is likely to fail within the next year.

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

Table 4 Transmission Line Maintenance Program Risk Assessment Summary		
Consequence	Probability	Risk
Critical (5)	Near Certain (5)	High (25)

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

JUSTIFICATION

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

GENERATION - HYDRO

Title:	**Hydro Facility Rehabilitation**
Asset Class:	**Generation**
Category:	**Project**
Investment Classification:	**General Plant**
Budget:	**$1,531,000**

PROJECT DESCRIPTION

The *Hydro Facility Rehabilitation* project is necessary for the replacement or rehabilitation of deteriorated hydroelectric facility components that have been identified through routine inspections, operating experience and engineering studies. For 2027, the *Hydro Facility Rehabilitation* project includes:

(i) *Rocky Pond Bearing Refurbishment* – capital expenditures of $410,000 are required to refurbish the bearing at the Rocky Pond hydro plant, including replacement of lignum vitae staves, bearing housing refurbishment, and upgrades to the cooling/lubricating water supply system. Design work will be completed by the end of the second quarter and rehabilitation work will be completed by the fourth quarter of 2027.

(ii) *Lookout Brook Bridge Replacement* – capital expenditures of $612,000 are required to replace one bridge leading to the Lookout Brook Hydro Plant on Flat Bay Brook Road. Design work will be completed by the end of the second quarter and rehabilitation work will be completed by the fourth quarter of 2027.

(iii) *Dam Safety Improvements* – capital expenditures of $509,000 are required to correct deficiencies identified through previously completed third-party dam safety reviews of the Company's water impounding structures. Work is expected to be ongoing throughout 2027.

PROJECT BUDGET

The budget for the *Hydro Facility Rehabilitation* project is based on cost estimates for the individual budget items.

Table 1 provides a breakdown of expenditures proposed for 2027 for the *Hydro Facility Rehabilitation* project.

Table 1
Hydro Facility Rehabilitation Project
2027 Budget
($000s)

Cost Category	2027
Material	1,016
Labour – Internal	148
Labour – Contract	-
Engineering	170
Other	197
Total	$1,531

Proposed expenditures for the *Hydro Facility Rehabilitation* project total $1,531,000 for 2027.

ASSET BACKGROUND

Newfoundland Power operates 23 hydro plants throughout its service territory that generate a combined annual normal production of 438.4 GWh.[41] These hydro plants provide low-cost electricity for customers and contribute to capacity on the Island Interconnected System.

Newfoundland Power maintains reliable operation of its hydro plants through a combination of inspections by plant operators, maintenance activities and replacement and refurbishment projects. The three items proposed for refurbishment in 2027 are:

a) *Rocky Pond Bearing Refurbishment ($410,000)*

The Rocky Pond turbine bearing consists of lignum vitae wooden staves secured in a steel housing. Lignum bearings are water lubricated and have proven to be a reliable bearing material historically. As is typical with all bearings, the bearing running surface is the sacrificial component of the rotating machinery such that the rotating shaft is not damaged during operation. In the case of the Rocky Pond bearing, this sacrificial material is the lignum vitae bearing staves.

The lignum vitae staves have worn to a condition in which excessive leakage is present as well as excessive vibrations induced into the rotating shaft. The vibrations caused by the worn bearing result in unit trips. To reduce shaft vibration to a reasonable level, packing materials have been inserted into the void between the bearing staves and rotating shaft caused by worn bearing staves to reduce the vibration amplitude. This

41 Newfoundland Power retained Hatch in 2020 to conduct an updated *Hydro Normal Production Review*. The review was completed in April 2021, setting the normal annual production of 438.4 GWh for Newfoundland Power's hydroelectric facilities.

packing material is a temporary fix and must be replaced often to maintain shaft vibration to a level that allows unit operation. If packing continues to be used over the longer term, damage to the rotating shaft is likely to occur.

In 2027, the Company is proposing to refurbish the Rocky Pond turbine bearing. The project includes: (i) replacement of lignum vitae staves; (ii) bearing housing refurbishment; and upgrades to the cooling/lubricating water supply system.

The project is estimated to cost $410,000 in 2027.

b) Lookout Brook Bridge Replacement ($612,000)

The Lookout Brook Hydro Plant is accessed via Flat Bay Brook Road, located near the community of St. Georges. Flat Bay Brook Road is approximately 13.1 kilometres long and was constructed in 1945 during the initial construction of the Lookout Brook Hydro Plant. The road extends from Route 1 to the Lookout Brook Hydro Plant. The road utilizes various forms of drainage infrastructure to manage overland water flows during rainfall events including ditching, culverts and bridges.

Bridges with sufficient load carrying capacity are required to complete the future replacement of the Lookout Brook Hydro Plant power transformer.[42] The current bridge infrastructure on the roadway is inadequate for transportation of a power transformer. The bridges are constructed using non-standard structural materials such as non-rated timber, utility poles, as well as a rail car chassis in one case. These bridge construction techniques are not sufficient for the load rating required to deliver the new power transformer to its location adjacent to the Lookout Brook Hydro Plant. In 2027, the Company is proposing replacement of one bridge on Flat Bay Brook Road.

The project is estimated to cost $612,000 in 2027.

c) Dam Safety Improvements ($509,000)

The *Dam Safety Improvements* project involves improvements to Newfoundland Power's water impounding structures to correct known deficiencies identified through the Company's dam safety program. The Company operates 23 hydro plants throughout the island portion of the province and maintains approximately 185 water impounding structures under a corporate dam safety program.[43] Newfoundland Power has dam safety reviews completed on its water impounding structures in accordance with Canadian Dam Association ("CDA") guidelines.[44]

Work to be completed in 2027 under the *Dam Safety Improvements* project will include the correction of deficiencies identified through previously completed third-party dam safety reviews of the Company's water impounding structures. Deteriorated hydraulic

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42 See report *2.2 Substation Power Transformer Strategy,* Appendix B filed with the Application.
43 Structures maintained in Newfoundland Power's Dam Safety Program include dams, dykes, canals, control structures and spillways but does not include penstocks.
44 The CDA prescribes a consequence-based approach to dam safety reviews, where dams with a higher consequence in the event of an unplanned release receive more frequent third-party reviews.

structures can result in unsafe conditions for employees and the public through uncontrolled release of water. Unplanned releases of water can result in damage to infrastructure, environmental impacts, and injury or loss of life.

The project is estimated to cost $509,000 in 2027.

ASSESSMENT OF ALTERNATIVES

The *Hydro Facility Rehabilitation* project is required to refurbish deteriorated hydroelectric facility components that have been identified through routine inspections, operating experience and engineering studies. The scope of work identified for 2027 includes infrastructure that is at risk of failure due to its condition. The alternative to maintaining these facilities is to retire them.

Maintaining the Company's hydroelectric assets ensures the realization of customer benefits provided by the electricity generated from these facilities. The value of electricity produced by Newfoundland Power's hydroelectric generating facilities consists of reduced marginal energy costs as well as avoidance of the need to build additional generation capacity. The *Hydro Facility Rehabilitation* project will provide an economic benefit to customers by ensuring the continued production of low-cost energy and will mitigate safety risks associated with deteriorated plant infrastructure. The energy-related value of the production from Newfoundland Power's hydro plants is estimated at $19,923,000 annually, while the capacity-related value is estimated at $27,021,000 annually.[45] When the Company's hydro plants are out of service, the lost production must be replaced by purchasing more expensive energy from Newfoundland and Labrador Hydro.

The refurbishments proposed for 2027 are required to realize the economic benefits of the Company's hydro plants and to maintain reliable operation of the Rocky Pond and Lookout Brook hydro plants and cannot be deferred. Completing the required hydro facility rehabilitations in 2027 is therefore the only viable alternative.

RISK ASSESSMENT

The *Hydro Facility Rehabilitation* project involves the replacement of deteriorated and obsolete components that are at risk of failure. Replacing this equipment is necessary to ensure the safe and reliable operation of the Company's hydro plants, which provide an economic benefit for customers.

The *Hydro Facility Rehabilitation* project will provide an economic benefit to customers by ensuring the continued production of low-cost energy and will mitigate safety risks associated with deteriorated plant infrastructure. The energy-related value of the production from Newfoundland Power's hydro plants is estimated at $19,923,000 annually, while the capacity-related value is estimated at $27,021,000 annually. When the Company's hydro plants are out of service, the lost production must be replaced by purchasing more expensive energy from Newfoundland and Labrador Hydro.

[45] Marginal supply costs are based on Hydro's December 2025 marginal cost update.

For 2027, the *Hydro Facility Rehabilitation* project will address deteriorated and obsolete components at two hydro facilities, including the Rocky Pond Plant bearing and Lookout Brook plant access road bridge. Combined, these two hydro plants represent approximately 11% of the normal annual production of Newfoundland Power. Failure of the components at these facilities could impede plant operations and result in safety hazards for employees. Based on the age and condition of these components, the probability of failure is considered likely.

Table 2 summarizes the risk assessment of the 2027 *Hydro Facility Rehabilitation* project.

Table 2
Hydro Facility Rehabilitation Project
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Hydro Facility Rehabilitation* project would pose a Medium-High (16) risk to the delivery of least-cost service to customers.

JUSTIFICATION

The *Hydro Facility Rehabilitation* project is required to provide continued low-cost energy to customers. Maintaining Newfoundland Power's hydro plants requires the replacement of deteriorated and failed equipment, components and systems. This includes the replacement of the Lookout Brook access bridge and the replacement of Rocky Pond Bearing in 2027. Safety improvements to dam infrastructure are required in 2027 to ensure the safety of the Company's employees and the public, and to mitigate damage to infrastructure and the environment. Completing these upgrades will ensure the continued operation of these hydro plants and the continued provision of low-cost energy to customers.

Title: **Rose Blanche Hydro Plant Refurbishment**
Asset Class: **Generation – Hydro**
Category: **Project**
Investment Classification: **Renewal**
Budget (Multi-Year): **$649,000 in 2027; and $1,079,000 in 2028**

PROJECT DESCRIPTION

The *Rose Blanche Hydro Plant Refurbishment* project involves refurbishing the Rose Blanche Hydroelectric Plant (the "Rose Blanche Plant" or the "Plant"), located in western Newfoundland near the community of Rose Blanche- Harbour LeCou over two years. The project includes replacing obsolete elements of the governor control system, governor hydraulic power unit, protection and control system, and plant auxiliary power unit.

The *Rose Blanche Hydro Plant Refurbishment* project will be carried out in 2027 and 2028. In 2027, procurement and design of the revised governor, protection and controls and auxiliary power systems will occur. In 2028, project execution will take approximately 32 weeks to complete with all commissioning completed by the end of the fourth quarter.

Additional information on this project is provided in report *3.1 Rose Blanche Hydro Plant Refurbishment* filed with the Application.

PROJECT BUDGET

The budget for the *Rose Blanche Hydro Plant Refurbishment* project is based on engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2027 and 2028 for the *Rose Blanche Hydro Plant Refurbishment* project.

Table 1
Rose Blanche Hydro Plant Refurbishment Project
2027-2028 Budget
($000s)

Cost Category	2027	2028
Material	556	638
Labour – Internal	15	170
Labour – Contract	-	-
Engineering	44	148
Other	34	123
Total	$649	$1,079

Proposed expenditures for the *Rose Blanche Hydro Plant Refurbishment* project total $1,728,000, with $649,000 in 2027 and $1,079,000 in 2028.

ASSET BACKGROUND

The Rose Blanche Plant was originally commissioned in 1998. The Plant has an operating capacity of 6.0 MVA under a net head of 114 metres. Annual production from the plant is 21.9 GWh or approximately 5% of Newfoundland Power's annual hydroelectric production.[46] The Rose Blanche Plant is operated throughout the year as a source of low-cost energy for Newfoundland Power's customers. The Plant is also routinely placed into service at the request of Hydro.

A condition assessment and corresponding risk assessment determined that the Rose Blanche Plant contains deteriorated, obsolete and non-standard equipment that must be refurbished to ensure the continued safe and reliable operation of the Plant. Equipment identified through the condition assessment were the governor control system, governor hydraulic power unit, protection and control system, and plant auxiliary power unit.

ASSESSMENT OF ALTERNATIVES

Newfoundland Power assessed two alternatives for the *Rose Blanche Hydro Plant Refurbishment* project. The alternatives are: (i) refurbishing the plant in 2027 and 2028; and (ii) deferring the refurbishment to a future year.

The assessment determined that completing the refurbishment in 2027 and 2028 is the least-cost alternative. The assessment was based on marginal supply costs as well as the potentially higher capital costs associated with an unplanned refurbishment if an in-service equipment failure were to occur.

A lifecycle cost analysis of the Rose Blanche Plant completed in connection with this proposed project shows that the benefits of the Plant's production exceed the cost of production.[47] This analysis shows a net benefit of Plant production is between 8 ¢/kWh and 16.47 ¢/kWh based on the most recent marginal cost estimates.[48] The lifecycle cost analysis confirms that continued operation of the Plant will provide an economic benefit for Newfoundland Power's customers over the longer term. For more details, see report *3.1 Rose Blanche Hydro Plant Refurbishment*.

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46 In 2020, Newfoundland Power retained Hatch to conduct an updated *Hydro Normal Production Review*. The review was completed in April 2021 setting the annual production for the Plant at 21.9 GWh.

47 Details on the benefits of the Plant's production are detailed in Table A-3, Lifecycle Analysis Results on Page A-5 of Appendix A of the *2027 Capital Budget Application*, report *3.1 Rose Blanche Plant Refurbishment*.

48 Marginal supply costs are based on Hydro's December 2025 marginal cost update.

RISK ASSESSMENT

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

The Plant's governor system and protection and control systems include obsolete components no longer manufactured or supported by the original equipment manufacturers. These components are critical to the continued safe operation of the plant and a failure in either system has the potential for significant damage to the plant equipment and would result in lengthy plant outages. The Plant auxiliary power unit provides an emergency supply of power to black start the plant. The auxiliary power unit as currently installed is inadequate to provide plant heating during an extended outage.

Table 2 summarizes the risk assessment of the *Rose Blanche Hydro Plant Refurbishment* project.

Table 2
Rose Blanche Hydro Plant Refurbishment Project
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Rose Blanche Hydro Plant Refurbishment* project would pose a High (20) risk to the delivery of least-cost service to customers.

JUSTIFICATION

The *Rose Blanche Hydro Plant Refurbishment* project is required to continue to provide low-cost energy to customers. Completing required upgrades to the Plant in 2027 and 2028 will minimize Plant downtime and ensure the continued provision of low-cost energy to customers.

Title:	**Hydro Plant Replacements Due to In-Service Failure**
Asset Class:	**Generation - Hydro**
Category:	**Program**
Investment Classification:	**Renewal**
Budget:	**$764,000**

PROGRAM DESCRIPTION

The *Hydro Plant Replacements Due to In-Service Failures* program involves the refurbishment or replacement of structures and equipment due to damage, deterioration, corrosion, technical obsolescence, and in-service failure.

PROGRAM BUDGET

The budget for the *Hydro Plant 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.[49]

Table 1 provides the annual expenditures for the *Hydro Plant Replacements Due to In-Service Failures* program from 2022 to 2026.

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

Year	2022	2023	2024	2025	2026F
Total	730	627	636	771	736
Adjusted Cost[1]	834	680	677	794	736

[1] 2026 dollars.

The average annual adjusted cost for the *Hydro Plant Replacements Due to In-Service Failures* program was approximately $744,000 from 2022 to 2026.

[49] 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 the expenditures proposed for 2027 for the Hydro Plant Replacements Due to In-Service Failures program.

Table 2
Hydro Plant Replacements Due to In-Service Failures Program
2027 Budget
($000s)

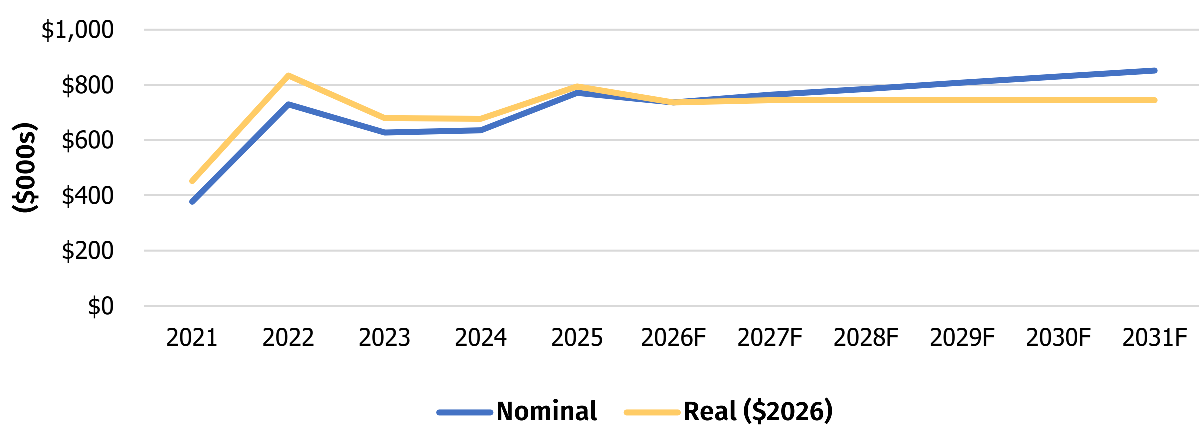
Cost Category	2027
Material	481
Labour – Internal	170
Labour – Contract	0
Engineering	72
Other	41
Total	$764

Proposed expenditures for the *Hydro Plant Replacements Due to In-Service Failures* program total $764,000 for 2027.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the Hydro Plant Replacements Due to In-Service Failures program from 2021 to 2031.

Figure 1
Hydro Plant Replacements Due to In-Service Failures
Program Expenditures
(2021-2031F)



Annual expenditures under this program averaged approximately $700,000 from 2022 to 2026, or approximately $744,000 when adjusted for inflation. Annual expenditures are forecast to average approximately $808,000 over the next five years.

ASSET BACKGROUND

Newfoundland Power operates 23 hydro plants throughout its service territory that generate a combined normal annual production of 438.4 GWh. These hydro plants provide low-cost electricity for customers and contribute to capacity on the Island Interconnected System.

In addition to contributing to low-cost energy production, Newfoundland Power's hydro plants also provide localized reliability benefits during planned and unplanned work on the transmission system. For example, a trip on Newfoundland and Labrador Hydro's radial Transmission Line TL214 serving the Port Aux Basques area on December 19, 2020, resulted in outage to approximately 5,300 customers. Operation of the Rose Blanche Hydro Plant in response to this outage helped in avoiding approximately 122,000 customer outage minutes.

Of Newfoundland Power's 23 hydro plants, 21 have been in service for over 50 years, including five that have been in service for over 100 years. These plants are routinely inspected by plant operators to identify deficiencies.

The *Hydro Plant Replacements Due to In-Service Failures* program involves the refurbishment or replacement of structures and equipment due to damage, deterioration, corrosion, technical obsolescence, and in-service failure. Replacements under this program are typically due to one of two reasons: (i) emergency replacements where components fail and require immediate replacement to return a unit to service; or (ii) observed deficiencies, where components are identified for replacement due to risk of imminent failure, or for safety or environmental reasons. Equipment replaced under this program includes civil infrastructure, instrumentation, mechanical, electrical, and protection and controls equipment. This equipment is critical to the safe and reliable operation of hydro plants and must be replaced in a timely manner.

RISK ASSESSMENT

The *Hydro Plant Replacements Due to In-Service Failures* program will provide an economic benefit to customers by ensuring the continued production of low-cost energy and will mitigate safety risks in plant operations.

The energy-related value of the production from Newfoundland Power's hydro plants is estimated at $19,923,000 annually, while the capacity-related value is estimated at $27,021,000 annually. When the Company's hydro plants are out of service, the lost production must be replaced by purchasing more expensive energy from Newfoundland and Labrador Hydro.

The *Hydro Plant Replacements Due to In-Service Failures* program is Newfoundland Power's corrective maintenance program for its hydro plants. The program allows hydro plants to be returned to service in a timely manner following equipment failure. The equipment replaced under the program has either failed or is at risk of imminent failure. Equipment failures can impede plant operations and result in safety hazards for employees working in the plants.

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

Table 3
Hydro Plant Replacements Due to In-Service Failures Program
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Hydro Plant Replacements Due to In-Service Failures* program would pose a High (25) risk to the delivery of least-cost service to customers.

JUSTIFICATION

The *Hydro Plant Replacements Due to In-Service Failures* program is required to provide reliable service to customers at the lowest possible cost. The Company's hydro plants continue to provide low-cost energy for customers, localized reliability benefits and a contribution to system capacity.

INFORMATION SYSTEMS

Title: **Shared Server Infrastructure**
Asset Class: **Information Systems**
Category: **Project**
Investment Classification: **General Plant**
Budget: **$1,974,000**

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 2027, 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 2027 for the *Shared Server Infrastructure* project.

Table 1
Shared Server Infrastructure Project
2027 Budget
($000s)

Cost Category	2027
Material	1,728
Labour – Internal	246
Labour – Contract	-
Engineering	-
Other	-
Total	$1,974

Proposed expenditures for the *Shared Server Infrastructure* project total $1,974,000 for 2027.

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 depend 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.

For 2027 the Company will replace eight server hosts that have reached end of life. This project is essential to maintaining reliable and secure operations across all business systems. Upgrading aging hardware ensures continued vendor support, compatibility with enterprise applications and compliance with cybersecurity requirements. The new infrastructure will provide improved performance, scalability and resilience to support growing operational demands.

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) requires upgrading as part of cybersecurity management. The annual assessment considers multiple factors, including vendor support and product roadmaps, the current performance of components, associated costs, the criticality of a component and the consequence in the event of a failure. Upgrades that are not critical to Newfoundland Power's operations are deferred.

This investment reduces the risk of hardware failure and service disruption, which could impact core business functions and customer service. By moving to modern server technology, the Company will strengthen operational continuity, support future growth and enhance disaster recovery capabilities. These upgrades are critical to sustaining business critical processes and ensuring long term infrastructure stability.

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 Supervisory Control and Data Acquisition ("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.

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.

50 See *Compute Infrastructure: How to Optimize the Management of Life Cycle Variations, Gartner Inc., August 23, 2017.*

Title: **System Upgrades**
Asset Class: **Information Systems**
Category: **Project**
Investment Classification: **General Plant**
Budget: **$1,899,000**

PROJECT DESCRIPTION

The *System Upgrades* project encompasses upgrades to third-party software solutions integral to Newfoundland Power's information systems. The proposed system upgrades for 2027 include improvements to the Database Management System ("DBMS"), Financial Management System ("FMS"), Customer Website, Customer Contact and Billing Information System ("CCB"), MC3 Equipment and the SCADA system.

Updates to the DBMS, FMS, Customer Website, CCB and MC3 Equipment are essential to maintain ongoing vendor support, which provides necessary bug fixes and security updates. Enhancements to the SCADA system are designed to align with industry best practices, preserve optimal performance, resolve identified issues and ensure the application of critical security updates.

Additionally, the *System Upgrades* project covers minor software applications that have reached the end of vendor support, require bug fixes or security patches, or must be modified to comply with technological advancements, regulatory changes, 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 2027 for the *System Upgrades* project.

Table 1
System Upgrades Project
2027 Budget
($000s)

Cost Category	2027
Material	925
Labour – Internal	974
Labour – Contract	-
Engineering	-
Other	-
Total	$1,899

Proposed expenditures for the *System Upgrades* project total $1,899,000 for 2027.

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 2027 are:

(i) *MC3 Equipment Upgrade ($625,000)*

This item involves the replacement of the MC3 drive-by collection devices used in operating Newfoundland Power's Automated Meter Reading ("AMR") Collection System. The Company has over 267,000 customer meters throughout its service territory. Typically, customer meters are read on a monthly basis. The AMR Collection System delivers ongoing operating cost savings by reducing the need for manual, on-site meter reading, improving meter reader productivity and avoiding higher labor and vehicle-related costs. Drive-by collection enables the retrieval of meter data from multiple customer meters simultaneously, supporting efficient monthly meter reading and accurate billing in a timely manner. The continued availability and reliability of drive-by collection devices is therefore integral to maintaining these savings and delivering least-cost service to customers.[51]

The current MC3 drive-by devices are no longer manufactured, and vendor repair or replacement services are not available. As these components reach end of life, any failure will directly impair the Company's ability to collect meter data efficiently. Failure of even a subset of collection devices would require Meter Readers to revert to manual meter reading for affected routes. This would increase operating costs, reduce productivity and extend meter reading cycles, potentially delaying billing and impacting customer service levels. A widespread or cascading device failure would compromise the integrity of the AMR system, resulting in significant operational disruption and higher costs for customers. Without replacement, the Company would face mounting reliability risks, loss of vendor support and increased exposure to unplanned manual workarounds.

This project involves the replacement of legacy MC3 drive-by collection devices used in the operation of Newfoundland Power's AMR Collection System, which have reached the end of their useful service life, with supported MC4 devices. To ensure continuity

[51] The Company began implementing AMR technology in 2013. AMR technology resulted in reduced FTEs related to meter readers by approximately 10 FTEs in each of 2017 and 2018. Since 2013, it has resulted in reduced FTEs related to meter readers by approximately 26 FTEs.

of AMR operations and to maintain meter reading efficiency, the Company will undertake a full replacement of these devices.

Upgrading these devices will ensure ongoing vendor support and maintain the operational efficiency achieved through the AMR system. The project will help preserve cost effective meter reading, avoid service disruptions associated with device failure and support continued high quality customer service delivery.

(ii) *Customer Care and Billing Information System Upgrade ($300,000)*

This item provides for a minor upgrade to Newfoundland Power's Oracle CCB Information System. CCB supports key customer service functions, including account management, billing, metering integration and service order processing. Routine upgrades are required to ensure ongoing vendor support, maintain system reliability and keep the platform aligned with current security and performance standards.

The proposed upgrade will deliver incremental improvements to system stability and functionality while ensuring compatibility with supported Oracle components. This work is part of the Company's ongoing practice of maintaining core customer service systems in a secure, supportable and efficient state.

Timely implementation of this upgrade reduces the risk of operating an unsupported platform, mitigates cybersecurity exposure and avoids potential service disruption resulting from deferred maintenance. Maintaining CCB in good working order supports the Company's continued ability to provide efficient and reliable customer service at least cost.

(iii) *Customer Website Upgrade ($275,000)*

This item involves upgrading the software used to manage and operate Newfoundland Power's customer website to a vendor supported version. The website was last upgraded in 2024 and is a key component of customer service delivery enabling customers to manage accounts, access outage information and use a range of programs and services.[52] The website is currently the most frequently used communication channel for customers. An average of approximately 2.7 million customer inquiries were received annually from 2021 to 2025. Approximately 81% of these inquiries were completed via the website.

This upgrade will include updating the Content Management System that supports the customer website, along with assessing the associated self-service codebase to ensure full compatibility with the latest vendor supported platform. The work will also include confirming that all website features, such as account management and outage related tools, function correctly following the upgrade.

To support a secure and reliable transition, a third-party vulnerability assessment will be completed to verify that the upgraded platform meets current cybersecurity

[52] See the Company's *2024 Capital Budget Application, Schedule B*, page 114.

expectations. In addition, a website performance test will be conducted to ensure that page load times, responsiveness and overall system stability meet acceptable parameters, particularly during high traffic events.

Completing this upgrade in 2027 ensures the website remains fully supported, secure and stable. New vendor versions address performance improvements, correct known issues and include required cybersecurity enhancements. Completing this upgrade will help maintain website availability and performance for customers and support continued delivery of efficient, reliable online services.

(iv) *Financial Management System Upgrade ($120,000)*

This item involves upgrading the Company's FMS to a version that continues to be fully supported by the vendor.

Newfoundland Power's FMS was implemented in 2002. It is used daily to manage the Company's financial resources, project accounting and procurement and inventory processes. The FMS 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 2027, the proposed upgrade of the Company's FMS will apply the latest software release available from the vendor. Commencing with the 2023 upgrade, the vendor introduced a new policy that requires upgrades on an annual cycle. The 2027 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 2027 and will be completed in the third quarter.

(v) *Database Management Software Upgrade ($75,000)*

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

The Company operates multiple versions of DBMS to support over 150 database applications. The DBMS 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 DBMS versions will no longer be supported by the vendor as of October 2027. This DBMS affects five different databases that support applications in the finance and operations areas of the Company.

An upgrade of the DBMS is required in 2027 to ensure continued vendor support of the software. The upgrade will also apply the latest database security patches to minimize any potential vulnerabilities.

(vi) *SCADA System Upgrade ($55,000)*

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 2027, 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 2027 and will be completed in the second quarter.

(vii) *Various Minor Upgrades ($449,000)*

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 2027 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 $55,000 to $449,000 and do not constitute major product releases that warrant consideration of system replacement. Completing the required system upgrades in 2027 is therefore the only viable alternative.

For the proposed *MC3 Equipment Upgrade*, Newfoundland Power evaluated three alternatives: (i) do nothing/run-to-failure; (ii) defer in anticipation of future Advanced Metering Infrastructure ("AMI") deployment; and (iii) replacement of MC3 equipment with supported MC4 equipment.

Alternative 1 is not a viable alternative as the current MC3 devices are no longer manufactured and vendor repair or replacement services will be unavailable. Any failure would immediately reduce the Company's ability to collect meter data efficiently and would require affected routes to revert to manual, on-site meter reading. This would increase operating costs, reduce meter reader productivity, extend meter reading cycles and introduce risks to billing timeliness and customer service. As failures increase over time, the likelihood of cascading operational disruption would also increase.

Alternative 2 is not a viable alternative as deferring the replacement of end-of-life MC3 devices would require the Company to absorb increasing customer service and operational risk, along with cost impacts over a prolonged interim period with no assurance of near-term AMI implementation.[53] Further, the drive-by collection devices are not associated with customer meter infrastructure nor does it duplicate AMI infrastructure. Deferral would therefore not avoid future AMI costs.

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[53] See the *2027-2031 Capital Plan,* Appendix B for an update on the implementation of AMI.

Alternative 3 is the recommended alternative. This option ensures continuity of AMR operations, restores vendor maintenance and support and maintains the efficiency and cost savings associated with drive-by meter reading. The MC4 devices provide a like-for-like functional replacement and do not constitute a major system change or a long-term investment that would constrain future AMI deployment. This alternative minimizes operational risk, avoids higher operating costs associated with manual meter reading and preserves flexibility to transition to AMI when it becomes economically justified.

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 2027 are essential to Newfoundland Power's operations. Upgrades of the Customer Website, DBMS and the FMS are necessary to ensure continued vendor support and to provide for the latest security patches and bug fixes for those systems. The MC3 equipment is integral to the Company's meter reading activities and requires replacement to continue these activities and realize the benefits of AMR. The criticality of the SCADA system necessitates annual upgrades to maximize system performance and security. Ensuring continued vendor support mitigates risks associated with system failures.
Failure of these systems would have serious consequences to the delivery of safe and reliable service to customers. As an example, a security failure of the SCADA system could expose the electrical system to external interference.

System upgrades are becoming more frequent due to changes in vendor requirements and the need to manage cybersecurity risks. The system upgrades proposed for 2027 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 2027 *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 2027 *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:	**Application Enhancements**
Asset Class:	**Information Systems**
Category:	**Project**
Investment Classification:	**General Plant**
Budget:	**$1,442,000**

PROJECT DESCRIPTION

The *Application Enhancements* project involves upgrading software applications with the goal of reducing customer costs and enhancing service delivery. The planned initiatives for 2027 include:

(i) business modernization;
(ii) learning management;
(iii) customer service automation enhancements; and
(iv) 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 2027 for the *Application Enhancements* project.

Table 1
Application Enhancements Project
2027 Budget
($000s)

Cost Category	2027
Material	497
Labour – Internal	870
Labour – Contract	-
Engineering	-
Other	75
Total	$1,442

Proposed expenditures for the *Application Enhancements* project total $1,442,000 for 2027.

ASSET BACKGROUND

The items included under the 2027 *Application Enhancements* project are:

(i) *Business Modernization ($400,000)*

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 artificial intelligence ("AI"), digital forms, robotic process automation, enterprise reporting and service desk technology can be further enhanced and expanded to provide additional business efficiencies.

Since the introduction of the Business Modernization project in 2025, Newfoundland Power has delivered numerous technology solutions including digitizing several manual business processes, automating third-party integrations to reduce manual work, improving data accessibility and quality across systems, developing new system automations and leveraging AI technology to support capacity building. New Human Resources and Finance dashboards have been developed for consolidated resource planning and forecasting, and to enable faster and more detailed budget insights. IT Service Management workflows were developed to automate tasks, support employee self service and embed AI for knowledge base inquiries. AI was also utilized to develop agents that support process automation and enable faster and deeper data insights for Company operations and administration tasks.

Examples of initiatives to be considered under this project in 2027 include:

(i) AI: Further leveraging AI technology to support employee capacity building through agent development and through the adoption of additional AI solutions.
(ii) Enterprise Reporting & Data Analytics: Further enhancing the Company's ability to securely pull data from multiple sources, streamline manual reporting and enhance the centralized reporting platform that reduces the need for direct database access and eliminates a security risk.
(iii) Digital Forms: Converting prioritized paper-based and manual processes into digital workflows to improve efficiency, accuracy and data flow across departments.
(iv) Robotic Process Automation: Developing additional automated workflows to reduce repetitive manual tasks across the business, with opportunities to incorporate Generative AI where appropriate.
(v) IT Service Management Enhancements: Expanding automation through the IT Service Management platform, including AI assisted help, automated asset health checks with self healing and improved approval workflows.

This project will provide the opportunity to continually improve manual processes and create operational efficiencies 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 improve data protection in securing customer and corporate information.

(ii) *Customer Service Automation Enhancements ($250,000)*

Newfoundland Power implemented a webchat service as an additional communication channel for customers using its website in 2022. In 2025, Newfoundland Power implemented enhancements to the Webchat service to include AI capabilities whereby customers can access information and perform business functions such as checking account balances, reporting an outage, checking outage information and making payment arrangements with an AI agent. With the continual growth in online customer interactions and with the capability of offering webchat services via AI continuously, offering enhanced AI webchat capabilities will provide increased customer service and business efficiencies. Additional capabilities include customer move-in/move-out requests and enrollment in programs including the automated payment plan and equal payment plan.

These enhancements will leverage upgraded AI models, improved natural language understanding and deeper integration with internal systems to allow customers to complete tasks quickly and accurately, without requiring contact centre assistance.

This work also includes the technical development, testing and deployment needed to support these expanded workflows, along with updates to conversational design, system integrations and monitoring dashboards. By extending webchat capabilities and ensuring 24/7 availability, the project improves accessibility and overall customer experience while keeping pace with increasing customer expectations for digital communication options.

(iii) *Learning Management System ($175,000)*

Newfoundland Power currently maintains and tracks training requirements manually across a number of different sources. This includes multiple spreadsheets, SharePoint lists, emails and department managed tools. This often results in inconsistent records, duplicate training and limited visibility into what training has been completed.

A unified Learning Management System will provide Newfoundland Power with a single, reliable way to track and manage all employee training requirements across the Company. By bringing all training into one environment, the Company can better support safety, compliance, onboarding, leadership development and technical skill progression. Employees gain a clearer understanding of their required training, supervisors receive accurate reporting and the Company benefits from stronger compliance oversight and reduced administrative workload. This approach supports a more consistent, scalable and efficient training experience for every department at Newfoundland Power.

The scope of work includes the planning, design and implementation of a centralized Learning Management System capable of managing, delivering and tracking all training across Newfoundland Power. This will involve gathering detailed training requirements from all departments, configuring the system to support role-based learning paths and setting up features such as tracking, reporting, certification printing, self scheduling and mobile/desktop access. Existing training materials, including presentations, videos and departmental content will be reviewed, organized, and uploaded into the new environment to ensure continuity and ease of access for all employees.

The project will also include establishing administrative structures and permission levels so the system functions appropriately for employees, supervisors and training administrators across the Company. Integration points with existing systems will be identified where needed, and the solution will be configured to support cloud-based backup, cross department use and long-term scalability.

(iv) *TakeCharge Website Enhancement ($70,000)*

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 621,000 visits to the TakeCharge website in 2025.

(v) *Various Minor Enhancements ($547,000)*

The Various Minor Enhancements item allows Newfoundland Power to respond to unforeseen requirements that occur throughout the year, such as legislative and compliance changes and employee-identified enhancements designed to improve customer service and operational efficiency.

Continuation of this project allows these enhancements to be completed as identified, which advances both operational efficiencies 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 2027 will advance operational efficiency and provide cost savings for customers. Deferring the 2027 *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 Customer Service Automation Enhancements project will reduce manual processes associated with customer service contacts and will improve overall accessibility and customer experience. The project will also mitigate the risk of technology obsolescence by expanding automated, 24/7 self-service functionality for high-volume customer transactions.

The Learning Management System project will mitigate operational, safety and compliance risk by establishing a centralized, auditable record of mandatory training and certifications and improving visibility for employees, supervisors and administrators. Implementing a single system reduces the risk of inconsistent records, duplicate training and missed or overdue requirements that could arise from the current reliance on multiple spreadsheets, lists and emails.

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 2027 *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 2027 *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: **Cybersecurity Upgrades**
Asset Class: **Information Systems**
Category: **Project**
Investment Classification: **General Plant**
Budget: **$962,000**

PROJECT DESCRIPTION

The *Cybersecurity Upgrades* project focuses on strengthening the Company's cybersecurity infrastructure. Proposed capital investments for 2027 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 2027 for the *Cybersecurity Upgrades* project.

Table 1
Cybersecurity Upgrades Project
2027 Budget
($000s)

Cost Category	2027
Material	455
Labour – Internal	481
Labour – Contract	-
Engineering	-
Other	26
Total	$962

Proposed expenditures for the *Cybersecurity Upgrades* project total $962,000 for 2027.

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 2027 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.

Title:	**Microsoft Enterprise Agreement**
Asset Class:	**Information Systems**
Category:	**Project**
Investment Classification:	**General Plant**
Budget (Multi-Year):	**$320,000 in 2027; $320,000 in 2028; and $320,000 in 2029**

PROJECT DESCRIPTION

The *Microsoft Enterprise Agreement* involves the purchase of Microsoft software products and provides access to the latest versions of each software product purchased under this agreement at the lowest cost.

The annual agreement is a fixed price based on the number of eligible employees that use Microsoft software products on Company-assigned personal computers. In 2027, a three-year agreement will be entered into to renew the Microsoft Enterprise Agreement.[54] Under this agreement, the Company will continue to distribute its purchasing costs for these licenses over three years.

PROJECT BUDGET

The budget for the *Microsoft Enterprise Agreement* project is based on detailed cost estimates.

Table 1 provides a breakdown of expenditures proposed for 2027 for the *Microsoft Enterprise Agreement* project.

Table 1
Microsoft Enterprise Agreement
Multi-Year Project Budget
($000s)

Cost Category	2027	2028	2029
Material	320	320	320
Labour – Internal	-	-	-
Labour – Contract	-	-	-
Engineering	-	-	-
Other	-	-	-
Total	$320	$320	$320

Proposed expenditures for the *Microsoft Enterprise Agreement* project total $960,000, with $320,000 in 2027, $320,000 in 2028 and $320,000 in 2029.

54 The existing Microsoft Enterprise Agreement will conclude on May 31, 2027. The terms of the next agreement will be from June 1, 2027 to May 31, 2030.

ASSET BACKGROUND

Newfoundland Power has had the Microsoft Enterprise Agreement in place for over 18 years, providing access to the latest versions of software products. Software licenced under this agreement includes the Windows operating system for each Company-assigned personal computer, the Microsoft Office suite of programs, Microsoft Teams, Exchange and SharePoint. This software is required to operate software systems used by all employees in delivering safe and reliable service to customers. The terms of the agreements are typically three years in duration, with requirements reviewed and adjusted annually. Purchasing Microsoft software under an enterprise agreement provides cost savings by availing of volume pricing discounts offered by Microsoft. It also provides upgrades to Microsoft technology at no additional cost.

RISK ASSESSMENT

The *Microsoft Enterprise Agreement* project is necessary to mitigate risks to the delivery of safe and reliable service to customers at the lowest cost.

Each Company-assigned personal computer requires the Windows Operating System in order to operate software. This is essential for operating the software applications required to provide least-cost, reliable service to customers. Failure to obtain the latest available upgrades to the Windows Operating System would have serious consequences to the delivery of safe and reliable service to customers. As examples, a security failure by using an unsupported operating system could compromise key systems and introduce security vulnerabilities. Failure of the Company's email system could compromise customer or Company information and disrupt communications with customers and among employees. As the existing Microsoft Enterprise Agreement is expiring in 2027, the probability of adverse consequences arising from losing access to this software is likely.

Table 2 summarizes the risk assessment of the *Microsoft Enterprise Agreement*.

Table 2
Microsoft Enterprise Agreement
Risk Assessment Summary

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

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

JUSTIFICATION

The *Microsoft Enterprise Agreement* project is required to ensure the secure and reliable operation of information systems that are essential to the delivery of service to customers. The *Microsoft Enterprise Agreement* is the least-cost option to ensure continued access to Microsoft software products.

Title:	**Personal Computer Infrastructure**
Asset Class:	**Information Systems**
Category:	**Program**
Investment Classification:	**General Plant**
Budget:	**$784,000**

PROJECT DESCRIPTION

The *Personal Computer Infrastructure* program is necessary for the replacement or upgrade of personal computers ("PCs") that have reached the end of their service lives. This program also includes the replacement of peripheral equipment, including monitors and workgroup printers.

Approximately 160 PCs are estimated to be replaced in 2027. The purchase of mobile units (laptops and tablets) enables greater flexibility for Newfoundland Power's workforce to work remotely.

PROGRAM BUDGET

The budget for the *Personal Computer Infrastructure* 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.[55]

Table 1 provides the annual expenditures for the *Personal Computer Infrastructure* program from 2022 to 2026.

Table 1
Personal Computer Infrastructure Program
Historical Expenditures
($000s)

Year	2022	2023	2024	2025	2026F
Total	702	672	761	766	733
Adjusted Cost[1]	784	730	801	786	733

[1] 2026 dollars.

The average annual adjusted cost for the *Personal Computer Infrastructure* program was approximately $767,000 from 2022 to 2026.

[55] 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 2027 for the *Personal Computer Infrastructure* program.

Table 2
Personal Computer Infrastructure Program
2027 Budget
($000s)

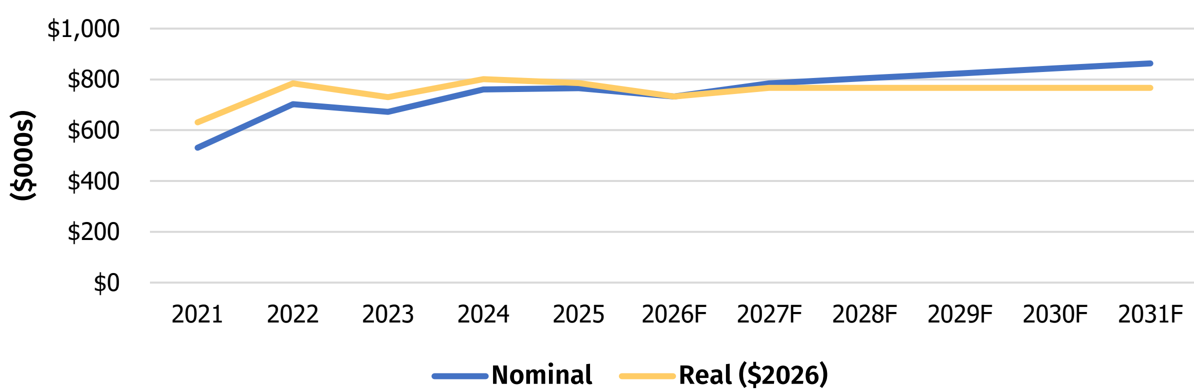
Cost Category	2027
Material	544
Labour – Internal	161
Labour – Contract	-
Engineering	-
Other	79
Total	$784

Proposed expenditures for the *Personal Computer Infrastructure* program total $784,000 for 2027.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Personal Computer Infrastructure* program from 2021 to 2031.

Figure 1
Personal Computer Infrastructure
Program Expenditures
(2021-2031F)



Annual expenditures under this program averaged approximately $727,000 from 2022 to 2026, or approximately $767,000 when adjusted for inflation. Annual expenditures are forecast to average approximately $824,000 over the next five years.

ASSET BACKGROUND

Newfoundland Power maintains a network of computers, servers, information systems and other hardware and software, including over 600 PCs. Specifications for replacement PCs and peripheral equipment are reviewed annually to ensure the personal computing infrastructure remains effective. Industry best practices, technology trends and the Company's experience are considered when establishing specifications.

Nearly all Company employees rely on the use of PCs in their role. PCs age quickly in relation to other pieces of equipment and can fail quickly and unexpectedly. This program allows for prudent and timely replacement of PCs to ensure efficient work.

RISK ASSESSMENT

The *Personal Computer Infrastructure* program will mitigate risks to the delivery of reliable service to customers.

PCs are used to operate the electrical system, manage field operations and provide customer service delivery in an effective and efficient manner. A total of 160 PCs are expected to require replacement in 2027, representing approximately 25% of Newfoundland Power's PC infrastructure used in providing service to customers. The replacement of PCs and associated equipment is necessary when they reach the end of their useful service lives. Failure to replace PCs that are at end of life could impede the delivery of service to customers, including responses to customer trouble calls and other enquiries.

Historically, Newfoundland Power has achieved a five-year lifecycle for its PCs before they require replacement. This compares to an industry average of three to five years.[56] Extending PCs beyond the upper limit of typical industry experience would result in failure becoming likely.

Table 2 summarizes the risk assessment of the Personal Computer Infrastructure program.

Table 2
Personal Computer Infrastructure Program
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Personal Computer Infrastructure* program would pose a Medium-High (16) risk to the delivery of reliable service to customers.

56 See *Recommended Life Spans to Guide PC, Mobile and Other Device Replacement Strategies,* Gartner Inc., March 31, 2021.

JUSTIFICATION

The *Personal Computer Infrastructure* program is required to provide reliable service to customers at the lowest possible cost as it permits the replacement of PCs and other equipment that have reached the end of their useful service lives. These PCs are essential to the Company's operations and provision of customer service.

TRANSPORTATION

Title:	**Replace Vehicles and Aerial Devices 2027-2028**
Asset Class:	**Transportation**
Category:	**Project**
Investment Classification:	**General Plant**
Budget (Multi-Year):	**$4,510,000 in 2027 and $2,916,000 in 2028**

PROJECT DESCRIPTION

The *Replace Vehicles and Aerial Devices 2027-2028* 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 2027 and continuing into 2028 under this project.

Table 1
Proposed Vehicle Replacements
2027-2028

Category	2027 No. of Units	2028 No. of Units
Passenger Vehicles	27	-
Light-Duty Vehicles	2	-
Heavy/Medium-Duty Vehicles	-	6
Total	29	6

Newfoundland Power has identified 27 passenger vehicles and two light-duty vehicles for replacement in 2027, and six heavy/medium-duty vehicles for replacement in 2028. The project also includes expenditures for the replacement of miscellaneous off-road vehicles in 2027, including the procurement of an underground cable pull vehicle. 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 2027-2028* project is based on 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 2027-2028* project for 2027 and 2028.

Table 2
Replace Vehicles and Aerial Devices
2027-2028 Project
Budget
($000s)

Cost Category	2027	2028	Total
Material	4,354	2,916	7,270
Labour – Internal	156	-	156
Labour – Contract	-	-	-
Engineering	-	-	-
Other	-	-	-
Total	$4,510	$2,916	$7,426

Proposed expenditures for the *Replace Vehicles and Aerial Devices 2027-2028* project total approximately $7,426,000, including $4,510,000 in 2027 and $2,916,000 in 2028.

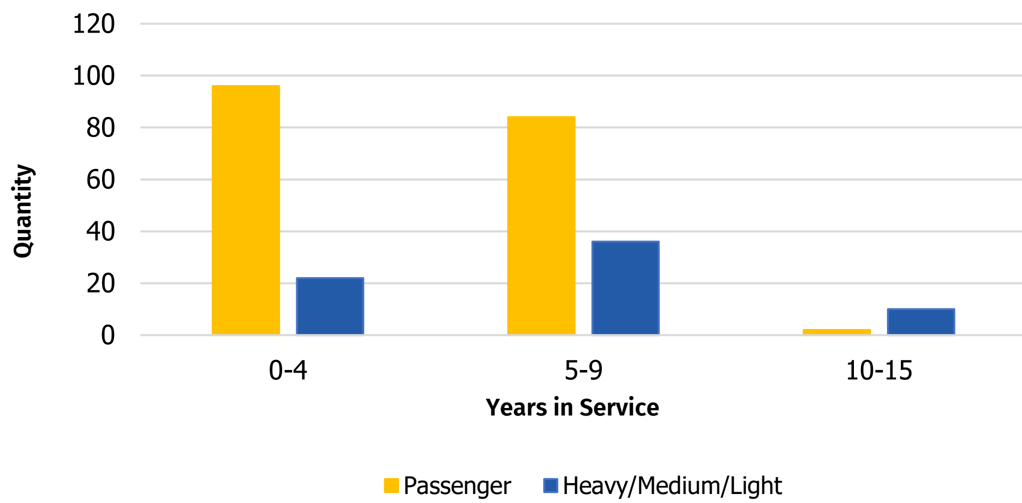
ASSET BACKGROUND

Newfoundland Power maintains a fleet of 250 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 vehicles.

Figure 1
Age Distribution of Vehicles



ASSESSMENT OF ALTERNATIVES

Newfoundland Power applies evaluation criteria to determine whether a vehicle requires replacement.[57] 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 projects 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

[57] 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 2027-2028* 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 2027 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 2027-2028* project.

Table 3
Replace Vehicles and Aerial Devices 2027-2028 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 2027-2028* project would pose a Medium-High (16) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Replace Vehicles and Aerial Devices 2027-2028* 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 2027 and 2028 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 major 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: **$5,000,000**

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.[58] 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*.[59]

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.*

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

2027 CAPITAL PROJECTS AND PROGRAMS

$750,000 AND UNDER

Distribution

Distribution Feeder MIL-02 Refurbishment

Budget: $685,000 *Investment Classification: Renewal* *Category: Project*

This project involves replacing deteriorated infrastructure on distribution feeder MIL-02 in the communities of Milton and George's Brook. A 2.8-kilometre section of the feeder has been identified as having deteriorated equipment including 1960s vintage poles and crossarms, as well as non-standard #4 copper conductor. A 2.8-kilometre section of distribution feeder MIL-02 will be refurbished including replacing deteriorated equipment and replacing non-standard conductor with 1/0 AASC primary conductor. This project is required to provide reliable service to customers at least cost as it addresses identified deficiencies and mitigates potential failures which would result in outages to customers located in Milton and George's Brook.

Distribution Feeder Automation

Budget: $662,000 *Investment Classification: Service Enhancement* *Category: Project*

This 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. This project will mitigate risks to the delivery of reliable service to customers.

New Meters

Budget: $573,000 *Investment Classification: Access* *Category: Program*

This program involves the purchase and installation of meters for new customers. Newfoundland Power is forecasting the requirement to install meters to serve 2,342 new customer connections in 2027. 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.

Replacement Meters

Budget: $616,000 *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 with the federal *Electricity and Gas Inspection Act* and associated regulations.

Distribution

Replacement Services

Budget: $397,000 *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: $249,000 *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: $743,000 *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: $369,000 *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.

Transmission

Transmission Line 59L Relocation

Budget: $715,000 *Investment Classification: Renewal* *Category: Project*

This project involves relocating a section of Transmission Line 59L to the roadside along Kevin Parsons Highway in the town of Torbay. The portion of Transmission Line 59L that will be relocated currently spans North Pond. As a result of increased water levels in North Pond, one of the two dead-end structures that buttress the pond is now inside the high-water mark of the Protected Public Water Supply Area ("PPWSA"). The relocation of this section of Transmission Line 59L will eliminate the long cross-pond span and removes transmission infrastructure from the PPWSA. The project will involve constructing a 1.5-kilometre section of transmission line routed around North Pond along the roadside of Kevin Parsons Highway. This work is necessary to ensure the continued delivery of reliable service to customers in the northern St. John's area.

Generation – Thermal

Mobile Diesel Generator 3 Refurbishment

Budget: $705,000 *Investment Classification: Renewal* *Category: Project*

This project involves the refurbishment of deteriorated components that have been identified in the Mobile Diesel Generator 3 ("MD3") fuel system, chassis, enclosure and protection and control systems. MD3 is operated to provide backup service to customers during planned outages and to restore service to customers following unplanned outages. The refurbishment of MD3 is necessary to ensure its continued operation to mitigate risks to the delivery of reliable service to customers.

Thermal Plant Replacements Due to In-Service Failures

Budget: $328,000 *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 and to support peak load management. 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 and thereby mitigates risks to the delivery of reliable service to customers.

Information Systems

Network Infrastructure

Budget: $465,000 *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

Communications Equipment Upgrades

Budget: $149,000 *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: $731,000 *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.

Tools and Equipment

Budget: $642,000 *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.

Specialized Tools and Equipment

Budget: $626,000 *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. 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 2027 project includes procurement of tools for electrical maintenance, distribution and stores workers, including a battery powered forklift, specialized calibration devices and test equipment, along with specialized thermography tools.

General Property

Physical Security Upgrades

Budget: $568,000 *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: $500,000 *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.

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

	2025	2024
Net Plant Investment		
Plant Investment	2,519,619	2,403,246
Accumulated Depreciation	(1,053,362)	(1,004,688)
Contributions in Aid of Construction	(47,587)	(47,797)
	$1,418,670	$1,350,761
Additions to Rate Base		
Deferred Pension Costs	109,843	108,293
Credit Facility Costs	161	167
Cost Recovery Deferral – Conservation	21,475	21,280
Cost Recovery Deferral – 2025 Revenue Shortfall	17,156	0
Cost Recovery Deferral – Load Research and Retail Rate Design Review	986	635
Cost Recovery Deferral – Hearing Costs	560	874
Cost Recovery Deferral – Pension Capitalization	849	1,198
Customer Finance Programs	1,101	1,049
Demand Management Incentive Account	0	1,545
	$152,131	$135,041
Deductions from Rate Base		
Weather Normalization Reserve	(4,035)	2,896
Other Post-Employment Benefits	88,543	86,308
Customer Security Deposits	688	618
Accrued Pension Obligation	5,671	5,512
Accumulated Deferred Income Taxes	34,678	33,287
Refundable Investment Tax Credits	33	294
	$125,578	$128,915
Year End Rate Base	1,445,223	1,356,887
Average Rate Base Before Allowances	1,401,055	1,334,897
Rate Base Allowances		
Materials and Supplies Allowance	17,319	14,743
Cash Working Capital Allowance	1,344	7,551
Average Rate Base at Year End	$1,419,718	$1,357,191

May 2026

2027 Capital Budget Overview

NEWFOUNDLAND POWER
A FORTIS COMPANY

TABLE OF CONTENTS

Page

1.0 APPLICATION OVERVIEW

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") proposed 2027 Capital Budget totals approximately $149.3 million. The 2027 Capital Budget includes:

(i) Proposed single-year projects and programs in excess of $750,000 in the amount of $79,411,000;
(ii) Proposed single-year projects and programs $750,000 and under in the amount of $9,723,000;
(iii) Proposed multi-year projects with capital expenditures $9,551,000 in 2027, $23,304,000 in 2028 and $12,867,000 in 2029; and
(iv) Previously approved multi-year projects with capital expenditures of $50,664,000 in 2027 and $8,040,000 in 2028.

The 2027 Capital Budget includes 22 recurring capital programs and 49 capital projects, 14 of which have been previously approved. The 2027 Capital Budget is approximately $11.4 million more than the approved *2026 Capital Budget Application*.[1]

Approximately 57% of the capital expenditures included in the 2027 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 2027 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 four 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 22% of capital expenditures included in the 2027 Capital Budget are associated with general plant, service enhancement and mandatory expenditures. These expenditures are associated with proposed enhancements and upgrades to key information systems, the purchase of vehicles, and recurring programs to maintain properties and tools.

The remaining 21% of capital expenditures included in the 2027 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 2,342 new customer connections in 2027, as well as the requirement to address load growth on two distribution feeders, one in St. John's Region and one in Eastern Region.

Overall, the 2027 Capital Budget represents the capital additions and improvements necessary to continue providing safe and reliable service to customers at the lowest possible cost and to ensure that customers continue to have equitable access to an adequate supply of power.

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1 The Board approved Newfoundland Power's *2026 Capital Budget Application* in the amount of $137,943,000 in Order No. P.U. 38 (2025).

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 *2027 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 Signal49 Research, such as forecasted housing starts.[6] 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.[7] 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 in 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.

[6] Signal49 Research, previously known as the Conference Board of Canada, changed its operating name in January 2026.
[7] 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.

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.[8]

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 or costs of individual budget items.

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.

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8 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 2027 Capital Budget identifies seven capital projects that were planned for 2027 but have been deferred to future years. There is one capital project that was previously deferred and is now proposed for 2027. One capital project was planned for a subsequent year and advanced to 2027. Two projects have been modified for inclusion in the 2027 Capital Budget. Appendix B provides the list of the capital projects that were deferred, modified or advanced.

The prioritization and potential deferral of capital expenditures are assessed based on potential risks to customers. This includes engineering assessments of the likelihood that an asset will fail and the potential reliability, safety, environmental or economic consequences for customers if failure were to occur. In 2022, following the issuance of 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 2027 capital expenditures.

2.3 Balancing Cost and Service

2.3.1 Service Reliability

Newfoundland Power owns and operates approximately 9,800 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.[9] Long-term asset management strategies, such as the *Substation Refurbishment and Modernization Plan, Transmission Line Rebuild Strategy* and the *Substation Power Transformer Strategy* provide a structured approach to maintaining the condition of a large volume of electrical system assets. Annual inspections support routine preventative and corrective maintenance programs, with substations inspected eight times annually, transmission lines inspected annually, and distribution lines inspected on a seven-year cycle.

The service reliability experienced by customers also reflects the Company's response when outages occur. Newfoundland Power's operational response requires the deployment of a skilled workforce throughout its service territory, including powerline technicians, technologists and engineers. A combination of operational technologies, and adequate tools and equipment are necessary to ensure the effective and efficient deployment of the Company's workforce.

Annual capital expenditures are essential to maintaining both the Company's electrical system condition and its operational response. The Company is currently focused on implementing the *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 meet current requirements. The selected asset management

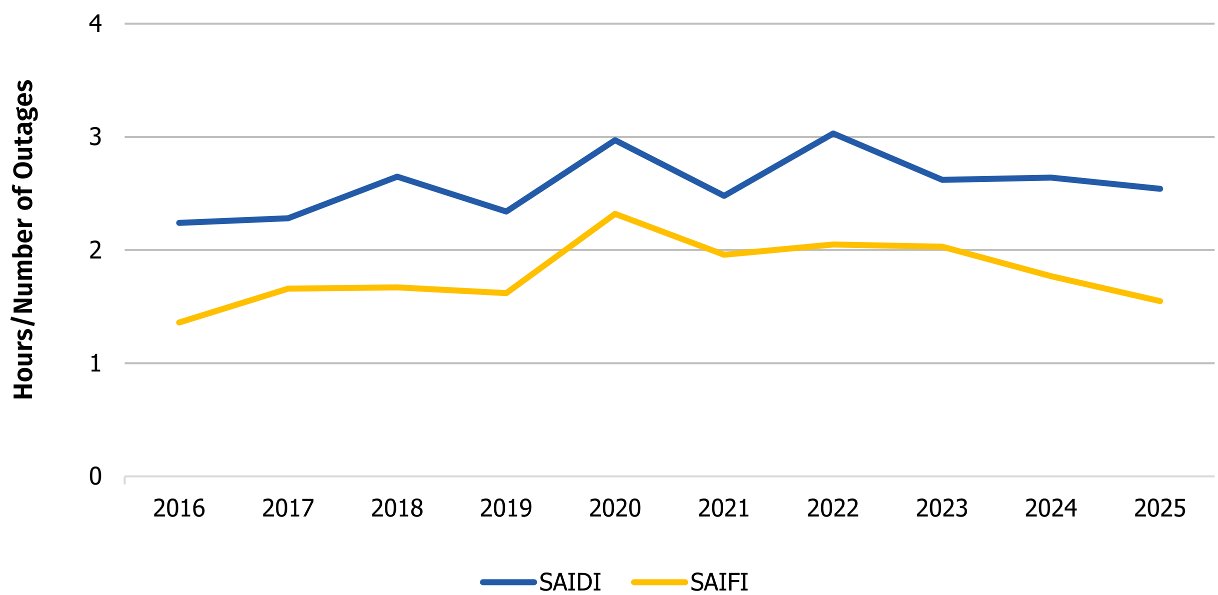
[9] The primary engineering standard for distribution and transmission systems is Canadian Standards Association ("CSA") standard *C22.3 No.1-15 Overhead Systems*.

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

technology is a modern equivalent to the legacy system, with integrations to several other technologies. The selected technology will also provide a foundation for future enhancements as the Company's asset management system continues to mature.

Figure 1 shows the average duration ("SAIDI") and frequency ("SAIFI") of outages to Newfoundland Power's customers from 2016 to 2025 under normal operating conditions.[11]

Figure 1
Newfoundland Power
SAIDI and SAIFI - Normal Operating Conditions
(2016-2025)



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 2016 to 2025.[12]

Figure 2
Newfoundland Power vs. Canadian Average
SAIDI - Normal Operations
(2016-2025)

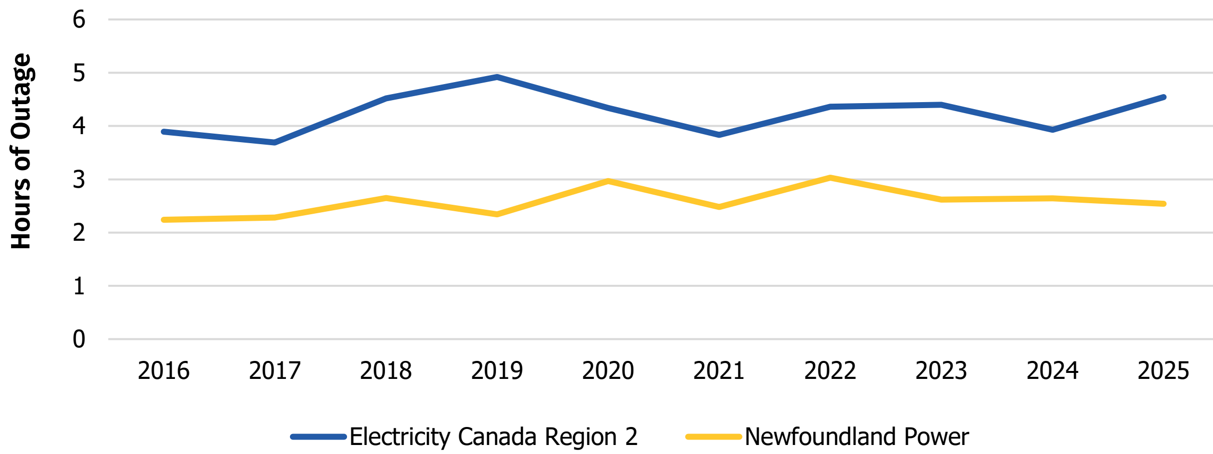
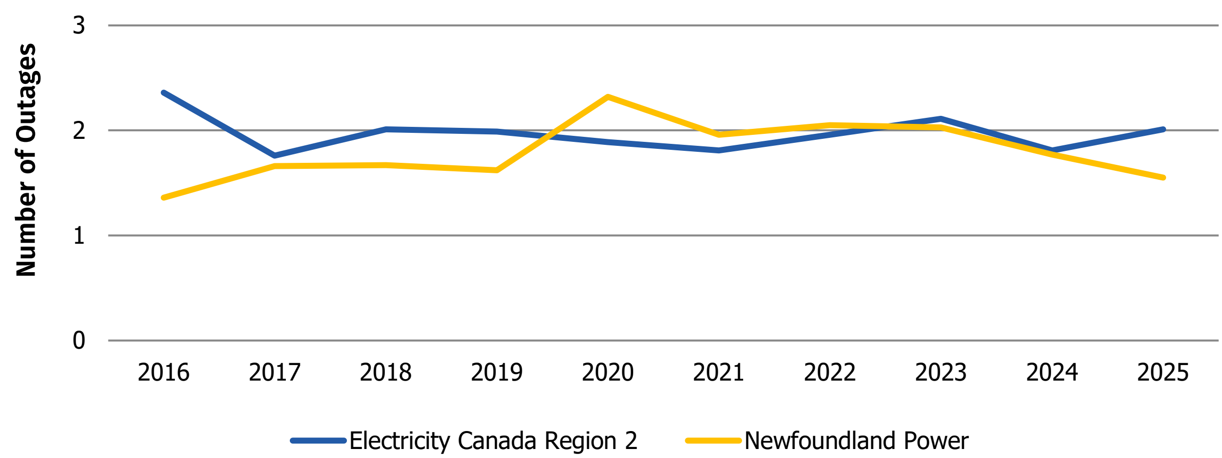


Figure 3
Newfoundland Power vs. Canadian Average
SAIFI - Normal Operating Conditions
(2016-2025)



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12 At the time of filing, 2025 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.

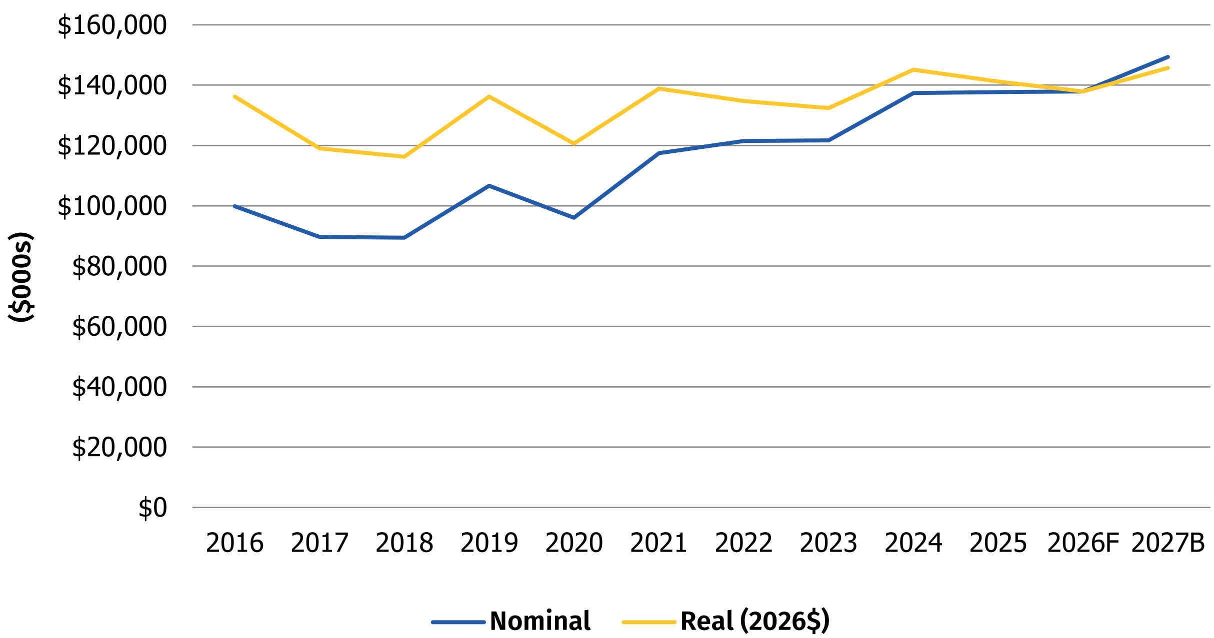
While overall levels of service reliability are viewed as acceptable, customers in certain areas experience service reliability that is below Newfoundland Power's corporate average. Appendix D provides a list of the Company's worst performing feeders.

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 2016 to 2025, the 2026 forecasted expenditure and the 2027 Capital Budget.

Figure 4
Newfoundland Power Capital Expenditures
(2015-2027F)



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13 Newfoundland Power's SAIDI averaged approximately 2.6 hours/year from 2016 to 2025. This compares to an Electricity Canada average SAIDI of 4.2 hours/year over the same period.

14 Newfoundland Power's SAIFI averaged approximately 1.8 outages/year from 2016 to 2025. This compares to an Electricity Canada average SAIFI of 2.0 outages/year over the same period.

Newfoundland Power's capital expenditures have averaged approximately $115.5 million annually from 2017 to 2026, or $132.3 million when adjusted for inflation. On an inflation-adjusted basis, annual expenditures have ranged from approximately $116 million in 2018 to $145.2 million in 2024. The 2027 Capital Budget of $149.3 million is approximately 3% higher than the top of this range. This primarily reflects the increase in planned refurbishments to address risks associated with the Company's aging assets.

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 forecast 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 $10 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 For example, customer benefits associated with hydro plant projects included in the Application will result in the continued provision of low-cost electricity production to customers.

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 2018 and 2027.[21]

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

	2018	2027[22]	Change
Actual	222.9[23]	291.0	31%
Inflation Adjusted[24]	295.0	291.0	-1%

Newfoundland Power's contribution to revenue requirement increased by approximately 31% from 2018 to 2027. On an inflation-adjusted basis, the Company's contribution to revenue requirement in 2027 decreased by approximately 1% from 2018 to 2027.

Table 2 compares Newfoundland Power's total contribution to average customer rates in cents per kWh in 2018 and 2027.

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

	2018	2027[25]	Change
Actual	3.72	4.87	31%
Inflation Adjusted[26]	4.92	4.87	-1%

Newfoundland Power's contribution to average customer rates increased by approximately 31% from 2018 to 2027. On an inflation-adjusted basis, the Company's contribution to average customer rates decreased by approximately 1% from 2018 to 2027.

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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 total base rate 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 $116 million per year over this period.

In Newfoundland Power's view, the Company's approach to capital planning aims to minimize overall costs to customers over the longer term. This is consistent with the least-cost delivery of reliable service to customers.

2.3.4 Atlantic Canadian Comparison

The four primary distributors of electricity in Atlantic Canada are: (i) Newfoundland Power; (ii) Nova Scotia Power; (iii) NB Power; and (iv) Maritime Electric. Each of these utilities serves a mix of urban and rural customers.

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 2015 to 2024; 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	2015	2024	Growth	2015-2024
Newfoundland Power	1,216	1,756	44%	2.4
Atlantic Canadian Utilities[28]	1,238	2,096	69%	3.9

Newfoundland Power's investment in T&D assets has increased by 44% over the 10-year period ending 2024. This is lower than the 69% average increase of other Atlantic Canadian utilities.

Over the same period, the Company's customers have experienced 38% fewer outage hours in comparison to customers of other Atlantic Canadian utilities.[29] The Company's average outage duration was among the lowest of any Atlantic Canadian utility over this period.[30]

27 Reflects the average property, plant and equipment in T&D assets of Nova Scotia Power and Maritime Electric. Due to a change in accounting standards in 2016, the Company is unable to provide the same information for New Brunswick Power. Newfoundland Power can provide that NB Power's property, plant and equipment relating to T&D assets increased by approximately 48% from 2016 to 2024. By comparison, Newfoundland Power's T&D assets increased by approximately 39% over the same period. 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 $2,476 million in 2015 ($2,476 million / 2 = $1,238 million) and $4,191 million in 2024 ($4,191 million / 2 = $2,096 million).

29 (2.4 – 3.9) / 3.9 = -0.38, or -38%.

30 The average SAIDI for the other Atlantic Canadian utilities ranged from 2.3 to 5.4.

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 2027 EXPENDITURES

3.1 2027 Capital Budget Overall

Newfoundland Power's proposed 2027 Capital Budget totals approximately $149.3 million, including approximately $9.7 million of 2027 expenditures that are $750,000 and under and approximately $50.7 million of 2027 expenditures that were previously approved by the Board.[31] The Application also proposes 14 new multi-year projects. The new multi-year projects include expenditures of approximately $9.6 million in 2027.

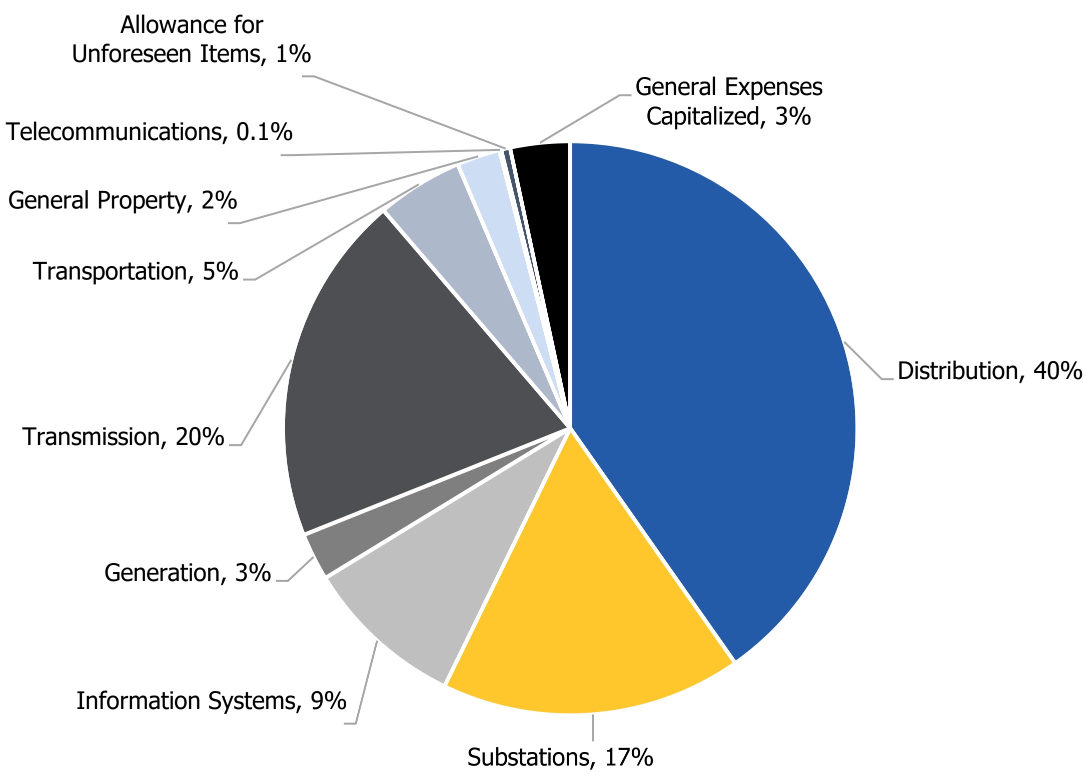
The following sections provide breakdowns of the 2027 Capital Budget by asset class, category, investment classification and materiality.

3.2 2027 Capital Budget by Asset Class

Newfoundland Power organizes its annual capital budget by asset class.

Figure 5 provides the proposed 2027 Capital Budget by asset class, including previously approved multi-year projects.

Figure 5
2027 Capital Budget by Asset Class



31 For expenditures incurred to date, see the *2026 Capital Expenditure Status Report* provided with the Application.

The Distribution asset class accounts for approximately 40% of proposed capital expenditures for 2027. Approximately half of distribution expenditures are required to connect new customers to the electrical system. Approximately 46% of distribution expenditures relate to the refurbishment of assets through preventative and corrective maintenance programs and specific feeder refurbishments for the distribution system. The remaining 5% of distribution expenditures are required to complete upgrades to the distribution system to accommodate load growth on specific areas of the distribution system. The largest expenditure under the Distribution asset class is *Extensions* at $13,852,000.

The Transmission asset class accounts for approximately 20% of proposed capital expenditures for 2027. The majority of transmission expenditures relate to the rebuilding of transmission lines constructed in the 1960s and 1970s. This includes the third 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 $9.6 million in 2027. Transmission expenditures also include approximately $13.3 million in 2027 to conclude the project to rebuild transmission line 100L.

The Substations asset class accounts for approximately 17% of proposed capital expenditures for 2027. The majority of substation expenditures relate to previously approved multi-year projects including the procurement of a spare power transformer, power transformer replacements at Molloy’s Lane Substation, Gander Substation, Mobile Plant Substation and King’s Bridge Substation, the refurbishment and modernization of the Greenspond Substation, and the Lewisporte-Boyd’s Cove 138 kV Conversion at a combined cost of $17.3 million in 2027.

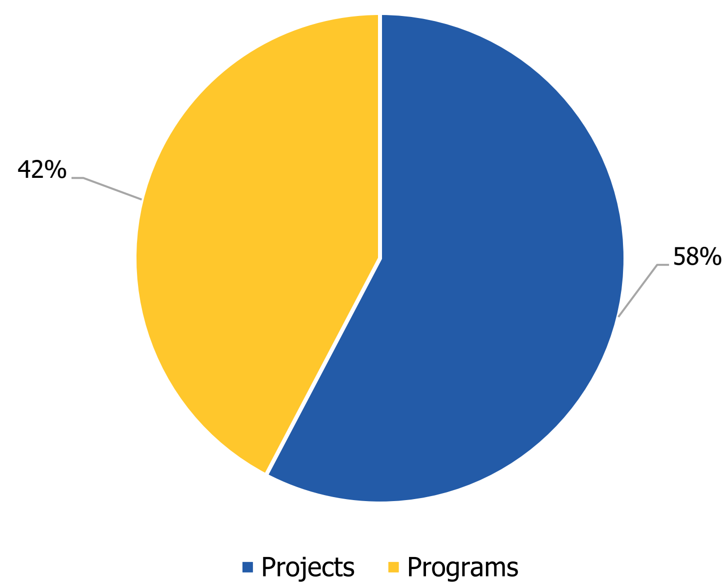
The Information Systems asset class accounts for approximately 9% of proposed capital expenditures for 2027. Approximately half of Information Systems expenditures relate to multi-year projects associated with the replacement of the Company’s Geographic Information System and the modernization of customer correspondence at a combined expenditure of $6.3 million in 2027. In addition, approximately $0.9 million of proposed capital expenditures are related to investments in cybersecurity in 2027.

The remaining asset classes account for between less than 1% and 5% of proposed capital expenditures for 2027.

3.3 2027 Capital Budget by Category

Figure 6 provides a breakdown of Newfoundland Power's 2027 Capital Budget by category, including previously approved multi-year projects.

Figure 6
2027 Capital Budget by Category

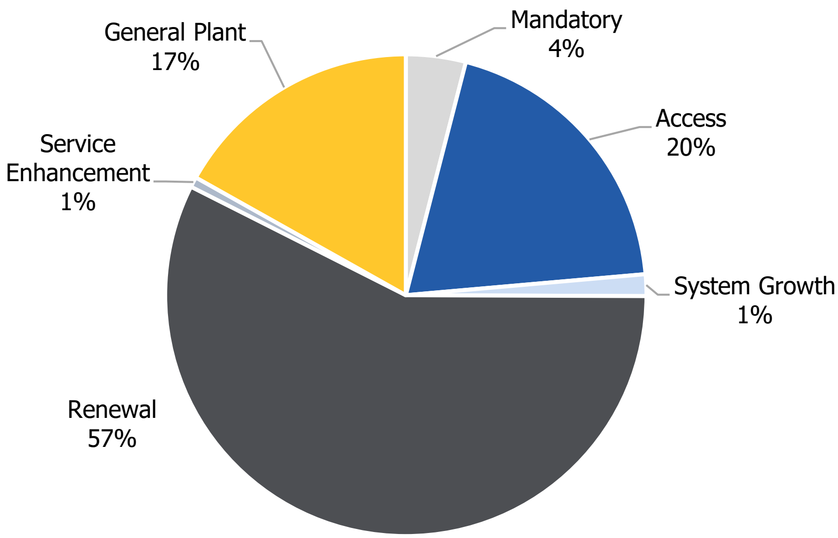


Newfoundland Power's proposed 2027 Capital Budget includes 49 capital projects and 22 capital programs. Capital projects account for approximately 58% of capital expenditures for 2027, with the remaining 42% attributable to recurring programs.

3.4 2027 Capital Budget by Investment Classification

Figure 7 shows Newfoundland Power's proposed 2027 Capital Budget by investment classification, including previously approved multi-year projects.

Figure 7
2027 Capital Budget by Investment Classification



Renewal expenditures account for approximately 57% of proposed capital expenditures for 2027. These expenditures are primarily driven by the age and condition of Newfoundland Power's electrical system. Subsequent years of previously approved multi-year projects account for approximately half of Renewal expenditures in 2027. Preventative and corrective maintenance programs account for approximately two thirds of the remaining Renewal expenditures.

Access expenditures account for approximately 20% of proposed capital expenditures for 2027. 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 2,342 new customer connections in 2027.

General Plant expenditures account for approximately 17% of proposed capital expenditures for 2027. 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. The 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.

Mandatory expenditures account for approximately 4% of proposed capital expenditures for 2027. 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 2% of proposed capital expenditures in 2027. There is one proposed capital project proposed for 2027 to address system growth on two distribution feeders on the electrical system. In addition, one previously approved multi-year project with expenditures in 2027 addresses localized load growth on one distribution feeder in the Deer Lake area.

Service Enhancement expenditures account for approximately 1% of proposed capital expenditures for 2027. Service Enhancement expenditures in 2027 are driven by the need to upgrade assets to meet system operational requirements more efficiently and effectively through the deployment of automation and safety improvements to the Company's assets.

3.5 2027 Capital Budget by Materiality

Table 4 provides an overview of the 2027 Capital Budget by materiality, including previously approved multi-year projects.[32]

Table 4
2027 Capital Budget by Materiality

Threshold	Quantity of Projects/Programs	Total Expenditures ($000s)	Percentage of Total Expenditures
Less than $1 million[33]	27	16,562	11%
$1 million - $5 million	31	50,195	34%
Greater than $5 million	13	82,592	55%
Total	71	$149,349	100%

Of the 71 total capital projects and programs included in the 2027 Capital Budget, 58 are less than $5 million. The 13 capital projects and programs greater than $5 million include the previously approved *Geographic Information System Upgrade, Lewisporte-Boyd's Cove 138 kV Conversion, New Transmission Line from LEW to BOY, Replace Vehicles and Aerial Devices 2026-2027* and *Transmission Line 100L Rebuild* projects. There has been no change in the nature, scope or magnitude of these projects.

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 19 capital projects and programs that are $750,000 and under.

The remaining 8 capital programs and projects greater than $5 million that are proposed for 2027 are:

(i) ***Extensions***, which involves the construction of distribution lines to connect new customers to the electrical system. Capital expenditures for this program total approximately $13.9 million for 2027. 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 $8.3 million for 2027. The budget estimate is based on historical expenditures.

(iii) ***Replacement Transformers***, which involves purchasing distribution system transformers to replace units that have deteriorated or failed in service. Capital expenditures for this program total approximately $5.6 million for 2027. The budget estimate is based on historical expenditures.

(iv) ***Rebuild Distribution Lines***, which involves the preventive maintenance of deteriorated distribution structures and electrical equipment identified through inspections. Capital expenditures for this project total approximately $5.5 million in 2027. The budget estimate is based on historical expenditures.

(v) ***Replace Vehicles and Aerial Devices 2027-2028,*** which involves the replacement of the Company's vehicle fleet to provide reliable service to customers at the lowest possible cost. Capital expenditures for this project in 2027 total approximately $4.5 million. The budget estimate is based on detailed estimates.

(vi) ***Blaketown Substation Refurbishment and Modernization,*** which is the replacement and modernization of deteriorated equipment at Blaketown ("BLK") Substation. Capital expenditures for this project in 2027 total approximately $528,000. The budget estimate is based on detailed engineering estimates.

(vii) ***Portable Substation*** involves the purchase of a portable substation designed to temporarily replace the functionality of a substation. Capital expenditures for this project in 2027 total approximately $990,000. The budget estimate is based on detailed engineering estimates.

(viii) ***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 $5.0 million for 2027. The budget estimate is determined in accordance with the percentage allocations as presented in Newfoundland Power's *2022/2023 General Rate Application*.

Including previously approved expenditures, the thirteen capital projects and programs exceeding $5 million in materiality account for approximately 55% of capital expenditures for 2027.

APPENDIX A:

Capital Expenditure Classification and Categorization Summary

Table A-1 2027 Capital Budget Proposed Single-Year Projects and Programs in Excess of $750,000			
Investment Classification	Budget ($000s)	Asset Class	Category
Mandatory			
General Expenses Capitalized	5,000	GEC	Project
Allowance for Unforeseen Items	750	Unforeseen Allowance	Project
Total Mandatory	$5,750		
Access			
Extensions	13,852	Distribution	Program
New Transformers	4,943	Distribution	Program
Relocate/Replace Distribution Lines for Third Parties	3,872	Distribution	Program
New Services	3,520	Distribution	Program
New Street Lighting	2,496	Distribution	Program
Total Access	$28,683		
System Growth			
Feeder Additions for Load Growth	1,284	Distribution	Project
Total System Growth	$1,284		
Renewal			
Reconstruction	8,319	Distribution	Program
Replacement Transformers	5,573	Distribution	Program
Rebuild Distribution Lines	5,502	Distribution	Program
Substation Replacements Due to In-Service Failures	4,613	Substations	Program
Transmission Line Maintenance	3,465	Transmission	Program

Table A-1
2027 Capital Budget
Proposed Single-Year Projects and Programs in Excess of $750,000

Investment Classification	Budget ($000s)	Asset Class	Category
Transmission Line 114L Replacement and 142L Relocation	2,341	Transmission	Project
Distribution Feeder Extension COB-02	1,828	Distribution	Project
Hydro Facility Rehabilitation	1,531	Generation - Hydro	Project
Distribution Feeder CAB-01 Refurbishment	972	Distribution	Project
Replacement Street Lighting	936	Distribution	Program
Distribution Feeder GDL-02 Loop 10 and Loop 20 Refurbishment	789	Distribution	Project
Hydro Plant Replacements due to In-Service Failure	764	Generation - Hydro	Program
Total Renewal	$36,633		
General Plant			
Shared Server infrastructure	1,974	Information Systems	Project
System Upgrades	1,899	Information Systems	Project
Application Enhancements	1,442	Information Systems	Project
Cybersecurity Upgrades	962	Information Systems	Project
Personal Computer Infrastructure	784	Information Systems	Project
Total General Plant	$7,061		
Total	$79,411		

Table A-2
2027 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	249	Distribution	Project
Total Mandatory	$249		
Access			
New Meters	573	Distribution	Program
Total Access	$573		
Renewal			
Substation Protection and Control Replacements	743	Substations	Program
Transmission Line 59L Relocation	715	Transmission	Project
MD3 Refurbishment	705	Generation-Thermal	Project
Distribution Feeder MIL-02 Refurbishment	685	Distribution	Project
Replacement Meters	616	Distribution	Program
Replacement Services	397	Distribution	Program
Thermal Plant Replacements Due to In-Service Failures	328	Generation - Thermal	Program
Total Renewal	$4,189		
Service Enhancement			
Distribution Feeder Automation	662	Distribution	Project
Substation Ground Grid Upgrades	369	Substations	Project
Total Service Enhancement	$1,031		

Table A-2 2027 Capital Budget Proposed Single-Year Projects and Programs $750,000 and Under			
Investment Classification	Budget ($000s)	Asset Class	Category
General Plant			
Additions to Real Property	731	General Property	Program
Tools and Equipment	642	General Property	Program
Purchase Specialized Tools and Equipment	626	General Property	Project
Physical Security Upgrades	568	General Property	Program
Building Accessibility Improvements	500	General Property	Project
Network Infrastructure	465	Information Systems	Project
Telecommunications	149	Telecommunications	Program
Total General Plant	$3,681		
Total	$9,723		

Table A-3
2027 Capital Budget
Proposed Multi-Year Projects

Title	Asset Class	Investment Classification	Project / Program	Budget ($000s)			
				2027	2028	2029	Total
Distribution Reliability Initiative	Distribution	Renewal	Project	871	2,069		2,940
Distribution Feeder ILC-02 Refurbishment	Distribution	Renewal	Project	595	610		1,205
Distribution Feeder GBY-01 Refurbishment	Distribution	Renewal	Project	402	958		1,360
Blaketown Substation Refurbishment and Modernization	Substations	Renewal	Project	528	5,700		6,228
Rattling Brook Substation Refurbishment and Modernization	Substations	Renewal	Project	74	1,426		1,500
Portable Substation	Substations	Renewal	Project	990	3,894	5,049	9,933
Mobile Plant Substation Refurbishment and Modernization	Substations	Renewal	Project	299	925		1,224
LAU-T1 Power Transformer Replacement	Substations	Renewal	Project	99	3,186		3,285
LBK-T1 Power Transformer Replacement	Substations	Renewal	Project	73	86	2,175	2,334
HAR-T1 Power Transformer Replacement	Substations	Renewal	Project	75	71	2,758	2,904
RRD-T3 Power Transformer Replacement	Substations	Renewal	Project	66	64	2,565	2,695
Rose Blanche Hydro Plant Refurbishment	Generation- Hydro	Renewal	Project	649	1,079		1,728
Microsoft Enterprise Agreement	Information Systems	General Plant	Project	320	320	320	960
Replace Vehicles and Aerial Devices 2027-2028	Transportation	General Plant	Project	4,510	2,916		7,426
			Total	$9,551	$23,304	$12,867	$45,722

Table A-4
2027 Capital Budget
Previously Approved Multi-Year Projects

Title	Asset Class	Investment Classification	Project / Program	Budget ($000s)				
				2025	2026	2027	2028	Total
Feeder Additions for Load Growth	Distribution	Renewal	Project		250	887		**1,137**
Greenspond Substation Refurbishment and Modernization	Substations	Renewal	Project		374	2,578		**2,952**
Gander Substation Power Transformer Replacement	Substation	Renewal	Project	17	3,905	263		**4,185**
Molloy's Lane Substation Power Transformer Replacement	Substation	Renewal	Project		12	2,789		**2,801**
Lewisporte-Boyd's Cove 138 kV Conversion	Substation	Renewal	Project		568	7,551		**8,119**
Substation Spare Power Transformer Inventory	Substation	Renewal	Project		13	3,906		**3,919**
Mobile Plant Substation Power Transformer Replacement	Substation	Renewal	Project		12	93	2,522	**2,627**
Kings Bridge Substation Power Transformer Replacement	Substation	Renewal	Project		12	93	2,866	**2,971**
New Transmission Line from LEW to BOY	Transmission	Renewal	Project	1,886	9,283	9,553		**20,722**
Transmission Line 100L Rebuild	Transmission	Renewal	Project		450	13,323		**13,773**
Geographic Information System Upgrade	Information Systems	General Plant	Project		500	5,173	2,652	**8,325**
Customer Correspondence Modernization	Information Systems	General Plant	Project		782	1,175		**1,957**
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	$1,903	$19,319	$50,664	$8,040	$79,926

APPENDIX B:

Deferred, Modified and Advanced Capital Expenditures

Deferred, Modified and Advanced Capital Expenditures

The Provisional Guidelines require an explanation of capital expenditures that were modified, re-prioritized or deferred. Specifically, the Provisional Guidelines require an explanation as to (i) the expenditures which had been planned for the year but which were modified, re-prioritized or deferred until a future year; and (ii) the expenditures which are proposed for the year after having been deferred in a previous year.

Table B-1 lists the capital expenditures that were planned for 2027 but have been deferred to subsequent years.

Table B-1
Capital Projects Deferred from 2027 to Subsequent Years

Project	Description
Distribution Feeder Reconfiguration PHR-GOU	The Distribution Feeder Reconfiguration from Petty Harbour to Goulds was originally planned for 2027 and has been deferred to allow for further engineering assessment and evaluation of alternatives. This project is now planned for 2028.
Grand Falls Substation 4.16 kV Conversion	The Grand Falls Substation 4.16 kV Conversion was originally planned for 2027 and has been deferred to allow for further engineering assessment and evaluation of alternatives. This project is now planned for 2028.
Tors Cove Hydro Plant Refurbishment	The Tors Cove Hydro Plant Refurbishment was originally planned for 2027 and has been deferred to allow for further engineering assessment and evaluation of alternatives. This project is now planned for 2028.
Lawn Hydro Plant Refurbishment	The Lawn Hydro Plant Refurbishment was originally planned for 2027 and has been deferred to allow for further engineering assessment and economic analysis. This project is now planned for 2031.
Hearts Content Hydro Plant Refurbishment	The Hearts Content Hydro Plant Refurbishment was originally planned for 2027 and has been deferred to allow for further engineering assessment and evaluation of alternatives. This project is now planned for 2031.
Victoria Hydro Plant Refurbishment	The Victoria Hydro Plant Refurbishment was originally planned for 2026 and has been deferred to allow for further engineering and economic assessment. This project is now planned for 2028.
Transmission Line Rebuilds – 95L	The Transmission Line Rebuild of 95L was originally planned for 2027 and has been deferred to allow for further engineering assessment and evaluation of alternatives. This project is now planned for 2028.

Table B-2 lists the capital expenditures that were planned for future years but have been advanced to 2027.

Table B-2 2027 Capital Projects Advanced from Future Years	
Project	Description
Rose Blanche Hydro Plant Refurbishment	The Rose Blanche Hydro Plant Refurbishment has been advanced to 2027 from 2029, due to an updated assessment of existing infrastructure condition.

Table B-3 lists the capital expenditures that were deferred from previous years and are now planned for 2027.

Table B-3 Capital Projects Deferred or Modified from Previous Years	
Project	Description
Rocky Pond Hydro Plant Refurbishment	The Rocky Pond Hydro Plant requires refurbishment to address its deteriorated condition. The project was originally planned for 2026 and was deferred to allow for further engineering assessment. Assessments have been completed and the refurbishment will be addressed under the 2027 *Hydro Facility Rehabilitation* project.

Table B-4 lists the capital expenditures proposed for 2027 that have been modified through the Company's capital planning process.

Table B-4 Capital Projects Modified in 2027	
Project	Description
Portable Substation	A Portable Substation is proposed for 2027-2029. This project is required to maintain spare capacity, ensuring system reliability. The project cost was updated to reflect more accurate cost estimates during project planning.
Transmission Line Extension – 142L	The Transmission Line Extension - 142L is proposed for 2027. During project planning, an updated analysis of alternatives determined a different route was required and remained least-cost.

APPENDIX C:

Prioritized List of 2027 Capital Expenditures

Prioritized List of 2027 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.[34]

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 2027 are provided below. The Company expects its approach may evolve going forward as its asset management practices are matured.

[34] Producing quantifiable risk and reliability values to prioritize capital expenditures would require the use of more advanced software. Newfoundland Power is currently focused on the implementation of the approved *Asset Management Technology Replacement* project. Options to gather the data required to calculate risk mitigation or reliability improvement are expected to be assessed upon completion of the project.

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	2	3	4	5
		Negligible	Minor	Moderate	Serious	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.[35] A capital project or program may be of consequence to one or more of these business objectives. Once the relevant consequences are identified, values are determined for the severity of these consequences based on guidelines that rely on a combination of quantifiable factors and engineering judgment.

Table C-1 provides the guidelines used in assigning consequence values.

Table C-1
Guidelines for Determining Consequence Values

Consequence	Factors	Other Considerations
Reliability	Number of customers affected by potential outage: 1 – Less than 100 customers 2 – 100 to 500 customers 3 – 500 to 1,000 customers 4 – 1,000 to 5,000 customers 5 – Greater than 5,000 customers	Examples of other considerations include outage duration and frequency, resiliency to severe weather, system configuration (e.g. radial or looped), and the impact on operations of the loss of a technology or piece of equipment.
Safety	Severity of potential safety incident: 1 – First Aid 2 – One Medical Aid 3 – Multiple Medical Aids 4 – Lost Time/Restricted Work 5 – Fatality/Permanent Disability	Examples of other considerations include regulatory compliance (e.g. Occupational Health and Safety Regulations), public safety and cybersecurity.
Environment	Severity of potential environmental incident: 1 – Immaterial Impact 2 – Internal Impact Only 3 – Isolated Off-Site Impact 4 – Widespread Off-Site Impact 5 – Regulatory Requirement Breached	Examples of other considerations include potential impact on local wildlife and biodiversity.
Economic	Overall customer benefit: 1 – Immaterial NPV 2 – $10,000 to $100,000 NPV 3 – $100,000 to $500,000 NPV 4 – $500,000 to $1,000,000 NPV 5 – Greater than $1,000,000 NPV	Examples of other considerations include annual operating cost impacts, maintenance cost trends and the cost of emergency response.

[35] As outlined in section 2.1, Newfoundland Power is required to provide services and facilities that are reasonably safe and adequate and just and reasonable and to provide customers with reliable service at the lowest possible cost. The Company must also comply with various other provincial and federal regulations, as well as industry standards including environmental, health and safety regulations.

Probability is assessed from the perspective of how likely the identified consequence is to occur if a capital project or program did not proceed.

Probability is based on engineering 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 2027 Capital Expenditures

Table C-2 provides the prioritized list of 2027 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.[36]

Table C-2
Prioritized List of 2027 Capital Expenditures

Project/Program Name	Priority Score
Previously Approved Multi-Year Projects	
Greenspond Substation Refurbishment & Modernization	-
Molloy's Lane Substation Power Transformer Replacement	-
Feeder Additions for Load Growth[37]	-
Replace Vehicles and Aerial Devices 2026-2027	-
Transmission Line 100L Rebuild	-
New Transmission Line from LEW-BOY	-
Mobile Substation Power Transformer Replacement	-
Kings Bridge Road Substation Power Transformer Replacement	-
Substation Spare Power Transformer Inventory	-
Geographic Information System Upgrade	-
Customer Correspondence Modernization	-
Gander Substation Power Transformer Replacement	-
Lewisporte-Boyd's Cove 138 kV Conversion	-
Mandatory	
General Expenses Capitalized	-
Allowance for Unforeseen Items	-
Access	
Extensions	-
New Transformers	-
New Services	-
Relocate/Replace Distribution Lines for Third Parties	-
New Street Lighting	-

36 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.

37 Previously approved multi-year project to address an identified overload condition of distribution feeder DLK-03.

Table C-2 Prioritized List of 2027 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
Hydro Plant Replacements Due to In-Service Failures	25
Rebuild Distribution Lines	20
Replacement Transformers	20
Transmission Line 114L Replacement and 142L Relocation	20
Shared Server Infrastructure	20
Cybersecurity Upgrades	20
Distribution Feeder COB-02 Extension	20
Distribution Reliability Initiative	20
Rose Blanche Hydro Plant Refurbishment	20
Blaketown Substation Refurbishment & Modernization	20
Portable Substation	20
Replace Vehicles and Aerial Devices 2027-2028	16
Distribution Feeder CAB-01 Refurbishment	16
Distribution Feeder ILC-02 Refurbishment	16
Hydro Facility Rehabilitation	16
System Upgrades	16
Personal Computer Infrastructure	16
Microsoft Enterprise Agreement	16
RRD-T3 Power Transformer Replacement	16
LBK-T1 Power Transformer Replacement	16
HAR-T1 Power Transformer Replacement	16
LAU-T1 Power Transformer Replacement	16
Rattling Brook Substation Refurbishment and Modernization	16
Mobile Plant Substation Refurbishment and Modernization	16
Replacement Street Lighting	15
Application Enhancements	15
Distribution Feeder GBY-01 Refurbishment	12
Distribution Feeder GDL-02 Loop 10 and Loop 20 Refurbishment	10

APPENDIX D:

List of Worst Performing Feeders

List of Worst Performing Feeders

The Provisional Guidelines require the utility to provide a list of its 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.[38] 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.

[38] 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 (2016-2025) Sorted by Customer Minutes of Interruption				
Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
SUM-01	5,814	849,467	3.20	7.79
GLV-02	6,986	736,583	4.54	7.98
BVS-04	5,065	629,971	3.14	6.54
DOY-01	6,215	592,141	3.53	5.60
DLK-03	4,399	491,892	3.04	5.72
SCR-01	2,699	441,481	2.81	7.64
BOT-01	4,213	433,282	2.42	4.16
DUN-01	4,185	415,422	3.98	6.59
ROB-01	2,297	405,659	2.12	6.26
BLK-01	3,545	397,500	2.11	3.92
Company Average	1,070	90,597	1.27	1.79

Table D-2
Unscheduled Distribution-Related Outages
10-Year Average
(2016-2025)
Sorted by Distribution SAIFI

Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
GLV-02	6,986	736,583	4.54	7.98
DUN-01	4,185	415,422	3.98	6.59
BHD-01	3,531	337,789	3.70	5.90
DOY-01	6,215	592,141	3.53	5.60
LEW-02	4,928	370,476	3.41	4.42
LGL-02	2,014	197,214	3.33	5.45
SUM-01	5,814	849,467	3.20	7.79
BVS-04	5,065	629,971	3.14	6.54
SMV-01	3,420	274,486	3.06	4.10
DLK-03	4,399	491,892	3.04	5.72
Company Average	1,070	90,597	1.27	1.79

Table D-3 Unscheduled Distribution-Related Outages 10-Year Average (2016-2025) Sorted by Distribution SAIDI				
Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
GLV-02	6,986	736,583	4.54	7.98
SUM-01	5,814	849,467	3.20	7.79
BUC-02	438	73,828	2.74	7.71
ROB-02	402	94,196	1.97	7.66
SCR-01	2,699	441,481	2.81	7.64
SCT-02	683	108,741	2.62	6.99
DUN-01	4,185	415,422	3.98	6.59
BVS-04	5,065	629,971	3.14	6.45
ROB-01	2,297	405,659	2.12	6.26
HBS-01	9	1,822	1.82	6.05
Company Average	**1,070**	**90,597**	**1.27**	**1.79**

Table D-4 Unscheduled Distribution-Related Outages 10-Year Average (2016-2025) Sorted by Distribution CHIKM	
Feeder	Annual Distribution CHIKM
WAV-03	236
KBR-10	193
PAB-05	184
SJM-06	180
PEP-04	180
SLA-10	179
KBR-13	174
TWG-02	168
SJM-04	166
PEP-01	159
Company Average	48

Table D-5 Unscheduled Distribution-Related Outages 10-Year Average (2016-2025) Sorted by Distribution CIKM	
Feeder	Annual Distribution CIKM
KBR-10	213
WAL-05	205
PEP-01	166
PAB-03	165
KEN-03	153
KBR-13	134
KBR-09	132
PAB-05	129
KEN-01	126
MOL-04	121
Company Average	34

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 continue to be consistent with the original approval, further approval of the project is not required.

The 2027 Capital Budget includes fourteen capital projects that were previously approved by the Board. Capital expenditures for these projects total approximately $50,664,000 in 2027.

The following section provides an update on each multi-year project for 2027 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: **Feeder Additions for Load Growth**
Asset Class: **Distribution**
Category: **Project**
Investment Classification: **System Growth**
2027 Expenditures: **$887,000**

The *Feeder Additions for Load Growth* project was included as a multi-year project in Newfoundland Power's *2026 Capital Budget Application*.[39] The *Feeder Additions for Load Growth* project involves addressing 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 and Labrador Hydro's ("Hydro") Wiltondale ("WDL") Terminal Station.

The Board approved the *Feeder Additions for Load Growth* project as a two-year project in Order No. P.U. 38 (2025). The project is proceeding as approved. Engineering design is ongoing to address the overloaded section. Construction is set to begin early in 2027.

Table E-1 provides the approved expenditures for the *Feeder Additions for Load Growth* project.

Table E-1
Feeder Additions for Load Growth Project
Multi-Year Expenditures
($000s)

Cost Category	2026F	2027F	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

Expenditures for the *Feeder Additions for Load Growth* project total approximately $1,137,000, including $887,000 in 2027. For expenditures incurred to date, see the *2026 Capital Expenditure Status Report* filed with the Application.

[39] See Newfoundland Power's *2026 Capital Budget Application,* report *1.1 Feeder Additions for Load Growth*.

Title: **Lewisporte-Boyd's Cove 138 kV Conversion**
Asset Class: **Substations**
Category: **Project**
Investment Classification: **Renewal**
2027 Expenditures: **$7,551,000**

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.*[40] 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.

The Board approved the *Lewisporte-Boyd's Cove 138 kV Conversion* project as a two-year project in Order No. P.U. 38 (2025). The project is proceeding as approved. Engineering design and procurement of long-lead time equipment are being completed in 2026, with overall project completion planned for the fourth quarter of 2027.

Table E-2 provides the approved expenditures for the *Lewisporte-Boyd's Cove 138 kV Conversion.*

Table E-2
Lewisporte-Boyd's Cove 138 kV Conversion Project
Multi-Year Expenditures
($000s)

Cost Category	2026F	2027F	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

Expenditures for the *Lewisporte-Boyd's Cove 138 kV Conversion* total approximately $8,119,000, including $7,551,000 in 2027. For expenditures incurred to date, see the *2026 Capital Expenditure Status Report* filed with the Application.

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

Title:	**Gander Substation Power Transformer Replacement**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
2027 Expenditures:	**$263,000**

The *Gander Substation Power Transformer Replacement* project was included as a multi-year project in Newfoundland Power's *2025 Capital Budget Application*.[41] 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 6,500 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. The new power transformer was procured in 2025 and scheduled to arrive in the fourth quarter of 2026. Final commissioning of the power transformer is scheduled for 2027.

Table E-3 provides the approved expenditures for the *Gander Substation Power Transformer Replacement* project.

Table E-3
Gander Substation Power Transformer Replacement Project
Multi-Year Expenditures
($000s)

Cost Category	2025	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* project total approximately $4,185,000, including $263,000 in 2027. For expenditures incurred to date, see the *2026 Capital Expenditure Status Report* filed with the Application.

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

Title: **Substation Spare Power Transformer Inventory**
Asset Class: **Substations**
Category: **Project**
Investment Classification: **Renewal**
2027 Expenditures: **$3,906,000**

The *Substation Spare Power Transformer Inventory* project was included as a multi-year project in Newfoundland Power's *2026 Capital Budget Application*.[42] The *Substation Spare Power Transformer Inventory* project 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 Board approved the *Substation Spare Power Transformer Inventory* project as a two-year project in Order No. P.U. 38 (2025). The project is proceeding as approved. Engineering design and procurement of the new power transformer are being completed in 2026, with the new transformer scheduled to arrive in the fourth quarter of 2027.

Table E-4 provides the approved expenditures for the *Substation Spare Power Transformer Inventory* project.

Table E-4
Substation Spare Power Transformer Inventory Project
Multi-Year Expenditures
($000s)

Cost Category	2026F	2027F	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

Expenditures for the *Substation Spare Power Transformer Inventory* project total approximately $3,919,000, including $3,906,000 in 2027. For expenditures incurred to date, see the *2026 Capital Expenditure Status Report* filed with the Application.

[42] See Newfoundland Power's *2026 Capital Budget Application*, report *2.2 Substation Power Transformer Strategy*.

Title:	**Greenspond Substation Refurbishment and Modernization**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
2027 Expenditures:	**$2,578,000**

The *Greenspond Substation Refurbishment and Modernization* project was included as a multi-year project in Newfoundland Power's *2026 Capital Budget Application*.[43] 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. 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 Board approved the *Greenspond Substation Refurbishment and Modernization* project as a two-year project in Order No. P.U. 38 (2025). The project is proceeding as approved. Engineering design and procurement of long-lead equipment are in progress and expected to be complete in 2026, with overall project completion expected for the fourth quarter of 2027.

Table E-5 provides the approved expenditures for the *Greenspond Substation Refurbishment and Modernization* project.

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

Cost Category	2026F	2027F	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

Expenditures for the *Greenspond Substation Refurbishment and Modernization* project total approximately $2,952,000, including $2,578,000 in 2027. For expenditures incurred to date, see the *2026 Capital Expenditure Status Report* filed with the Application.

[43] See Newfoundland Power's *2026 Capital Budget Application,* report *2.1 2026 Substation Refurbishment and Modernization*.

Title: **King's Bridge Substation Power Transformer Replacement**
Asset Class: **Substations**
Category: **Project**
Investment Classification: **Renewal**
2027 Expenditures: **$93,000**

The *King's Bridge Substation Power Transformer Replacement* project was included as a multi-year project in Newfoundland Power's *2026 Capital Budget Application*.[44] The *King's Bridge Substation Power Transformer Replacement* project involves the replacement of the King's Bridge ("KBR") Substation power transformer KBR-T3. KBR-T3 is deteriorating, and an assessment of alternatives determined that the unit should be replaced.

The Board approved the *King's Bridge Substation Power Transformer Replacement* project as a three-year project in Order No. P.U. 38 (2025). The project is proceeding as approved. Engineering design and procurement of the new power transformer are being completed in 2026, with the new transformer scheduled to arrive in the third quarter of 2028.

Table E-6 provides the approved expenditures for the *King's Bridge Substation Power Transformer Replacement* project.

Table E-6
King's Bridge Substation Power Transformer Replacement Project
Multi-Year Expenditures
($000s)

Cost Category	2026F	2027F	2028F	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

Expenditures for the *King's Bridge Substation Power Transformer Replacement* project total approximately $2,971,000, including $93,000 in 2027. For expenditures incurred to date, see the *2026 Capital Expenditure Status Report* filed with the Application.

[44] See Newfoundland Power's *2026 Capital Budget Application,* report *2.2 Substation Power Transformer Strategy.*

Title: **Molloy's Lane Substation Power Transformer Replacement**
Asset Class: **Substations**
Category: **Project**
Investment Classification: **Renewal**
2027 Expenditures: **$2,789,000**

The *Molloy's Lane Substation Power Transformer Replacement* project was included as a multi-year project in Newfoundland Power's *2026 Capital Budget Application*.[45] The *Molloy's Lane Substation Power Transformer Replacement* project involves the replacement of the Molloy's Lane ("MOL") Substation power transformer MOL-T2. MOL-T2 is deteriorating, and an assessment of alternatives determined that the unit should be replaced. MOL Substation ensures reliable service for approximately 9,000 customers.

The Board approved the *Molloy's Lane Substation Power Transformer Replacement* project as a two-year project in Order No. P.U. 38 (2025). The project is proceeding as approved. Engineering design and procurement of the new power transformer are being completed in 2026, with the new transformer scheduled to arrive in the fourth quarter of 2027.

Table E-7 provides the approved expenditures for the *Molloy's Lane Substation Power Transformer Replacement.*

Table E-7
Molloy's Lane Substation Power Transformer Replacement Project
Multi-Year Expenditures
($000s)

Cost Category	2026F	2027F	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

Expenditures for the *Molloy's Lane Substation Power Transformer Replacement* project total approximately $2,801,000 including $2,789,000 in 2027. For expenditures incurred to date, see the *2026 Capital Expenditure Status Report* filed with the Application.

45 See Newfoundland Power's *2026 Capital Budget Application,* report *2.2 Substation Power Transformer Strategy.*

Title:	**Mobile Plant Substation Power Transformer Replacement**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
2027 Expenditures:	**$93,000**

The *Mobile Plant Substation Power Transformer Replacement* project was included as a multi-year project in Newfoundland Power's *2026 Capital Budget Application*.[46] 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 Board approved the *Mobile Plant Substation Power Transformer Replacement* project as a three-year project in Order No. P.U. 38 (2025). The project is proceeding as approved. Engineering design and procurement of the new power transformer are being completed in 2026, with the new transformer scheduled to arrive in the third quarter of 2028.

Table E-8 provides the approved expenditures for the *Mobile Plant Substation Power Transformer Replacement* project.

Table E-8
Mobile Plant Substation Power Transformer Replacement Project
Multi-Year Expenditures
($000s)

Cost Category	2026F	2027F	2028F	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

Expenditures for the *Mobile Plant Substation Power Transformer Replacement* project total approximately $2,627,000, including $93,000 in 2027. For expenditures incurred to date, see the *2026 Capital Expenditure Status Report* filed with the Application.

46 See Newfoundland Power's *2026 Capital Budget Application,* report *2.2 Substation Power Transformer Strategy*.

Title: **New Transmission Line from Lewisporte to Boyd's Cove**
Asset Class: **Transmission**
Category: **Project**
Investment Classification: **Renewal**
2027 Expenditures: **$9,553,000**

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*.[47] 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 Newfoundland and Labrador Hydro customers on Fogo Island and Change Islands.

The Board approved the *New Transmission Line from Lewisporte to Boyd's Cove* project as part 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. Environmental approvals and a draft design for the project were completed in 2025. Brush clearing of the right-of-way is planned to begin in the second quarter of 2026, with line construction to follow. Work will continue on this project throughout the remainder of 2026 and 2027.

Table E-9 provides the approved expenditures for the *New Transmission Line from Lewisporte to Boyd's Cove* project.

Table E-9
New Transmission Line from LEW to Boyd's Cove Project
Multi-Year Expenditures
($000s)

Cost Category	2025	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 $9,553,000 in 2027. For expenditures incurred to date, see the *2026 Capital Expenditure Status Report* filed with the Application.

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

Title: **Transmission Line 100L Rebuild**
Asset Class: **Transmission**
Category: **Project**
Investment Classification: **Renewal**
2027 Expenditures: **$13,323,000**

The *Transmission Line 100L Rebuild* project was included as a multi-year project in Newfoundland Power's *2026 Capital Budget Application*.[48] 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.

The Board approved the *Transmission Line 100L Rebuild* project as a two-year project in Order No. P.U. 38 (2025). The project is proceeding as approved. Engineering design is ongoing, and construction will begin in 2027.

Table E-10 provides the approved expenditures for the *Transmission Line 100L Rebuild* project.

Table E-10
Transmission Line 100L Rebuild Project
Multi-Year Expenditures
($000s)

Cost Category	2026F	2027F	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

Expenditures for the *Transmission Line 100L Rebuild Project* total approximately $13,773,000, including $13,323,000 in 2027. For expenditures incurred to date, see the *2026 Capital Expenditure Status Report* filed with the Application.

48 See Newfoundland Power's *2026 Capital Budget Application,* report *3.1 Transmission Line 100L Rebuild.*

Title:	**Geographic Information System Upgrade**
Asset Class:	**Information Systems**
Category:	**Project**
Investment Classification:	**General Plant**
2027 Expenditures:	**$5,173,000**

The *Geographic Information System Upgrade* project was included as a multi-year project in Newfoundland Power's *2026 Capital Budget Application*.[49] The current Geographic Information System ("GIS") technology is at the end of its useful life and requires 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.

The Board approved the *Geographic Information System Upgrade* project as a three-year project in Order No. P.U. 38 (2025). The project is proceeding as approved. Initial architecture design is ongoing, with data migration initiatives planned for 2027. The project is expected to be completed in 2028.

Table E-11 provides the approved expenditures for the *Geographic Information System Upgrade* project.

Table E-11
Geographic Information System Upgrade Project
Multi-Year Expenditures
($000s)

Cost Category	2026F	2027F	2028F	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

Expenditures for the *Geographic Information System Upgrade* project total approximately $8,325,000, including $5,173,000 in 2027. For expenditures incurred to date, see the *2026 Capital Expenditure Status Report* filed with the Application.

49 See Newfoundland Power's *2026 Capital Budget Application,* report *4.2 Geographic Information System Upgrade*.

Title: **Customer Correspondence Modernization**
Asset Class: **Information Systems**
Category: **Project**
Investment Classification: **General Plant**
2027 Expenditures: **$1,175,000**

The *Customer Correspondence Modernization* project was included as a multi-year project in Newfoundland Power's *2026 Capital Budget Application*.[50] The *Customer Correspondence Modernization* project involves upgrading customer bill design and delivery. The technology supporting the production of bills and letters, as well as their design, does not meet customers' evolving needs, lacking the ability to effectively manage current and future business requirements.

The Board approved the *Customer Correspondence Modernization* project as a two-year project in Order No. P.U. 38 (2025). This project is proceeding as approved. Planning assessments have commenced and remain ongoing, with architecture design expected to begin in the fourth quarter of 2026.

Table E-12 provides the approved expenditures for the *Customer Correspondence Modernization* project.

Table E-12
Customer Correspondence Modernization Project
Multi-Year Expenditures
($000s)

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

Expenditures for the *Customer Correspondence Modernization* project total approximately $1,957,000, including $1,175,000 in 2027. For expenditures incurred to date, see the *2026 Capital Expenditure Status Report* filed with the Application.

50 See Newfoundland Power's *2026 Capital Budget Application,* report *4.1 Customer Correspondence Modernization*.

Title: **Summerford Building Replacement**
Asset Class: **General Property**
Category: **Project**
Investment Classification: **General Plant**
2027 Expenditures: **$562,000**

The *Summerford Building Replacement* project was included as a multi-year project in Newfoundland Power's *2026 Capital Budget Application*.[51] The *Summerford Building Replacement* project involves the replacement of Newfoundland Power's building in the Summerford area. A condition assessment determined the building is exhibiting significant deterioration and replacement is required to deliver effective and timely service to customers in the area.

The Board approved the *Summerford Building Replacement* project as a two-year project in Order No. P.U. 38 (2025). The project is proceeding as approved. Engineering design is ongoing with construction anticipated to be completed by the fourth quarter of 2027.

Table E-13 provides the approved expenditures for the *Summerford Building Replacement* project.

Table E-13
Summerford Building Replacement Project
Multi-Year Expenditures
($000s)

Cost Category	2026F	2027F	Total
Material	132	526	658
Labour – Internal	-	3	3
Labour – Contract	-	-	-
Engineering	13	18	31
Other	10	15	25
Total	$155	$562	$717

Expenditures for the *Summerford Building Replacement* project total approximately $717,000, including $562,000 in 2027. For expenditures incurred to date, see the *2026 Capital Expenditure Status Report* filed with the Application.

51 See Newfoundland Power's *2026 Capital Budget Application,* Schedule C, page 8.

Title:	**Replace Vehicles and Aerial Devices 2026-2027**
Asset Class:	**Transportation**
Category:	**Project**
Investment Classification:	**General Plant**
2027 Expenditures:	**$2,718,000**

The *Replace Vehicles and Aerial Devices 2026-2027* project was included as a multi-year project in Newfoundland Power's *2026 Capital Budget Application*.[52] 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.

The Board approved the *Replace Vehicles and Aerial Devices 2026-2027* project as a two-year project in Order No. P.U. 38 (2025). The project is proceeding as approved. The vehicles have been ordered and are expected to arrive in 2027.

Table E-14 provides the approved expenditures for the *Replace Vehicles and Aerial Devices 2026-2027* project.

Table E-14
Replace Vehicles and Aerial Devices 2026-2027 Project
Multi-Year Expenditures
($000s)

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

Expenditures for the *Replace Vehicles and Aerial Devices 2026-2027* project total approximately $5,721,000, including $2,718,000 in 2027. For expenditures incurred to date, see the *2026 Capital Expenditure Status Report* filed with the Application.

52 See Newfoundland Power's *2026 Capital Budget Application, Schedule B,* pages 106 to 109.

May
2026

2027 - 2031 Capital Plan

NEWFOUNDLAND
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TABLE OF CONTENTS

Page

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 Board of Commissioners of Public Utilities of Newfoundland and Labrador (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, as well as thermal and hydroelectric assets.

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 $94 million of annual capital expenditures from 2027 to 2031, or 46% of total annual expenditures.

The Company is anticipating filing a supplemental application in the third quarter of 2026 for the refurbishment of thermal generation facilities at Greenhill and Wesleyville over the next five years. These units have been in service approximately 50 years and have reached the end of their useful service lives. While the Company is not seeking approval of the replacement of these units in the *2027 Capital Budget Application*, Newfoundland Power has presented the most recent available budget estimates for the projects in its five-year plan for visibility and transparency. The refurbishment of these facilities is currently forecast to account for a total of approximately $231 million from 2027 to 2031.

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 $31 million of annual capital expenditures from 2027 to 2031, or 15% of total annual expenditures.

The Company's current capital plan forecasts average annual investments of approximately $207 million from 2027 to 2031.[1] 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.

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1 Includes most recent available budget estimates for the refurbishment of thermal generation facilities at Greenhill and Wesleyville.

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.[2] 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.[3]

Table 1 provides the forecast number of new customer connections from 2027 to 2031.

Table 1
Forecast New Customer Connections
(2027F-2031F)

	2027F	2028F	2029F	2030F	2031F
New Customer Connections	2,342	1,989	1,682	1,377	1,178

New customer connections are forecast to decline from 2,342 in 2027 to 1,178 in 2031. Approximately 40% 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 and residential electrification of heating systems.[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 form oil heat to electric heat.[5] Approximately 4,700 oil-to-electric conversions have been completed, with approximately 820 further conversions pre-approved as of April 2026.

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2 See section 3(b)(ii) of the *Electrical Power Control Act, 1994.*

3 For example, of 21 *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.

4 The addition of transformer capacity at Hardwoods Substation is forecast to be required to respond to load growth on the Northeast Avalon.

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.

Changes in government policy have shifted the projected Electric Vehicle ("EV") landscape in the short term. While system load growth is expected to be affected by electric vehicle adoption over the forecast period, significant impacts on the bulk electricity system are not expected until the 2030s. Impacts on individual distribution feeders may be realized prior to this depending on the clustering of EVs in certain neighbourhoods and the prevalence of at-home level 2 charging.

Newfoundland Power's *EV Load Management Pilot Project* was completed in 2025.[6] The results showed that while both active and passive load management strategies showed evidence of being able to successfully move EV load from peak periods to overnight, significant technical and operational challenges still exist that may be a barrier to scaling the program.[7] Newfoundland Power will continue to monitor EV adoption and EV load management technologies to ensure that, when EV load does drive significant system impacts in the 2030s, the Company is able to cost-effectively shift a portion of this load. As part of the report outlining the update on the implementation of Advanced Metering Infrastructure ("AMI"), included as Appendix B to the *2027-2031 Capital Plan*, Newfoundland Power provided preliminary use-case assessments of AMI, in which it was noted that utility-driven equipment demand response measures, including EV charging, show the highest potential to reduce peak demand.

Newfoundland Power is exploring other opportunities to manage system load through demand-side management. The Company has received $258,400 from the Government of Newfoundland and Labrador's *Green Transition Fund* to perform a smart thermostat load management pilot for baseboard heaters. The pilot aims to understand the impacts of shifting baseboard heating load during times of system peak. The pilot began in December 2025, and the results will be available in 2027. Additionally, Newfoundland Power continues to offer customer energy efficiency programs which help contribute to reductions in system peak.

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.[8] 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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6 The *EV Load Management Pilot Project* was approved by the Board in Order No. P.U. 23 (2023).

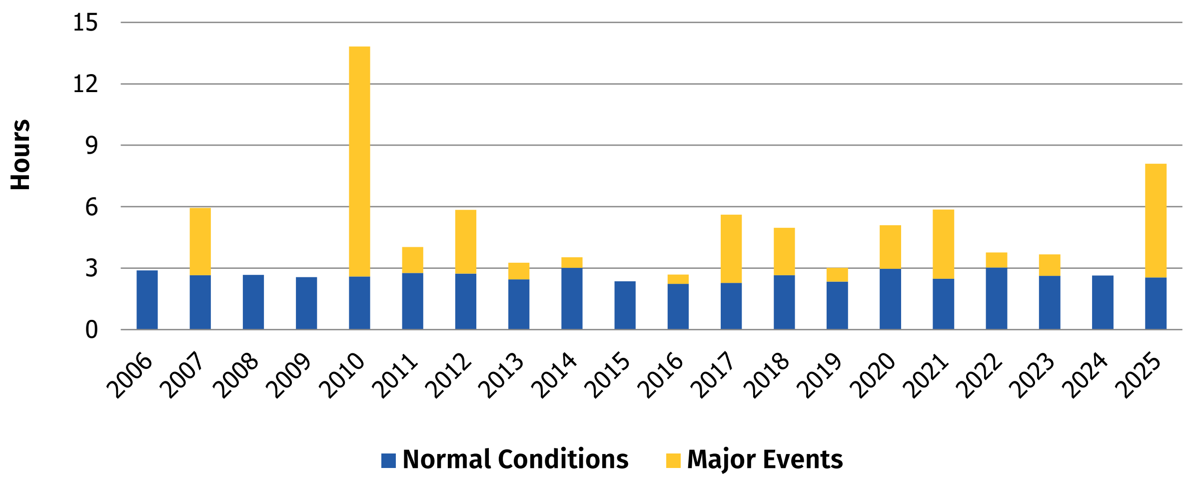
7 Newfoundland Power filed the evaluation report of the *EV Load Management Pilot Project* in Appendix B of the *2025 Conservation, Demand Management and Electrification Report*, filed with the Board April 23, 2026.

8 Overall customer satisfaction with Newfoundland Power's service averaged 86% from 2016 to 2025. Customer satisfaction averaged 93% when customers were surveyed about their direct interactions with field staff, including technologists and field service representatives.

In 2027, 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 2006 to 2025 including major events.[9]

Figure 1
Newfoundland Power
Outage Duration Including Major Events
(2006 to 2025)



Major customer outages due to severe weather have become more frequent in the Company's service territory, causing customer outages in nine of the last ten years compared to 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 Hurricane Fiona in September 2022 and a wildfire in the Conception Bay North area in August 2025.[10] Restoring

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[9] 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 2006 to 2025, major events have resulted in an average SAIFI of 0.37, ranging as high as an average SAIFI of 1.25 in 2025.

[10] On August 3, 2025, a wildfire was officially reported near Kingston in the Conception Bay North area. Over a three-week period, the wildfire remained out of control and covered a total of more than 10,000 hectares, resulting in evacuation orders and alerts to residents in the communities affected by the wildfire. At its peak, approximately 1,400 Newfoundland Power customers experienced an outage to their electrical service as a result of power being disconnected to avoid damage to distribution infrastructure. A total of more than 20 million minutes of customer outages were experienced. Newfoundland Power's response was three-fold including remediation, replacement and reconnection. The Company worked closely with Fire and Emergency Services as well as the Provincial Emergency Operation Centre to ensure customers were reconnected as soon as practicable following remediation and replacement activities.

service to customers following such events typically requires a robust operational response as well as capital investments to repair damage to the electrical system.[11]

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 the Company's forecast expenditures.[12] 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.[13]

While ensuring the electrical system is designed to standards, local climatic conditions are changing. This change is being monitored by the Company to ensure historical and changing climate are adequately addressed in terms of asset management, winter operations, wildfire and emergency response planning. The Company is undertaking a climate risk vulnerability study to ensure its strategies and forecast of capital investments continue to reflect shifting priorities and risks related to climate change.[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 the Avalon Combustion Turbine in the *Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and*

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[11] 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).

[12] The Federal Government has recognized the importance of adapting the energy sector to climate change. The Federal Government states "Electricity infrastructure and operations need to strengthen reliability and resiliency to a growing range of threats, particularly extreme climate-related events, long-term shifts in climate, and cyber threats. Climate change is increasing the physical risks to Canada's electricity systems, with regional variations in impacts and hazards. These changes can result in risks to electricity generation (e.g., droughts affecting hydropower production), transmission and distribution infrastructure (e.g., ice storms, wildfires, and melting permafrost affecting grid operation), and increased consumer demand (e.g., heat waves that increase air-conditioning loads)." See *Powering Canada's Future: A Clean Electricity Strategy*, Government of Canada, page 39.

[13] 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.

[14] The Company's most recent *Climate Change Adaptation Plan* was completed in December 2021.

[15] The urgency for investment in electrical supply was demonstrated by the recent shutdown at the Bay d'Espoir generating facility. On January 21, 2026, Hydro reported it had decided to shut down all units at the facility for the first time in its history due to the presence of frazil ice. At the same time, issues were experienced at the Holyrood Thermal Generating Station. This prompted a Power Warning on January 24, 2026, signaling customers to conserve electricity and prepare for rotating power outages. For additional information, see Hydro's report *Frazil Ice at Bay d'Espoir Hydroelectric Generating Station*, filed with the Board on April 30, 2026.

Avalon Combustion Turbine (the "2025 Build Application").[16] The 2025 Build Application is currently under review by the Board.

Newfoundland Power's operations and capital investments must continue to adapt to increasing cybersecurity risks. Cybersecurity risks have increased materially for critical infrastructure operators in recent years, including electric utilities.[17] Newfoundland Power expects that continual investment in cybersecurity technologies will be required as these risks continue to evolve, and 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 *2027-2031 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 affected by 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. The Company continues to monitor market conditions to assess potential impacts on its operations.

2.4 Asset Condition Outlook

2.4.1 General

Newfoundland Power's electrical system is maintained through a combination of preventative and corrective maintenance programs and long-term asset management strategies. The Company's asset management practices have been found to conform with good utility practice.[18] As part of the Company's asset management review, Newfoundland Power is undertaking an asset management maturity assessment aligned with ISO 55001 to establish a baseline of current organizational practices.[19] This work builds on the Company's prior external assessment and supports a structured evaluation of how asset management practices have progressed over time. The outcomes of the assessment will provide a consolidated view of strengths and areas for improvement and will support the continued evolution of the Company's

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16 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.

17 For example, on April 25, 2025, Nova Scotia Power Inc. ("NSPI") announced they had discovered and were actively responding to a cybersecurity incident involving unauthorized access to certain parts of its Canadian network and servers supporting portions of its business applications. The incident resulted in the loss of communication to NSPI's metering infrastructure, affecting the billing process to its customers. Over 900,000 current and former customers were affected by the incident. As a result of this incident, the Nova Scotia Energy Board has initiated two inquiries, the *Board Inquiry into Nova Scotia Power Incorporated's Cybersecurity Incident*, and the inquiry titled *Nova Scotia Power Incorporated - Cybersecurity Accountability*. In addition, as part of NSPI's *2026 ACE Plan*, NSPI is seeking approval for capital expenditures totaling $84.5 million to replace its legacy customer information system as well as $6.8 million for new cybersecurity controls.

18 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.

19 The assessment evaluates the extent to which asset management activities are consistently applied across the Company, including the integration of decision-making processes, information, resources, and governance structures that support the delivery of value from assets.

Asset Management System in a coordinated and planned manner. In addition, Newfoundland Power is currently replacing its asset management technology with a modern solution.[20]

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. Over the period 2021 to 2025, equipment-related failures on the distribution system accounted for an average annual total of over 29 million customer minutes of interruption.[21] 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.

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 Company's worst performing feeders for capital investment.[22] Newfoundland Power's distribution system includes approximately 227,000 wooden support structures and overhead conductor on approximately 9,800 kilometres of distribution line. Industry experience

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[20] 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.*"

[21] Includes equipment failures resulting in an outage to customers. Excludes transmission equipment failures.

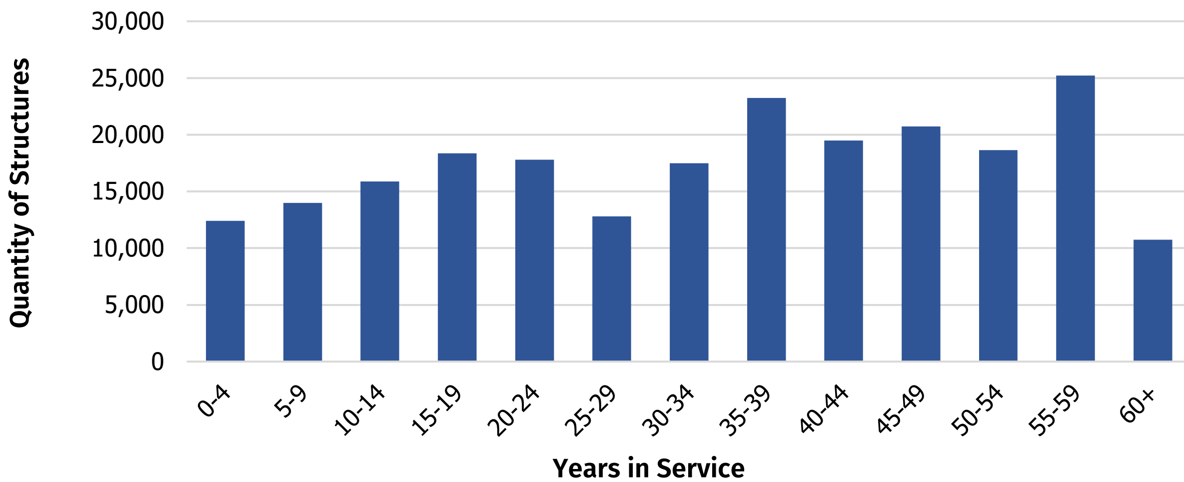
[22] The *Distribution Reliability Initiative* project has evolved in recent years to include isolated, discrete sections of feeders or neighbourhoods that are experiencing poor reliability performance. Additionally, the Outage Management System is capable of providing outage data with greater granularity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

indicates an average expected useful service life of 54 years for distribution wooden support structures and 50 years for distribution overhead conductor.[23]

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

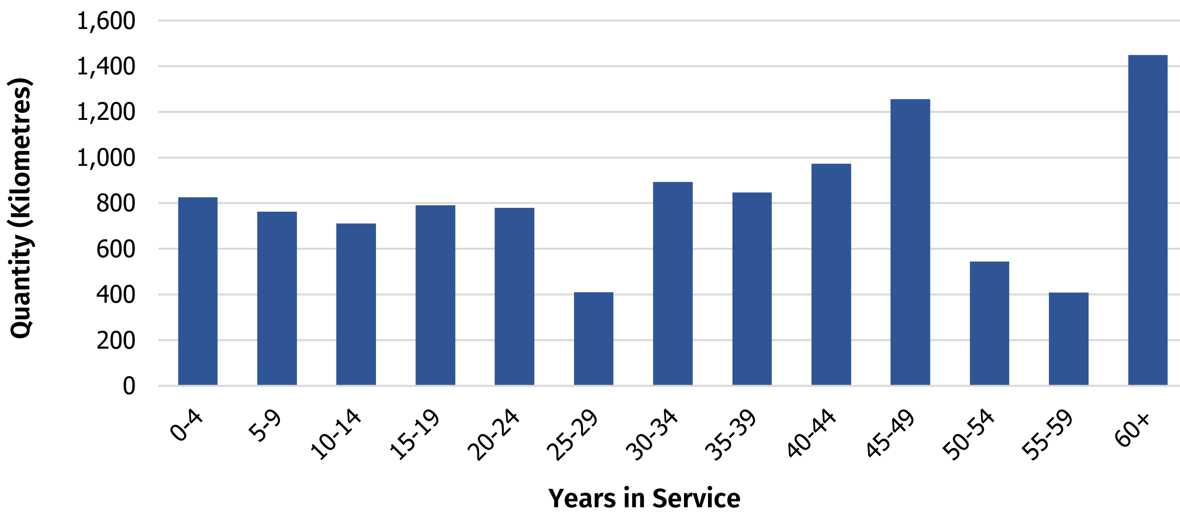


Approximately 16% of distribution wooden support structures have exceeded the average industry expected useful service life of 54 years. An additional 19% of distribution wooden support structures will reach 54 years in service over the next decade.

23 The average industry expected useful service lives of distribution assets were derived from information filed with the Federal Energy Regulatory Commission ("FERC"). Electric utilities subject to FERC's jurisdiction are required to file a Form 1 report annually. Form 1 reports are publicly available and provide financial and operational information for electric utilities. A total of 38 utilities were included in the analysis.

Figure 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 16% of distribution overhead conductor will reach 50 years in service within the next decade.

2.4.3 Transmission

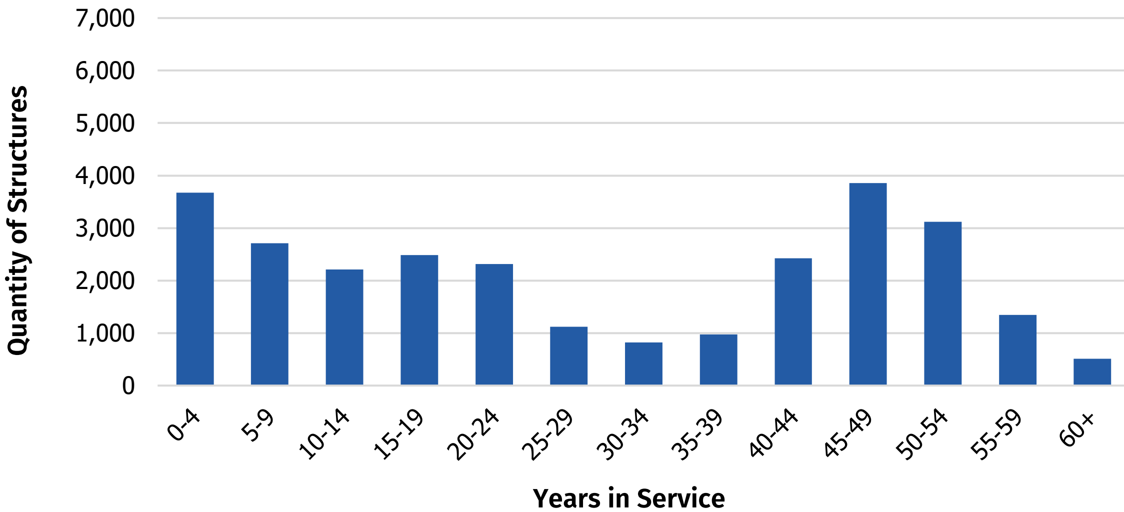
Transmission lines are the backbone of the electricity system serving customers. Transmission lines are inspected annually to identify deficiencies. Deficiencies are prioritized for correction based on severity through the annual *Transmission Line Maintenance* program. The condition of the transmission 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 28,000 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.[24]

[24] 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

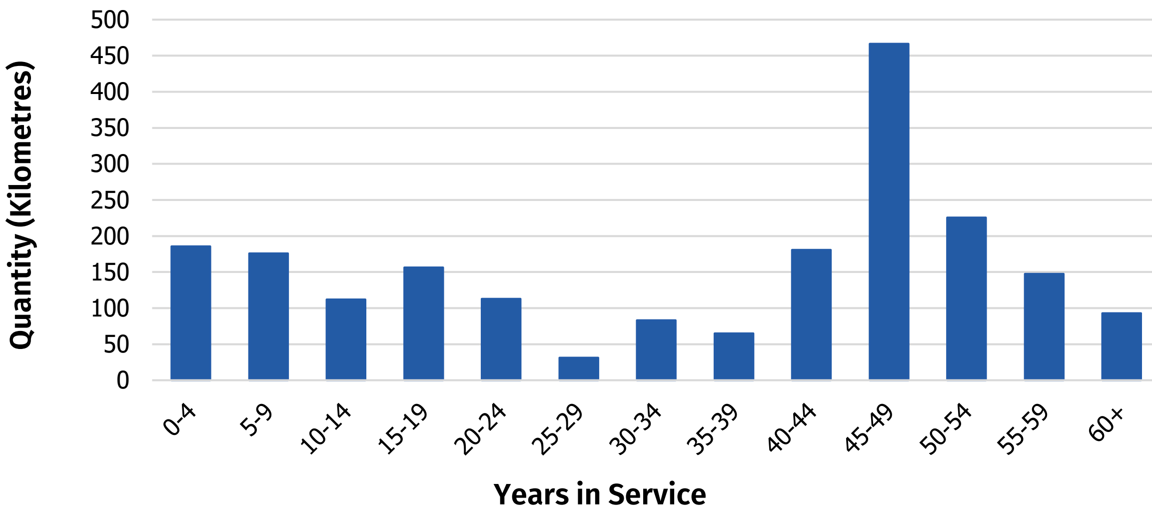


Approximately 3% of transmission wooden support structures have exceeded the average industry expected useful service life of 58 years.[25] An additional 27% of transmission wooden support structures will reach 58 years in service over the next decade.

25 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 88% complete by the end of 2026. The strategy outlined a long-term plan to rebuild the Company's aging transmission lines.

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

Figure 5
Transmission Overhead Conductor
Asset Age



Approximately 2% of transmission overhead conductor has currently exceeded the average industry expected useful service life of 63 years. An additional 13% of transmission overhead conductor will reach 63 years in service within the next decade.

2.4.4 Substations

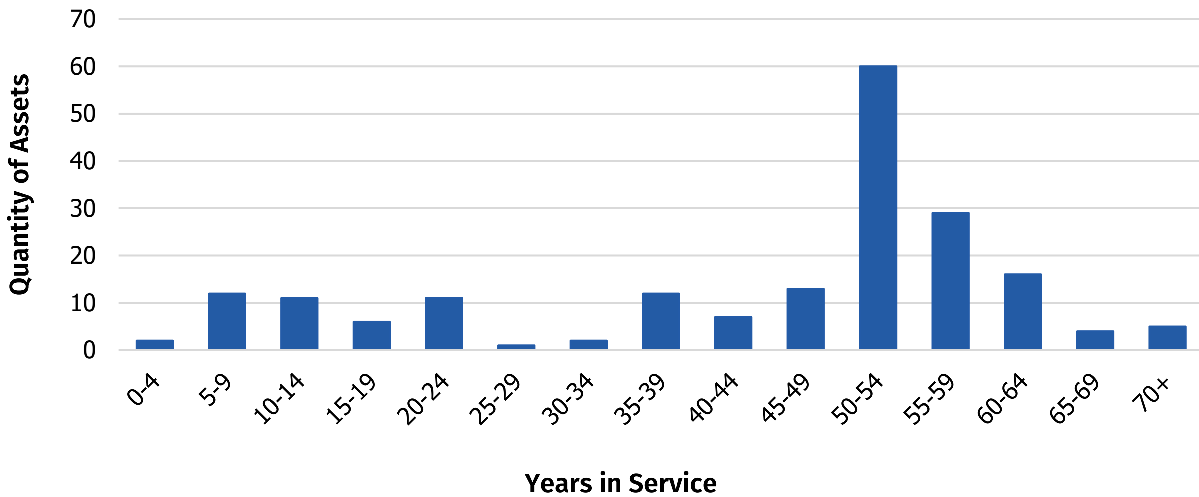
Newfoundland Power operates 131 substations throughout its service territory. Substations are inspected eight times annually to identify deficiencies and required maintenance. Equipment that fails in service or is at imminent risk of failure is addressed under the *Substation Replacements Due to In-Service 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.[26] Based on the current age profile, the Company's power transformers are exposed to a high risk of failure.

[26] Operating 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.

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

Figure 6
Substation Power Transformers
Asset Age



Approximately 60% of substation power transformers have exceeded the industry expected useful service life of 50 years. An additional 10% of substation power transformers will reach 50 years in service over the next decade.[27]

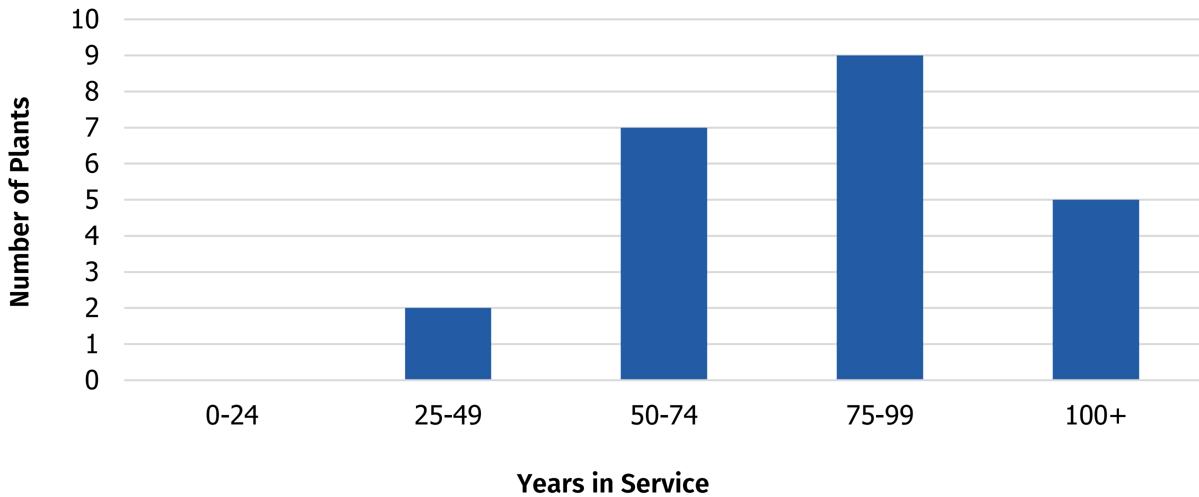
2.4.5 Hydro Generation

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. 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. 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.

[27] 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 the *2027 Capital Budget Application*.

Figure 7 provides the number of hydro plants in operation by age as of the end of 2025.

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.[28]

2.4.6 Thermal Generation

Newfoundland Power operates six thermal plants on the island with a total generation capacity of 44.5 MW. These thermal plants supply customers experiencing localized outages and provide system support when requested by Hydro. 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").[29] Two of the thermal plants are mobile. These include the Mobile Diesel #3 and Mobile Gas Turbine #2.

[28] 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.

[29] 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. 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.

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

Newfoundland Power is currently undertaking a review of two thermal assets. These include the Wesleyville gas turbine and the Greenhill gas turbine.[30] This review includes a detailed condition assessment of both sites, updating the Company's annual 138 kV and 66 kV Loop Assessments,[31] and conducting a planning study to assess alternatives. Newfoundland Power anticipates filing a supplemental capital budget application (the "Thermal Supplemental") in the third quarter of 2026 seeking approval of the refurbishment of thermal generation facilities at Wesleyville and Greenhill. Anticipated capital expenditures associated with the projects for the Company's thermal generation facilities are discussed further in section 3.3.5 below.

3.0 SUMMARY OF PLANNED EXPENDITURES

3.1 General

Newfoundland Power's *2027-2031 Capital Plan* forecasts average annual capital expenditures of approximately $207 million from 2027 to 2031. This section provides a breakdown of forecast capital expenditures by investment classification and asset class.[32] While Newfoundland Power is not seeking approval of capital expenditures associated with thermal generation facilities in the *2027 Capital Budget Application*, for visibility and transparency, the Company has shown the total breakdown of anticipated capital costs based on the most recently available budget estimates.

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30 The Wesleyville gas turbine has been in service for 56 years and 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. The Greenhill gas turbine has been in service for 50 years.

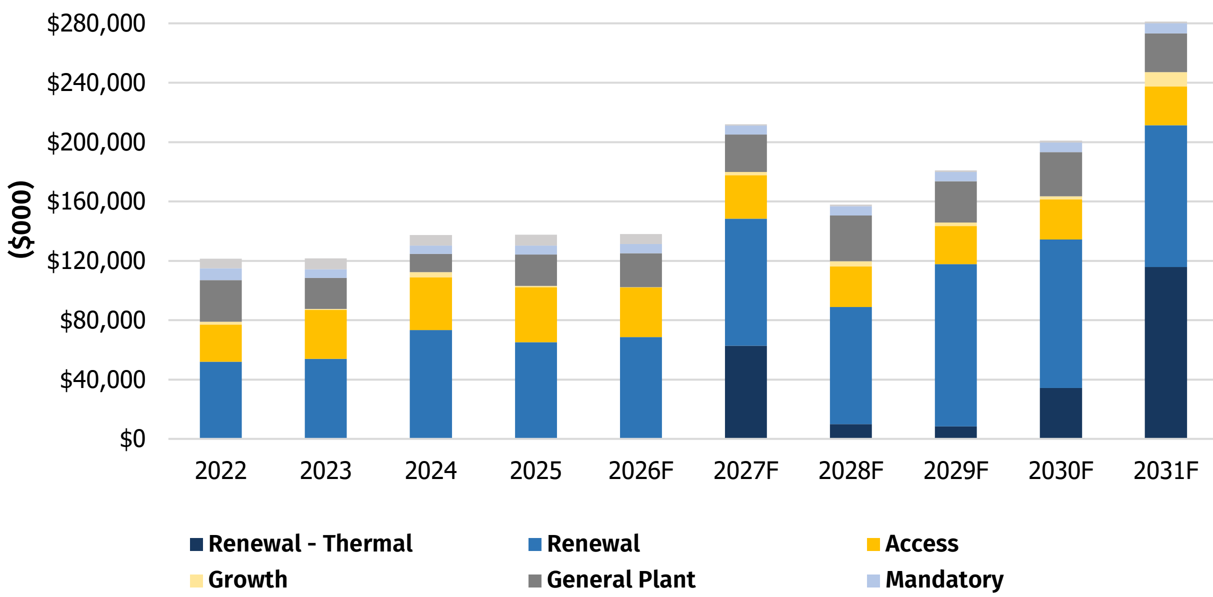
31 The purpose of the annual loop assessment is to simulate various equipment outage scenarios at the transmission level during peak conditions and to provide recommendations to minimize customer impacts and equipment overloads for each transmission loop. The annual loop assessment is included as part of the Newfoundland and Labrador System Operator's Annual Planning Assessment, which is typically filed in May of each year.

32 Capital expenditures are organized by investment classification in accordance with the Board's provisional *Capital Budget Application Guidelines* effective January 2022.

3.2 Planned Expenditures by Investment Classification

Figure 8 provides historical and forecast capital expenditures from 2022 to 2031 by investment classification.

Figure 8
Capital Expenditures by Investment Classification
(2022-2031F)



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.[33] Renewal investments are forecast to account for approximately 46% of capital expenditures from 2027 to 2031, compared to approximately 48% 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,* the *Substation Refurbishment and Modernization Plan,* and the *Substation Power Transformer Strategy* over the forecast period. Renewal investments in the Generation asset class reflect both an increase in refurbishment projects for hydro plants, the planned refurbishment of the Wesleyville and Greenhill thermal generation facilities, 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.

[33] Increases in the Renewal classification in the next five years are driven by the planned replacement of the Greenhill and Wesleyville gas turbines.

Access and System Growth investments are forecast to account for approximately 15% 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 $6.9 million of investments between 2030 and 2031 relate to transformer capacity additions at 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 14% of annual capital expenditures over the next five years. General Plant investments are expected to continue to be driven by expenditures in the Information Systems asset class. Information Systems account for approximately half of General Plant investments over the forecast period. Capital expenditures for Information Systems are largely driven by more frequent upgrades being required for third-party software products due to increasing cybersecurity threats and vendor requirements.

Service Enhancement investments are forecast to account for approximately 1% of annual capital expenditures over the next five years. Service Enhancement investments reflect continued automation of the distribution system.

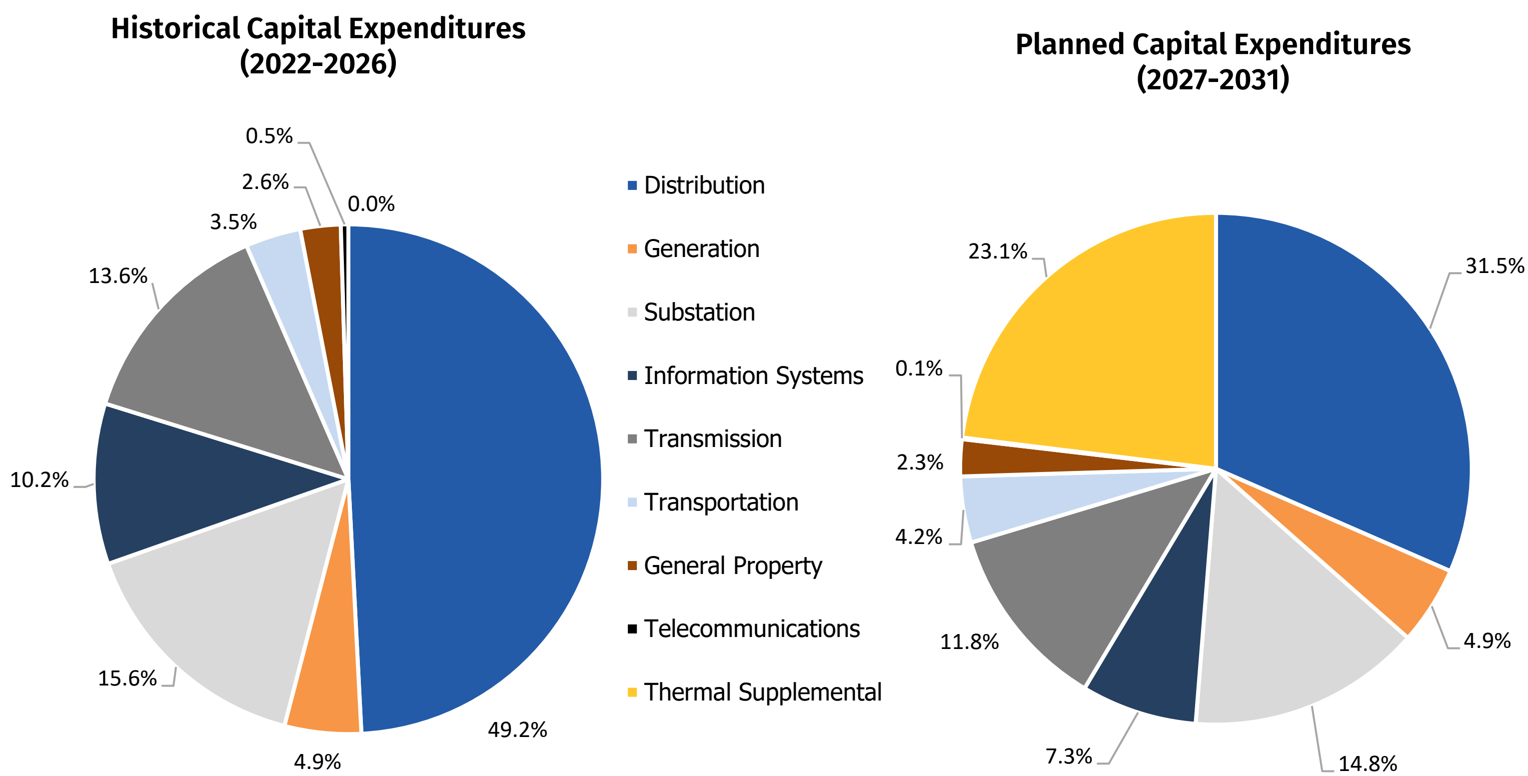
Mandatory investments are forecast to account for approximately 3% of annual capital expenditures over the next five years. Mandatory investments reflect capital expenditures resulting from Board Orders, including *General Expenses Capitalized*, the *Allowance for Unforeseen Items*, and the *Allowance 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.[34]

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 2027 to 2031. 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 projects as described below.

[34] 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 2022 to 2031.

Table 2 Distribution Capital Expenditures ($000s)					
Actual/Forecast					Average
2022	2023	2024	2025	2026F	2022-2026F
50,449	57,328	71,093	67,831	61,824	61,705
Plan					Average
2027B	2028B	2029B	2030B	2031B	2027B-2031B
59,823	64,343	64,863	64,779	62,500	63,262

Distribution capital expenditures are forecast to average approximately $63.3 million annually from 2027 to 2031. This compares to an average of approximately $61.7 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 $14.8 million annually. Refurbishment projects for individual distribution feeders are expected to increase over the forecast period, with annual expenditures increasing from approximately $3.4 million in 2027 to approximately $6.3 million in 2031.

Expenditures related to the *Distribution Reliability Initiative* are forecast to average approximately $1.6 million annually as the Company continues to target the worst performing feeders, or discrete sections of feeders, on its distribution system.[35]

[35] 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 2022 to 2031.

Table 3
Substations
Capital Expenditures
($000s)

Actual/Forecast					Average
2022	2023	2024	2025	2026F	2022-2026F
14,252	21,096	23,714	15,952	22,634	19,530
Plan					Average
2027B	2028B	2029B	2030B	2031B	2027B-2031B
25,202	28,750	34,633	23,125	36,411	29,624
Thermal Supplemental – Substations Component					Average
2027B	2028B	2029B	2030B	2031B	2027B-2031B
20	20	520	8,140	-	1,740

Substations expenditures are forecast to average approximately $29.6 million annually from 2027 to 2031. This compares to an average of approximately $19.5 million annually over the previous five-year period.

Increased substations expenditures are driven by the Company's *Substation Refurbishment and Modernization Plan* and *Substation Power Transformer Strategy*. Forecast expenditures over the next five years reflect the refurbishment and modernization of 14 substations, including the Blaketown, Rattling Brook and Mobile Plant substations beginning in 2027. 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 $8.9 million from 2027 to 2031. An additional $8.7 million in capital expenditures is forecast to address substation components at the Wesleyville and Greenhill substations as part of the planned refurbishment of thermal generation facilities. Newfoundland Power will seek approval of these expenditures as part of the Thermal Supplemental, anticipated in the third quarter of 2026.

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 account for an average of $7.3 million annually from 2027 to 2031.[36]

Forecast substation expenditures also include approximately $4.9 million annually to address in-service equipment failures in substations.

[36] 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 2022 to 2031.

Table 4
Transmission
Capital Expenditures
($000s)

Actual/Forecast					Average
2022	2023	2024	2025	2026F	2022-2026F
18,588	8,662	16,852	19,409	22,114	17,125
Plan					Average
2027B	2028B	2029B	2030B	2031B	2027B-2031B
29,397	9,309	24,037	30,888	24,212	23,569

Transmission capital expenditures are forecast to average approximately $23.6 million annually from 2027 to 2031. This compares to an average of approximately $17.1 million annually over the previous five-year period.

Forecast expenditures from 2027 to 2031 include rebuild projects on eight transmission lines throughout the Company's service territory. These include the five transmission lines remaining to complete the *Transmission Line Rebuild Strategy* (the "Strategy") by 2030, and three transmission lines beginning in 2029 which are not part of the original Strategy. The transmission lines in the capital plan beyond the Strategy have been identified based on specific observed issues such as pole cracking and shell separation.[37]

The rebuild of Transmission Line 100L in 2026 and 2027 is expected to cost approximately $13.8 million. The average annual cost of transmission line rebuild projects from 2027 to 2031 is approximately $17.4 million. Forecast transmission expenditures also include capital maintenance of transmission line structures at an annual average cost of approximately $3.6 million.

[37] Newfoundland Power is currently replacing its asset management technology with a modern solution. The replacement technology and available data will enable the assessment of electrical system assets, including transmission, based on condition and risk. It is anticipated that this data will be used to determine future strategies required to maintain the transmission system beyond the timeframe of the original Strategy.

3.3.5 Generation

Table 5 provides historical and forecast generation capital expenditures from 2022 to 2031.

Table 5
Generation
Capital Expenditures
($000s)

Actual/Forecast					Average
2022	2023	2024	2025	2026F	2022-2026F
2,869	8,684	8,875	7,585	2,473	6,097
Plan					Average
2027B	2028B	2029B	2030B	2031B	2027B-2031B
3,977	8,633	15,339	11,854	9,760	9,913
Thermal Supplemental					Average
2027B	2028B	2029B	2030B	2031B	2027B-2031B
62,700	10,000	7,800	26,200	115,700	44,480

Generation capital expenditures are forecast to average approximately $9.9 million annually from 2027 to 2031.[38] This compares to an average of approximately $6.1 million annually over the previous five-year period. Increased generation expenditures reflect a forecast requirement to undertake refurbishment projects at nine hydro plants over the next five years. Expenditures of approximately $1 million are also included in 2031 to start the engineering to refurbish thermal units located in Port aux Basques.[39]

Newfoundland Power is anticipating filing the Thermal Supplemental in the third quarter of 2026 seeking approval of expenditures to refurbish thermal generation facilities at Greenhill and Wesleyville beginning in 2027. The project is anticipated to require five years and a total of approximately $222 million in capital expenditures. These budget estimates are expected to change between the time of filing the *2027 Capital Budget Application* and the filing of the Thermal Supplemental. For visibility and transparency, the Company has provided the most recently available budget estimates.

[38] Generation-Hydro capital expenditures are forecast to average approximately $9.2 million annually from 2027 to 2031. Excluding expenditures associated with the Thermal Supplemental, Generation-Thermal capital expenditures are forecast to average approximately $1 million annually from 2027 to 2031.

[39] 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 2022 to 2031.

Table 6 Information Systems Capital Expenditures ($000s)					
Actual/Forecast					Average
2022	2023	2024	2025	2026F	2022-2026F
21,495	12,251	6,484	11,009	12,673	12,783
Plan					Average
2027B	2028B	2029B	2030B	2031B	2027B-2031B
14,194	17,696	14,121	13,743	13,622	14,675

Information systems capital expenditures are forecast to average approximately $14.7 million annually from 2027 to 2031. This compares to an average of approximately $12.8 million annually over the previous five-year period.

Expenditures from 2027 to 2031 are comparable to the previous five-year average. Forecast expenditures encompass enhancements to Operations Technology, as well as the replacement of the Company's Geographic Information System, 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 2022 to 2031.

Table 7 Transportation Capital Expenditures ($000s)					
Actual/Forecast					Average
2022	2023	2024	2025	2026F	2022-2026F
3,212	5,143	2,854	5,042	5,805	4,411
Plan					Average
2027B	2028B	2029B	2030B	2031B	2027B-2031B
7,228	8,476	9,001	9,513	7,679	8,379

Transportation capital expenditures are forecast to average approximately $8.4 million annually from 2027 to 2031. This compares to an average of approximately $4.4 million annually over the previous five-year period.

The increase in transportation capital expenditures from 2027 through 2031 primarily reflects inflationary increases and the number of heavy, medium, and light-duty fleet and passenger vehicles forecasted to be replaced over the five-year period.

3.3.8 General Property

Table 8 provides historical and forecast general property capital expenditures from 2026 to 2031.

Table 8
General Property
Capital Expenditures
($000s)

Actual/Forecast					Average
2022	2023	2024	2025	2026F	2022-2026F
2,843	2,694	2,401	4,010	4,089	3,207
Plan					Average
2027B	2028B	2029B	2030B	2031B	2027B-2031B
3,629	4,551	4,236	6,209	4,740	4,673

General Property capital expenditures are forecast to average approximately $4.7 million annually from 2027 to 2031. This compares to an average of approximately $3.2 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 2027 to 2031 period are driven by refurbishments required at the Company's Kenmount Road 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 2022 to 2031.

Table 9 Telecommunications Capital Expenditures ($000s)					
Actual/Forecast					Average
2022	2023	2024	2025	2026F	2022-2026F
593	707	425	994	281	600
Plan					Average
2027B	2028B	2029B	2030B	2031B	2027B-2031B
149	153	369	162	166	200

Telecommunications capital expenditures are forecast to average approximately $0.2 million annually from 2027 to 2031. This compares to an average of approximately $0.6 million annually over the previous five-year period.

Expenditures from 2027 to 2031 are decreased in comparison to the previous five-year average. This is primarily driven by the completion of the Company's Very High Frequency mobile radio system replacement in 2025. Telecommunications expenditures over the next five years are predominantly focused on the installation of a fibre optic cable from Goulds Substation to Glendale Substation in 2029, as well as other minor upgrades to communications equipment.

APPENDIX A:

Capital Projects and Programs: 2027-2031

Table A-1 2027-2031 Capital Plan By Asset Class ($000s)					
Asset Class	2027F	2028F	2029F	2030F	2031F
Distribution	59,823	64,343	64,863	64,779	62,500
Substations	25,202	28,750	34,633	23,125	36,411
Transmission	29,397	9,309	24,037	30,888	24,212
Generation	3,977	8,633	15,339	11,854	9,760
Information Systems	14,194	17,696	14,121	13,743	13,622
Transportation	7,228	8,476	9,001	9,513	7,679
General Property	3,629	4,551	4,236	6,209	4,740
Telecommunications	149	153	369	162	166
Allowance for Unforeseen Items	750	750	750	750	750
General Expenses Capitalized	5,000	5,200	5,350	5,550	5,750
Subtotal	**149,349**	**147,861**	**172,699**	**166,573**	**165,590**
Thermal Generation Supplemental	62,720	10,020	8,320	34,340	115,700
Total	**212,069**	**157,881**	**181,019**	**200,913**	**281,290**

Table A-2
2027-2031 Capital Plan
Distribution
($000s)

	2027F	2028F	2029F	2030F	2031F
Project					
Distribution Feeder ILC-02 Refurbishment	595	610	0	0	0
Distribution Feeder GBY-01 Refurbishment	402	958			
Distribution Reliability Initiative	871	2,069	2,117	1,293	1,643
Distribution Feeder Reconfiguration PHR-GOU	-	2,448	2,498	2,543	-
George Street Relocation	-	-	-	3,232	3,286
Distribution Feeder Refurbishment	-	3,212	5,805	5,865	6,349
Feeder Additions for Load Growth	2,171	3,489	2,467	1,731	1,915
Distribution Feeder Automation	662	720	760	808	833
Distribution Feeder CAB-01 Refurbishment	972	-	-	-	-
Distribution Feeder Extension COB-02	1,828	-	-	-	-
Distribution Feeder MIL-02 Refurbishment	685	-	-	-	-
Allowance for Funds Used During Construction	249	253	257	260	263
Distribution Feeder GDL-02 LOOP 10 and LOOP 20 Refurbishment	789	-	-	-	-
Distribution Feeder FER-01 Rebuild	-	-	529	-	-
Underground Cable Replacement Strategy	-	1,556	1,588	1,616	1,643
Distribution Upgrades for RRD Switchgear	-	-	758	-	-
Program					
Extensions	13,852	12,114	10,558	8,896	7,829
Reconstruction	8,319	8,593	8,881	9,169	9,464
Rebuild Distribution Lines	5,502	5,688	5,885	6,082	6,284
New Services	3,520	3,097	2,715	2,303	2,041
Replacement Services	397	411	426	440	456
New Meters	573	501	436	367	323
Replacement Meters	616	387	501	1,073	663
New Transformers	4,943	5,038	5,141	5,233	5,320
Replacement Transformers	5,573	5,682	5,798	5,902	6,000
New Street Lighting	2,496	2,564	2,637	2,709	2,780
Replacement Street Lighting	936	957	980	1,001	1,021
Relocate/Replace Distribution Lines for Third Parties	3,872	3,996	4,126	4,256	4,387
Total	$59,823	$64,343	$64,863	$64,779	$62,500

Table A-3
2027-2031 Capital Plan
Substations
($000s)

	2027F	2028F	2029F	2030F	2031F
Project					
Substation Ground Grid Upgrades	369	385	404	423	443
Blaketown Substation Refurbishment & Modernization	528	5,700	-	-	-
Portable Substation	990	3,894	5,049	-	-
Rattling Brook Substation Refurbishment & Modernization	74	1,426	-	-	-
Mobile Plant Substation Refurbishment & Modernization	299	925	-	-	-
Laurentian Power Transformer Replacement	99	3,186	-	-	-
Lookout Brook Power Transformer Replacement	73	86	2,175	-	-
Harmon Power Transformer Replacement	75	71	2,758	-	-
Ridge Road Power Transformer Replacement	66	64	2,565	-	-
Substation Termination for Transmission Line Rebuilds - 95L	-	308	-	-	-
Clarenville Substation Feeder Termination	-	-	-	32	329
Substation Refurbishment and Modernization	-	1,652	14,844	8,169	13,998
Grand Falls Substation 4.16kV Conversion	-	94	1,085	175	-
Substation Additions Due to Load Growth	-	-	-	324	6,573
Kelligrews Substation Feeder Termination	-	-	-	65	854
Power Transformer Replacement Strategy	-	68	93	8,123	8,248
Gander Substation Power Transformer Replacement	263	-	-	-	-
Lewisporte-Boyd’s Cove 138 kV Conversion	7,551	-	-	-	-
Greenspond Substation Refurbishment & Modernization	2,578	-	-	-	-
Molloys Lane Substation Power Transformer Replacement	2,789	-	-	-	-
Substation Spare Power Transformer Inventory	3,906	-	-	-	-
Mobile Plant Substation Power Transformer Replacement	93	2,522	-	-	-
King's Bridge Substation Power Transformer Replacement	93	2,866	-	-	-
Program					
Substation Protection and Control Replacements	743	763	786	809	831
Substation Replacements Due to In-Service Failures	4,613	4,740	4,874	5,005	5,135
Subtotal	$25,202	$28,750	$34,633	$23,125	$36,411
Thermal Supplemental – Substation Component	20	20	520	8,140	-
Total	$25,222	$28,770	$35,153	$31,265	$36,411

Table A-4 2027-2031 Capital Plan Transmission ($000s)					
	2027F	2028F	2029F	2030F	2031F
Project					
Transmission Line 59L Relocation	715	-	-	-	-
Transmission Line 114L Replacement and 142L Relocation	2,341	-	-	-	-
New Transmission Line from LEW to BOY	9,553	-	-	-	-
Transmission Line Rebuild - 100L Sunnyside to Clarenville	13,323	-	-	-	-
Transmission Line Rebuilds	-	5,758	20,395	27,160	20,398
Program					
Transmission Line Maintenance[1]	3,465	3,551	3,642	3,728	3,814
Total	**$29,397**	**$9,309**	**$24,037**	**$30,888**	**$24,212**

[1] Includes retreatment of wood transmission poles with preservative.

Table A-5
2027-2031 Capital Plan
Generation
($000s)

	2027F	2028F	2029F	2030F	2031F
Project					
Hydro Facility Rehabilitation	1,531	1,141	2,117	539	548
Rose Blanche Hydro Plant Refurbishment	649	1,079	-	-	-
Cape Broyle Hydro Plant Switchgear	-	-	-	-	876
Hydro Plant Refurbishments	-	4,875	12,066	8,727	6,022
MD3 Refurbishment	705	-	-	-	-
Load Bank	-	415	-	-	-
MG2 Overhaul	-	-	-	1,401	-
Port Aux Basques Gas Turbine	-	-	-	-	1,095
Program					
Hydro Plant Replacements Due to In-Service Failures	764	785	808	830	852
Thermal Plant Replacements Due to In-Service Failures	328	338	348	357	367
Subtotal	**$3,977**	**$8,633**	**$15,339**	**$11,854**	**$9,760**
Thermal Generation Supplemental	62,700	10,000	7,800	26,200	115,700
Total	**$66,677**	**$18,633**	**$23,139**	**$38,054**	**$125,460**

Table A-6 2027-2031 Capital Plan Information Systems ($000s)					
	2027F	2028F	2029F	2030F	2031F
Project					
Application Enhancements	1,442	2,418	1,480	3,196	1,687
Cybersecurity Upgrades	962	965	1,056	907	1,048
Network Infrastructure	465	679	540	571	542
Shared Server Infrastructure	1,974	4,086	1,799	1,939	1,972
System Upgrades	1,899	5,772	7,308	2,674	2,749
Geographic Information System Upgrade	5,173	2,652	-	-	-
Customer Correspondence Modernization	1,175	-	-	-	-
Microsoft Enterprise Agreement	320	320	320	380	380
SCADA Replacement	-	-	-	2,155	3,286
Technical Work Request Software Replacement	-	-	794	1,077	1,095
Program					
Personal Computer Infrastructure	784	804	824	844	863
Total	$14,194	$ 17,696	$14,121	$13,743	$13,622

Table A-7
2027-2031 Capital Plan
Transportation
($000s)

	2027F	2028F	2029F	2030F	2031F
Project					
Replace Vehicles and Aerial Devices 2026-2027	2,718	-	-	-	-
Replace Vehicles and Aerial Devices 2027-2028	4,510	2,916	-	-	-
Replace Vehicles and Aerial Devices 2028-2029	-	4,710	3,840	-	-
Replace Vehicles and Aerial Devices 2029-2030	-	-	4,301	4,514	-
Replace Vehicles and Aerial Devices 2030-2031	-	-	-	4,999	2,799
Replace Vehicles and Aerial Devices 2031-2032	-	-	-	-	4,880
Purchase Specialized Offroad Vehicle	-	850	860	-	-
Total	$7,228	$8,476	$9,001	$9,513	$7,679

Table A-8 2027-2031 Capital Plan General Property ($000s)					
	2027F	2028F	2029F	2030F	2031F
Project					
Building Accessibility Improvements	500	519	318	215	-
Purchase Specialized Tools and Equipment	626	648	672	695	717
Summerford Building Replacement	562	-	-	-	-
Clarenville Storage Building	-	-	212	-	-
Building Refurbishments	-	1,400	741	538	1,917
Kenmount Road Electrical Upgrade	-	-	265	2,694	-
Program					
Additions to Real Property	731	747	763	778	792
Physical Security Upgrades	568	583	597	610	623
Tools and Equipment	642	654	668	679	691
Total	$3,629	$4,551	$4,236	$6,209	$4,740

Table A-9 2027-2031 Capital Plan Telecommunications ($000s)					
	2027F	2028F	2029F	2030F	2031F
Project					
Goulds to Glendale Fibre Optic Cable Build	-	-	212	-	-
Program					
Communications Equipment Upgrades	149	153	157	162	166
Total	$149	$153	$369	$162	$166

Table A-10 2027-2031 Capital Plan Allowance for Unforeseen Items ($000s)					
	2027F	2028F	2029F	2030F	2031F
Project					
Allowance for Unforeseen Items	750	750	750	750	750
Total	$750	$750	$750	$750	$750

Table A-11
2027-2031 Capital Plan
General Expenses Capitalized
($000s)

	2027F	2028F	2029F	2030F	2031F
Project					
General Expenses Capitalized	5,000	5,200	5,350	5,550	5,750
Total	$5,000	$5,200	$5,350	$5,550	$5,750

APPENDIX B:

2027 CBA AMI Update

TABLE OF CONTENTS

Page

1.0 INTRODUCTION

1.1 The 2026 Update

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* ("CBA").[1]

On June 27, 2025, the Company filed an AMI Update report (the "2026 Update") as an Appendix to the *2026-2030 Capital Plan* in compliance with Order No. P.U. 3 (2025).[2] In summary, the 2026 Update provided that Newfoundland Power's current metering technology, automated meter reading ("AMR"), allows for the delivery of least-cost service to customers and that transitioning to AMI would increase the costs borne by customers for metering. These findings were recognized by the Board in Order No. P.U. 38 (2025).[3]

Newfoundland Power stated in the 2026 Update that it would 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 a potential mid-2030s timeframe, when its AMR technology will require mass replacement.[4]

1.2 The 2027 Update

In Order No. P.U. 38 (2025), the Board directed Newfoundland Power to provide a further update on its review of the implementation of AMI as part of its 2027 CBA.[5] This report (the "2027 Update") is filed in compliance with that directive in Order No. P.U. 38 (2025).

The 2027 Update is designed to build on the 2026 Update and therefore should be considered in conjunction with it. The 2027 Update provides:

- an updated jurisdictional scan with respect to utility metering practices across Canada;
- an update on government funding opportunities; and
- an update on the Company's assessment of the potential benefits of AMI and how they compare to the costs of an AMI implementation, on a preliminary basis.[6]

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1 See Order No. P.U. 3 (2025), page 64.
2 See Newfoundland Power's *2026 CBA, 2026-2030 Capital Plan, Appendix B: AMI Update.*
3 On page 16 of Order No. P.U. 38 (2025), the Board stated that *"smart metering through AMI implementation could provide additional benefits to customers beyond what is currently being provided by AMR; however, the evidence does not support a change at this time."*
4 In accordance with the *CBA Guidelines (Provisional)*, a transition to AMI 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.
5 See Order No. P.U. 38 (2025), page 16.
6 As provided in footnote 2 to the 2026 Update, 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.

The 2027 Update provides a substantially similar conclusion as the 2026 Update. Newfoundland Power's current metering technology allows for the delivery of least-cost service to customers and that transitioning to AMI at this time would not be consistent with the provision of least-cost service to customers. The Company will continue to explore funding opportunities, which could enable a transition to AMI in the shorter term.

2.0 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, and do not differ substantively from the jurisdictional scan completed in the 2026 Update.[7]

The scan found that eight 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.[8] The remaining seven utilities continue to use AMR, electromechanical meters, or a combination of these technologies.

The Company continues to observe 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.[9]

With respect to the Atlantic Canadian utilities, Newfoundland Power observes the following, which was outlined as part of the 2026 CBA process:[10]

- Each of Nova Scotia Power Inc. ("Nova Scotia Power") and New Brunswick Power Corporation ("New Brunswick Power") applied to their regulators with an AMI project when their existing meters were nearing the end of their expected service lives.[11] Both utilities were able to realize significant savings from transitioning from electromechanical meters.[12] Newfoundland Power's current circumstances are different than those of Nova Scotia Power and New Brunswick Power as the Company does not have any electromechanical meters in service and the average age of its AMR meter fleet is an estimated 11 years.

- Newfoundland Power's circumstances are generally more comparable to that of Maritime Electric Company Limited ("Maritime Electric") based on the fact it transitioned from a full AMR system to AMI technology. Newfoundland Power observes that Maritime Electric implemented AMR meters in 2005 before applying to its regulator to implement AMI

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7 See Newfoundland Power's *2026 CBA, 2026-2030 Capital Plan, Appendix B: AMI Update, Attachment A: Survey of Canadian Utility Practice on Metering System.* The only year-over-year changes include one utility completing their AMI deployment, and one announcing they intend to transition to AMI.

8 Powerline carrier AMI has limited functionality compared to AMI.

9 Regarding government mandates, utilities in Ontario were mandated by the Government of Ontario to implement AMI.

10 For a summary of the Company's evidence provided on AMI in its 2026 CBA, see pages 19-22 of Newfoundland Power's final submission on its 2026 CBA filed with the Board on November 13, 2025.

11 See part a) of Request for Information CA-NP-093 filed as part of the Company's 2026 CBA.

12 *Ibid*.

meters beginning in 2024, representing an in-service period of 19 years.[13] Further, Maritime Electric received $19.0 million in federal funding, offsetting the AMI project costs of $38.6 million by almost 50% to support its transition to AMI technology at that time.[14]

3.0 GOVERNMENT FUNDING OPPORTUNITIES

Since the 2026 Update, Newfoundland Power has not identified any provincial or federal funding opportunities for which (i) the Company would be an eligible applicant, and (ii) AMI deployment would be an eligible project.

Newfoundland Power continues to build on its preliminary AMI assessment to be positioned to apply for government funding that could enable an adoption of AMI in the shorter term. This also builds internal knowledge and capacity associated with an AMI implementation ahead of a full engineering assessment. This has enabled the Company to apply for funding opportunities in the past.[15]

Newfoundland Power will apply for any provincial and federal funding opportunities that arise.[16]

4.0 PREMLIMINARY COST BENEFIT ANALYSES

4.1 General

In the 2026 Update, Newfoundland Power provided preliminary cost estimates associated with an AMI implementation in its service territory.[17] The cost estimates were prepared in 2025.

Section 4.2 reproduces key cost estimate information provided in the 2026 Update as the cost of AMI technology is the starting point of an overall preliminary cost benefit analysis of an AMI project.

Section 4.3 provides preliminary assessments of potential use cases associated with AMI technology that could provide benefits to customers, net of the associated costs.

Section 4.4 provides a preliminary overall cost benefit analysis of an AMI project at this time. Net present value ("NPV") figures provided in this section are in 2025 dollars to align with the year the cost estimates were prepared.

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13 *Ibid.*

14 *Ibid.* $19.0 million federal funding / $38.6 million AMI project costs = 49.2%, or almost 50%.

15 See section 3.2 of the 2026 Update for further information on previous applications for funding assistance for a potential AMI project.

16 For example, Natural Resources Canada's Smart Renewables and Electrification Pathways Program (SREPs), launched in 2021, is a $4.5-billion program designed to support the deployment of grid modernization, energy storage and renewable energy technologies in Canada. The program includes support for transmission and distribution infrastructure. The program is currently expected to end March 31, 2036. While Natural Resources Canada is not currently accepting proposals under the Utility Support Stream of the SREPs funding, opportunities could arise in the future.

17 See section 3.3 of the 2026 Update.

4.2 Preliminary Cost Estimates

In the 2026 Update, Newfoundland Power provided that the capital cost associated with an AMI implementation in its service territory is estimated to be approximately $118.0 million, on a preliminary basis.

Table 1 reproduces the breakdown of that capital cost provided in the 2026 Update. The cost estimates are based on broad assumptions, primarily associated with the AMI network type, and therefore will change following detailed engineering assessments.[18]

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**

In addition to the capital costs of an AMI implementation, Newfoundland Power also assessed, on a preliminary basis, the operating costs associated with AMI technology. The annual aggregate costs associated with operating AMI technology is estimated to be approximately $2.0 million in 2025 dollars. Operating costs for AMI technology include annual subscriptions, support and data costs associated with meter data management systems, integration platforms and communication systems.

For comparison to the Company's current AMR metering technology:[19]

- *Capital costs:* Beyond the upfront network and project costs associated with an AMI implementation, the average cost of an AMI meter is estimated to be $220 per meter or roughly double the average cost of an AMR meter of $110 per meter.[20]

- *Operating costs:* the annual costs associated with operating AMI technology of $2.0 million in 2025 dollars is estimated to be more than 40% higher than the annual costs to operate AMR technology of an estimated $1.4 million in 2025.[21]

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18 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.
19 As provided in the 2026 Update.
20 The average cost is weighted between residential, multi-unit and general service customers and excludes installation costs.
21 Includes meter reading and maintenance costs as well as costs associated with vehicles and support systems.

4.3 Preliminary AMI Use-Case Assessments

The Company has assessed, on a preliminary basis, 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. These uses cases can be broadly considered in three categories: (i) load management, (ii) customer service and (iii) field operations. The following discusses key aspects of each category.

Load management

AMI enables the administration of load management initiatives, including time-varying rate ("TVR") structures.[22] The potential benefit of TVR structures for managing peak load on the Island Interconnected System ("IIS") was analyzed in the 2025 Potential Study completed by Posterity Group (the "Study"), which was filed with the Board in late 2025.[23]

The Study estimates that the use of TOU rates could reduce peak demand by 10.9 MW by 2040.[24] Similarly, the Study estimates that CPP rates could reduce peak demand by 9.7 MW by 2040.[25] Challenges of TVR structures on the IIS include the flatness and persistence of the load curve observed on peak days, which limits the ability to shift load without potentially creating a new peak due to equipment rebound effects,[26] as well as relatively low adoption rates for TVR structures.[27] Importantly, the Study provides that utility-driven equipment demand response measures show the highest potential to reduce peak demand, which generally would not require AMI technology.[28] The measures primarily relate to electric vehicle ("EV") charging (e.g., EV telematics and EV chargers).[29]

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22 Time varying rate structures typically include Time-of-Use ("TOU") rates and Critical Peak Pricing ("CPP"). Further, interval consumption data supports improved understanding of load shapes and peak demand drivers, which can enhance the utility's ability to manage system load over time. Without AMI, these analyses are completed through the use of load research studies. From an energy management perspective, AMI technology would enable providing customers with greater visibility into their electricity consumption patterns, which could help customers manage their energy usage.

23 The Study was filed with the Board by Newfoundland and Labrador Hydro ("Hydro") on November 5, 2025 as part of Hydro's 2025 *Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine*.

24 See Exhibit 155 on page 169 of the Study.

25 *Ibid.* Of note, the demand reductions associated with TOU and CPP rates are mutually exclusive as opposed to additive.

26 Exhibit 122 on page 134 of the Study provides the reference load shape for the IIS. Newfoundland Power observes similar challenges outlined in Prince Edward Island. For example, Dunsky Energy Consulting concluded in its Prince Edward Island Efficiency Potential Study that peak shifting measures, such as time-varying rate structures, will likely have limited potential to reduce annual peak. See the *Prince Edward Island Energy Efficiency Potential Study: Volume 1*, page 56.

27 The Study assumed an opt-in rate of 15% for time-varying rates, consistent with forecasts in other jurisdictions such as Nova Scotia and British Columbia.

28 See Exhibit 155 on page 169 of the Study. For further information on utility-driven equipment demand response measures, see section *7.3.2 Utility-Driven Measure Results* of the Study, starting on page 146.

29 Another utility-driven equipment demand response measure is shifting heating load via a smart thermostat program. In the 2025-26 winter season, Newfoundland Power, under the TakeCharge brand (with support from Hydro) implemented an electric space heating load management pilot using Mysa thermostats for baseboard heaters.

Customer Service

AMI supports improvements in customer service by enabling more granular and timely information related to customer usage and service status. Enhanced usage visibility allows customers to better understand their consumption patterns and supports customer service responses to billing-related inquiries. Real-time data collection also reduces the need for customer bill estimations. These capabilities support improved customer engagement and more efficient resolution of service-related issues.

AMI technology also provides the ability to complete disconnection-reconnections remotely. This enables the utility to execute these functions safely and reduce customer service restoration times, without deploying field personnel.

Field Operations

AMI provides improved visibility into system conditions that supports more efficient outage management and service restoration operations, such as improved coordination of field activities, and the dispatching of field crews across routine and emergency response operations. AMI also allows utilities to monitor and manage voltage profiles across the distribution system more precisely, which could provide the potential to reduce overall energy consumption while maintaining service quality. Further, AMI can provide more efficient revenue protection processes, such as automated alerting of theft of electricity.

4.4 Preliminary Overall Cost Benefit Analysis

Based on the cost estimates and potential use case assessments outlined in sections 4.2 and 4.3, Newfoundland Power conducted a NPV analysis to broadly indicate the economic viability of an AMI implementation at this time.

The NPV analysis reflects a preliminary, high-level assessment of a potential AMI implementation and is based on broad assumptions regarding costs, benefits, and implementation parameters.[30] Accordingly, the results are indicative in nature and will change following detailed engineering assessments and more detailed analyses that would be expected to accompany an AMI capital project filed with the Board for approval.

[30] The NPV assumes a useful life of AMI technology of 20 years and that an AMI project would be completed over a five-year period, following an estimated two-year timeframe for completion of detailed engineering assessments and a fulsome business case as well as to account for the regulatory approval process.

The results of the preliminary NPV analysis are provided in Table 2.

Table 2
Preliminary NPV Analysis of an AMI Implementation
($millions)

Cost Description	NPV[31]
Capital AMI implementation costs[32]	(91)
AMI operating and sustaining capital costs[33]	(39)
Avoided AMR costs[34]	47
Potential use case – Load management[35]	23
Potential use case – Customer service[36]	10
Potential use case – Field operations[37]	13
Net benefit (cost)	**(37)**

The preliminary NPV analysis indicates a negative NPV of approximately $37 million, which demonstrates that an AMI implementation is not least-cost for customers at this time.[38]

5.0 CONCLUSION

Newfoundland Power's current metering technology allows for the delivery of least-cost service to customers. Transitioning to AMI at this time would not be consistent with the provision of least-cost service to customers. While the Company continues to build on its preliminary AMI assessment, it does not expect the preliminary business case for an AMI implementation across the Newfoundland Power's service territory to change substantively in the near term, absent government funding. The Company will continue to explore funding opportunities, which could enable a transition to AMI in the shorter term.

[31] 2025 dollars.
[32] The capital implementation costs as are shown in section 4.2, Table 1, expressed here in 2025 dollars.
[33] Primarily related to the operating costs associated with AMI technology, as discussed in section 4.2. There would also be sustaining capital costs related to meter failures over the 20-year period.
[34] The Company would no longer incur capital and operating costs, as outlined in section 4.2, related to its AMR system.
[35] Based on lower demand, energy, and operating costs as a result of load management benefits outlined in section 4.3.
[36] Based on potential net lower operating costs as a result of the customer service benefits outlined in section 4.3.
[37] Based on potential net lower operating costs as a result of the field operations benefits outlined in section 4.3.
[38] For context, if capital implementation costs were partially offset by government funding equal to that provided to Maritime Electric's AMI project (almost 50% as outlined in section 2.0), the business case would be positive, with a projected NPV in that scenario of an estimated $8 million. With funding, Maritime Electric's AMI business case was a positive $7 million. See paragraph 56 on page 10 of Order UE24-06 issued by the Prince Edward Island Regulatory & Appeals Commission on October 4, 2024.

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	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	Currently transitioning to AMI
Naka Power	AMR, with possible use of electromechanical
Northwest Territories Power Corporation	Electromechanical and possible use of AMR
Quilliq Energy Corporation	Electromechanical, AMR, and AMI[2]

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 AMI implemented in Iqaluit.

2025 Capital Expenditure Report

March 27, 2026

Newfoundland Power Inc.

2025 Capital Expenditure Report

Explanatory Note

This report is filed in compliance with Order No. P.U. 27 (2024) of the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board"), and pursuant to section 41 of the *Public Utilities Act*.

Pages one and two of the *2025 Capital Expenditure Report* provide an overview of the 2025 capital expenditures and outline variances from budget of the capital expenditures approved by the Board in Order Nos. P.U. 27 (2024), P.U. 2 (2024), and P.U. 38 (2022). The tables on pages three through 14 provide additional detail on capital expenditures in 2025 and include information on capital projects approved for prior years that were not completed prior to 2025. Page 14 provides additional detail on multi-year projects.

Consistent with the variance criteria outlined in the *Capital Budget Application Guidelines (Provisional)* (the "Provisional Guidelines"), variances of more than 10% of approved expenditure and $100,000 or greater are explained in Appendix A.

For multi-year capital projects, total expenditures to date are reported, compared to total approved budget to date. Variances for multi-year capital projects will be reported in the capital expenditure report in the year following project completion.

Consistent with section V.C of the Provisional Guidelines, a discussion of approved capital expenditures in 2025 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 2025 are provided in Appendix C.

Consistent with section V.C. of the Provisional Guidelines, a summary report of the use of the Allowance for Unforeseen Items is provided in Appendix D.

2025 Capital Expenditures Overview

Newfoundland Power's actual 2025 capital expenditures were $135.7 million, resulting in a total variance of $7.7 million, or 6%, from the 2025 capital budget amount of $128.0 million. Of the total variance, $7.6 million, or 98.7%, relates to the distribution class with the remaining relating to all other asset classes.

This variance reflects the cumulative impact of multiple projects and programs; however, the primary contributor to the variance in both the distribution class and in the overall total is increased customer connections compared to budget estimates.

Additional detail on individual variances of more than 10% of approved expenditure and $100,000 or greater are explained in Appendix A.

Newfoundland Power Inc. 2025 Capital Budget Variances ($000s)			
	Approved[1]	Actual	Variance
Generation - Hydro	7,267	7,154[2]	(113)
Generation - Thermal	318	298	(20)
Substations	15,952	14,201[3]	(1,751)
Transmission	18,064	19,178[4]	1,114
Distribution	59,464	67,033[5]	7,569
General Property	4,010	3,871[6]	(139)
Transportation	5,042	6,399[7]	1,357
Telecommunications	994	1,119	125
Information Systems	11,009	11,215[8]	206
Unforeseen Allowance	750	579	(171)
General Expenses Capitalized	5,081	4,631	(450)
Total	**127,951**	**135,678**	**7,727**
Projects carried forward from prior years		14,852	

1 Approved in Order Nos. P.U. 27 (2024), P.U. 2 (2024), and P.U. 38 (2022).
2 Includes forecast expenditure of $789,000 for *Mobile Hydro Plant Penstock Refurbishment* and $3,248,000 for *Mount Carmel Pond Dam Refurbishment* carried forward into 2026.
3 Includes forecast expenditure of $400,000 for *Northwest Brook Substation Refurbishment and Modernization* and $192,000 for *Lockston Substation Refurbishment and Modernization* carried forward into 2026.
4 Includes forecast expenditure of $1,536,000 for *New Transmission Line from Lewisporte to Boyd's Cove* and $3,310,000 for *Transmission Line 94L Rebuild* carried forward into 2026.
5 Includes forecast expenditure of $845,000 for *Distribution Feeder Automation* and $646,000 for *Distribution Feeders SCT-01 and BLK-01 Relocation* carried forward into 2026.
6 Includes forecast expenditure of $169,000 for *Building Accessibility Improvements* and $184,000 for *Port Union Building Replacement* carried forward into 2026.
7 Includes forecast expenditure of $3,013,000 for *Replace Vehicles and Aerial Devices 2024-2025* carried forward into 2026.
8 Includes forecast expenditure of $294,000 for *Asset Management Technology Replacement* and $400,000 for *Outage Management System Upgrade* carried forward into 2026.

2025 Capital Expenditure Report
(000s)

	Capital Budget			Actual Expenditure				
	2022 - 2024	2025	Total	2022 - 2024	2025	Carryover	Total	Variance
	A	B	C	D	E	F	G	H
2025 Projects and Programs	$ -	$ 127,951	$ 127,951	$ -	$ 120,652	$ 15,026	135,678	$ 7,727
2022-2024 Projects and Programs	62,266	-	62,266	50,363	13,552	1,300	65,215	2,949
Grand Total	**$ 62,266**	**$ 127,951**	**$ 190,217**	**$ 50,363**	**$ 134,204**	**$ 16,326**	**$ 200,893**	**$ 10,676**

Column A	Approved Capital Budget for 2022, 2023 and 2024
Column B	Approved Capital Budget for 2025
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2022, 2023 and 2024
Column E	Actual Capital Expenditure for 2025
Column F	Capital Projects Carried Forward to 2026
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2025 Capital Expenditure Report
(000s)

Category: Generation - Hydro

	Capital Budget			Actual Expenditure					
	2024	2025	Total	2024	2025	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2025 Projects and Programs									
Mobile Hydro Plant Penstock Refurbishment	$ -	$ 825	$ 825	$ -	$ 36	$ 789	$ 825	$ -	
Hydro Plant Replacements Due to In-Service Failures	-	731	731	-	769	-	769	38	
La Manche Canal Bridge Replacement	-	530	530	-	528	-	528	(2)	
	$ -	$ 2,086	$ 2,086	$ -	$ 1,333	$ 789	$ 2,122	$ 36	
2024 Projects and Programs									
Mobile Hydro Plant Surge Tank Refurbishment	$ 977	-	$ 977	$ 499	$ 281	$ 197	$ 977	$ -	
Hydro Facility Rehabilitation	794	-	794	596	170	-	766	(28)	
	$ 1,771	$ -	$ 1,771	$ 1,095	$ 451	$ 197	$ 1,743	$ (28)	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2024
Column B	Approved Capital Budget for 2025
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2024
Column E	Actual Capital Expenditure for 2025
Column F	Capital Projects Carried Forward to 2026
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2025 Capital Expenditure Report
(000s)

Category: Generation - Thermal

	Capital Budget			Actual Expenditure					
	2024	**2025**	**Total**	**2024**	**2025**	**Carryover**	**Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
2025 Projects and Programs									
Thermal Plant Replacements Due to In-Service Failures	$ -	$ 318	$ 318	$ -	$ 298	$ -	$ 298	$ (20)	
	$ -	$ 318	$ 318	$ -	$ 298	$ -	$ 298	$ (20)	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2024
Column B	Approved Capital Budget for 2025
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2024
Column E	Actual Capital Expenditure for 2025
Column F	Capital Projects Carried Forward to 2026
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2025 Capital Expenditure Report
(000s)

Category: Substations

	Capital Budget			Actual Expenditure					
	2023 - 2024	**2025**	**Total**	**2023 - 2024**	**2025**	**Carryover**	**Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
2025 Projects and Programs									
Substation Replacements Due to In-Service Failures	$ -	$ 4,927	$ 4,927	$ -	$ 3,914	$ -	$ 3,914	$ (1,013)	1
Northwest Brook Substation Refurbishment and Modernization	-	4,175	4,175	-	3,609	400	4,009	(166)	
Substation Protection and Control Replacements	-	685	685	-	686	-	686	1	
Substation Ground Grid Upgrades	-	609	609	-	449	-	449	(160)	2
	$ -	$ 10,396	$ 10,396	$ -	$ 8,658	$ 400	$ 9,058	$ (1,338)	
2023 and 2024 Projects and Programs									
Gambo Substation Refurbishment and Modernization	$ 5,267	-	$ 5,267	$ 5,021	$ 413	$ -	$ 5,434	$ 167	
Memorial Substation Refurbishment and Modernization	4,351	-	4,351	3,318	1,053	-	4,371	20	
Old Perlican Substation Refurbishment and Modernization	3,356	-	3,356	3,149	265	-	3,414	58	
Substation Spare Transformer Inventory (2023)	1,500	-	1,500	145	1,523	-	1,668	168	3
	$ 14,474	$ -	$ 14,474	$ 11,633	$ 3,254	$ -	$ 14,887	$ 413	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2023 and 2024
Column B	Approved Capital Budget for 2025
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2023 and 2024
Column E	Actual Capital Expenditure for 2025
Column F	Capital Projects Carried Forward to 2026
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2025 Capital Expenditure Report
(000s)

Category: Transmission

	Capital Budget			Actual Expenditure					
	2024	**2025**	**Total**	**2024**	**2025**	**Carryover**	**Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
2025 Projects and Programs									
Transmission Line Maintenance	$ -	$ 2,884	$ 2,884	$ -	$ 3,754	$ -	$ 3,754	$ 870	4
Wood Pole Retreatment	-	600	600	-	255	-	255	(345)	5
	$ -	$ 3,484	$ 3,484	$ -	$ 4,009	$ -	$ 4,009	$ 525	
2024 Projects and Programs									
Transmission Line 24L Relocation	701	-	701	10	568	122	700	(1)	
	$ 701	$ -	$ 701	$ 10	$ 568	$ 122	$ 700	$ (1)	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2024
Column B	Approved Capital Budget for 2025
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2024
Column E	Actual Capital Expenditure for 2025
Column F	Capital Projects Carried Forward to 2026
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2025 Capital Expenditure Report
(000s)

Category: Distribution

	Capital Budget			Actual Expenditure					
	2024	**2025**	**Total**	**2024**	**2025**	**Carryover**	**Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
2025 Projects and Programs									
LED Street Lighting Replacement	$ -	$ 5,654	$ 5,654	$ -	$ 5,572	$ -	$ 5,572	$ (82)	
Feeder Additions for Load Growth	-	960	960	-	1,023	-	1,023	63	
Distribution Feeder Automation	-	1,125	1,125	-	280	845	1,125	-	
Distribution Feeder PEP-02 Refurbishment	-	667	667	-	624	-	624	(43)	
Distribution Feeder SMV-01 Refurbishment	-	654	654	-	572	-	572	(82)	
Allowance for Funds Used During Construction	-	220	220	-	243	-	243	23	
Extensions	-	13,402	13,402	-	18,558	-	18,558	5,156	6
Reconstruction	-	7,425	7,425	-	8,488	-	8,488	1,063	7
Rebuild Distribution Lines	-	5,115	5,115	-	5,270	-	5,270	155	
Relocate/Replace Distribution Lines for Third Parties	-	3,528	3,528	-	3,814	-	3,814	286	
Replacement Transformers	-	6,340	6,340	-	6,530	-	6,530	190	
New Transformers	-	5,623	5,623	-	5,788	-	5,788	165	
New Services	-	3,208	3,208	-	4,308	-	4,308	1,100	8
New Street Lighting	-	2,460	2,460	-	1,856	-	1,856	(604)	9
Replacement Street Lighting	-	884	884	-	847	-	847	(37)	
Replacement Meters	-	648	648	-	580	-	580	(68)	
Replacement Services	-	445	445	-	448	-	448	3	
New Meters	-	457	457	-	738	-	738	281	10
	$ -	$ 58,815	$ 58,815	$ -	$ 65,539	$ 845	$ 66,384	$ 7,569	
2024 Projects and Programs									
Feeder Additions for Load Growth	$ 2,811	$ -	$ 2,811	$ 1,648	$ 1,424	$ -	$ 3,072	$ 261	
Distribution Feeder BIG-02 Relocation	196	-	196	3	37	156	196	-	
	$ 3,007	$ -	$ 3,007	$ 1,651	$ 1,461	$ 156	$ 3,268	$ 261	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2024
Column B	Approved Capital Budget for 2025
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2024
Column E	Actual Capital Expenditure for 2025
Column F	Capital Projects Carried Forward to 2026
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2025 Capital Expenditure Report
(000s)

Category: General Property

	Capital Budget			Actual Expenditure					
	2024	2025	Total	2024	2025	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2025 Projects and Programs									
Additions to Real Property	$ -	$ 682	$ 682	$ -	$ 625	$ -	$ 625	$ (57)	
Building Accessibility Improvements	-	650	650	-	481	169	650	-	
Specialized Tools and Equipment	-	595	595	-	430	-	430	(165)	11
Tools and Equipment	-	589	589	-	631	-	631	42	
Physical Security Upgrades	-	456	456	-	515	-	515	59	
	$ -	$ 2,972	$ 2,972	$ -	$ 2,682	$ 169	$ 2,851	$ (121)	

* See Appendix A for notes containing variance explanations.

Column A Approved Capital Budget for 2024
Column B Approved Capital Budget for 2025
Column C Total of Columns A and B
Column D Actual Capital Expenditure for 2024
Column E Actual Capital Expenditure for 2025
Column F Capital Projects Carried Forward to 2026
Column G Total of Columns D, E and F
Column H Column G less Column C

2025 Capital Expenditure Report
(000s)

Category: Telecommunications

	Capital Budget			Actual Expenditure					
	2024	2025	Total	2024	2025	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2025 Projects and Programs									
VHF Radio System Replacement	$ -	$ 870	$ 870	$ -	$ 964	$ -	$ 964	$ 94	
Communications Equipment Upgrade	-	124	124	-	155	-	155	31	
	$ -	$ 994	$ 994	$ -	$ 1,119	$ -	$ 1,119	$ 125	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2024
Column B	Approved Capital Budget for 2025
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2024
Column E	Actual Capital Expenditure for 2025
Column F	Capital Projects Carried Forward to 2026
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2025 Capital Expenditure Report
(000s)

Category: Information Systems

	Capital Budget			Actual Expenditure					
	2024	2025	Total	2024	2025	Carryover	Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2025 Projects and Programs									
Application Enhancements	$ -	$ 914	$ 914	$ -	$ 915	$ -	$ 915	$ 1	
Shared Server Infrastructure	-	970	970	-	912	-	912	(58)	
System Upgrades	-	1,408	1,408	-	1,437	-	1,437	29	
Cybersecurity Upgrades	-	940	940	-	1,022	-	1,022	82	
Network Infrastructure	-	470	470	-	569	-	569	99	
Personal Computer Infrastructure	-	720	720	-	766	-	766	46	
	$ -	$ 5,422	$ 5,422	$ -	$ 5,621	$ -	$ 5,621	$ 199	
2024 Projects and Programs									
Application Enhancements	$ 1,892	$ -	$ 1,892	$ 1,680	$ 262	$ -	$ 1,942	$ 50	
Shared Server Infrastructure	964	-	964	860	203	-	1,063	99	
	$ 2,856	$ -	$ 2,856	$ 2,540	$ 465	$ -	$ 3,005	$ 149	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2024
Column B	Approved Capital Budget for 2025
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2024
Column E	Actual Capital Expenditure for 2025
Column F	Capital Projects Carried Forward to 2026
Column G	Total of Columns D, E and F
Column H	Column G less Column C

2025 Capital Expenditure Report
(000s)

Category: Unforeseen Allowance

	Capital Budget		Actual Expenditure				
	2025	**Total**	**2025**	**Carryover**	**Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	
2025 Projects and Programs							
Allowance for Unforeseen Items	$ 750	$ 750	$ 579	$ -	$ 579	$ (171)	12
	$ 750	$ 750	$ 579	$ -	$ 579	$ (171)	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2025
Column B	Total of Column A
Column C	Actual Capital Expenditure for 2025
Column D	Capital Projects Carried Forward to 2026
Column E	Total of Columns C and D
Column F	Column E less Column B

2025 Capital Expenditure Report
(000s)

Category: General Expenses Capitalized

	Capital Budget		Actual Expenditure				
	2025	**Total**	**2025**	**Carryover**	**Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	
2025 Projects and Programs							
General Expenses Capitalized	$ 5,081	$ 5,081	$ 4,631	$ -	$ 4,631	$ (450)	
	$ 5,081	$ 5,081	$ 4,631	$ -	$ 4,631	$ (450)	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2025
Column B	Total of Column A
Column C	Actual Capital Expenditure for 2025
Column D	Capital Projects Carried Forward to 2026
Column E	Total of Columns C and D
Column F	Column E less Column B

2025 Capital Expenditure Report
Multi-Year Projects
(000s)

Category: Multi-Year Projects

	Capital Budget			Actual Expenditure					
	2022 - 2024	**2025**	**Total**	**2022 - 2024**	**2025**	**Carryover**	**Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**H**	**I**	
Distribution									
Distribution Feeders SCT-01 and BLK-01 Relocation	$ -	$ 649	$ 649	$ -	$ 3	$ 646	$ 649	$ -	
Distribution Reliability Initiative (SUM-01)	1,671	-	1,671	1,360	321	-	1,681	10	
Substations									
Islington Substation Refurbishment and Modernization	308	4,706	5,014	900	4,144	-	5,044	30	
Summerville Substation Refurbishment and Modernization	-	511	511	-	668	-	668	157	
Lockston Substation Refurbishment and Modernization	-	305	305	-	113	192	305	-	
Gander Substation Power Transformer Replacement	-	17	17	-	18	-	18	1	
Pulpit Rock Substation Power Transformer Replacement	-	17	17	-	8	-	8	(9)	
Transmission									
Transmission Line 55L Rebuild	10,612	-	10,612	12,158	874	-	13,032	2,420	13
New Transmission Line from Lewisporte to Boyd's Cove	-	1,886	1,886	-	350	1,536	1,886	-	
Transmission Line 146L Rebuild	2,152	9,209	11,361	1,401	10,550	-	11,951	590	
Transmission Line 94L Rebuild	13,095	3,485	16,580	9,779	1,346	3,585	14,710	(1,870)	
Generation - Hydro									
Lookout Brook Hydro Plant Refurbishment	362	1,573	1,935	508	1,424	-	1,932	(3)	
Mount Carmel Pond Dam Refurbishment	-	3,608	3,608	-	360	3,248	3,608	-	
Mobile Hydro Plant Refurbishment	4,146	-	4,146	3,963	2,585	-	6,548	2,402	14
Information Systems									
Microsoft Enterprise Agreement	297	297	594	316	304	-	620	26	
Asset Management Technology Replacement	-	3,479	3,479	-	3,185	294	3,479	-	
Outage Management System Upgrade	-	1,811	1,811	-	1,411	400	1,811	-	
General Property									
Gander Building Renovation	175	760	935	140	777	-	917	(18)	
Port Union Building Replacement	-	278	278	-	94	184	278	-	
Transportation									
Replace Vehicles and Aerial Devices 2025-2026	-	2,173	2,173	-	2,590	-	2,590	417	
Replace Vehicles and Aerial Devices 2024-2025	1,940	2,869	4,809	772	937	3,013	4,722	(87)	
Replace Vehicles and Aerial Devices 2023-2024	4,699	-	4,699	2,137	1,474	550	4,161	(538)	15
	$ 39,457	$ 37,633	$ 77,090	$ 33,434	$ 33,536	$ 13,648	$ 80,618	$ 3,528	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2022, 2023 and 2024
Column B	Approved Capital Budget for 2025
Column C	Total of Columns A and B
Column D	Actual Capital Expenditure for 2022, 2023 and 2024
Column E	Actual Capital Expenditure for 2025
Column F	Capital Projects Carried Forward to 2026
Column G	Total of Columns D, E and F
Column H	Column G less Column C

APPENDIX A:

Variance Notes

Substations

1. *Substation Replacements Due to In-Service Failures:*
Budget: $4,927,000 Actual: $3,914,000 Variance: ($1,013,000)

The actual expenditure for the *Substation Replacements Due to In-Service Failures* program was $1,013,000, or 21%, lower 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 decrease is primarily due to lower material costs to address work encountered in 2025.

2. *Substation Ground Grid Upgrades*
Budget: $609,000 Actual: $449,000 Variance: ($160,000)

The actual expenditure for the *Substation Ground Grid Upgrades* project was $160,000, or 26%, lower than the budget estimate.

This decrease is largely due to lower than anticipated contractor pricing compared to the budget estimate.

3. *Substation Spare Transformer Inventory (2023 Project):*
Budget: $1,500,000 Actual: $1,668,000 Variance: $168,000

The actual expenditure for the *Substation Spare Transformer Inventory* project was $168,000, or 11%, higher than the budget estimate, primarily due to higher-than-expected purchase costs for the transformer.

The original budget estimate for this project was prepared 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 procurement commenced 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% between the time the estimate was completed in 2022 to the time the procurement contract was completed in 2023.

Transmission

4. *Transmission Line Maintenance:*
   Budget: $2,884,000 Actual: $3,754,000 Variance: $870,000

   The actual expenditure for the *Transmission Line Maintenance* program was $870,000, or 30%, higher than the budget estimate.

   The *Transmission Line Maintenance* program budget estimate is determined based on the five-year historical average. This increase is primarily due to the relocation of sections of Transmission Lines 38L and 39L, near Newfoundland and Labrador Hydro's ("Hydro") Holyrood Generating Station, to accommodate the approved early execution capital work required for the proposed construction of the Avalon Combustion Turbine.[1]

5. *Wood Pole Retreatment:*
   Budget: $600,000 Actual: $255,000 Variance: ($345,000)

   The actual expenditure for the *Wood Pole Retreatment* project was $345,000, or 58%, lower than the budget estimate.

   This decrease was primarily due to lower than anticipated contractor pricing compared to the budget estimate. The *2025 Capital Budget Application* was the first year of the *Wood Pole Retreatment* project and historical costs were not available to inform the budget estimate. In the *2026 Capital Budget Application*, this scope of work is incorporated into the *Transmission Line Maintenance* program.[2]

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1 The *Transmission Line Maintenance* program includes a component to accommodate third-party requests to relocate or replace sections of transmission lines. In Order No. P.U. 30 (2025), the Board approved a contribution by Hydro for the costs associated with the relocation of a portion of Newfoundland Power's Transmission Lines 38L and 39L at the request of Hydro.

2 See the Company's *2026 Capital Budget Application, Schedule B*, page 78.

Distribution

6. *Extensions:*
   Budget: $13,402,000 Actual: $18,558,000 Variance: $5,156,000

   The actual expenditure for the *Extensions* program was $5,156,000 or 38%, 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. The 2025 budget estimate was based on a forecast of 2,220 customer connections. Actual customer connections were 3,122 representing a 41% increase.[3]

   In addition, approximately $1,756,000 of costs were incurred in 2025 for large-scale extensions to connect customers.[4]

7. *Reconstruction:*
   Budget: $7,425,000 Actual: $8,488,000 Variance: $1,063,000

   The actual expenditure for the *Reconstruction* program was $1,063,000, or 14%, 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 major events in 2025 resulting in the requirement for additional work.[5]

8. *New Services:*
   Budget: $3,208,000 Actual: $4,308,000 Variance: $1,100,000

   The actual expenditure for the *New Services* program was $1,100,000, or 34%, higher than the budget estimate.

   The *New Services* program budget estimate is determined based on the forecast number of new customer connections, and the average historical cost of connecting a new customer. The 2025 budget estimate was based on a forecast of 2,220 customer connections. Actual customer connections were 3,122 representing a 41% increase.[6]

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[3] In the *2025 Capital Expenditure Status Report* filed as part of the *2026 Capital Budget Application*, Newfoundland Power revised its 2025 forecast to $19,982,000 based on an increase to 3,310 new customer connections. Actual expenditures were $1,424,000, or 7% below the revised forecast.

[4] The large-scale extension developments in 2025 were primarily related to the Joe Batt's Pond and Jonathan's Pond cottage areas. CIACs for these developments were approved in Order Nos. P.U. 19 (2025) and 22 (2023), respectively.

[5] Major events in 2025 included a severe winter storm in January, a windstorm in November and four winter storms in December. In addition, major events include costs related to summer wildfires excluding those allocated to the *Allowance for Unforeseen Items* project. Total capital expenditure for these events totaled approximately $692,000.

[6] In the *2025 Capital Expenditure Status Report* filed as part of the *2026 Capital Budget Application*, Newfoundland Power revised its 2025 forecast to $4,784,000 based on an increase to 3,310 new customer connections. Actual expenditures were $476,000, or 10% below the revised forecast.

9. *New Street Lighting:*
Budget: $2,460,000 Actual: $1,856,000 Variance: ($604,000)

The actual expenditure for the *New Street Lighting* program was $604,000, or 25%, lower than the budget estimate.

The *New Street Lighting* program budget estimate is determined based on the five-year historical average cost. This decrease is primarily attributable to a 26% decrease in requests for new street light installations as compared to the previous five-year average.[7]

10. *New Meters:*
Budget: $457,000 Actual: $738,000 Variance: $281,000

The actual expenditure for the *New Meters* program was $281,000, or 61%, higher than the budget estimate.

The *New Meters* program budget estimate is determined based on the forecast number of new customer connections and the five-year historical average cost. The 2025 budget estimate was based on a forecast of 2,220 customer connections. Actual customer connections were 3,122 representing a 41% increase.[8]

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7 There were 704 new street lights installed in 2025. Over the period 2020 to 2024, there were an average of 955 new street lights installed (1 – (704 / 955) = 0.26 or 26%).

8 In the *2025 Capital Expenditure Status Report* filed as part of the *2026 Capital Budget Application*, Newfoundland Power revised its 2025 forecast to $668,000 based on an increase to 3,310 new customer connections. Actual expenditures were $70,000, or 10% above the revised forecast.

General Property

11. *Specialized Tools and Equipment*
Budget: $595,000 Actual: $430,000 Variance: ($165,000)

The actual expenditure for the *Specialized Tools and Equipment* project was $165,000, or 28%, lower than the budget estimate.

This decrease is largely due to lower than expected requirements for tools in 2025.

Unforeseen Allowance

12. Allowance for Unforeseen Items:
Budget: $750,000 Actual: $579,000 Variance: ($171,000)

The *Allowance for Unforeseen Items* is used as required in accordance with the Provisional Guidelines. The $579,000 expenditure was related to the restoration activities arising from wildfires in the Kingston area of Conception Bay North. The remaining allowance of $171,000 was not required to be used in 2025.

The Kingston Wildfire caused damage to the Company’s distribution infrastructure, including poles, transformers, service wires, and streetlights, requiring repair or replacement to safely restore electricity service to affected customers.

Additional information on the use of the *Allowance for Unforeseen Items* in 2025 is provided in Appendix D.

Multi-Year Projects

13. Transmission Line 55L Rebuild (2023-2024 Multi-Year Project)
Budget: $10,612,000 Actual: $13,032,000 Variance: $2,420,000

The *Transmission Line 55L Rebuild* project was a multi-year project that commenced in 2023. Actual capital expenditures on the project were $2,420,000, or 23%, higher than the budget estimate. The increase was largely associated with higher-than-expected contractor and material costs.[9]

14. Mobile Hydro Plant Refurbishment (2023-2024 Multi-Year Project)
Budget: $4,146,000 Actual: $6,548,000 Variance: $2,402,000

The *Mobile Hydro Plant Refurbishment* project was a multi-year project that commenced in 2023. Actual capital expenditures on the project were $2,402,000, or 58%, higher than the budget estimate. The increase was largely associated with additional mechanical refurbishment work identified during the project, as well as delays due to longer than anticipated lead times associated with the governor, switchgear and generator refurbishment.[10]

Progress on the project was constrained by delays in the completion of the generator stator rewind. Mechanical refurbishment activities were dependent on completion of the stator work and the full disassembly of the generating unit. Upon reassembly of the generating unit, the unit underwent commissioning and failed in service. Additional unplanned disassembly, repair work and reassembly were required to identify and correct the issue, after which final commissioning activities successfully returned the unit to service.

15. Replace Vehicles and Aerial Devices 2023-2024
Budget: $4,699,000 Actual: $4,161,000 Variance: ($538,000)

The *Replace Vehicles and Aerial Devices (2023-2024)* project was a multi-year project that commenced in 2023. Actual capital expenditures on the project were $4,161,000, including a $550,000 carryover to 2026, resulting in a $538,000, or 11%, reduction from the approved budget. The decrease in expenditures is primarily attributable to lower requirements for passenger vehicles and offroad vehicles.[11]

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[9] See the Company's *2024 Capital Expenditure Report,* Appendix A, page 5.
[10] *Ibid.*
[11] See the Company's *2023 Capital Expenditure Report*, Appendix A, page 11.

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 discrete 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 based on 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, which 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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[1] 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.

2025 Capital Expenditures Overall

Approved capital expenditures in 2025 totaled $128.0 million. Actual expenditures were $135.7 million, including forecast expenditures of $15.0 million carried forward into 2026. Actual expenditure was $7.7 million, or 6% higher than the total approved capital budget of $128.0 million.

For additional information on Newfoundland Power's 2025 capital expenditures, see the 2025 Capital Expenditures Overview of the *2025 Capital Expenditure Report.*

2025 Capital Project Changes

Mobile Hydro Plant Refurbishment

A portion of the scope of the *Mobile Hydro Plant Refurbishment* project was not completed as originally anticipated. Progress on the project was constrained by the completion of the generator stator rewind, which extended later than originally anticipated. Associated mechanical refurbishment activities were dependent on completion of the stator work and the full disassembly of the generating unit. Upon reassembly of the generating unit, the unit underwent commissioning and failed in service. Additional unplanned disassembly, repair work and reassembly were required to identify and correct the issue, after which final commissioning activities successfully returned the unit to service.

The *Mobile Hydro Plant Refurbishment* project was a multi-year project submitted in the *2023 Capital Budget Application*. This project was approved by the Board in Order No. P.U. 38 (2022).

Mobile Hydro Plant Penstock Refurbishment

The *Mobile Hydro Plant Penstock Refurbishment* project was a single-year project that commenced in 2025 but could not be executed as planned. The project was planned to be undertaken during the summer months to take advantage of favourable water conditions and minimize spillage from the Mobile Big Pond reservoir. Due to delays in the completion of the generator refurbishment at the Mobile Plant as discussed above, Newfoundland Power determined that the penstock refurbishment work could not be completed as originally scheduled. The construction of the penstock has been deferred to the following spring and will be completed in 2026.

The *Mobile Hydro Plant Penstock Refurbishment* project was submitted in the *2025 Capital Budget Application*. This project was 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.

2025 Capital Projects

In 2025, Newfoundland Power had a total of 39 capital projects, 26 of which were fully completed in 2025. The approved budget of the 26 completed capital projects totaled $41,155,000 and the final cost was $40,422,000. Projects not completed include eight multi-year capital projects that commenced in 2025 and continued in 2026. An additional five capital projects have forecast carryover expenditures into 2026. Of the five capital projects classified under General Plant not completed in 2025, three projects are ongoing multi-year projects with expenditures in 2026. An additional two capital projects have forecast expenditures carried over into 2026.

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
2025 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	9	8
	$1 million to $5 million	5	2
	>$5 million	1	-
Total General Plant		15	10
Mandatory	<$1 million	2	2
	$1 million to $5 million	-	-
	>$5 million	1	1
Total Mandatory		3	3

Table 1 2025 Capital Projects Planned and Completed (Continued)			
Investment Classification	Materiality Threshold	Planned	Completed
Renewal	<$1 million	5	4
	$1 million to $5 million	7	3
	>$5 million	5	3
Total Renewal[1]		**17**	**10**
Service Enhancement	<$1 million	1	1
	$1 million to $5 million	1	-
	>$5 million	1	1
Total Service Enhancement[2]		**3**	**2**
System Growth	<$1 million	1	1
	$1 million to $5 million	-	-
	>$5 million	-	-
Total System Growth		**1**	**1**
Overall	<$1 million	18	16
	$1 million to $5 million	13	5
	>$5 million	8	5
Total Overall		**39**	**26**

1 Of the seven capital projects classified under Renewal not completed in 2025, five projects are ongoing multi-year projects with expenditures in 2026. The remaining two projects have associated carryover work to be completed in 2026.

2 Of the three capital projects classified under Service Enhancement, one project was not completed. This project has associated carryover work to be completed in 2026.

Table 2 provides the approved 2025 budget amount of the capital projects that were completed in 2025 compared to the final cost of the project, presented by investment classification and materiality threshold.

Table 2
2025 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	5,816	5,858
	$1 million to $5 million	3,581	4,027
	>$5 million	-	-
Total General Plant		**9,397**	**9,885**
Mandatory	<$1 million	970	822
	$1 million to $5 million	-	-
	>$5 million	5,081	4,631
Total Mandatory		**6,051**	**5,453**
Renewal	<$1 million	2,451	1,979
	$1 million to $5 million	1,607	1,450
	>$5 million	14,426	14,611
Total Renewal		**18,484**	**18,040**
Service Enhancement	<$1 million	609	449
	$1 million to $5 million	-	-
	>$5 million	5,654	5,572
Total Service Enhancement		**6,263**	**6,021**

Table 2 2025 Capital Projects Completed Budget and Final Costs ($000s) (Continued)			
Investment Classification	Materiality Threshold	Approved Budget	Final Cost
System Growth	<$1 million	960	1,023
	$1 million to $5 million	-	-
	>$5 million	-	-
Total System Growth		960	1,023
Overall	<$1 million	10,806	10,131
	$1 million to $5 million	5,188	5,477
	>$5 million	25,161	24,814
Total Overall		41,155	40,422

2025 Capital Programs

In 2025, 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
2025 Capital Programs

Materiality Threshold	Program	Approved Budget ($000s)	Final Cost ($000s)	Number of Planned Units[3]	Actual Number of Units[4]	Estimated Average Unit Cost ($)	Actual Average Unit Cost ($)
<$1 million	New Meters	457	738	2,220	3,122	206	236
	Replacement Meters	648	580	3,549	3,375	183	172
$1 million to $5 million	New Services	3,208	4,308	2,220	3,122	1,445	1,380
>$5 million	Extensions	13,402	18,558	2,220	3,122	6,037	5,944

3 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").

4 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.

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, 2024 and 2025.

Table 4
Capital Projects
Planned and Completed

Investment Classification	Materiality Threshold	2023 Planned	2023 Completed	2024 Planned	2024 Completed	2025 Planned	2025 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	9	8
	$1 million to $5 million	5	2	3	-	5	2
	>$5 million	2	-	-	-	1	-
Total General Plant		**13**	**5**	**11**	**5**	**15**	**10**
Mandatory	<$1 million	3	3	3	3	2	2
	$1 million to $5 million	1	1	1	1	-	-
	>$5 million	-	-	-	-	1	1
Total Mandatory		**4**	**4**	**4**	**4**	**3**	**3**

Table 4
Capital Projects
Planned and Completed
(Continued)

Investment Classification	Materiality Threshold	2023 Planned	2023 Completed	2024 Planned	2024 Completed	2025 Planned	2025 Completed
Renewal	<$1 million	5	4	10	4	5	4
	$1 million to $5 million	6	1	7	1	7	3
	>$5 million	3	-	2	-	5	3
Total Renewal		**14**	**5**	**19**	**5**	**17**	**10**
Service Enhancement	<$1 million	1	1	2	2	1	1
	$1 million to $5 million	1	-	-	-	1	-
	>$5 million	1	1	1	1	1	1
Total Service Enhancement		**3**	**2**	**3**	**3**	**3**	**2**
System Growth	<$1 million	1	1	1	1	1	1
	$1 million to $5 million	-	-	1	-	-	-
	>$5 million	-	-	-	-	-	-
Total System Growth		**1**	**1**	**2**	**1**	**1**	**1**
Overall	<$1 million	16	12	24	15	18	16
	$1 million to $5 million	15	6	12	2	13	5
	>$5 million	6	1	3	1	8	5
Total Overall		**37**	**19**	**39**	**18**	**39**	**26**

Table 5 compares the approved budget amount of the capital projects planned in 2023, 2024 and 2025 that were completed to 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	2025 Approved Budget	2025 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	5,816	5,858
	$1 million to $5 million	2,351	1,900	-	-	3,581	4,027
	>$5 million	-	-	-	-	-	-
Total General Plant		**4,054**	**3,778**	**3,226**	**3,190**	**9,397**	**9,885**
Mandatory	<$1 million	1,422	738	1,554	875	970	822
	$1 million to $5 million	4,000	5,100	4,500	4,701	-	-
	>$5 million	-	-	-	-	5,081	4,631
Total Mandatory		**5,422**	**5,838**	**6,054**	**5,576**	**6,051**	**5,453**
Renewal	<$1 million	2,659	2,609	2,723	2,846	2,451	1,979
	$1 million to $5 million	1,577	1,556	1,566	1,496	1,607	1,450
	>$5 million	-	-	-	-	14,426	14,611
Total Renewal		**4,236**	**4,165**	**4,289**	**4,342**	**18,484**	**18,040**

Table 5
Capital Projects Completed
Budget and Final Costs
($000s)
(Continued)

Investment Classification	Materiality Threshold	2023 Approved Budget	2023 Final Cost	2024 Approved Budget	2024 Final Cost	2025 Approved Budget	2025 Final Cost
Service Enhancement	<$1 million	563	511	1,468	1,276	609	449
	$1 million to $5 million	-	-	-	-	-	-
	>$5 million	5,453	5,953	5,541	5,945	5,654	5,572
Total Service Enhancement		**6,016**	**6,464**	**7,009**	**7,221**	**6,263**	**6,021**
System Growth	<$1 million	670	732	451	364	960	1,023
	$1 million to $5 million	-	-	-	-	-	-
	>$5 million	-	-	-	-	-	-
Total System Growth		**670**	**732**	**451**	**364**	**960**	**1,023**
Overall	<$1 million	7,017	6,468	9,422	8,551	10,806	10,131
	$1 million to $5 million	13,931	14,099	6,066	6,197	5,188	5,477
	>$5 million	5,453	5,953	5,541	5,945	25,161	24,814
Total Overall		**26,401**	**26,520**	**21,029**	**20,693**	**41,155**	**40,422**

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, 2024 and 2025.

Table 6
Capital Programs
Number of Units by Materiality Threshold

Materiality Threshold	Program	2023 Number of Planned Units[5]	2023 Actual Number of Units[6]	2024 Number of Planned Units	2024 Actual Number of Units	2025 Number of Planned Units	2025 Actual Number of Units
<$1 million	New Meters	2,185	2,372	2,053	3,052	2,220	3,122
	Replacement Meters	4,877	2,898	3,884	775	3,549	3,375
$1 million to $5 million	New Services	2,185	2,372	2,053	3,052	2,220	3,122
>$5 million	Extensions	2,185	2,372	2,053	3,052	2,220	3,122

5 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.

6 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.

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	2025 Planned Cost per Unit	2025 Actual Cost per Unit
<$1 million	New Meters	136	215	147	256	206	236
	Replacement Meters	136	183	147	439	183	172
$1 million to $5 million	New Services	1,335	1,374	1,387	1,200	1,445	1,380
>$5 million	Extensions	5,592	6,385	5,670	6,422	6,037	5,944

APPENDIX D:

Allowance for Unforeseen Items – Kingston Wildfire

THE KINGSTON WILDFIRE

On August 3, 2025, a wildfire was officially reported near Kingston, Newfoundland and Labrador (the "Kingston Wildfire" or the "Wildfire"). The Wildfire remained out of control for approximately three weeks until August 27, 2025, due to high temperatures and extremely dry conditions. The Wildfire covered a total of more than 10,000 hectares.

The Kingston Wildfire resulted in evacuation orders and customers' power being disconnected, as well as homes and businesses being destroyed. The Wildfire also caused significant damage to Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") electricity system in the Conception Bay North area, requiring immediate repair or replacement.[1]

Newfoundland Power worked closely with Fire and Emergency Services throughout the Wildfire. In addition, the Company had daily involvement with the Provincial Emergency Operation Centre ("PEOC") for damage assessment and electrical system restoration activities. The Company's Geographic Information System ("GIS") technology also played an important role in emergency coordination and infrastructure restoration, by allowing the Company to view the impact of the fire with respect to Newfoundland Power's distribution assets.

Figure 1 provides an image from the Company's GIS system of the Kingston Wildfire and distribution infrastructure on August 11, 2025.

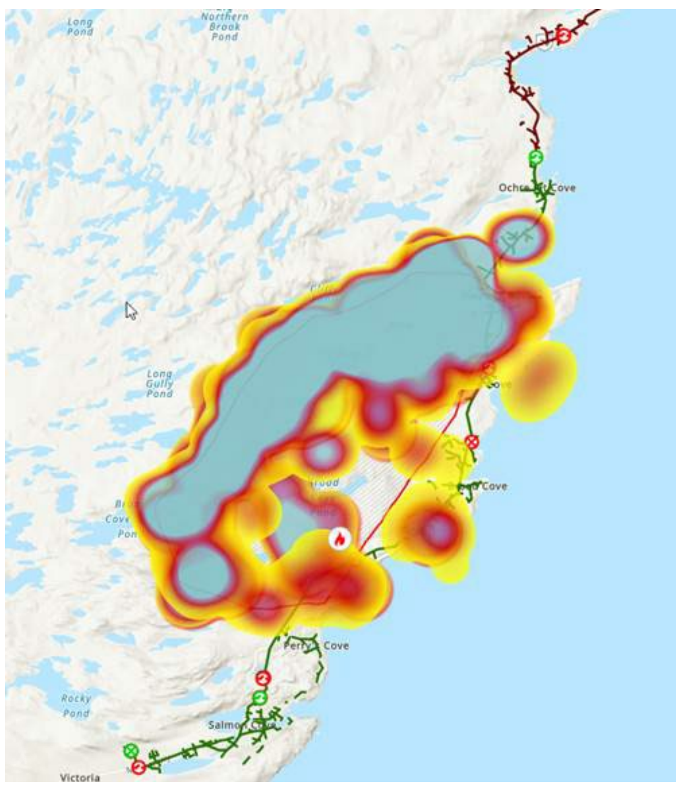

Figure 1: GIS image of the Kingston Wildfire, including Newfoundland Power distribution lines.

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1 This included significant damage to the Company's distribution feeders VIC-02 and OPL-02.

Beginning on August 4, 2025, evacuation orders and alerts were issued by Fire and Emergency Services for the communities affected by the Wildfire.[2] In total, 12 communities were forced to evacuate, eight of which experienced direct fire damage.[3]

Newfoundland Power disconnected power from Kingston to Adam's Cove on August 4, 2024, to assist fire fighting efforts, in accordance with the direction given by Fire and Emergency Service personnel.[4] The Company continued to disconnect its electrical infrastructure in a staged approach, to ensure the safety of Fire and Emergency Service personnel. Power was disconnected to the following communities as a result:

- Western Bay – August 9, 2025
- Ochre Pit Cove – August 10, 2025
- Northern Bay – August 11, 2025
- Perry's Cove, Gull Island and Burnt Point – August 12, 2025

At its peak, approximately 1,400 Newfoundland Power customers experienced an outage to their electrical service.[5] A total of more than 20 million minutes of customer outages were experienced.

NEWFOUNDLAND POWER'S RESPONSE

On Monday, August 18, 2025, Newfoundland Power was given permission to enter parts of the evacuation zone and begin damage assessment and repairs. Fire damage to Newfoundland Power's infrastructure was significant, consisting of damage to 245 poles and 17 pole-top transformers. There was also damage to primary and secondary conductors, street lighting, service wires and metering. Among the damaged infrastructure were poles and equipment that fell to the ground, some of which blocked roadways and prevented vehicle traffic.

The Company's response occurred in three stages: (i) remediation; (ii) replacement; and (iii) reconnection. The safe and timely restoration of service was the primary focus of Newfoundland Power's response.[6]

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[2] Evacuation orders occurred from August 4, 2025 to August 9, 2025. Evacuation orders remained in place until August 23, 2025 with the last evacuation order being lifted on August 28, 2025.

[3] Direct fire damage includes exposure to flames and heat resulting in either burning or melting. The eight communities that experienced direct fire damage spanned from Kingston to Northern Bay.

[4] This included the operation of water bombers, helicopters and ground crew.

[5] The electrical system did not experience any faults, as a result of power being disconnected before any distribution lines were damaged by fire.

[6] In addition to taking a phased approach to damage assessment and repairs, Newfoundland Power took steps to ensure a fast and efficient response. This included: responding as quickly as possible and working continuously until work was completed; focusing only on necessary replacements; working with emergency services to complete as much work as possible before the evacuation order was lifted; leveraging contractors to complete activities not directly related to restoring power to customers; and like-for-like replacements. The majority of necessary repairs were completed within a two-week period as a result of these efforts. This minimized disruption to Newfoundland Power's planned work.

In addition, the Company's distribution system configuration allowed for limited customer outages and mitigation of additional capital expenditures.[7]

The initial stage of the response involved remedying any damaged equipment that posed a safety concern and clearing roadways of equipment and wires. This included identifying services connected to destroyed and damaged homes that would require electrical inspection authorization before being reconnected. In addition to the removal of any fallen poles or wires that were blocking roadways and preventing vehicle traffic, the Company also removed any debris or damaged equipment that caused a public safety risk. This work was primarily completed over the August 18 to August 20 timeframe.

The second stage of the response involved replacing damaged equipment required to restore power to undamaged customer premises. This included replacing poles, stringing new conductor, replacing transformers, and disconnecting service to damaged properties. Immediate replacement of 163 poles and 10 transformers was required to restore power.[8] This work was primarily completed over the August 21 to August 28 timeframe.

The final stage of the response involved reconnecting individual customer premises identified as damaged during assessment, which involved coordination with the province's electrical inspection authority. This work was primarily completed over the August 25 to August 28 timeframe, with power being restored to all non-damaged customer premises not requiring electrical inspection or repairs by August 28, 2025.[9]

A total of 199 electrically serviced customer premises were destroyed, and a further 124 premises were damaged. The 124 damaged premises required repairs and/or an electrical inspection before electrical service can be reconnected. As of March 26, 2026, all 124 customers have been reconnected.

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7 The system configuration allowed the Company to isolate the affected portion of the distribution system without interrupting service to customers located downstream of the affected area. Absent this configuration, customers who were not directly affected by the Wildfire could have experienced an extended loss of electrical service, in which case Newfoundland Power may have been required to deploy portable generation to maintain service, resulting in additional cost and operational requirements.

8 The Company has deferred replacement of 82 poles and 7 transformers, which will require replacement in the future once properties are rebuilt.

9 Eleven services were reconnected after August 28, 2025, as the Company received electrical authorization from the province's electrical inspection authority to reconnect.

COSTS

The total capital expenditure associated with replacing distribution poles, transformers, primary and secondary conductor, service wires, streetlighting and meters due to the Kingston wildfire was approximately $579,000.[10]

These capital expenditures were undertaken in accordance with the *Allowance for Unforeseen Items* capital project approved as part of the Company's *2025 Capital Budget Application*. Work arising from the Kingston Wildfire was not anticipated at the time of the filing of Newfoundland Power's *2025 Capital Budget Application*. Wildfires are unpredictable by nature, and a wildfire event of this magnitude was previously unprecedented for Newfoundland Power. The costs incurred in rebuilding the fire damaged infrastructure on an urgent basis were necessary to restore electricity service to customers affected by the Kingston Wildfire.

[10] This includes approximately $201,000 in materials, $350,000 in internal labour and $28,000 in contract labour.

May 2026

2026 Capital Expenditure Status Report

NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

2026 Capital Budget Expenditure
Status Report

Compliance Matter

The *2026 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 17, paragraph 6 of Order No. P.U. 38 (2025):

> *"Unless otherwise directed by the Board Newfoundland Power shall provide, in conjunction with its 2027 Capital Budget Application, a status report on the 2026 capital budget expenditures showing for each project:*
>
> *i) the approved budget for 2026;*
> *ii) the expenditures prior to 2026;*
> *iii) the 2026 expenditures to the date of the application;*
> *iv) the remaining projected expenditures for 2026;*
> *v) the variance between the projected total expenditures and the approved budget; and*
> *vi) an explanation of the variance."*

Overview

Page 1 of the *2026 Capital Budget Expenditure Status Report* outlines the forecast variances from budget of the 2026 capital expenditures approved by the Board. The tables on pages 2 to 7 provide additional detail on the capital expenditures for 2026 which were approved in Order Nos. P.U. 38 (2025), P.U. 27 (2024) and P.U. 2 (2024).[1] The additional detail is organized by single-year projects and programs approved for 2026, multi-year projects approved to commence in 2026 and previously approved multi-year projects with expenditures occurring in 2026.

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 *2026 Capital Budget Expenditure Status Report*, there are no projects or programs that meet the criteria for variance explanations.

Newfoundland Power will provide updated information to the Board in its regular reporting and upon request of the Board.

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[1] The *2026 Capital Budget Expenditure Status Report* reflects year-to-date actual expenditures as of March 31, 2026. This represents the most recent reporting period available prior to the filing of the *2027 Capital Budget Application*.

Newfoundland Power Inc.
2026 Capital Budget Expenditure Status Report
Capital Expenditure Overview

	Annual Budget	Expenditures		Annual Forecast	
		Actual	Forecast		
Asset Class and Project Description	**2026 Budget**	**January to March**	**April to December**	**2026 Forecast**	**Variance**
Distribution	61,824	14,331	47,493	61,824	0
Substations	22,634	1,172	21,462	22,634	0
Transmission	22,114	600	21,514	22,114	0
Generation - Hydro	2,142	256	1,886	2,142	0
Generation - Thermal	331	44	287	331	0
Information Systems	12,673	2,687	9,986	12,673	0
Telecommunications	281	15	266	281	0
General Property	4,089	361	3,728	4,089	0
Transportation	5,805	772	5,033	5,805	0
Unforeseen Items	750	0	750	750	0
General Expenses Capitalized	5,300	1,442	3,858	5,300	0
Total	**137,943**	**21,680**	**116,263**	**137,943**	**0**
Expenditure Type					
Single-Year Projects and Programs Over $750,000	75,158	17,292	57,866	75,158	0
Single-Year Projects and Programs $750,000 and Under	10,212	1,440	8,772	10,212	0
Multi-Year Projects Commencing in 2026	6,131	410	5,721	6,131	0
Multi-Year Projects Commencing Prior to 2026	46,442	2,538	43,904	46,442	0
Total	**137,943**	**21,680**	**116,263**	**137,943**	**0**

Newfoundland Power Inc.
2026 Capital Budget Expenditure Status Report
Single-Year Projects and Programs Over $750,000[1]
($000s)

	Annual Budget	Expenditures		Annual Forecast		
		Actual	Forecast			
Asset Class and Project Description	**2026 Budget**	**January to March**	**April to December**	**2026 Forecast**	**Variance**	**Notes**
Distribution						
Extensions	16,747	3,292	13,455	16,747	0	
Reconstruction	7,674	2,157	5,517	7,674	0	
LED Street Lighting Replacement	5,559	2,059	3,500	5,559	0	
Rebuild Distribution Lines	5,263	634	4,629	5,263	0	
Replacement Transformers	4,954	1,804	3,150	4,954	0	
New Transformers	4,394	1,599	2,795	4,394	0	
New Services	4,218	928	3,290	4,218	0	
Relocate/Replace Distribution Lines for Third Parties	3,702	781	2,921	3,702	0	
New Street Lighting	2,425	482	1,943	2,425	0	
Mount Carmel Pond Feeder Extension CAB 01	1,346	23	1,323	1,346	0	
Replacement Street Lighting	914	313	601	914	0	
Total Distribution	**57,196**	**14,072**	**43,124**	**57,196**	**0**	
Substations						
Substation Replacements Due to In-Service Failures	4,733	559	4,174	4,733	0	
Total Substations	**4,733**	**559**	**4,174**	**4,733**	**0**	
Transmission						
Transmission Line Maintenance	3,306	428	2,878	3,306	0	
Total Transmission	**3,306**	**428**	**2,878**	**3,306**	**0**	
Information System						
Shared Server Infrastructure	990	138	852	990	0	
Application Enhancements	968	298	670	968	0	
System Upgrades	965	203	762	965	0	

Newfoundland Power Inc.
2026 Capital Budget Expenditure Status Report
Single-Year Projects and Programs Over $750,000[1]
($000s)

	Annual Budget	Expenditures		Annual Forecast		
		Actual	Forecast			
Asset Class and Project Description	**2026 Budget**	**January to March**	**April to December**	**2026 Forecast**	**Variance**	**Notes**
Cybersecurity Upgrades	950	152	798	950	0	
Total Information System	**3,873**	**791**	**3,082**	**3,873**	**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	5,300	1,442	3,858	5,300	0	
Total General Expenses Capitalized	**5,300**	**1,442**	**3,858**	**5,300**	**0**	
Total	**75,158**	**17,292**	**57,866**	**75,158**	**0**	

[1] Approved in Order No. P.U. 38 (2025).

Newfoundland Power Inc.
2026 Capital Budget Expenditure Status Report
Single-Year Projects and Programs $750,000 and Under[1]
($000s)

	Annual Budget	Expenditures		Annual Forecast		
		Actual	Forecast			
Asset Class and Project Description	**2026 Budget**	**January to March**	**April to December**	**2026 Forecast**	**Variance**	**Notes**
Distribution						
Distribution Feeder GDL 03 Loop 1 and 2 Refurbishment	722	3	719	722	0	
New Meters	701	75	626	701	0	
Distribution Feeder Automation	648	15	633	648	0	
Replacement Meters	562	23	539	562	0	
Replacement Services	382	75	307	382	0	
Allowance for Funds Used During Construction	223	64	159	223	0	
Total Distribution	**3,238**	**255**	**2,983**	**3,238**	**0**	
Substations						
Substation Protection and Control Replacements	719	86	633	719	0	
Substation Ground Grid Upgrades	350	31	319	350	0	
Total Substations	**1,069**	**117**	**952**	**1,069**	**0**	
General Property						
Additions to Real Property	714	5	709	714	0	
Specialized Tools and Equipment	616	169	447	616	0	
Tools and Equipment	605	127	478	605	0	
Physical Security Upgrades	506	60	446	506	0	
Building Accessibility Improvements	490	0	490	490	0	
Total General Property	**2,931**	**361**	**2,570**	**2,931**	**0**	
Generation - Hydro						
Hydro Plant Replacements Due to In-Service Failures	736	219	517	736	0	
Cape Broyle and Horsechops Plant Control Upgrades	398	30	368	398	0	
Total Generation - Hydro	**1,134**	**249**	**885**	**1,134**	**0**	

2026 Capital Budget Expenditure Status Report
Single-Year Projects and Programs $750,000 and Under[1]
($000s)

	Annual Budget	Expenditures		Annual Forecast		
		Actual	Forecast			
Asset Class and Project Description	**2026 Budget**	**January to March**	**April to December**	**2026 Forecast**	**Variance**	**Notes**
Generation - Thermal						
Thermal Plant Replacements Due to In-Service Failures	331	44	287	331	0	
Total Generation - Thermal	**331**	**44**	**287**	**331**	**0**	
Information Systems						
Personal Computer Infrastructure	733	370	363	733	0	
Network Infrastructure	495	29	466	495	0	
Total Information Systems	**1,228**	**399**	**829**	**1,228**	**0**	
Telecommunications						
Mount Carmel Pond Dam Fibre	150	0	150	150	0	
Communications Equipment Upgrades	131	15	116	131	0	
Total Telecommunications	**281**	**15**	**266**	**281**	**0**	
Total	**10,212**	**1,440**	**8,772**	**10,212**	**0**	

[1] Approved in Order No. P.U. 38 (2025).

Newfoundland Power Inc.
2026 Capital Budget Expenditure Status Report
Multi-Year Projects Commencing in 2026[1]
($000s)

	2026 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	**2026 Budget**	**January to March**	**April to December**	**2026 Forecast**	**2026 Forecast vs Budget**	**2026 - 2028**	**YTD March 2026**	**2026 - 2028**	**Total Forecast vs Budget**	
Distribution										
Feeder Additions for Load Growth	250	4	246	250	0	1,137	4	1,137	0	
Distribution Total	**250**	**4**	**246**	**250**	**0**	**1,137**	**4**	**1,137**	**0**	
Substations										
Lewisporte-Boyd's Cove 138 kV Conversion	568	43	525	568	0	8,119	43	8,119	0	
Greenspond Substation Refurbishment & Modernization	374	37	337	374	0	2,952	37	2,952	0	
Substation Spare Power Transformer Inventory	13	11	2	13	0	3,919	11	3,919	0	
Molloy's Lane Substation Power Transformer Replacement	12	0	12	12	0	2,801	0	2,801	0	
Mobile Substation Power Transformer Replacement	12	0	12	12	0	2,627	0	2,627	0	
King's Bridge Substation Power Transformer Replacement	12	0	12	12	0	2,971	0	2,971	0	
Substations Total	**991**	**91**	**900**	**991**	**0**	**23,389**	**91**	**23,389**	**0**	
Information Systems										
Customer Communications Modernization	782	48	734	782	0	1,957	48	1,957	0	
Geographic Information System Upgrade	500	3	497	500	0	8,325	3	8,325	0	
Information Systems total	**1,282**	**51**	**1,231**	**1,282**	**0**	**10,282**	**51**	**10,282**	**0**	
General Property										
Summerford Building Replacement	155	0	155	155	0	717	0	717	0	
General Property Total	**155**	**0**	**155**	**155**	**0**	**717**	**0**	**717**	**0**	
Transmission										
Transmission Line Rebuild - 100L Sunnyside to Clarenville	450	7	443	450	0	13,773	7	13,773	0	
Transmission Total	**450**	**7**	**443**	**450**	**0**	**13,773**	**7**	**13,773**	**0**	
Transportation										
Replace Vehicles and Aerial Devices 2026-2027	3,003	257	2,746	3,003	0	5,721	257	5,721	0	
Transportation Total	**3,003**	**257**	**2,746**	**3,003**	**0**	**5,721**	**257**	**5,721**	**0**	
Total	**6,131**	**410**	**5,721**	**6,131**	**0**	**55,019**	**410**	**55,019**	**0**	

[1] Approved in Order No. P.U. 38 (2025).

Newfoundland Power Inc.
2026 Capital Budget Expenditure Status Report
Multi-Year Projects Approved in Previous Years[1]
($000s)

	2026 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	**2026 Budget**	**January to March**	**April to December**	**2026 Forecast**	**2026 Forecast vs Budget**	**2022-2027**	**YTD March 2026**	**2022-2027**	**Total Forecast vs Budget**	
Distribution										
Distribution Feeder SCT 01 & BLK 01 Relocation	1,140	0	1,140	1,140	0	1,789	3	1,789	0	
Distribution Total	**1,140**	**0**	**1,140**	**1,140**	**0**	**1,789**	**3**	**1,789**	**0**	
Substations										
Lockston Substation Refurbishment & Modernization	4,521	90	4,431	4,521	0	4,826	395	4,826	0	
Summerville Substation Refurbishment & Modernization	4,510	279	4,231	4,510	0	5,021	947	5,021	0	
Gander Substation Power Transformer Replacement	3,905	7	3,898	3,905	0	4,185	25	4,185	0	
Pulpit Rock Substation Power Transformer Replacement	2,905	29	2,876	2,905	0	2,922	37	2,922	0	
Substations Total	**15,841**	**405**	**15,436**	**15,841**	**0**	**16,954**	**1,404**	**16,954**	**0**	
Information Systems										
Asset Management Technology Replacement	4,534	946	3,588	4,534	0	8,013	4,425	8,013	0	
Outage Management System Upgrade	1,459	500	959	1,459	0	3,270	2,075	3,270	0	
Microsoft Enterprise Agreement	297	0	297	297	0	891	620	891	0	
Information Systems total	**6,290**	**1,446**	**4,844**	**6,290**	**0**	**12,174**	**7,120**	**12,174**	**0**	
General Property										
Port Union Building Replacement	1,003	0	1,003	1,003	0	1,281	132	1,281	0	
General Property Total	**1,003**	**0**	**1,003**	**1,003**	**0**	**1,281**	**132**	**1,281**	**0**	
Generation - Hydro										
Mount Carmel Pond Dam Refurbishment	1,008	7	1,001	1,008	0	4,616	417	4,616	**0**	
Generation - Hydro Total	**1,008**	**7**	**1,001**	**1,008**	**0**	**4,616**	**417**	**4,616**	**0**	
Transmission										
New Transmission Line from Lewisporte to Boyd's Cove	9,283	165	9,118	9,283	0	20,722	574	20,722	0	
Transmission Line 94L Rebuild	9,075	0	9,075	9,075	0	25,655	11,888	25,655	0	
Transmission Total	**18,358**	**165**	**18,193**	**18,358**	**0**	**46,377**	**12,462**	**46,377**	**0**	
Transportation										
Replace Vehicles and Aerial Devices 2025-2026	2,802	515	2,287	2,802	0	4,975	3,187	4,975	0	
Transportation Total	**2,802**	**515**	**2,287**	**2,802**	**0**	**4,975**	**3,187**	**4,975**	**0**	
Total	**46,442**	**2,538**	**43,904**	**46,442**	**0**	**88,166**	**24,725**	**88,166**	**0**	

[1] Approved in Order Nos. P.U. 27 (2024) and P.U. 2 (2024).

May 2026

1.1 Distribution Reliability Initiative

Prepared by:

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TABLE OF CONTENTS

Page

1.0 INTRODUCTION

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") *Distribution Reliability Initiative* targets the Company's worst performing feeders and sections of feeders for capital upgrades. Customers served by these feeders experience service reliability that is considerably below the Company's corporate average. By targeting the worst performing feeders for capital upgrades, Newfoundland Power aims to maintain an adequate and equitable level of service reliability for customers throughout its service territory at the lowest possible cost.

The *Distribution Reliability Initiative* involves: (i) calculating reliability performance indices for all feeders; (ii) analyzing the reliability data for the worst performing feeders to identify the cause of the poor reliability performance; and (iii) completing engineering assessments for those feeders where poor reliability performance cannot be directly related to isolated events that have already been addressed.

Newfoundland Power implemented a new Outage Management System in 2019 that is capable of providing outage data with greater detail and precision than was previously possible. This allows the Company to not only identify worst performing feeders, but to isolate specific sections of feeders or neighbourhoods that are experiencing poor reliability performance. This data is incorporated into the *Distribution Reliability Initiative* to permit a more targeted approach to required capital upgrades.

For 2027, Newfoundland Power is proposing to refurbish two sections of Glovertown ("GLV") Substation distribution feeder GLV-02.

The refurbishment of distribution feeder GLV-02 will include rebuilding deteriorated off-road sections of line, identified through detailed condition-based engineering assessments, and relocating them to roadside corridors. This includes a 12-kilometre section between Traytown and Charlottetown that will be rebuilt and relocated to the Trans-Canada Highway, as well as a 5-kilometre section between Traytown and Sandringham that will be rebuilt and relocated to Route 301. The project is planned for completion over the 2027–2028 period, with forecast expenditures of $871,000 in 2027 and $2,069,000 in 2028.

2.0 BACKGROUND

Newfoundland Power is focused on maintaining current levels of overall electrical system reliability for customers. While current levels of system reliability are viewed as acceptable, customers in certain areas experience reliability that is significantly worse than the corporate average. The *Distribution Reliability Initiative* directs capital investments to areas where customers receive particularly poor service reliability.

The monitoring of reliability metrics and the targeting of capital expenditures on the worst performing feeders is considered good utility practice and is increasingly required by regulatory bodies. Improving the reliability of worst performing feeders in this way serves the goal of equitable access as required by the *Electrical Power Control Act*.

Newfoundland Power's *Distribution Reliability Initiative* has been ongoing since 1998 and has resulted in improved reliability on the feeders selected for inclusion.[1]

Newfoundland Power's approach to assessing its worst performing feeders uses five reliability indices and is consistent with good utility practice.[2]

(i) System Average Interruption Duration Index ("SAIDI");[3]
(ii) System Average Interruption Frequency Index ("SAIFI");[4]
(iii) Customer minutes of outage;
(iv) Customer Hours of Interruption per Kilometre ("CHIKM");[5] and
(v) Customers Interrupted per Kilometre ("CIKM").[6]

SAIDI, SAIFI and customer minutes of outage are the indices most commonly used in Canada and are reflective of overall system condition. However, it is recognized that relying solely on these indices to identify worst performing feeders can lead to overlooking shorter feeders with chronic issues.[7] CHIKM and CIKM are used to rank the reliability performance of distribution feeders based on the length of line exposed to outages. These indices tend to be more reflective of infrastructure condition and better identify issues associated with shorter feeders.

Appendix A provides distribution reliability data for the Company's worst performing feeders.

Appendix B summarizes the results of the engineering assessment completed for each of the worst performing feeders identified.

In 2019, Newfoundland Power implemented a new Outage Management System ("the OMS").[8] The OMS can provide customer outage data with much greater granularity, allowing Newfoundland Power to isolate specific sections of feeders that are experiencing poor reliability performance. The OMS also integrates with the Company's Geographic Information System ("the GIS") and uses this integration to determine outage customer counts and provide

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1 See the response to Request for Information CA-NP-297 in Newfoundland Power's *2025 General Rate Application*.

2 The Company conducts its analysis based on feeder performance over the most recent five-year period and excludes outages resulting from significant events and loss of supply. A report by Electricity Canada indicates that, for these projects, utilities typically assess reliability performance over three to seven years and exclude loss of supply and significant events from their analyses. See *Worst Performing Feeders, Service Continuity Committee: A New Measures Working Group Whitepaper.*

3 SAIDI is calculated by dividing the number of customer-outage-hours by the total number of customers in an area (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours). Distribution SAIDI represents the average hours of outage related to distribution system failure.

4 SAIFI is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area. Distribution SAIFI represents the average number of outages related to distribution system failure.

5 CHIKM is calculated by dividing the number of customer-outage-hours by the kilometres of line.

6 CIKM is calculated by dividing the number of customers that have experienced an outage by the kilometres of line.

7 Smaller feeders will typically have fewer customers than larger feeders and, as a result, outages of similar duration will involve fewer customer minutes of outage.

8 The implementation of the Outage Management system in 2019 was consistent with the Company's 2017 *Outage Management System Replacement & Enhancement Plan* and the review of the Company's Outage Management System completed in connection with the *Investigation and Hearing into Supply Issues on the Island Interconnected System*. See the Company's *2018 Capital Budget Application*, report *5.5 Outage Management System Enhancement*.

predictive fault locations. In addition, this integration allows the visualization of outage and reliability data through the GIS.

Figure 1 shows the Company's Customer Reliability Dashboard that provides a visualization of reliability metrics for various sections of distribution feeders.

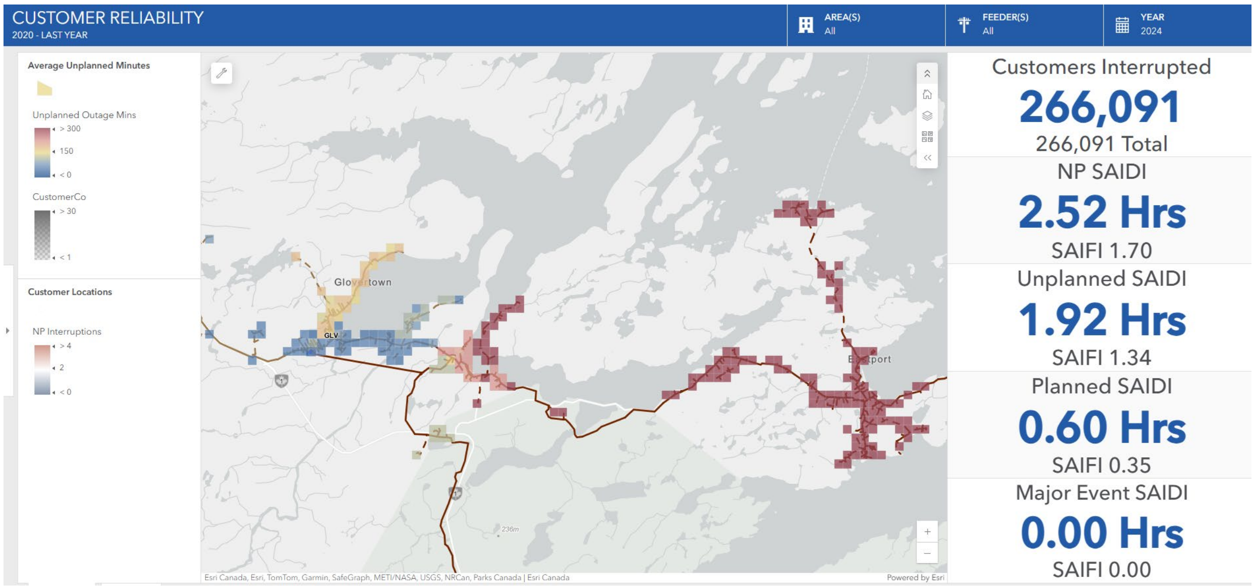

Figure 1 - Visualization of Reliability Metrics Using OMS and GIS

Through the analysis of reliability data obtained through the OMS and GIS tools, Newfoundland Power can identify distribution feeders or sections of distribution feeders for potential inclusion in the *Distribution Reliability Initiative*.

The decision to make upgrades to improve the reliability performance of the identified worst performing feeders or specific sections of feeders is based on detailed engineering assessments. These assessments are completed by Newfoundland Power engineering staff, including Professional Engineers and technologists, and is supported by the Company's transmission and distribution planners.[9]

3.0 DISTRIBUTION FEEDER RISK ASSESSMENT

3.1 General

The 2027 *Distribution Reliability Initiative* targets specific sections of distribution feeder GLV-02, which have been identified as experiencing reliability significantly below the corporate average.

Distribution feeder GLV-02 is one of two feeders leaving GLV Substation. It extends east from Glovertown traveling through Traytown along Route 310 toward Eastport and Sandringham, and branches south toward Malady Head and Charlottetown along the Trans Canada Highway.

[9] Planners are experienced Engineering Technologists or Powerline Technicians that have been trained to complete transmission and distribution line inspections and identify required corrective actions, amongst other qualifications.

The feeder is predominately within the boundary of the Terra Nova National Park and currently serves approximately 1,560 customers. The total length of the feeder, including all taps, is 126 kilometres.

Figure 2 shows a map illustrating the route of distribution feeder GLV-02 and its service area.

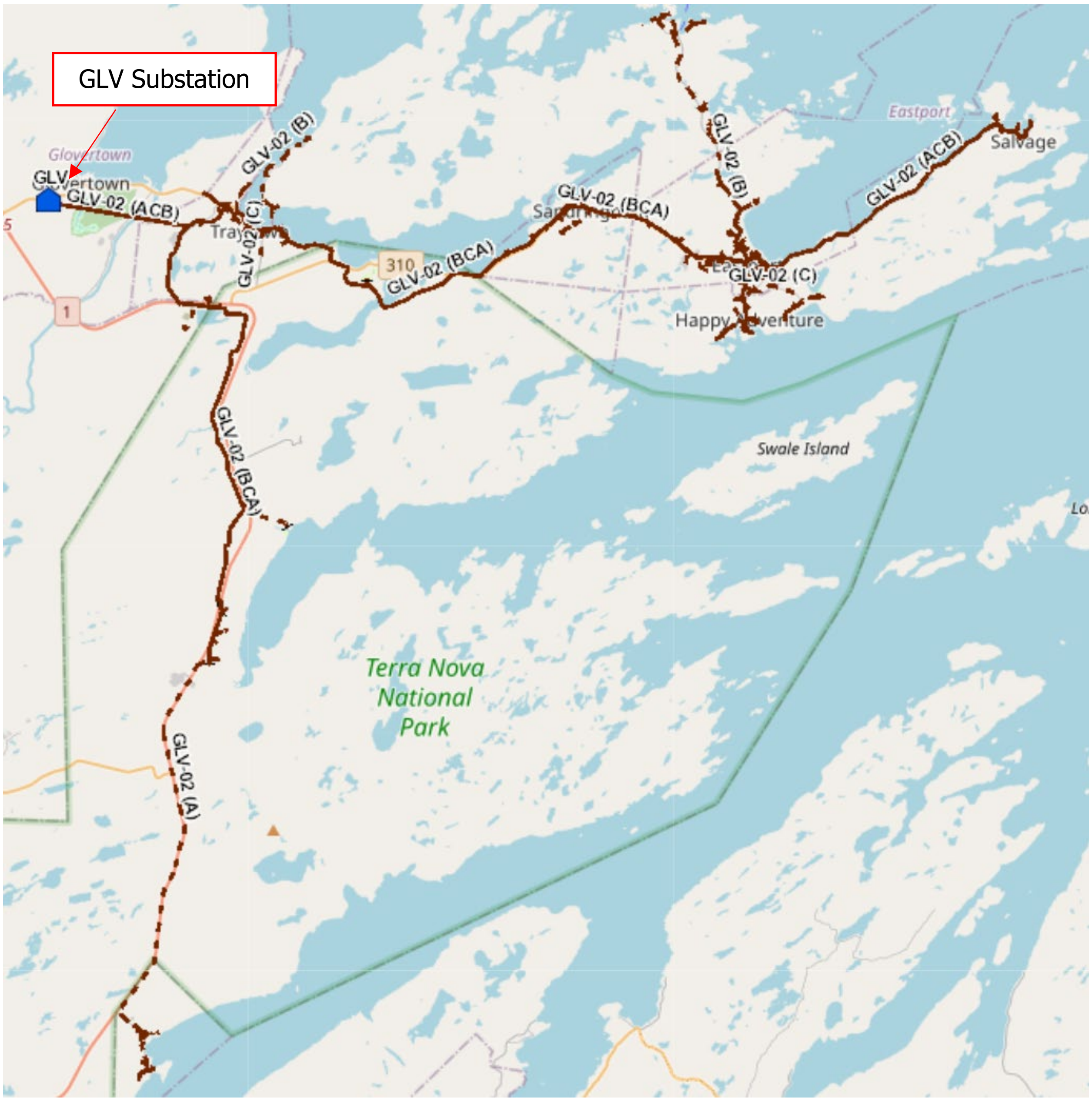

Figure 2 - Location of Distribution Feeder GLV-02

3.2 Reliability Performance

Table 1 summarizes the feeder-level reliability data from 2021 to 2025 for distribution feeder GLV-02 and provides a comparison to the corporate average for Newfoundland Power's distribution system.

Table 1
Distribution Interruption Statistics
5-Year Average to December 31, 2025

Feeder	Customer Minutes of Outage	SAIFI	SAIDI	CHIKM	CIKM
GLV-02	1,004,070	5.64	10.85	133	69
Corporate Average	89,226	1.23	1.74	49	35

At the feeder level, GLV-02 has been experiencing below average reliability performance for four out of four indicators.

The OMS and GIS data for distribution feeder GLV-02 shows that the majority of outage minutes on this feeder are associated with two specific off-road and deteriorated sections: a 12-kilometre section between Traytown and Charlottetown near the Trans-Canada Highway, as well as a 5-kilometre section between Traytown and Sandringham near Route 301. Both sections of distribution feeder are within the Terra Nova National Park boundary.

Figure 3 shows the 12-kilometre section between Traytown and Charlottetown.

Figure 3 - Location of 12-kilometre Off Road Section of Distribution Feeder GLV-02

Figure 4 shows the 5-kilometre section between Traytown and Sandringham.

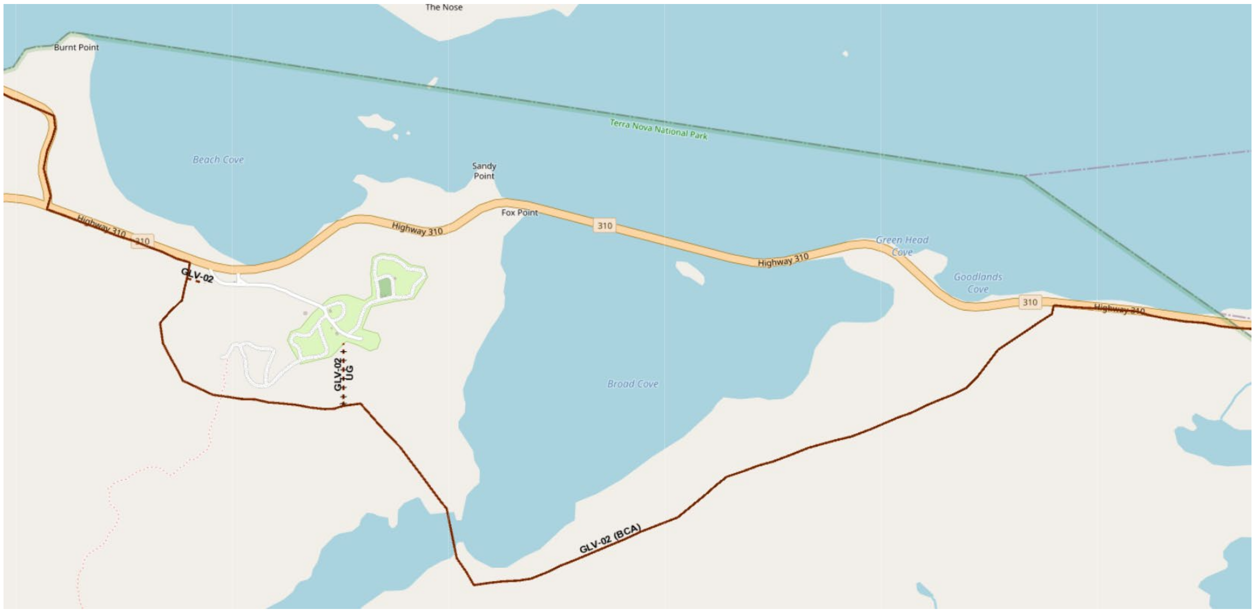

Figure 4 - Location of 5-kilometre Off Road Section of Distribution Feeder GLV-02

The reliability performance experienced by the 1,280 customers served by these sections of distribution feeder GLV-02 has been considerably worse than Newfoundland Power's corporate average over the last five years. Furthermore, the remote nature of these line sections requires specialized equipment to access them for maintenance and repair purposes, which have contributed to the long duration of outages.

Table 2 summarizes the reliability data from 2021 to 2025 for the identified sections of distribution feeder GLV-02 and provides a comparison to the corporate average for Newfoundland Power's distribution system.

Table 2
Distribution Interruption Statistics
5-Year Average to December 31, 2025

Feeder Section[10]	Customer Minutes of Outage	SAIFI	SAIDI
12-km section between Traytown and Charlottetown	162,619	6.26	14.8
5-km section between Traytown and Sandringham	838,345	5.73	12.6
Corporate Average (5-Year)	89,510	1.23	1.74

10 Interruption statistics reflect customers along the noted feeder sections, as well as customers downstream of the noted feeder sections.

The average SAIDI for approximately 180 customers along and downstream of the 12-kilometre section of feeder is 14.8 or approximately nine times the corporate average for SAIDI. The average SAIFI is 6.26, or approximately five times the corporate average for SAIFI.[11]

The average SAIDI for approximately 1,100 customers along and downstream of the 5-kilometre section of feeder is 12.6 or approximately seven times the corporate average for SAIDI. The average SAIFI is 5.73, or approximately five times the corporate average for SAIFI.[12]

The reliability performance of the identified sections of GLV-02 are consistent with what would generally be considered a worst performing feeder in the electric utility industry.[13]

3.3 Engineering Assessment

General

Once a worst performing distribution feeder or feeder section has been identified as a candidate for inclusion in the *Distribution Reliability Initiative*, Newfoundland Power undertakes a detailed engineering assessment to determine the likely causes of the poor reliability. This assessment is undertaken by the Company's Professional Engineers, technologists and transmission and distribution planners. These analyses consider reliability metrics, asset condition, distribution line location and operating experience. Generally, poor reliability can be caused by increased frequency of outages and delays in response to outages.

Broadly, distribution lines experiencing asset degradation will experience higher interruption frequency as shown through frequency indices such as SAIFI and CIKM. A detailed engineering assessment is necessary to confirm the type, extent and nature of the asset degradation causing the increased outage frequency. The inspection is also necessary to ensure that the increased interruption frequency is not being caused by other factors which will not be corrected by capital upgrades.

Distribution lines which are experiencing reduced reliability through increased interruption duration as shown by increased SAIDI, CHIKM and customer minutes of outage, may be indicative of several causes. Increased interruption duration can indicate interruptions requiring complex repairs or specialized equipment to resolve as well as interruptions requiring repairs in difficult to access areas.[14] Generally, increased outage duration will require an engineering assessment to determine if increased interruption duration is caused by asset condition, asset

11 Comparisons to CHIKM and CIKM are excluded from Table 2 as these indices are typically used to identify issues with shorter feeders located in urban settings.

12 *Ibid*.

13 The standards used by electric utilities in identifying worst performing feeders vary. Examples of standards include feeders where the SAIDI exceeds the corporate average by 300% and feeders where the SAIDI is in the top 10% for two consecutive years. This is consistent with Newfoundland Power's characterization of the identified sections of distribution feeder GLV-02 as a worst performing feeder. See *State of Distribution Reliability Regulation in the United States,* September 2005, prepared by Davies Consulting Inc. for the Edison Electric Institute.

14 Interruption duration includes the time from an interruption being identified until power is restored. This includes the time for a crew to be dispatched, arrive on scene, identify the cause and complete any necessary repairs. Any access issues will necessarily increase the time required to resolve an outage.

location or an extraordinary event which may not indicate a reliability improvement project being necessary.

Once a likely cause for the poor reliability performance has been identified, alternatives are considered to address the likely cause, and a project is proposed based on the selected alternative.

Distribution Feeder GLV-02

Distribution feeder GLV-02 is a 25 kV distribution feeder originally constructed in the 1960s. The main three-phase trunk portion of GLV-02 is approximately 36 kilometres in length and extends from the Glovertown area to Salvage, predominantly along Route 301 within the boundary of the Terra Nova National Park. A 5-kilometre section of the main three-phase trunk portion between Traytown and Sandringham runs cross-country. In addition to the main three-phase trunk portion heading towards Salvage, an additional three-phase section of distribution line branches off in the Traytown area and runs south through Malady Head towards Charlottetown. This section of three-phase line is approximately 16 kilometres in length and includes the identified 12-kilometre section of off-road line near the Trans Canada Highway.

The 5-kilometre section toward Sandringham and the 12-kilometre section toward Charlottetown (Figures 3 and 4) are difficult to access, resulting in longer restoration times. Repair and restoration work in either area requires off-road vehicles, which can further delay crews' arrival and response.

An engineering assessment of the 5-kilometre section toward Sandringham and the 12-kilometre section toward Charlottetown has identified that deteriorated conductor, poles, crossarms and insulators, as well as inaccessibility of the lines, have contributed to their poor reliability performance.

The 12-kilometre section of feeder toward Charlottetown is constructed using #2 Aluminum Conductor Steel Reinforced ("ACSR") conductor. The Company has experienced issues with this particular conductor, as oxidation between the steel core and aluminum outer strands is known to occur. The conductor on the identified section of distribution feeder is exhibiting advanced deterioration and separation of the conductor strands. Due to the deteriorated condition of the conductor, it cannot be safely repaired using hotline work methods.[15] Completing maintenance on this section of feeder requires an outage to the 180 customers supplied by the 12-kilometre section towards Charlottetown.[16]

Approximately 40 poles along the specified sections have been identified through inspections as requiring replacement.[17] These poles exhibit significant deterioration, including shell separation, cracking, woodpecker damage, and substantial structural deformation.

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[15] If the corroded conductor were to break while hotline work methods were ongoing, an energized piece of conductor would fall away, presenting a serious safety hazard for employees.

[16] As examples, maintenance could include the installation of replacement conductor or maintenance involving the transfer of existing conductor to new poles.

[17] There are 39 poles along the specified sections which have been classified as TD2. The Company's *Distribution Inspection and Maintenance Practices* state that poles classified as TD2 should be replaced within one month. An additional 100 poles have been identified as TD4 and should be monitored for replacement within one year.

Figure 5 illustrates a deteriorated pole along GLV-02 with a pronounced lean due to advanced structural degradation.

Figure 5 – Pole Along GLV-02 with Advanced Structural Degradation

Figure 6 shows further damage along GLV-02, including a bent insulator resulting from pole cracking along with woodpecker damage.

Figure 6 – Bent Insulator and Pole Damage on GLV-02

4.0 ASSESSMENT OF ALTERNATIVES

4.1 General

Newfoundland Power proposes projects under the *Distribution Reliability Initiative* as specific solutions to resolve identified causes of poor reliability. There are generally three categories of alternatives to resolve poor reliability on distribution feeders based on the common causes of poor reliability as described previously. These alternatives are not intended to limit the solutions available under this project but are used as guides to the type of solutions that can be implemented to solve reliability issues experienced by customers.

(i) ***Rebuild or Refurbish in Existing Right-of-Way -*** In cases where an engineering assessment indicates poor asset condition as the major driver of poor reliability, rebuild or refurbishment of the feeder or a section of the feeder is often necessary. Rebuilding or refurbishing the feeder in an existing right-of-way addresses the deteriorated condition of installed assets while retaining the existing right-of-way. This alternative does not address any issues related to access to the distribution assets or environmental conditions which may contribute to the reduced reliability customers are experiencing.[18] This alternative also frequently results in customer outages or requirements for generation to minimize customer outages while the rebuild is ongoing, as the rebuilding of distribution lines is generally not completed while lines are energized.

(ii) ***Relocation of Distribution Line -*** This category of alternative involves the reconstruction of a segment or an entire distribution line, along with a relocation of the distribution line to a new right-of-way. Relocating the distribution line can offer two main benefits over reconstruction in the existing right-of-way:

1. Relocating a distribution line allows the existing line to remain in service until the new distribution line or line segment has been completed. This reduces the requirement for customer outages or local generation to maintain service while the line is being constructed.

2. It offers the opportunity to address any accessibility concerns identified with the existing right-of-way, including access to complete maintenance or emergency repairs, as well as routing the line away from known areas of bog.

(iii) ***Non-Wire or Smart Grid Alternatives -*** Non-wires alternatives represent a broad range of innovative options that can defer or avoid traditional "poles-and-wires" investments. These can include distributed energy resources, microgrids, advanced demand response, and battery energy storage systems ("BESS"). Historically, Newfoundland Power's assessment of non-wire alternatives for distribution reliability and load growth has primarily focused on the potential application of utility-scale BESS. While the Company has not installed a BESS as of 2026, it continues to monitor the changing costs of storage technologies and evaluate their feasibility as alternatives for both transmission and distribution projects.

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18 Reliability may be negatively impacted by salt contamination, water crossings, tree contacts, and other environmental causes.

> Smart grid alternatives include technologies designed to improve distribution system automation, monitoring, and operational flexibility. These include devices such as downline reclosers, automated sectionalizers, and advanced fault-location equipment, as well as technologies that support improved power quality and voltage optimization, including reactive power devices capable of advanced volt-VAR control.

The 1,280 customers supplied by the identified 12-kilometre section of distribution feeder GLV-02 between Traytown and Charlottetown and the 5-kilometre section between Traytown and Sandringham are experiencing significantly worse reliability compared to the average reliability experienced by Newfoundland Power's customers. An engineering assessment of the identified sections of distribution feeder GLV-02 identified the factors contributing to poor reliability performance are: (i) deteriorated conductor; (ii) danger tree contacts; (iii) deteriorated poles, crossarms and insulators; and (iv) inaccessibility of line.

A significant number of deficiencies and outage incidents have been identified on these specific sections of distribution feeder GLV-02. The risk of equipment failure and outages to customers is therefore considered high and will continue to increase if this project is deferred.

Customers supplied from these sections of feeder are experiencing outages that are seven to nine times longer and five times more frequent than the Company average. Deferring the upgrades of distribution feeder GLV-02 would result in customers continuing to experience poor service reliability. This would be inconsistent with maintaining adequate and equitable levels of service reliability for customers throughout Newfoundland Power's service territory.

Two alternatives were identified and evaluated with respect to distribution feeder GLV-02. The two alternatives are: (i) rebuild the existing 5-kilometre and 12-kilometre sections of line in their existing rights-of-way; and (ii) rebuild and relocate the existing 5-kilometre section of line to the roadside of Route 301, and rebuild and relocate the existing 12-kilometre section of line to the roadside of the Trans Canada Highway.

4.2 Alternative 1 – Rebuild in Existing Right-of-Way

Alternative 1 involves rebuilding the following three-phase sections of GLV-02 feeder in their existing rights-of-way: the 5-kilometre section from Traytown to Sandringham, and the 12-kilometre section between Traytown and Charlottetown. This would include replacing all deteriorated poles and crossarms and upgrading the primary conductor to standard 4/0 AASC. The existing rights-of-way would also be widened as required to prevent tree contacts from danger trees outside of the existing rights-of-way.

This alternative would require the temporary installation and operation of portable generation to mitigate lengthy outages that customers would experience during completion of the work identified in this alternative. Completing the work identified in this alternative using hot line work methods is not possible due to the inaccessible locations and condition of the infrastructure on these sections of feeder. The identified sections of feeder are located cross-country and are not truck accessible. In addition, the condition of the infrastructure on these sections of feeder creates a safety risk for employees completing hot line work. Given that there are no tie points with other feeders in the area, there is no way to transfer the load to maintain supply to the 1,280 customers served.

The capital costs of Alternative 1 are $1,094,000 in 2027 and $2,553,000 in 2028, for a total capital cost of $3,647,000.

4.3 Alternative 2 – Relocation of Distribution Line to Roadside

Alternative 2 involves reconstruction of a 5-kilometre section of the GLV-02 feeder to the roadside of Route 201 and reconstruction of a 12-kilometre section to the roadside of the Trans-Canada Highway, replacing deficient off-road sections of line.

Under this alternative, a total of 15-kilometres of new three-phase of distribution feeder would be constructed. This alternative would not require the installation and operation of portable generation to complete the work as the new line can be constructed while the existing line remains energized, maintaining service to customers. Once construction of the new line is completed, downstream customers would be transferred to the new line sections.

The capital costs of Alternative 2 are $871,000 in 2027 and $2,069,000 in 2028, for a total capital cost of $2,940,000.

5.0 PROJECT SCOPE

The assessment of alternatives determined that Alternative 2 – Relocation of Distribution Line to Roadside is the least cost alternative to address the poor service reliability experienced by customers supplied from specific sections of distribution feeder GLV-02. The reconstruction and relocation of these sections of distribution feeder to the roadsides of Route 301 and the Trans Canada Highway will also improve access to the lines during outage response activities and will result in efficiencies in preventative maintenance and inspection activities.

The project scope to complete the reconstruction and relocation of the identified sections of distribution feeder GLV-02 includes:

(i) Constructing 12-kilometres of new three-phase distribution line along the Trans Canada Highway; and
(ii) Constructing 5-kilometres of new three-phase distribution along Route 301.

The project scope for distribution feeder GLV-02 is proposed to be completed over the two-year period from 2027 to 2028, with design and procurement completed in year 1, and construction completed by the end of year 2.

6.0 PROJECT COST

Table 3 provides a detailed cost breakdown of the projects to be completed on distribution feeder GLV-02.

Table 3
Distribution Reliability Initiative
Project Cost
($000s)

Description	2027	2028
Engineering	3	6
Labour - Contract	433	1,029
Labour - Internal	13	31
Material	415	986
Other	7	17
Total	$871	$2,069

The total cost to complete the rebuild of the identified sections of distribution feeder GLV-02 is $871,000 in 2027 and $2,069,000 in 2028.

7.0 CONCLUSION

The *Distribution Reliability Initiative* targets areas where customers experience among the worst reliability in Newfoundland Power's service territory for capital upgrades. This targeted approach is consistent with maintaining adequate and equitable levels of service reliability for customers at the lowest possible cost.

The Company reviewed performance indices and OMS data for its distribution feeders and determined that approximately 1,280 customers supplied by two deteriorated off-road sections of distribution feeder GLV-02 are experiencing significantly worse reliability performance than the Company average. A detailed engineering assessment concluded that these deficiencies are attributable to the condition and location of the existing infrastructure, and that the reconstruction and relocation of these sections to nearby roadsides would address the poor service reliability experienced by affected customers. Accordingly, a two-year project spanning 2027–2028 is proposed to reconstruct and relocate these off-road sections at a total estimated cost of $2,940,000.

APPENDIX A:

Distribution Reliability Data: Worst Performing Feeders

Table A-1
Unscheduled Distribution-Related Outages
5-Year Average
(2021-2025)
Sorted by Customer Minutes of Interruption

Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
GLV-02	8,683	1,004,070	5.64	10.85
SUM-01	5,446	854,123	3.00	7.84
BVS-04	4,086	740,105	2.47	7.44
DOY-01	5,521	640,224	3.08	5.98
ROB-01	3,039	589,969	2.81	9.11
BLK-01	4,550	497,114	2.67	4.81
DLK-03	5,772	458,747	3.92	5.18
BOT-01	5,609	427,494	3.20	4.06
SMV-01	5,525	413,496	4.91	6.12
BLK-02	2,551	393,508	1.13	2.89
LEW-02	4,899	339,692	3.22	3.72
HOL-03	3,240	326,775	2.99	5.03
SCR-01	2,377	326,329	2.50	5.71
NWB-02	1,827	321,464	1.64	4.82
BLA-01	2,270	301,003	1.94	4.29
Company Average	1,054	89,510	1.23	1.74

Table A-2 Unscheduled Distribution-Related Outages 5-Year Average (2021-2025) Sorted by Distribution SAIFI				
Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
GLV-02	8,683	1,004,070	5.64	10.85
SMV-01	5,525	413,496	4.91	6.12
LGL-02	2,362	277,245	3.96	7.75
DLK-03	5,772	458,747	3.92	5.18
WAL-05	4,337	123,222	3.47	1.64
BHD-01	3,317	216,733	3.44	3.74
GAM-02	448	48,246	3.33	5.98
LEW-02	4,899	339,692	3.22	3.72
BOT-01	5,609	427,494	3.20	4.06
SCT-02	818	100,283	3.09	6.33
DOY-01	5,521	640,224	3.08	5.98
SUM-01	5,446	854,123	3.00	7.84
HOL-03	3,240	326,775	2.99	5.03
ROB-02	593	145,373	2.89	11.76
SCT-01	2,121	178,588	2.83	3.97
Company Average	1,054	89,510	1.23	1.74

Table A-3
Unscheduled Distribution-Related Outages
5-Year Average
(2021-2025)
Sorted by Distribution SAIDI

Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
ROB-02	593	145,373	2.89	11.76
GLV-02	8,683	1,004,070	5.64	10.85
HBS-01	14	3,319	2.61	10.82
ROB-01	3,039	589,969	2.81	9.11
SUM-01	5,446	854,123	3.00	7.84
LGL-02	2,362	277,245	3.96	7.75
BVS-04	4,086	740,105	2.47	7.44
NWB-01	1,543	290,987	2.26	7.11
MKS-01	1,032	193,335	2.24	6.99
LGL-01	613	142,133	1.75	6.74
SCT-02	818	100,283	3.09	6.33
SMV-01	5,525	413,496	4.91	6.12
BUC-02	278	57,788	1.74	6.01
GAM-02	448	48,246	3.33	5.98
DOY-01	5,521	640,224	3.08	5.98
Company Average	1,054	89,510	1.23	1.74

Table A-4 Unscheduled Distribution-Related Outages 5-Year Average (2021-2025) Sorted by Distribution CHIKM	
Feeder	Annual Distribution CHIKM
SJM-04	260
PAB-05	227
KBR-13	222
KBR-15	218
WAL-01	217
HUM-09	198
SJM-06	187
WAL-05	184
TWG-02	178
SLA-06	175
LGL-01	170
GIL-02	158
SLA-07	152
PAB-03	149
KEN-01	144
Company Average	49

Table A-5 Unscheduled Distribution-Related Outages 5-Year Average (2021-2025) Sorted by Distribution CIKM	
Feeder	Annual Distribution CIKM
WAL-05	390
PAB-03	203
SLA-06	178
KBR-10	172
KEN-01	146
WAL-01	143
HWD-08	139
HUM-09	138
KEN-03	135
MSY-04	134
GOU-01	125
MOL-01	117
WAL-02	115
SLA-08	114
SJM-06	114
Company Average	38

APPENDIX B:

Worst Performing Feeders: Summary of Data Analysis

Table B-1 Worst Performing Feeders Summary of Data Analysis	
Feeder	Comments
BHD-01	Reliability is worsening due to increasing conductor failures from 2023-2025. No work is proposed at this time but the feeder will continue to be monitored and will potentially require future capital investment to address reliability performance.
BLA-01	Poor reliability statistics were driven by wind and vegetation-related events in 2022. No work is required at this time.
BLK-01	Poor reliability statistics were driven by vandalism in 2024 and a significant failure of a primary underground cable in 2025. No work is required at this time.
BLK-02	Poor reliability statistics were driven by a vehicle accident and vandalism event in 2024.
BOT-01	Poor reliability is driven by significant vegetation-related events. This feeder will continue to be monitored.
BUC-02	Reliability is worsening principally due to conductor issues. No work is proposed at this time, but conductor issues are expected to increase. The feeder will continue to be monitored and will potentially require future capital investment to address reliability performance.
BVS-04	Poor reliability statistics were predominately driven by equipment failures and vegetation-related events along a specific section of single-phase line in 2023. This section was rebuilt and upgraded to three-phase in 2024. No work is required at this time.
DLK-03	Poor reliability statistics were predominately driven by equipment failures and vegetation-related events along a specific section of single-phase line in 2023 and 2024. This section is being upgraded to three-phase and is being transferred to a different substation in 2026. No additional work is required at this time.
DOY-01	Overall reliability statistics on this feeder have been impacted by feeder unbalance caused by a number of long, single-phase taps. No work is required at this time.
GAM-02	Reliability statistics are due to vegetation related issues driven by extreme wind conditions in 2022 and 2024 and wildlife contact. No work is required at this time.
GIL-02	Poor reliability statistics were driven by a vehicle accident and vegetation-related events in 2023. No work is required at this time.
GLV-02	Work is proposed on this feeder in 2027 and 2028 as part of the Distribution Reliability Initiative.
GOU-01	Poor reliability statistics were driven by conductor issues and a lightning storm in 2021. No work is required at this time.

Table B-1 Worst Performing Feeders Summary of Data Analysis	
Feeder	Comments
HBS-01	Poor reliability due to vegetation-related events in 2023 and 2024. No work is required at this time.
HOL-03	Reliability is worsening principally due to conductor and vegetation issues. The feeder will continue to be monitored and will potentially require future capital investment to address reliability performance.
HUM-09	Poor reliability statistics are primarily driven by vegetation issues and wildlife contact, as well as several insulator failures in 2021. No work is required at this time.
HWD-08	Poor reliability statistics are primarily driven by a damaged underground conductor in 2023 and a broken pole in 2024. No work is required at this time.
KBR-10	There were several outages in 2021 and 2022 due to adverse weather and tree contacts. No work is required at this time.
KBR-13	Poor reliability statistics driven by vegetation related events and multiple conductor issues in 2021.
KBR-15	Reliability is worsening due to conductor and insulator issues. No work is proposed at this time, but conductor issues are expected to increase. The feeder will continue to be monitored and will potentially require future capital investment to address reliability performance.
KEN-01	Poor reliability is primarily related to a substation breaker failure in 2022. No work is required at this time.
KEN-03	Poor reliability statistics were driven by conductor and insulator issues in 2022. No work is required at this time.
LEW-02	Poor reliability statistics can be attributed to a wind event and a broken pole in 2022. No work is required at this time.
LGL-01	Poor reliability was driven by a conductor failure and weather events in 2022. No work is required at this time.
LGL-02	Poor reliability was driven by conductor failure events in 2023 and 2024. No work is required at this time.
MKS-01	Reliability is worsening principally due to access and vegetation issues. The feeder will continue to be monitored and will potentially require future capital investment to address reliability performance.
MOL-01	Poor reliability statistics are primarily driven by two significant failures of primary conductors in 2021 and 2022, as well as a vehicle accident in 2024. No work is required at this time.
MSY-04	Poor reliability statistics were driven by conductor and insulator issues in 2023 and 2025. No work is required at this time.

Table B-1 Worst Performing Feeders Summary of Data Analysis	
Feeder	Comments
NWB-01	Poor reliability statistics due to numerous extreme wind events in 2024 and 2025. No work is required at this time.
NWB-02	Poor reliability statistics were driven by high frequency of tree contacts in 2025. No work is required at this time.
PAB-03	Poor reliability statistics were due to wind issues in 2022. No work is required at this time.
PAB-05	Poor reliability statistics were due to wind issues in 2022. No work is required at this time.
ROB-01	Poor reliability statistics were due to vehicle accident in 2023. No work is required at this time.
ROB-02	Poor reliability statistics were due to tree contacts in 2023. No work is required at this time.
SBK-01	SBK-01 serves only two customer owned microwave radio sites in the remote wilderness close to the Company's Sandy Brook hydroelectric plant. Both sites are difficult to access, particularly during the winter. Both sites also operate emergency standby generators allowing them to tolerate extended outages. No work is required at this time.
SCR-01	Poor reliability statistics were due to tree contacts in 2024 and 2025. No work is required at this time.
SCT-01	Poor reliability statistics were driven by several lightning-related outages in 2021 and multiple significant vegetation-related outages from 2021 to 2025. No work is proposed at this time, but the feeder will continue to be monitored and may require future capital investment to improve reliability performance.
SCT-02	Poor reliability statistics were driven by wind and vegetation-related events in 2024 and 2025. No work is required at this time.
SJM-04	Poor reliability statistics were due to vehicle accident in 2023. No work is required at this time.
SJM-06	Poor reliability statistics were due to tree contacts in 2022. No work is required at this time.
SLA-06	Poor reliability statistics were driven by lightning and a vehicle accident in 2021 causing damage to poles. No work is required at this time.
SLA-07	Poor reliability statistics were primarily driven by lightning in 2021 and a vehicle accident in 2024 causing a broken pole. No work is required at this time.

Table B-1 Worst Performing Feeders Summary of Data Analysis	
Feeder	Comments
SLA-08	Significant equipment failure events in the 2021-2025 period as well as lightning in 2021 were primary factors driving poor reliability statistics. The feeder will continue to be monitored and will potentially require future capital investment to improve reliability performance.
SMV-01	Poor reliability statistics are attributable to an insulator failure during a wind event in 2022. No work is required at this time.
SUM-01	Poor reliability statistics were predominately driven by equipment failures along a specific section of line in 2021 and 2022. This section was refurbished in 2023 as part of the Distribution Reliability Initiative.
TWG-02	Poor reliability statistics were driven by a significant broken pole incident in 2025 as well as continuous equipment failures across the 2021 to 2025 period. The feeder will continue to be monitored and will potentially require future capital investment to improve reliability performance.
WAL-01	Poor reliability is driven by a vehicle accident in 2021. No work is required at this time.
WAL-02	Poor reliability statistics were driven by a high frequency of wind and tree-related events. Multiple equipment failure events were also significant in driving poor reliability statistics. The feeder will continue to be monitored and will potentially require future capital investment to improve reliability performance.
WAL-05	Poor reliability is driven by tree-related issues. No work is required at this time.

May
2026

1.2
Feeder Additions for Load Growth

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TABLE OF CONTENTS

Page

1.0 INTRODUCTION

As load increases on an electrical system, the components of the system can become overloaded. These overload conditions can occur within substations, 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 increase capacity or alter system configuration to eliminate overload conditions.

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") has identified two overload conditions to be addressed in 2027 by upgrading existing distribution lines. The overload conditions described in this report can each be attributed to residential growth in specific areas of the Company's service territory.

2.0 OVERLOADED 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 contacting other conductors or the conductor breaking, causing a fault and subsequent customer outages and safety hazards. 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 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 three-phase 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 two locations where a single-phase line is overloaded. Mitigation of these overload conditions is required, and each is described below.

3.2 Distribution Feeder BLK-02 Upgrade

Distribution feeder BLK-02 leaves Blaketown ("BLK") Substation and extends east along the Trans Canada Highway supplying customers in the Whitbourne and the Brigus Junction areas around Ocean's Pond, Whalen's Pond and Middle Gull Pond. This distribution feeder serves 2,295 customers.

Figure 1 illustrates the route of distribution feeder BLK-02.

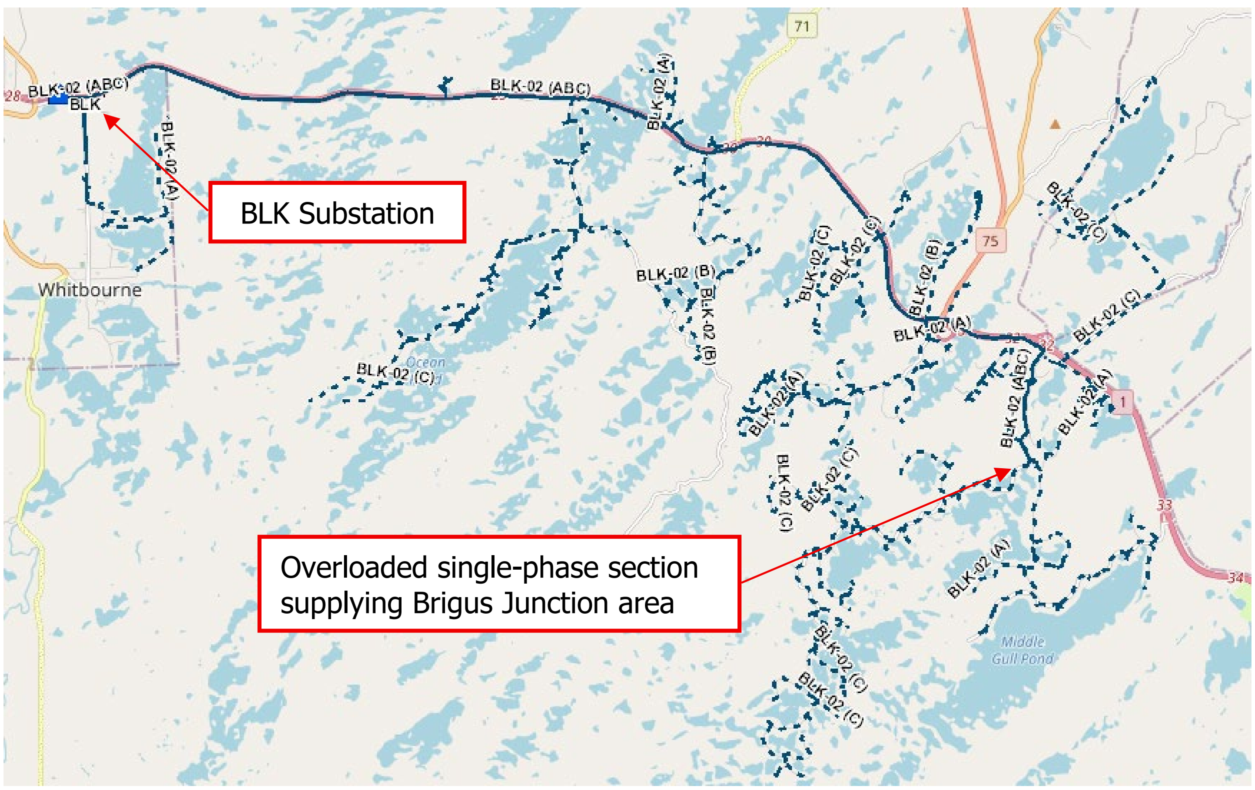

Figure 1 – Distribution Feeder BLK-02

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 many customers requiring single-phase service are added over time. Further growth on these taps is also expected because 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 6-kilometre section of single-phase distribution feeder is overloaded. This section of line extends southwest along Mill Road to serve customers in Brigus Junction near Whalen's Pond. 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 117% over the last 15 years.[5]

An analysis of distribution feeder BLK-02 was completed using CYME Power Engineering software and verified using field load measurements. The analysis showed that the peak load on the identified single-phase section of the feeder is approximately 107 amps, which exceeds the Company's planning criteria for maximum current on a single-phase distribution line.[6]

Three categories of alternatives that are generally available to address overloaded conductor are not applicable to BLK-02. Feeder balancing is not applicable as the identified section of BLK-02 is single-phase. A new feeder build from BLK Substation is not feasible due to the magnitude of the associated costs. A load transfer is not applicable since there is no adjacent feeder.

As a result, the alternatives evaluated for their viability to mitigate the overloaded section of distribution feeder BLK-02 are: (i) upgrading from single-phase to three-phase; and (ii) a non-wires alternative.

Alternative 1: Upgrade Single-Phase Section to Three-Phase

Alternative 1 would involve upgrading 6 kilometres of the overloaded single-phase section along Mill Road in Brigus Junction to three-phase 1/0 AASC conductor to resolve the overload condition. The total capital cost associated with this alternative is estimated to be approximately $723,000. This corresponds to $837,000 on a net present value basis.[7]

---

5 There were 241 customers supplied by this section of line in 2010 and 522 customers in 2025, an increase of 281 customers or 117% (281 / 241 = 1.17, or 117%).

6 Newfoundland Power's planning criteria for maximum current on a single-phase distribution line is 85 amps.

7 Alternative 2 for distribution feeder BLK-02 includes multi-year expenditures. As a result, net present value analyses were completed to assess the alternatives.

Figure 2 illustrates the route of the three-phase upgrade described in Alternative 1.

Figure 2 – Three-Phase Upgrade of Distribution Feeder BLK-02

Alternative 2: Non-Wires Alternative

Alternative 2 would utilize commercial-grade battery storage technology to provide capacity to alleviate the overload condition during peak load conditions. Based on load readings and distribution feeder modelling, approximately 16 hours of capacity would be required to alleviate the overload conditions on this section of line during peak load.

A preliminary cost estimate for the procurement of a battery storage solution for this application is approximately $557,000 and would have an expected lifetime of 15 years. This corresponds to $1,029,000 on a net-present value basis.[8]

[8] During the 2026 winter season, the single-phase section of the overloaded line experienced sustained loading above 85 A for approximately 16 consecutive hours. To offload this section of single-phase phase line to be within Newfoundland Power's ampacity limits, a 1.13 MWh battery system would be required. The estimated cost of $557,000 for this option is derived from *Cost Projections for Utility-Scale Battery Storage: 2025 Update* by Cole et al., which is based on 4-hour battery systems. Battery costs for 16-hour durations are not yet well established.

Recommended Alternative

Of the technically viable alternatives considered, upgrading the overloaded section of distribution feeder BLK-02 from single-phase to three-phase is least cost on a net-present value basis. This is therefore the recommended alternative to address the identified overload condition.

3.3 Distribution Feeder CHA-04 Upgrade

Distribution feeder CHA-04 leaves Chamberlains ("CHA") Substation and extends east along Buckingham Drive supplying customers in Paradise in areas around Adam's Pond, Three Island Pond and Topsail Pond. This distribution feeder serves 2,683 customers.

Figure 3 illustrates the route of distribution feeder CHA-04.

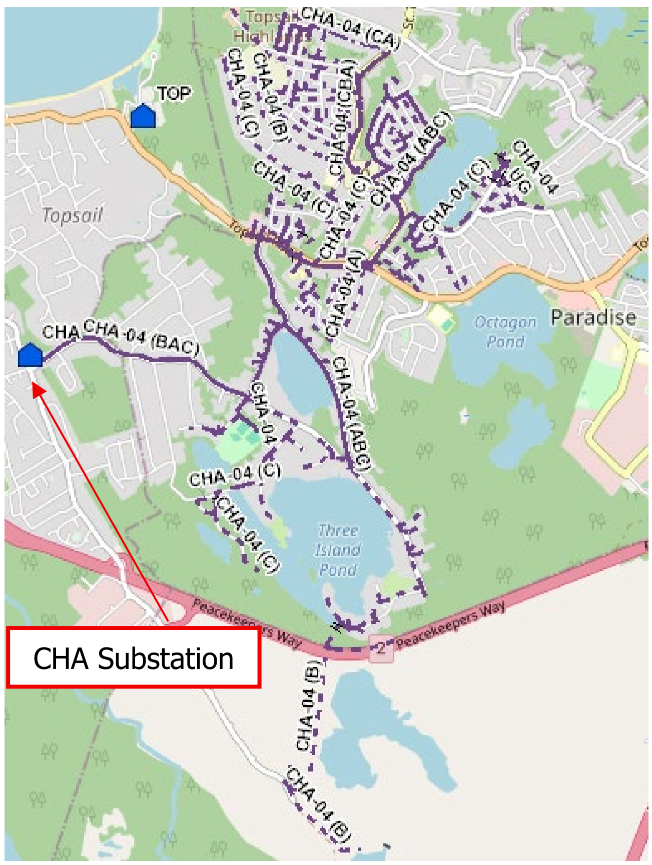

Figure 3 – Distribution Feeder CHA-04

A 1-kilometre section of single-phase backlot distribution line is currently overloaded, and is forecast to be substatially overloaded in 2027 due to an ongoing subdivision development. This section of line extends northeast along Lanark Drive in Paradise, which serves the new subdivision development.

An analysis of distribution feeder CHA-04 was completed using CYME Power Engineering software and verified using load measurements. Following the completion of the first phase of the subdivision development, which resulted in 45 new customers connected in 2025, peak load on the section of single-phase line was approximately 93 amps, which exceeds the Company's planning criteria for maximum current on a single-phase line.[9] The second phase of the subdivision development, which is ongoing, involves the constructon of 140 new properties. The forecasted peak on the single-phase section is expected to reach up to 163 amps in 2027.

Three categories of alternatives that are generally available to address overloaded conductor are not applicable to distribution feeder CHA-04. Feeder balancing is not applicable as the identified section of distribution feeder CHA-04 is single phase. A new feeder build from CHA Substation is not feasible due to the magnitude of the associated costs. A non-wires alternative ("NWA"), such as a utility-scale battery system, is not feasible due to the prolonged forecasted duration of the overload condition.[10]

A load transfer was also considered which would involve building extensions from Hardwoods ("HWD") Substation distribution feeders HWD-07 and HWD-09. However, due to a lack of available easements, in conjunction with future load growth forecasted on distribution feeder HWD-07 in particular, this option was determined to be not viable.[11]

As a result, only one alternative has been identified as being technically and economically viable to mitigate the overloaded section of distribution feeder CHA-04. This alternative involves upgrading the overloaded section of distribution feeder CHA-04 from single-phase to three-phase, as described below.

Recommended Alternative: Upgrade Single-Phase Section to Three-Phase

The recommended alternative would involve upgrading 1 kilometre of the overloaded single-phase backlot section along Lanark Drive in Paradise to three-phase 1/0 AASC conductor. The total capital cost associated with this alternative is estimated to be approximately $561,000.

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9 Newfoundland Power's planning criteria for maximum current on a single-phase distribution line is 85 amps.

10 Based on forecasted peak data, a battery that could offload the single-phase section of distribution feeder CHA-04 to be within Newfoundland Power's planning criteria would be required to be outputting power for an entire continuous winter season. As per Cole et al., utility-scale battery systems operate in the 4-hour range. Therefore, this option is not technically viable.

11 To offload the single-phase section of distribution feeder CHA-04 to be within Newfoundland Power's planning criteria, load associated with the new subdivision development on Lanark Drive would have to be equally split between the existing single-phase section of distribution feeder CHA-04 and the nearby single-phase sections of distribution feeders HWD-07 and HWD-09. However, additional subdivision developments are ongoing along distribution feeder HWD-07 and transferring additional load to distribution feeder HWD-07 would result in future overloads to this feeder. Similarly, transferring load from distribution feeder CHA-04 solely to HWD-09 would overload the single-phase section of distribution feeder HWD-09 based on current loading conditions. As a result, a load transfer is not feasible.

Figure 4 illustrates the route of the recommended three-phase upgrade.

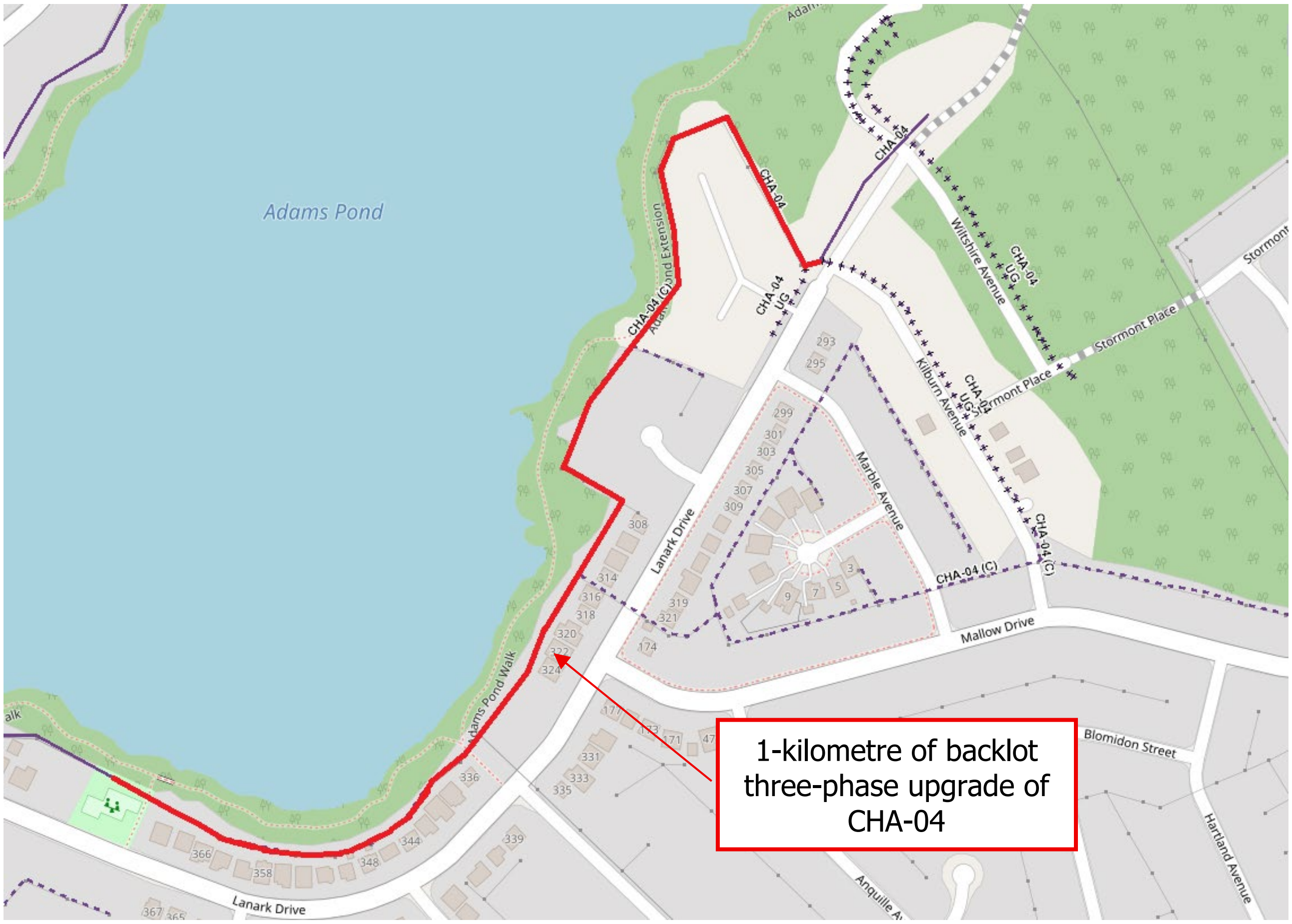

Figure 4 – Three-Phase Upgrade of Distribution Feeder CHA-04

4.0 PROJECT COST

Table 1 provides the costs of the 2027 *Feeder Additions for Load Growth* project to address overload conditions on distribution feeders BLK-02 and CHA-04 in 2027.

Table 1
Feeder Additions for Load Growth Project
2027 Project Costs
($000s)

Category	BLK-02	CHA-04	Total
Material	297	87	384
Labour – Internal	173	160	333
Labour - Contract	217	274	491
Engineering	34	30	64
Other	2	10	12
Total	723	561	1,284

The total cost of the *Feeder Additions for Load Growth* project is $1,284,000 in 2027.

5.0 CONCLUSION

The *Feeder Additions for Load Growth* project for 2027 includes:

(i) Upgrading a 6-kilometre single-phase section of distribution feeder BLK-02 along Mill Road in Brigus Junction to three-phase 1/0 AASC.
(ii) Upgrading a 1-kilometre single-phase section of backlot distribution feeder CHA-04 along Lanark Drive in Paradise to three-phase 1/0 AASC.

These upgrades are the least-cost solutions to address overload conditions resulting from customer growth in Brigus Junction and Paradise. Completing this work in 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	MVA 12.5 kV	MVA 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	0.9	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 serving electric heating load, the load on the feeder can be 2.0 times as high as the normal winter peak load when power is restored. 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.

May 2026

2.1 2027 Substation Refurbishment and Modernization

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A FORTIS COMPANY

TABLE OF CONTENTS

Page

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 2027, the Company is proposing to commence three two-year projects to refurbish and modernize: (i) Blaketown ("BLK") Substation in the town of Blaketown at a total cost of $6,178,000; (ii) Mobile hydro plant ("Mobile Plant" or "MOP") Substation in the town of Mobile at a total cost of $1,250,000; and Rattling Brook ("RBK") Substation in the Norris Arm area at a total cost of $1,527,000. All three Substations contain a considerable amount of deteriorated and obsolete equipment that poses a risk to reliable operation.

Substation refurbishment and modernization projects are proposed over multiple years when equipment having long procurement lead times is required.[3] This provides the ability to complete design, procurement, and contract approval in year one and construction and commissioning in subsequent years.

This report provides an update on Newfoundland Power's *Substation Refurbishment and Modernization Plan* and the overall condition of substation assets. The projects proposed as part of the *2027 Capital Budget Application* are detailed in the appendices that follow.

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.

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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.

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.*[4]

Table 1
Substation Refurbishment and Modernization Five-Year Forecast
2027 to 2031

Substation Designations	Cost Estimates ($000s)				
	2027	2028	2029	2030	2031
GPD*	2,578	-	-	-	-
MOP	299	925	-	-	-
RBK	74	1,426	-	-	-
BLK	528	5,700	-	-	-
RRD	-	568	6,820	-	-
HAR	-	980	6,303	-	-
GFS**	-	198	2,096	175	-
PHR	-	-	254	1,758	-
SLA	-	-	456	5,511	-
GOU	-	-	-	738	6,891
SJM†	-	-	-	-	610
KBR†	-	-	-	-	202
HWD†	-	-	-	-	374
BCV†	-	-	-	-	444
TOTAL	3,479	9,798	15,930	8,182	8,520

Note: See the Electrical System Handbook included with the *2006 Capital Budget Application* for three letter substation designations.
* Year two of multi-year projects in 2027.
** This includes the retirement of the 4.16 kV associated with 25kV conversion
† Year one of multi-year projects in 2031.

Newfoundland Power's current plan includes the refurbishment and modernization of 14 substations over the next five years. The refurbishment and modernization plan during this

[4] Table 1 includes substation projects associated with the refurbishment and modernization plan that are justified on asset condition. Projects that require substation modifications not justified on asset condition are excluded from this table, such as the *Lewisporte-Boyd's Cove 138 kV Conversion* filed in Newfoundland Power's *2026 Capital Budget Application*.

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 variety of electrical system equipment, such as power transformers, reclosers and circuit breakers, together with 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 the proposed 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.[5] 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.[6,7] 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.[8]

5 Power transformers in hydro plants change from generation voltages of between 2,400 volts and 6,900 volts to either distribution or transmission voltages.

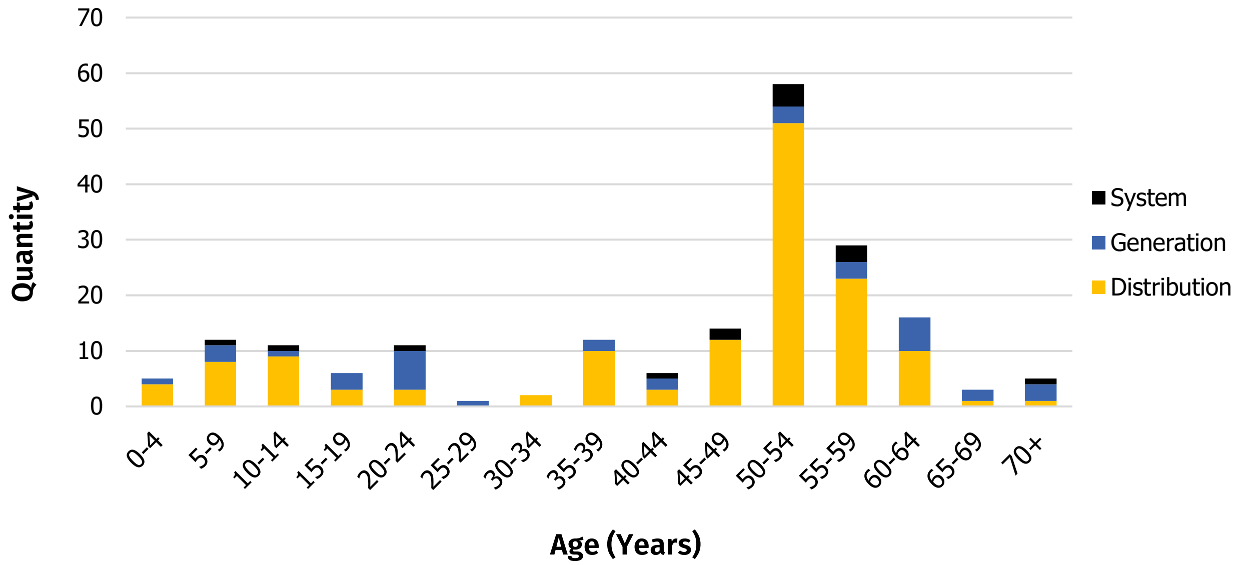
6 Based on information published by the International Council on Large Electric Systems ("CIGRE"). CIGRE is an international association with an objective to develop and facilitate the exchange of engineering knowledge and information in the field of electric power systems. CIGRE published a report on 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.

7 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.

8 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 58% 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 five power transformer failures in the past five years.[9]

As part of its 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.[10] All power transformers undergo annual oil sampling.[11] 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.

9 A major power transformer failure requires either transformer replacement, transportation off site for repairs, or removal from service for six months or longer. The five major power transformers failures since 2021 include MUN-T2, BLK-T2, DUN-T1, SLA-T3, and SLA-T4.

10 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.

11 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 power 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.[12] 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.[13] 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 381 high voltage circuit breakers in service.[14] 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.[15] A majority of the SF6 type breakers were installed to replace older bulk-oil type breakers. Several 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.[16]

12 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.

13 See the *2027 Capital Budget Application*, report *2.2 Substation Power Transformer Strategy*.

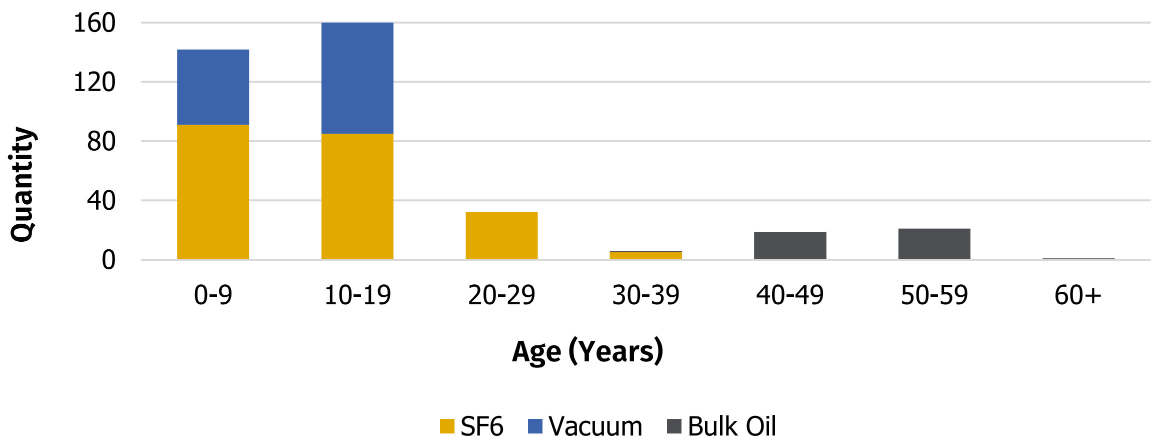
14 There are additional circuit breakers located in switchgear in the Company's substations and generation plants. This quantity of 381 breakers excludes switchgear circuit breakers.

15 Sulfur hexafluoride ("SF6") gas is used in high voltage circuit breaker design to extinguish the electrical arc created when opening energized breaker contacts.

16 The average age of failure for the Company's fleet of SF6 breakers is 26 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 due to the *Substation Refurbishment and Modernization*, *PCB Bushing Phase-out*, and *Replacements Due to In-Service Failures* projects and programs.

There are 213 SF6 type breakers in service. The majority of these breakers are less than 20 years old, with an average age of approximately 14 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.[17] These breakers have started to experience issues with excessive SF6 leaks, with 12 of these units having gaskets replaced to address this issue.[18] These breakers are being monitored closely for further leakage issues and will be repaired as required.

There are 42 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 50 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 47 years and can no longer be economically maintained.[19] The GE FKP breakers were manufactured from 1970 to 1982 and have an average age of 50 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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[17] This included 18 66 kV breakers and 26 138 kV breakers.

[18] 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.

[19] 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.

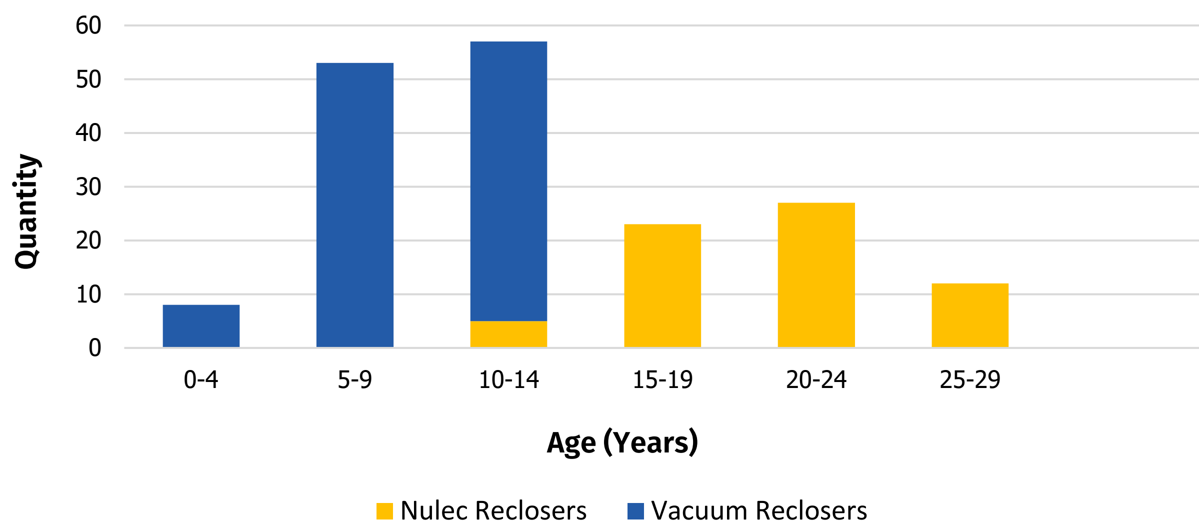
Reclosers

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 180 substation reclosers.[20] 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.[21]

Industry experience indicates the expected life of reclosers is between 30 and 50 years. This includes vintage hydraulic reclosers which have 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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20 There are additional reclosers located on the Company's distribution feeders. This quantity of 180 reclosers excludes the downline reclosers installed on distribution feeders.

21 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 that have 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.[22] All substation reclosers are currently less than 30 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 61 Nulec reclosers installed between 2001 to 2012 for distribution feeder protection.[23] Since 2021, 15 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.[24]

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.[25] The majority of this switchgear is operated at 12.5 kV distribution voltage; however, there are two locations with 4.16 kV switchgear.[26] The Company's substation switchgear consists of a total of 51 individual circuit breakers.[27]

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 75% 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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22 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.

23 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.

24 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.

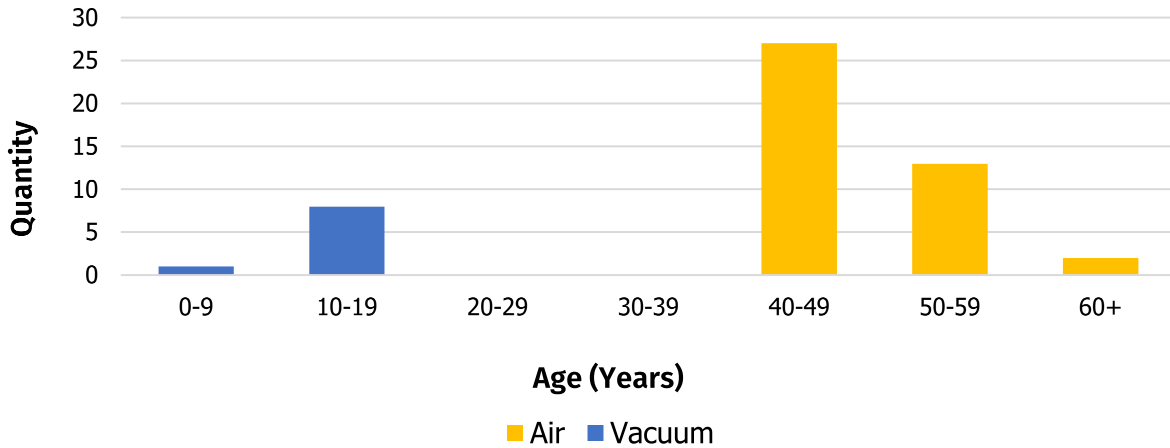
25 There are 25 switchgear lineups associated with the Company's generation plants.

26 The only 4.16 kV distribution switchgear remaining in service are located at the Company's Grand Falls ("GFS") and Stamps Lane ("SLA") substations.

27 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.[28] Arc flash technologies on newer switchgear mitigate the arc flash hazard to prevent injury to personnel and contain equipment damage.[29] 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 17 sites with voltage regulators inside of the substation.

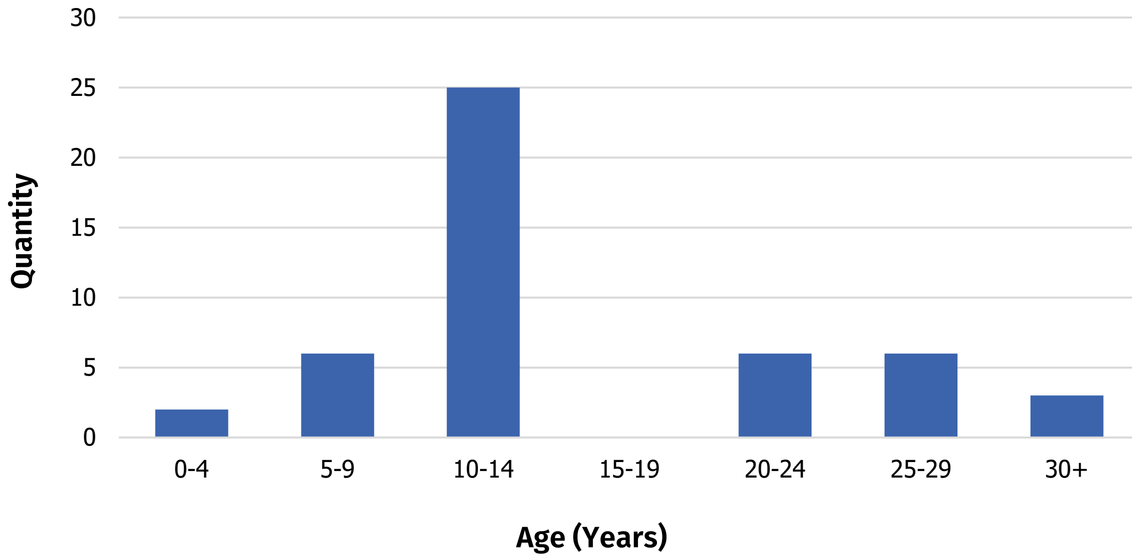
Industry experience indicates the expected useful service life for voltage regulators is 30 to 50 years.

[28] 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.

[29] 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. 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]

[30] Remote administration of upgraded devices allows protection relays to be interrogated and reconfigured remotely, facilitating 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.

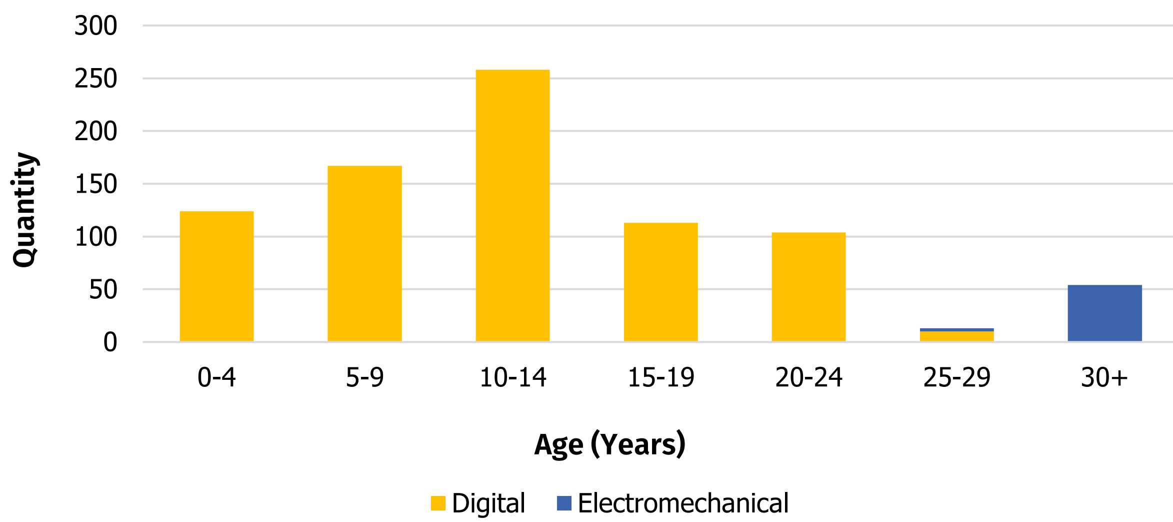
Over the past 20 years, Newfoundland Power has upgraded most of the electromechanical protection devices. However, approximately 7% of the protection devices currently in service are still electromechanical.

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

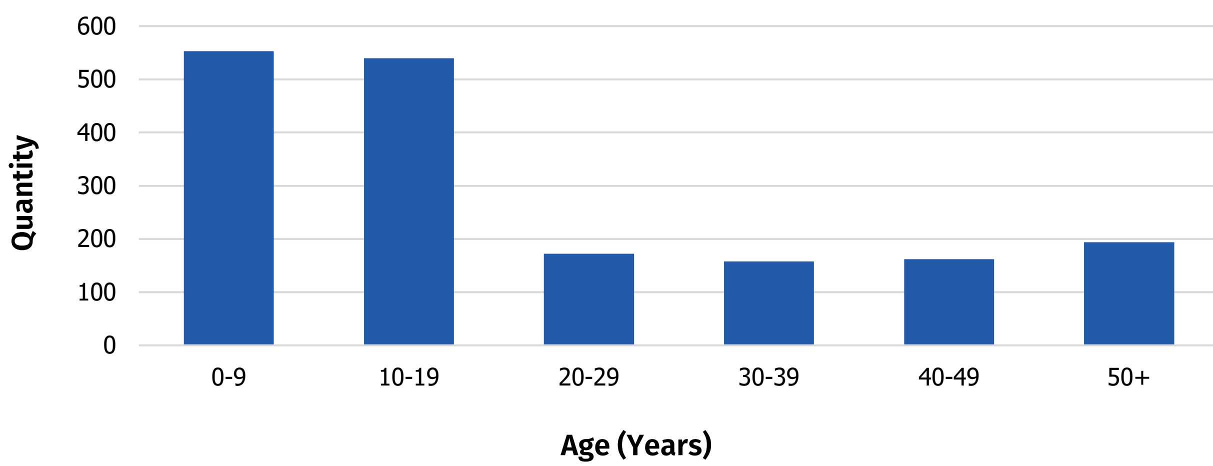
Substation high voltage switches provide isolation for equipment such as power transformers, circuit breakers and reclosers.[33] Newfoundland Power has approximately 1,800 high voltage switches in service.[34]

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 10 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 transformer protection that conforms to current industry 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]

Approximately 71% of the existing wooden bus structures are over 40 years of age, with 43% being over 50 years of age. Wooden structures over 50 years of age show signs of deterioration

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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 Seven of the 10 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.

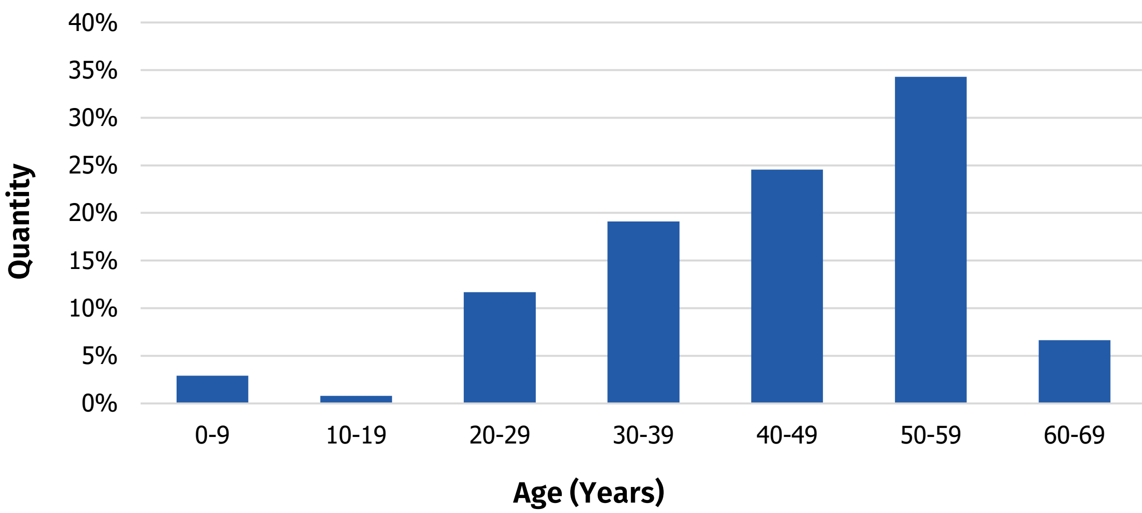
41 Circuit breakers also provide the ability to remotely control the energization of the transformer through the Company's SCADA system.

42 Newfoundland Power has 105 wooden and 156 steel bus structures.

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, 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 the need for 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, 102 of the 191 in-service power transformers have spill containment installed. Newfoundland Power has 17 substations that contain voltage regulators and six 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 particular concerns. A significant increase in substation break-ins has been observed in recent years. From 2021 to 2025 there were 57 substation break-ins, with a peak of 22 break-ins occurring in 2024.

To address this, 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, 54 substations have been equipped with surveillance and alarm systems to deter theft and vandalism.

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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 risk of imminent 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. This combined approach is reflected in the three refurbishment and modernization capital projects proposed for 2027 and represents the investments that are necessary to mitigate risks to the delivery of reliable service to customers resulting from deteriorated and obsolete equipment.

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 cycles 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 Blaketown Substation Refurbishment and Modernization

BLK Substation was constructed in 1967. The substation has two incoming 138 kV transmission lines and four outgoing 66 kV transmission lines. A 25/33.3/41.6 MVA power transformer, BLK-T3, converts the 138 kV to 66 kV to support the 66 kV transmission system in the area. A 15/20 MVA power transformer, BLK-T2, supplies two 25 kV distribution feeders, serving approximately 4090 customers in Blaketown and the surrounding 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 proposed *Blaketown Substation Refurbishment and Modernization* project.

Table 2 provides a detailed breakdown of the *Blaketown Substation Refurbishment and Modernization* multi-year project.

Table 2
Blaketown Substation Refurbishment and Modernization Project
Project Cost Estimate
($000s)

Cost Category	2027	2028	Total
Material	123	4,561	4,684
Labour - Internal	51	380	431
Labour - Contract	-	-	-
Engineering	340	539	879
Other	14	220	234
Total	528	5,700	6,228

The proposed project to refurbish and modernize BLK Substation is estimated to cost $528,000 in 2027 and $5,700,000 in 2028 for a total project cost of $6,228,000.

4.2 Rattling Brook Substation Refurbishment and Modernization

RBK Substation was constructed in 1959 as a transmission, distribution, and generation substation. The RBK Plant's 8.25 MVA and 7.5 MVA generators are connected to the 66 kV system through a 15/20 MVA, 66 kV to 6.9 kV power transformer. A 15/20/25 MVA, 138 kV to 66 kV power transformer connects RBK Substation to the 138 kV transmission system. The substation also supplies the Norris Arm area through a 5 MVA, 66 kV to 12.5 kV power transformer and associated distribution feeder infrastructure serving approximately 780 customers.

An engineering assessment of the substation identified deterioration of the existing 66 kV wood pole bus structures, 66kV disconnect switches approaching end of life, and an obsolete 12.5 kV feeder recloser that is no longer supported by the manufacturer.

Appendix B provides a detailed condition assessment and scope of work for the proposed *Rattling Brook Substation Refurbishment and Modernization* project.

Table 3 provides a detailed breakdown of the proposed *Rattling Brook Substation Refurbishment and Modernization* multi-year project.

Table 3 Rattling Brook Substation Refurbishment and Modernization Project Project Cost Estimate ($000s)			
Cost Category	2027	2028	Total
Material	11	1,066	1,077
Labour - Internal	-	157	157
Labour - Contract	-	-	-
Engineering	59	112	171
Other	4	91	95
Total	74	1,426	1,500

The project to refurbish and modernize RBK Substation is estimated to cost $74,000 in 2027 and $1,426,000 in 2028 for a total project cost of $1,500,000.

4.3 Mobile Plant Substation Refurbishment and Modernization

MOP Substation was constructed in 1951 as the generation substation for the Mobile Plant. The Plant's 11 MVA generator supplies the MOP Substation power transformer (MOP-T1), rated at 10 MVA, which provides the interface between the generating plant and the 66 kV transmission system.

Replacement of the MOP-T1 power transformer was approved under the 2026 *Capital Budget Application*. Additional *Refurbishment and Modernization* works are required to support installation of the approved MOP-T1 replacement transformer.

An engineering assessment of the substation identified that the existing yard arrangement and associated 66 kV and 6.9 kV infrastructure cannot accommodate the larger footprint of the approved MOP-T1 replacement transformer. Modifications to the existing infrastructure are therefore required to support installation of the replacement transformer in accordance with current Newfoundland Power standards.

Appendix C provides a detailed condition assessment and scope of work for the proposed *Mobile Plant Substation Refurbishment and Modernization* project.

Table 4 provides a detailed breakdown of the proposed *Mobile Plant Substation Refurbishment and Modernization* multi-year project.

Table 4
Mobile Plant Substation Refurbishment and Modernization Project
Project Cost Estimate
($000s)

Cost Category	2027	2028	Total
Material	166	555	721
Labour - Internal	8	99	107
Labour - Contract	-	-	-
Engineering	121	175	296
Other	4	96	100
Total	**299**	**925**	**1,224**

The project to refurbish and modernize MOP Substation is estimated to cost $299,000 in 2027 and $925,000 in 2028 for a total project cost of $1,224,000.

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 while contributing to overall system reliability and safety.

For 2027, Newfoundland Power is proposing to refurbish and modernize BLK, RBK, and MOP Substations.[50] These substations contain a significant amount of deteriorated and obsolete equipment. Refurbishing and modernizing these substations will ensure the continued provision of safe and reliable service to customers they supply.

[50] The refurbishment of BLK, RBK, and MOP Substations are two-year projects commencing in 2027.

APPENDIX A:

Blaketown Substation Refurbishment and Modernization

TABLE OF CONTENTS

Page

1.0 BLAKETOWN SUBSTATION

Blaketown ("BLK") Substation was constructed in 1967. The substation has two incoming 138 kV transmission lines and four outgoing 66 kV transmission lines. A 25/33.3/41.6 MVA power transformer, BLK-T3, converts the 138 kV voltage to 66 kV, to service communities in the Dunville and Bay Roberts Areas. Two of the 66 kV transmission lines, 55L and 94L, are radial and service approximately 5,970 customers. A 15/20 MVA power transformer, BLK-T2, supplies two 25 kV distribution feeders, serving approximately 4,090 customers in Blaketown and the surrounding area. Figures A-1 and A-2 show BLK Substation.

Figure A-1: BLK Substation

Figure A-2: BLK Substation

2.0 ENGINEERING ASSESSMENT

2.1 138 kV Infrastructure

The 138 kV steel structure was constructed in 1977 as an addition to the existing substation. During this time two 138 kV transmission lines were brought into the substation. Prior to this, BLK Substation did not have 138 kV infrastructure.

An engineering assessment of the BLK Substation determined that the 138 kV steel structure remains structurally sound, with minimal deficiencies, and can support the loads imposed by critical substation equipment. The galvanized steel coating has experienced flaking and degradation over the structure's 49-year service life, resulting in minor surface corrosion, as depicted in Figure A-3. Surface preparation and application of galvanizing coating is required to halt the observed corrosion and provide a long-term cathodic protection that will extend the service life of the steel structure.

Discoloration where surface corrosion is present

Figure A-3: 138 kV Structure Surface Corrosion

All eight of the 138 kV switches have been in service for 49 years and are deteriorated. These switches require replacement as a result of their mechanical operating condition and corrosion. This includes two air break switches, four side break switches, and two ground switches.

2.2 66 kV Infrastructure

The 66 kV steel structure was constructed in 2001. An engineering assessment of the BLK Substation determined that the 66 kV steel structure remains in good condition and is structurally sound.

The 66 kV switches are approximately 25 years old and are approaching the later stages of their expected service life. Infrared inspections have identified localized heating consistent with known deterioration mechanisms such as contact wear and misalignment. Field staff have also encountered challenges during operation of several of the switches, suggesting age-related degradation of operating components. Due to the four 66 kV transmission lines terminating in this structure, replacement of the switches is a complex activity, and undertaking this work in coordination with the project allows for improved efficiency and reduced operational disruption.

2.3 25 kV Infrastructure

The 25 kV steel structure was constructed in 2001. An engineering assessment of the BLK Substation determined that the 25 kV steel structure remains in good condition and is structurally sound. The 25 kV switches are not notably deteriorated, and have no operational difficulties; the 25 kV switches will therefore not be replaced during this project.

The 25 kV breaker protecting distribution feeder BLK-02-B was manufactured by General Electric in 1982. This breaker is obsolete and does not include modern oil containment measures, increasing environmental and operational risk. This breaker will be replaced with a new vacuum type circuit breaker.

2.4 Power Transformers

BLK-T3 is a 49-year-old system power transformer that was manufactured by Westinghouse in 1977. BLK-T3 is a 138 kV to 66 kV, 25/33.3/41.6 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 surface rusting on several transformer components.

Newfoundland Power utilizes the Electric Power Research Institute's Power Transformer Expert software to monitor the health of its power transformer assets. For BLK-T3, the Abnormal Condition Index indicates low short-term risk, and the Normal Degradation Index indicates low long-term risk. BLK-T3 is not expected to be replaced within the next five years based on its present risk.

BLK-T3 power 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.[1]

[1] Power transformer BLK-T3 contains approximately 31,500 liters of oil.

Figures A-4 shows power transformer BLK-T3.

Figure A-4: BLK-T3 Power Transformer

BLK-T2 is a 49-year-old distribution power transformer, manufactured by Federal Pioneer in 1977. The unit is a 138 kV to 25 kV, 15/20 MVA power transformer. The main tank and associated equipment are in good condition.

In 2021, the on-load tap changer experienced a fault. As a result of the fault, the tap changer was locked in a fixed position, and an external set of voltage regulators wsa installed to maintain voltage regulation on the distribution system. External voltage regulators are temporary measures to support continued operation of the transformer while voltage regulation capability from the on-load tap changer is unavailable.[2]

It was determined that repair of the on-load tap changer will require external resources. BLK-T2 will be removed from service during the project, at which time the on-load tap changer repair can be coordinated and completed.

Newfoundland Power utilizes the Electric Power Research Institute's Power Transformer Expert software to monitor the health of its power transformer assets. For BLK-T2, the Abnormal Condition Index indicates low short-term risk, and the Normal Degradation Index indicates moderate long-term risk. BLK-T2 is not expected to be replaced within the next five years based on its present risk.

2 The position of the temporary voltage regulators is a non-standard configuration intended for short term operation as there is inadequate space for maintenance and troubleshooting.

BLK-T2 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-5 shows power transformer BLK-T2 with temporary voltage regulators.

Figure A-5: BLK-T2 Power Transformer

2.5 Protection and Control

The protection relays for BLK-T2 and BLK-T3 are vintage electromechanical type and are 49 years old.

3 Power transformer BLK-T2 contains approximately 25,400 liters of oil.

Figure A-6 shows the vintage electromechanical relays.

Figure A-6: Electromechanical Relays

The protection and control of substation assets require modernization by replacing the obsolete electromechanical relays with microprocessor-based digital relays, significantly reducing the quantity of relays. This approach minimizes the number of active devices used to provide protection to substation assets, consolidates the control and automation architecture, and reduces ongoing maintenance.

The remaining protection system includes a mix of relay vintages and platforms. As part of the proposed refurbishment and modernization project, Newfoundland Power will replace the existing protection relays and associated panels with a standardized digital protection platform. This approach is consistent with prior refurbishment projects where replacing multiple relay types with a consolidated digital scheme reduces the number of active devices, consolidates the control and automation architecture, and reduces ongoing maintenance.

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 breach signal or fire alarm. There has been one break-in at BLK Substation in the last five years, which break-in resulted in an outage to all distribution customers served by BLK Substation due to equipment grounding damage associated with copper theft.

2.6 Building

The existing control building at BLK Substation was built in 1967. The control building currently houses the substation's communications, protection and control equipment.

The control building is a prefabricated building with a metal roof and siding. The exterior building envelope shows signs of corrosion and material degradation, including rusted wall panels and aging cladding, indicating a loss of weather resistance. Internally, the building exhibits significant deterioration of wall and ceiling finishes, including damaged and delaminated materials, exposed substrate, and evidence of material failure at the base of interior walls. This poses an operational risk to electrical equipment, which is susceptible to moisture and environmental conditions.

Due to the prefabricated design and deteriorated condition of the existing control building, it will be replaced with a new building.

Figures A-7 and A-8 depict the deteriorated condition of BLK Substation control building.

Figure A-7: BLK Control Building

Figure A-8: BLK Control Building

2.7 Site Condition

The cable trench system at BLK Substation provides routing and protection for power, protection, control, and communications cables connecting primary equipment throughout the substation yard and into the control building. The cable trench is a critical element of the substation's civil infrastructure.

Visual inspection of the existing cable trench infrastructure indicates that the system is in advanced deteriorated condition. The trench covers exhibit widespread corrosion, significant surface material loss, and visible section thinning. In several locations, the covers show gaps and misalignment between adjacent sections, resulting in open slots along the trench length.

The observed corrosion and deformation indicate that the trench covers have reached the end of their useful service life and no longer provide reliable mechanical protection for the cables housed below. The cable trench will be replaced; the new infrastructure will include corrosion resistant trench covers.

Figures A-9 and A-10 show the deteriorated condition of BLK Substation cable trench.

Figure A-9: BLK Cable Trench

Figure A-10: BLK Cable Trench

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.

BLK Substation ground grid is up to standard and minimal modifications will be required to accommodate the planned work for the substation.

3.0 RISK ASSESSMENT

The proposed *Blaketown Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to approximately 4,090 customers in the Blaketown area and 5,970 customers serviced from radial transmission lines 55L and 94L. BLK Substation is the sole source of supply to customers in the Blaketown area. Equipment failure in the substation exposes all customers supplied by BLK 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 to 36 hours.

BLK Substation contains equipment that is deteriorated, obsolete, and at end of life, increasing the probability of outages to customers. One circuit breaker and a large quantity of switches require replacement based on their age and mechanical condition. The protection and control system includes obsolete equipment that is no longer industry standard and requires replacement. Modernization of these systems is required to reduce operational risk and support reliable fault detection, isolation, and restoration.

Both power transformers in BLK 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.

The existing control building, constructed in 1967, is in a deteriorated condition and no longer provides a suitable environment for housing critical protection, control, and communications equipment. The condition of the building increases the risk of equipment exposure to moisture and environmental conditions, which could result in equipment damage or failure.

The cable trench infrastructure at BLK Substation is in advanced deteriorated condition. The trench covers exhibit widespread corrosion, section thinning, and misalignment, reducing mechanical protection for critical power, protection, control, and communications cables. Failure of the cable trench system could result in damage to critical cables and extended outage durations.

Overall, refurbishment and modernization of BLK Substation is necessary to ensure the continued delivery of reliable, safe and environmentally responsible service to customers in the Blaketown area.

4.0 ASSESSMENT OF ALTERNATIVES

In the case of BLK Substation, the number of components currently requiring preventative and corrective maintenance justifies the refurbishment and modernization of the substation in 2027 and 2028. One 25 kV oil-filled breaker and a large quantity of switches require replacement as they have reached the end of their useful service life. The protection and control system includes obsolete equipment that is no longer industry standard and requires replacement. The power transformers do not have spill containment foundations. The control building and cable trench are substantially deteriorated and require replacement.

Deferral of the *Blaketown Substation Refurbishment and Modernization* project would increase the risk that some components will be run-to-failure. Run-to-failure is not a viable alternative as it would increase risks to the delivery of safe and reliable service to 10,060 customers.

5.0 PROJECT SCOPE

The proposed 2027 and 2028 scope of work at BLK Substation includes the following:

- (i) Construct a new control building to replace existing building;
- (ii) Construct new spill containment foundations for existing transformers;
- (iii) Replace deteriorated 138 kV and 66 kV switches;
- (iv) Replace one oil-filled 25 kV breaker;
- (v) Replace obsolete electromechanical relays with new digital relays;
- (vi) Install new security cameras; and
- (vii) Replace the deteriorated cable trench.

Table A-1 summarizes the age and condition of the primary equipment planned to be replaced.

Table A-1
2027/2028 Planned Equipment Replacements
Blaketown Substation

Equipment	Age (Years)	Condition
138 kV Switches	49	Deteriorated
66 kV Switches	25	Deteriorated
25 kV Breaker	44	End of Life
Electromechanical Protection Relays	49	End of Life
Control Building	59	Deteriorated
Cable Trench	53	Deteriorated

Engineering design and procurement of long lead equipment will be completed in 2027. Construction will begin in the second quarter of 2028 and be completed in the fourth quarter of 2028. Commissioning of the substation will be completed during the fourth quarter of 2028.

6.0 PROJECT COST

Table A-2 provides the cost breakdown for the proposed multi-year *Blaketown Substation Refurbishment and Modernization* project.

Table A-2
Blaketown Substation
Refurbishment and Modernization Project
Project Cost
($000s)

Cost Category	2027	2028	Total
Material	123	4,561	4,684
Labour - Internal	51	380	431
Labour - Contract	-	-	-
Engineering	340	539	879
Other	14	220	234
Total	$528	$5,700	$6,228

The *Blaketown Substation Refurbishment and Modernization* project is estimated to cost $528,000 in 2027 and $5,700,000 in 2028 for a total project cost of $6,228,000.

7.0 CONCLUSION

The proposed *Blaketown 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 BLK Substation. New 138 kV and 66 kV switches will replace the deteriorated switches, the oil-filled breaker will be replaced, the deteriorated control building and cable trench will be replaced, and new digital relays will provide improved automation and protection. New transformer 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 *Blaketown Substation Refurbishment and Modernization* project is estimated to be $6,228,000.

APPENDIX B:

Rattling Brook Substation Refurbishment and Modernization

TABLE OF CONTENTS

Page

1.0 BACKGROUND

1.1 Rattling Brook Substation

RBK Substation was constructed in 1959 as a transmission, distribution, and generation substation. The RBK Plant's 8.25 MVA and 7.5 MVA generators are connected to the 66 kV bus through the 15/20 MVA, 66 kV to 6.9 kV power transformer, RBK-T1.

In 2021, the deteriorated 66 kV transmission lines entering RBK Substation were decommissioned as part of Newfoundland Power's *2021 Refurbishment and Modernization* project, consistent with recommendations from the *2021 Central Newfoundland System Planning Study*. Following this work, RBK Substation was transferred to the 138 kV transmission system through a 15/20/25 MVA, 138 kV to 66 kV power transformer, RBK-T3.

The 12.5 kV distribution bus structure is energized by a single 5 MVA, 66 kV to 12.5 kV power transformer, RBK-T2. There is one 12.5 kV distribution feeder, RBK-01, serving approximately 780 customers in the Norris Arm area.

Figure B-1 shows the RBK Substation.

Figure B-1: RBK Substation

2.0 ENGINEERING ASSESSMENT

2.1 138 kV Infrastructure

The RBK Substation includes 138 kV infrastructure connecting the site to the Bishop's Falls and Lewisporte transmission systems that was constructed in 2021. The 138 kV infrastructure includes line terminations, circuit breakers, associated switching equipment, and a 25 MVA, 138 kV to 66 kV power transformer, RBK-T3, supplying the 66 kV bus. The 138 kV infrastructure remains in good condition and no modifications are required.

2.2 66 kV Infrastructure

The existing 66 kV infrastructure at RBK Substation consists of wood-pole bus structures, disconnect switches, and associated equipment that support the following assets: the 15/20 MVA, 66 kV to 6.9 kV power transformer (RBK-T1), the 5 MVA, 66 kV to 12.5 kV distribution power transformer (RBK-T2), and the 25 MVA, 138 kV to 66 kV power transformer (RBK-T3).

Condition assessments identified deterioration of the existing wood pole structures, including splitting and checking, increasing the likelihood of structural failure and associated outages.

The existing 66 kV disconnect switches associated with RBK-T1 and RBK-T2 were installed approximately 28 years ago and are approaching the typical end of service life.[54] Replacement of these switches will align with lifecycle expectations and given the planned reconstruction of the 66 kV bus structures, can be completed efficiently as part of the project.

As part of the proposed *Rattling Brook Substation Refurbishment and Modernization* project, the existing wood pole structures and associated equipment will be replaced with new steel pole structures and switching equipment to maintain reliable operation and reduce maintenance requirements.

[54] Disconnect switches installed in transmission and substation applications typically have an expected service life of approximately 30 years depending on operating conditions, maintenance practices, and manufacturer design specifications.

Figure B-2 shows deteriorating wood poles.

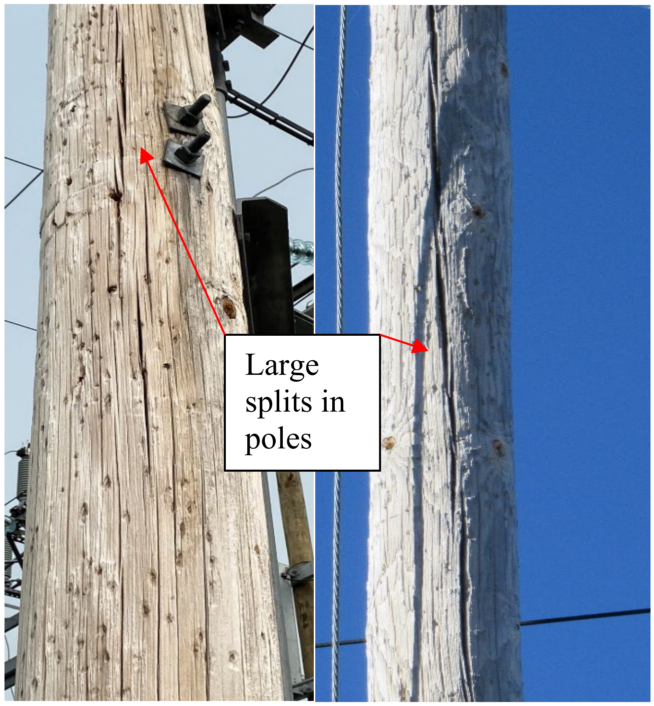

Figure B-2: Deteriorating 66 kV Wood Poles

2.3 12.5 kV Infrastructure

The 12.5 kV infrastructure at RBK Substation includes the outgoing distribution feeder supplied from the 5 MVA, 66 kV to 12.5 kV power transformer RBK-T2. The existing Nulec recloser installed on the feeder is obsolete and no longer supported by the manufacturer.[55]

Due to age and limited parts availability, the recloser presents an increased risk of failure and may result in prolonged customer outages in the event of equipment failure.

As part of the proposed *Rattling Brook Substation Refurbishment and Modernization* project, the existing recloser will be replaced with a modern equivalent to maintain reliable operation of the 12.5 kV feeder.

2.4 6.9 kV Infrastructure

The existing 6.9 kV infrastructure at RBK Substation is mounted on shared wood pole structures that support both 6.9 kV and 66 kV equipment.

The condition of the existing structures and the proposed replacement of 66 kV infrastructure requires associated modifications to the 6.9 kV infrastructure to maintain safe clearances and reliable operation.

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55 Since 2021, 15 of these reclosers have required replacement. The failures experienced and the lack of manufacturer support of the Nulec reclosers indicate that they are reaching the end of their useful service life.

As part of the proposed *Rattling Brook Substation Refurbishment and Modernization* project, the affected 6.9 kV infrastructure will be replaced to accommodate the new steel pole structures and to maintain continued operation of the generating plant.

2.5 Power Transformers

RBK-T1 is a 20 MVA, 66 kV to 6.9 kV power transformer installed in 2002. The transformer connects generation at the RBK plant to the 66 kV system. RBK-T1 is in good working order and oil test results show no indication of abnormal internal conditions. No additional work for RBK-T1 is required under this project.

RBK-T2 is a 5 MVA, 66 kV to 12.5 kV distribution power transformer installed in 1968 supplying customers in the Norris Arm area. The transformer is in working order and oil test results show no indication of abnormal internal conditions. Annual inspections indicate the transformer remains in good physical condition. No additional work is required for RBK-T2 under this project.

RBK-T3 is a 25 MVA, 138 kV to 66 kV power transformer installed in 2021 as recommended by the *Central Newfoundland System Planning Study*[56] to connect the RBK Substation onto Newfoundland Power's 138 kV Transmission network. The power transformer is in good working condition and does not require additional work as part of this project.

2.6 Protection and Control

Protection and control at RBK Substation is provided through modern multifunction microprocessor-based relays and associated control systems supporting transformer, bus, transmission, and feeder protection functions.

The existing protection and control systems remain in service, and no modifications are required as part of the *Rattling Brook Substation Refurbishment and Modernization* project.

2.7 Building

The RBK Substation has one primary building that supports operations of the generating facility and associated substation infrastructure. This building includes the protection and control equipment, communication systems, and associated auxiliary equipment supporting RBK-T1, RBK-T2, RBK-T3, 66 kV infrastructure, and 138 kV infrastructure.

The existing building is in good condition, and no modifications are required as part of the *Rattling Brook Substation Refurbishment and Modernization* project.

2.8 Site Condition

The existing yard at RBK Substation was developed to accommodate the current equipment layout at the Substation. The proposed work replaces existing structures and equipment within the existing yard envelope and does not require site expansion or reconfiguration. The

[56] See Newfoundland Power's 2019 *Capital Budget Application,* Central Newfoundland System Planning Study.

replacement 66 kV steel pole bus structures are expected to maintain a similar footprint to the existing wood pole bus structures and minimize rework. The RBK Substation ground grid is up to standard and only minor modifications will be required to accommodate the planned work.

3.0 RISK ASSESSMENT

The proposed *Rattling Brook Substation Refurbishment and Modernization* project will mitigate risks to delivery of generation from the two generating units (8.25 MVA and 7.5 MVA) and support continued reliable service delivery to customers in the Norris Arm area.

Failure of equipment on the 66 kV bus could result in loss of supply from the plant generators and expose approximately 780 customers in the Norris Arm area to prolonged outages. Outage duration would depend on the nature of the failure and restoration requirements.

The RBK Substation contains infrastructure that is deteriorating, obsolete, or approaching the end of its expected service life. Condition assessments identified deterioration of the existing 66 kV wood pole bus structures, including deep splits and checks, which increase the likelihood of structural failure and associated outages.

The existing 66 kV disconnect switches associated with RBK-T1 and RBK-T2 were installed approximately 28 years ago and are approaching the typical service life for this equipment. Replacement of these switches as part of the proposed work will reduce the risk of equipment failure and support continued reliable operation of the substation.

In addition, the existing 12.5 kV Nulec recloser installed on the RBK-01 feeder is obsolete and no longer supported by the manufacturer. Similar units have demonstrated increased failure risk due to age and limited parts availability.

Based on current asset condition, the probability of failure is elevated and could result in significant operational and customer impacts. The proposed *Rattling Brook Substation Refurbishment and Modernization* project represents the minimum scope required to mitigate these risks and maintain reliable service.

4.0 ASSESSMENT OF ALTERNATIVES

In the case of RBK Substation, the number of components currently requiring preventive maintenance supports selection of the *Rattling Brook Substation Refurbishment and Modernization* approach while deferral, run-to-failure, and abandonment are not viable alternatives.

The *Rattling Brook Substation Refurbishment and Modernization* project cannot be deferred. The 66 kV disconnect switch for RBK-T1 is approaching end of life and poses risks to complete substation shutdown in the event of maintenance on RBK-T1. The wood poles used for the installation of the 66 kV bus structure are deteriorated and prone to failure, increasing the likelihood of prolonged customer outage hours for customers in the Norris Arm area.

In addition, the existing 66 kV disconnect switches associated with RBK-T1 and RBK-T2 are approaching the typical service life for this equipment. Replacement of these switches during the planned reconstruction of the 66 kV bus structures allows the work to be completed efficiently while minimizing future system disruptions.

The existing 12.5 kV Nulec recloser installed on the outgoing distribution feeder RBK-01 is obsolete, no longer supported by the manufacturer, and prone to failure. Failure of this recloser could result in prolonged customer outage hours to the customers supplied from RBK-T2.

Deferral of the *Rattling Brook Substation Refurbishment and Modernization* project would increase the risk that some components will be run-to-failure.[57] Running to failure is not a viable alternative as it would increase risks to the delivery of safe and reliable service to approximately 780 customers in the Norris Arm area.

5.0 PROJECT SCOPE

The proposed 2027 and 2028 scope of work at RBK Substation includes the following:

(i) Remove existing deteriorating 66 kV wood pole bus arrangement and construct a new 66 kV steel pole bus structure as replacement;
(ii) Remove existing 6.9 kV deteriorated wooden crossarms and install fiberglass crossarms in their place on the new steel pole structures;
(iii) Remove existing disconnect switches and install new disconnect switches as replacement;
(iv) Remove existing 12.5 kV obsolete Nulec recloser and install a modern recloser as replacement.

Engineering design and procurement of long-lead equipment will be completed in 2027. Construction will begin in the second quarter of 2028 and be completed in the fourth quarter of 2028. Commissioning will be completed during the fourth quarter of 2028.

[57] The scope presented in the 2027 *Rattling Brook Substation Refurbishment and Modernization* project was deferred when the RBK substation 138 kV bus addition was completed in 2021 as recommended in the *2021 Central Newfoundland System Planning Study.*

6.0 PROJECT COST

Table B-1 provides the cost breakdown for the proposed multi-year *Rattling Brook Substation Refurbishment and Modernization* project.

Table B-1
Rattling Brook Substation
Refurbishment and Modernization Project
Project Cost
($000s)

Cost Category	2027	2028	Total
Material	11	1,066	1,077
Labour - Internal	-	157	157
Labour - Contract	-	-	-
Engineering	59	112	171
Other	4	91	95
Total	$74	$1,426	$1,500

The *Rattling Brook Substation Refurbishment and Modernization* project is estimated to cost $74,000 in 2027 and $1,426,000 in 2028 for a total project cost of $1,500,000.

7.0 CONCLUSION

The existing wood poles supporting the 66 kV Bus Support Structures are approaching end of life and showing signs of deterioration. In addition, the existing 66 kV disconnect switches associated with RBK-T1 and RBK-T2 are approaching the typical service life for this equipment. The existing 12.5 kV Nulec recloser installed on the outgoing distribution feeder is obsolete and no longer supported by the manufacturer.

The proposed *Rattling Brook Substation Refurbishment and Modernization* project will reconstruct the existing 66 kV wood pole bus structure with steel poles, replace the 66 kV disconnect switches on RBK-T1, and replace the obsolete 12.5 kV Nulec recloser. These upgrades will reduce the risk of prolonged outages and support continued reliable service to customers in the Norris Arm area.

Completing these replacements as part of the planned *Rattling Brook Substation Refurbishment and Modernization* work allows the equipment to be replaced efficiently while minimizing future system disruptions and avoiding separate replacement projects.

The proposed *Rattling Brook Substation Refurbishment and Modernization* project represents a cost-effective solution to maintain reliable service and modernize aging infrastructure. The total project cost is estimated to be $1,500,000.

APPENDIX C:

Mobile Plant Substation Refurbishment and Modernization

TABLE OF CONTENTS

Page

1.0 BACKGROUND

1.1 Mobile Plant Substation

The MOP Substation was constructed in 1951 as the generation substation for the Mobile Plant. The Mobile Plant supplies the MOP Substation power transformer (MOP-T1), rated 10 MVA, which provides the interface between the Mobile Plant and Newfoundland Power's 66 kV transmission system.

As part of Newfoundland Power's *2026 Capital Budget Application*, replacement of MOP-T1 was approved under the *Substation Power Transformers Replacement Strategy*. Additional work is required under a *Mobile Plant Substation Refurbishment and Modernization* project to support the installation of the approved MOP-T1 replacement transformer.[58]

Figure C-1 shows the MOP Substation.

Figure C-1: MOP Substation

2.0 ENGINEERING ASSESSMENT

2.1 66 kV Infrastructure

The existing 66 kV infrastructure at the MOP Substation consists of a wood pole bus arrangement constructed in 1999. An inspection and engineering assessment completed in 2022 confirmed that the poles are generally in acceptable condition for continued service.

[58] In the *2026 Substation Power Transformers* report the estimated cost of the *MOP Substation Refurbishment and Modernization* project and the MOP-T1 substation power transformer replacement was estimated to be $3,877,000.

However, the approved replacement transformer for MOP-T1 has a larger physical footprint than the existing transformer. As a result, the current 66 kV pole arrangement cannot be reused. To accommodate the size of the new MOP-T1 replacement transformer and to align the installation with current Newfoundland Power standards, the existing 66 kV wood pole structures will be replaced with a steel pole bus arrangement.

As part of this work, a 66 kV fused disconnect and 66 kV air-break switch will be installed to provide transformer protection and isolation consistent with standard plant installations. These modifications are required to ensure the 66 kV infrastructure can safely and reliably support installation and operation of the approved MOP-T1 replacement transformer.

These modifications are required to ensure the 66 kV infrastructure can safely and reliably support installation and operation of the approved MOP-T1 replacement transformer.

2.2 6.9 kV Infrastructure

The existing 6.9 kV infrastructure at the MOP Substation consists of wood pole structures installed in 1999. While the poles are generally in acceptable condition, the approved MOP-T1 replacement transformer requires a larger physical footprint than the existing unit. As a result, the current 6.9 kV pole arrangement cannot be retained in its present configuration and must be reconstructed to accommodate the revised transformer layout.

In addition, the existing wood crossarms exhibit advanced surface deterioration, including extensive mould growth, reflecting prolonged exposure to the local environmental conditions. The condition of the crossarms reduces their structural capability to support substation equipment such as switches, lightning arrestors, and power cables.

Figure C-2 shows deteriorated wood crossarms.

Figure C-2: Deteriorated 6.9 kV Wood Crossarms

As part of the *MOP Substation Refurbishment and Modernization* project, the existing 6.9 kV wood pole structures and associated crossarms will be replaced with steel pole structures. This approach supports integration of the approved MOP-T1 replacement transformer, eliminates the need for preservative-treated wood in very close proximity to a water body, and reduces ongoing maintenance requirements. The replacement structures will maintain the existing electrical arrangement while accommodating the revised site footprint.

2.3 MOP-T1 Power Transformer

MOP-T1 is a 10 MVA, 66 kV to 6.9 kV power transformer manufactured by Westinghouse and installed at the MOP Substation in 1951. The transformer has been in continuous service since installation and has approximately 75 years of expected service life.

Replacement of MOP-T1 power transformer and spill containment foundation was approved under Newfoundland Power's 2026 *Capital Budget Application* as part of the *Substation Power Transformer Strategy*. Construction of the *Mobile Plant Substation Refurbishment and Modernization* project will be completed in 2028 to coincide with the arrival of the new power transformer.

Figure C-3 illustrates the existing MOP-T1 power transformer.

Figure C-3: Power Transformer MOP-T1

2.4 Protection and Control

Protection and control for MOP-T1 is provided through modern multifunction microprocessor-based relays and associated control systems. These systems operate the 6.9 kV generation plant circuit breaker MOP-G1-B and the upstream 66 kV bus tie breaker MOB-TIE-B, depending on system operating conditions. Under certain configurations, including when MOB-TIE-B is bypassed for maintenance, primary high-voltage clearing for the transformer may not be maintained.

As part of the proposed *Mobile Plant Substation Refurbishment and Modernization* work, 66 kV power fuses will be installed to ensure transformer fault protection is maintained during periods when the upstream breaker is bypassed, reducing the likelihood of major transformer damage and extended outages.

Protection settings and interfaces will be reviewed and updated as required to support integration of the approved MOP-T1 replacement transformer and to align with current Newfoundland Power protection and operating practices.

2.5 Building

The Mobile Plant site includes two primary buildings that support generating plant operations and associated substation infrastructure.

The Mobile Plant building houses electrical and mechanical equipment required for plant operation, including the 6.9 kV metal-clad circuit breaker for the generator, MOP-G1-B, and associated generator equipment.

The MOP Substation building houses protection, control, communication systems, and auxiliary equipment supporting MOP-T1 power transformer and the 66 kV substation infrastructure.

The proposed *Mobile Plant Substation Refurbishment and Modernization* project associated with the approved MOP-T1 replacement does not require modifications to the existing buildings. The buildings will continue to provide the required protection, control, and communication interfaces to support integration and operation of the replacement transformer.

2.6 Site Condition

The existing transformer yard at MOP was developed to accommodate the existing non-standard sized MOP-T1 power transformer. The approved MOP-T1 replacement transformer has a larger physical footprint and requires a standard containment arrangement that cannot be accommodated within the existing yard limits.

Modifications to the site layout are required to support installation of the approved MOP-T1 replacement transformer. Minor site improvements will also be completed as part of the project, including addressing local drainage requirements, removal of unsuitable soil and vegetation, and placement of structural fill as required to support the expanded transformer yard.

The existing ground grid at MOP Substation has deficiencies that pose a risk to the safe and reliable operation of the electric equipment in the substation. There are sections of the yard with insufficient grounding and there are also missing connections between the main ground grid and the substation fence. A grounding study is necessary and the ground grid for the substation requires an upgrade to align with current standards.

These works include expansion of the transformer yard, upgrades to the grounding grid, installation of a standard 66 kV steel pole bus and 6.9 kV steel pole bus, and installation of new perimeter fencing, access gate, and safety signage.

3.0 RISK ASSESSMENT

The proposed *Mobile Plant Substation Refurbishment and Modernization* project will mitigate risks to the continued delivery of approximately 11 MVA of generation from the Mobile Plant to Newfoundland Power's transmission system. The MOP-T1 power transformer steps the plant's generation voltage from 6.9 kV to the 66 kV transmission system. If the MOP-T1 transformer is unavailable, generation from the Mobile Plant cannot be delivered to the electrical system.

Replacement of MOP-T1 power transformer was approved as part of Newfoundland Power's *2026 Capital Budget Application*. The proposed *Mobile Plant Substation Refurbishment and Modernization* project represents the remaining infrastructure work required to enable installation of the approved replacement of MOP-T1.

The approved MOP-T1 replacement transformer has a larger physical footprint than the existing unit and cannot be accommodated within existing yard clearances. As a result, the existing 66 kV wood pole bus arrangement and 6.9 kV infrastructure must be reconstructed to maintain required electrical clearances and support installation of the replacement transformer.

Retaining the existing bus structures would result in reduced phase-to-phase and phase-to-ground clearances, increasing the risk of flashover and potential personnel exposure during construction, maintenance, and emergency response activities. These conditions would not align with Newfoundland Power standards and could delay installation and commissioning of the approved MOP-T1 replacement transformer.

In addition, prolonged outages of the Mobile Hydro Plant resulting from substation infrastructure limitations could increase reliance on alternative generation sources and place additional stress on the electrical system during periods of peak demand.

Overall, the proposed *Mobile Plant Substation Refurbishment and Modernization* project is necessary to ensure the continued delivery of reliable service and to enable the installation of the approved MOP-T1 replacement power transformer under Newfoundland Power's 2026 *Capital Budget Application*.

4.0 ASSESSMENT OF ALTERNATIVES

The proposed scope of the *Mobile Plant Substation Refurbishment and Modernization* project is required to accommodate the installation of the approved MOP-T1 replacement power transformer. The approved MOP-T1 replacement power transformer has a larger physical footprint than the existing non-standard unit and requires modifications to the 66 kV and 6.9 kV infrastructure.

Alternative options, including retaining existing infrastructure and deferring the required modifications, were considered. However, the existing power transformer containment and bus arrangements cannot accommodate the approved MOP-T1 replacement power transformer within current yard limits. In addition, the current high-voltage configuration does not provide the required isolation and protection arrangements for the approved MOP-T1 replacement power transformer.

Deferral of the *Mobile Plant Substation Refurbishment and Modernization* project would prevent the installation of the approved MOP-T1 replacement power transformer and increase the risk of a potential loss of supply from the MOP generators due to a failure of the deteriorated power transformer MOP-T1. This project will facilitate installation of the approved MOP-T1 replacement power transformer and support continued reliable plant and grid operations.

5.0 LIFECYCLE COST ANALYSIS

The MOP Substation serves the Mobile Plant by stepping the 6.9 kV plant generation voltage up to the 66 kV transmission voltage. Newfoundland Power's hydro plants provide economic benefits for customers. 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 is only required to serve the Mobile Plant. If the Mobile Plant was decommissioned and removed, this equipment would no longer be needed.

A lifecycle cost analysis of the Mobile Plant, including the necessary capital investment required for equipment in the 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.[59] This work was deferred, and the proposed work is scheduled for completion between 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 the Mobile Plant remains economically viable.

6.0 PROJECT SCOPE

The proposed 2027 and 2028 scope of work at MOP Substation includes the following:

(i) Expand the existing yard;
(ii) Upgrade and extend the ground grid;
(iii) Remove existing non-standard 66 kV wood pole bus arrangement and construct a standard 66 kV steel pole bus;
(iv) Remove existing 6.9 kV wood pole structures and deteriorated crossarms and install steel pole structures aligned with new MOP-T1 replacement transformer footprint;
(v) Install new disconnect switches on the 66 kV and 6.9 kV systems;
(vi) Install 66 kV fused protection for MOP-T1; and
(vii) Install a new substation fence, access gate, and safety signage.

Engineering design and procurement of long-lead equipment will be completed in 2027. Construction will begin in the second quarter of 2028 and be completed in the fourth quarter of 2028. Commissioning will be completed during the fourth quarter of 2028.

7.0 PROJECT COST

Table C-1 provides the cost breakdown for the proposed multi-year *Mobile Plant Substation Refurbishment and Modernization* project.

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59 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 C-1 Mobile Plant Substation Refurbishment and Modernization Project Project Cost ($000s)			
Cost Category	2027	2028	Total
Material	166	555	721
Labour - Internal	8	99	107
Labour - Contract	-	-	-
Engineering	121	175	296
Other	4	96	100
Total	$299	$925	$1,224

The *Mobile Plant Substation Refurbishment and Modernization* project is estimated to cost $299,000 in 2027 and $925,000 in 2028 for a total project cost of $1,224,000.

8.0 CONCLUSION

The proposed *Mobile Plant Substation Refurbishment and Modernization* project is required to enable installation of the approved MOP-T1 replacement power transformer under Newfoundland Power's *2026 Capital Budget Application*. This work is necessary to allow continued delivery of Mobile Plant generation into the electrical system, supporting reliable service to customers at the lowest possible cost.

The project will include a new spill containment foundation, yard expansion, grounding upgrades, and associated 66 kV and 6.9 kV infrastructure necessary to accommodate installation and operation of the replacement power transformer in accordance with current Newfoundland Power standards and operational practices.

Completion of the project will support continued delivery of approximately 11 MVA of generation from the Mobile Plant while maintaining safe, reliable, and environmentally compliant operation. The project cost is estimated to be $1,224,000.

May
2026

2.2 Substation Power Transformer Strategy

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TABLE OF CONTENTS

Page

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 power transformers. The in-service failure of a power transformer can result in extended outages to thousands of customers.

Newfoundland Power introduced its Substation Power Transformer Strategy (the "Strategy") as part of the *2026 Capital Budget Application*. The Strategy established a proactive, planned approach to replace aging and deteriorating power transformers while strengthening emergency response capabilities to manage increasing failure risks. Its purpose is to reduce the likelihood and duration of customer outages by coordinating condition-based replacements, spare transformer inventory, and portable substation resources considering extended transformer procurement lead times.

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 executing a power transformer strategy to ensure the continued reliability of the electrical system.

This report provides an update on the Strategy and the overall condition of the power transformer fleet. The four projects proposed as part of the *2027 Capital Budget Application* are detailed in the appendices that follow.

In 2027, the Company is proposing a two-year project to replace power transformer LAU-T1 at Laurentian ("LAU") Substation in the Town of St. Lawrence at a cost of $3,285,000. In 2027, the Company is also proposing three-year projects to replace: (i) power transformer LBK-T1 at Lookout Brook ("LBK) Substation on the west coast of Newfoundland at a cost of $2,334,000; (ii) power transformer HAR-T1 at Harmon ("HAR") Substation in the Town of Stephenville at a cost of $2,904,000;[2] and (iii) power transformer RRD-T3 at Ridge Road ("RRD") Substation in the City of St. John's at a cost of $2,695,000.[3] These power transformers are deteriorated and pose a risk to reliable system operation.

Due to supply chain constraints and procurement lead times for power transformers, Newfoundland Power is proposing multi-year projects for substation power transformer replacements. This approach enables the completion of design, procurement, and contract approval in year one with installation and commissioning being completed in subsequent years.

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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] Procurement of HAR-T1 is being proposed to coordinate with the refurbishment and modernization of HAR Substation planned for 2028 and 2029 as per the five-year capital plan. See report *2.1 2027 Substation Refurbishment and Modernization*, Table 1.

[3] Procurement of RRD-T3 is being proposed to coordinate with the Refurbishment and Modernization of Ridge Road Substation planned for 2028 and 2029 as per the five-year capital plan.

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.[4]

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. According to industry experience, the expected life of a power transformer is between 30 and 50 years,[5] with a sharp decline for in-service power transformers past 70 years of age.[6] 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.[7]

[4] Power transformers in hydro plants change generation voltages from 2,400 volts and 6,900 volts to either distribution or transmission voltages.

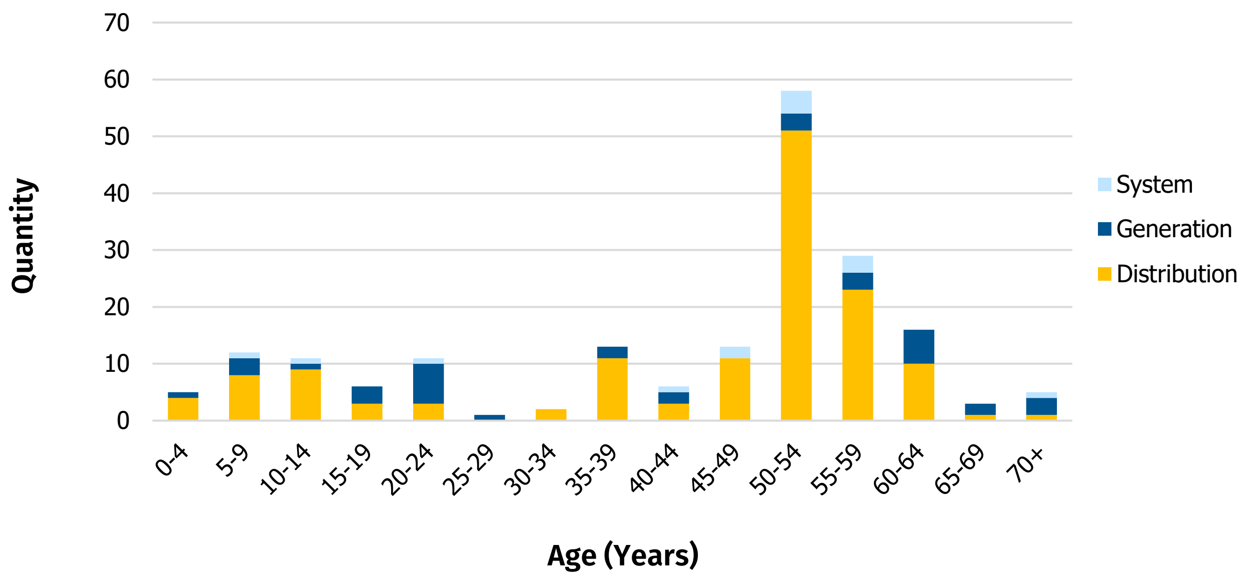
[5] Based on information published by the International Council on Large Electric Systems ("CIGRE"). CIGRE is an international association with an objective to develop and facilitate the exchange of engineering knowledge and information in the field of electric power systems. CIGRE published a report 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 is 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] See Centre for Energy Advancement through Technological Innovation ("CEATI"), *Station Equipment: Failure Rates, 2016,* page 3-3.

Figure 1 shows the age distribution of the Company's power transformers.

Figure 1
Power Transformer Age Distribution



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 the lowest.[8] 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.[9] Portable substations are also installed to maintain service to customers during planned capital projects and emergency response to 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.

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8 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.

9 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.

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.[10] The Company also has access to one portable substation from Newfoundland and Labrador Hydro ("Hydro"), P2, through an equipment sharing agreement.[11]

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[12]	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 12 and 60 years. Combined, these units can provide emergency backup for most power transformers in Newfoundland Power's system.[13]

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 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 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.

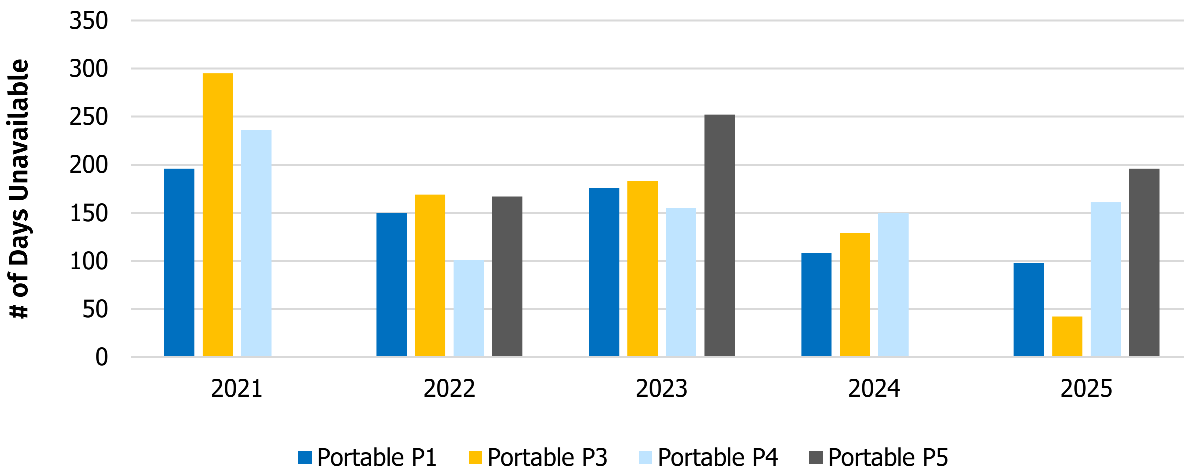
11 Hydro's portable substation has a capacity of 15 MVA. P2 can provide coverage for 87 of Newfoundland Power's 191 power transformers. However, all but one of these power transformers is covered by a Newfoundland Power portable substation.

12 *Ibid.*

13 See report *2.3 Portable Substation*, Appendix A for the coverage by each of the portable substations.

Figure 2 shows the utilization of Newfoundland Power's portable substations from 2021 to 2025.[14]

Figure 2
Portable Substation Utilitization
(2021-2025)



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.

For additional information on risks associated with reduced availability of portable substations, see report *2.3 Portable Substation*, section *4.0 Risk Assessment*.

2.3 Spare Power Transformer Inventory

The availability of a suitable spare power transformer following a failure 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.

[14] 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.

Table 2 provides details on Newfoundland Power's current inventory of spare power transformers.[15]

Table 2 Spare Transformer Inventory				
Equipment ID	Age	Capacity (MVA)	Primary Voltage (kV)	Secondary Voltage (kV)
200385[16]	2 Years	15/20/25	66	12.5/25
200299	50 Years	15/20	138	25
200219	56 Years	10	66	12.5
200328	43 Years	5/6.7/8.3	66	25
200185	58 Years	1.68/2.24	33/66	4.16/12.5
200358	17 Years	0.5	66	7.2/14.4
200220	56 Years	10/13.3	66	4.16/12.5
200352	23 Years	25/33.3/41.6	138	66

Maintaining an adequate inventory of spare power transformers is consistent with good utility practice.

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.[17] All power transformers undergo annual oil sampling which is analyzed by TJ|H2b Analytic Services Incorporated ("TJ|H2b").[18,19] Additionally, power transformers are scheduled for preventative maintenance

15 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.

16 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*.

17 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.

18 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.

19 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.

every 12 years where they undergo full transformer maintenance.[20] 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.[21] This assessment tool yields a set of indices for each power 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.

3.0 PROJECT SCOPE AND COST

3.1 LAU-T1

LAU Substation was constructed in 1975 as both a distribution and transmission substation. This substation is supplied by Newfoundland Power 66kV Transmission Lines 302L from Salt Pond ("SPO") Substation and 305L from Webber's Cove ("WBC") Substation. LAU Substation is also the 66kV interconnection point to Newind's 66kV Transmission Line 901E to Ryan's Hill Substation and Wind Generation Site. One 13.3 MVA distribution power transformer, LAU-T1, supplies two 12.5kV distribution feeders, serving approximately 700 customers in the Town of St. Lawrence.

LAU-T1 is a 50-year-old, 13.3 MVA 66-12.5kV distribution power transformer manufactured by Federal Pioneer. This transformer has remained at LAU Substation since its original installation in 1976.

LAU-T1 is deteriorating and an assessment of alternatives determined that it should be replaced.

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20 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.

21 The EPRI PTX software is also used by other utilities as a tool to aid in the development of transformer condition assessments.

Appendix A provides a detailed condition assessment and scope of work for the *LAU-T1 Power Transformer Replacement* project.

Table 3 provides a detailed breakdown of the *LAU-T1 Power Transformer Replacement* project.

Table 3
LAU-T1 Power Transformer Replacement Project
Project Cost
($000s)

Cost Category	2027	2028	Total
Material	-	2,854	2,854
Labour - Internal	-	105	105
Labour - Contract	-	-	-
Engineering	91	124	215
Other	8	103	111
Total	$99	$3,186	$3,285

The project to replace LAU-T1 is estimated to cost $99,000 in 2027 and $3,186,000 in 2028 for a total project cost of $3,285,000.

3.2 LBK-T1

LBK Substation was constructed in 1966 as a generation substation for the Lookout Brook Hydro Plant (the "Plant"). The Plant's two hydro generators supply the LBK Substation 7.5 MVA generation power transformer that interconnects the Plant to Newfoundland Power's 66kV Transmission Line 403L to Robinsons ("ROB") Substation.[22]

LBK-T1 is a 64-year-old, 7.5 MVA 66/33-2.4kV power transformer manufactured by English Electric. This transformer was installed in LBK Substation in 1997 after being relocated from Grand Falls Substation.

LBK-T1 is deteriorating and an assessment of alternatives determined that it should be replaced.

Appendix B provides a detailed condition assessment and scope of work for the *LBK-T1 Power Transformer Replacement* project.

[22] Lookout Brook Hydro Plant includes one 3 MVA generator, G3 and one 2.889 MVA generator, G4.

Table 4 provides a detailed breakdown of the *LBK-T1 Power Transformer Replacement* project.

Table 4
LBK-T1 Power Transformer Replacement Project
Project Cost
($000s)

Cost Category	2027	2028	2029	Total
Material	-	-	2,025	2,025
Labour - Internal	-	-	5	5
Labour - Contract	-	-	-	-
Engineering	68	36	107	211
Other	5	50	38	93
Total	$73	$86	$2,175	$2,334

The project to replace LBK-T1 is estimated to cost $73,000 in 2027, $86,000 in 2028, and $2,175,000 in 2029 for a total project cost of $2,334,000.

3.3 HAR-T1

HAR Substation was constructed in 1968 as both a distribution and transmission substation. This substation is supplied by Newfoundland Power 66kV Transmission Lines 405L from Stephenville Gas Turbine ("STV") Substation and 406L from Gallants ("GAL") Substation. One 11.125 MVA distribution power transformer, HAR-T1, supplies two 12.5kV distribution feeders, serving approximately 1,400 customers in the Town of Stephenville.

HAR-T1 is a 57-year-old, 11.125 MVA 66-12.5kV power transformer manufactured by General Electric. This transformer has remained at HAR Substation since its original installation in 1969.

HAR-T1 is deteriorating and an assessment of alternatives determined that it should be replaced.

Appendix C provides a detailed condition assessment and scope of work for the *HAR-T1 Power Transformer Replacement* project.

Table 5 provides a detailed breakdown of the *HAR-T1 Power Transformer Replacement* project.

Table 5
HAR-T1 Power Transformer Replacement Project
Project Cost
($000s)

Cost Category	2027	2028	2029	Total
Material	-	1	2,468	2,469
Labour - Internal	-	-	108	108
Labour - Contract	-	-	-	-
Engineering	69	39	115	223
Other	6	31	67	104
Total	$75	$71	$2,758	$2,904

The project to replace HAR-T1 is estimated to cost $75,000 in 2027, $71,000 in 2028 and $2,758,000 in 2029 for a total project cost of $2,904,000.

3.4 RRD-T3

RRD Substation was constructed in 1960 as both a distribution and transmission substation. This substation is supplied by Newfoundland Power 66kV Transmission Lines 30L from King's Bridge ("KBR") Substation, 32L from Oxen Pond ("OXP") Substation, and 67L from OXP Substation. Two 20 MVA distribution power transformers, RRD-T2 and RRD-T3, supply eight 12.5kV distribution feeders, serving over 4,400 customers in the City of St. John's.

RRD-T3 is a 51-year-old, 20 MVA 66-12.5kV power transformer manufactured by Ferranti Packard. This transformer has remained at RRD Substation since its original installation in 1977.

RRD-T3 is deteriorating and an assessment of alternatives determined that it should be replaced.

Appendix D provides a detailed condition assessment and scope of work for the *RRD-T3 Power Transformer Replacement* project.

Table 6 provides a detailed breakdown of the *RRD-T3 Power Transformer Replacement* project.

Table 6
RRD-T3 Power Transformer Replacement Project
Project Cost
($000s)

Cost Category	2027	2028	2029	Total
Material	-	-	2,404	2,404
Labour - Internal	-	-	5	5
Labour - Contract	-	-	-	-
Engineering	61	33	95	189
Other	5	31	61	97
Total	$66	$64	$2,565	$2,695

The project to replace RRD-T3 is estimated to cost $66,000 in 2027, $64,000 in 2028 and $2,565,000 in 2029 for a total project cost of $2,695,000.

4.0 CONCLUSION

The implementation of Newfoundland Power's Substation Power Transformer Strategy continues to be appropriate given the age and condition of the Company's power transformer fleet. Implementing this strategy allows the Company to maintain the overall condition of its power transformer fleet in a manner that provides reliable service to customers.

For 2027, Newfoundland Power is proposing capital projects to replace LAU-T1, LBK-T1, HAR-T1 and RRD-T3. These power transformers are deteriorated. Replacing these power transformers will ensure the continued provision of safe and reliable service to approximately 6,540 customers and 5.889 MVA of hydroelectric generation supplied by LBK, LAU, HAR, and RRD substations.

Appendices A through D provide a detailed review of the Substation Power Transformer Strategy scope proposed for 2027.

Appendix E summarizes the Substation Power Transformer Five-Year Plan. The plan will be revisited annually 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 A:

LAU-T1 Power Transformer Replacement

TABLE OF CONTENTS

Page

1.0 LAURENTIAN SUBSTATION POWER TRANSFORMER REPLACEMENT

1.1 Background

Laurentian Substation

Laurentian ("LAU") Substation was constructed in 1975 as both a distribution and transmission substation. This substation is supplied by Newfoundland Power 66kV Transmission Lines 302L from Salt Pond ("SPO") Substation and 305L from Webber's Cove ("WBC") Substation. LAU Substation is also the 66kV interconnection point to Newind's 66kV Transmission Line 901E to Ryan's Hill Substation and Wind Generation Site. One 13.3 MVA distribution power transformer, LAU-T1, supplies two 12.5kV distribution feeders, serving approximately 700 customers in the Town of St. Lawrence.

LAU-T1 Power Transformer

LAU-T1 is a 50-year-old, 13.3 MVA 66-12.5kV power transformer manufactured by Federal Pioneer. This transformer has remained at LAU since its original installation in 1976.

LAU-T1 is deteriorating and an assessment of alternatives determined that it should be replaced.

Figure A-1 shows power transformer LAU-T1.

Figure A-1: Power Transformer LAU-T1

Newfoundland Power is proposing a capital project to replace LAU-T1 over two years commencing in 2027 at an estimated cost of $3,285,000.

2.0 ENGINEERING ASSESSMENT

Oil Analysis and Electrical Testing

Power transformer LAU-T1 undergoes regular maintenance and routine oil sampling in accordance with Newfoundland Power's maintenance program. The transformer has undergone annual oil sampling since at least 2002. The transformer last had full maintenance in October 2025.

In October 2024, oil samples were taken from the on-load tap changer of LAU-T1 as part of routine testing. The Tapchanger Activity Signature Analysis ™ ("TASA") completed by TJ|H2b Analytic Services Incorporated ("TJ|H2b") at this time produced a Code 3 assessment score.[1] It indicated that a moderately abnormal dissipation of energy is noted. This is a leading indicator of fault or wear activity. Partial discharge, heating and abnormal arcing are all indicated by a Code 3 score. TASAs completed before 2023 produced a Code 2 assessment score. This information indicates continued deterioration of the on-load tap changer.

A subsequent oil sample was taken in November of 2025 from the on-load tap changer of LAU-T1 as part of routine testing. The TASA indicated that no abnormal dissipation of energy was present at the time of testing. This result is attributed to the refurbishment completed in October 2025, during which the tap changer oil was replaced. The oil replacement removed key gases typically generated by arcing and thermal stress, temporarily improving the diagnostic results. The replacement of tap changer components may also have mitigated the previously identified abnormal tap changer condition. However, the last major tap changer overhaul prior to this work was completed in 2017, and based on the unit's age and operating history, it is anticipated that tap changer-related issues will reoccur. As a result, the recent oil results are not considered indicative of a sustained improvement in long-term asset condition.

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 LAU-T1 based on information received as of December 31, 2025, is shown in Figure A-2.

[1] See Attachment A. TJ| /H2b's Condition Assessment Diagnostic Evaluation ranges from Code 1 to a Code 4*. The code evaluation system is a measure of a transformer's health with Code 1 representing a transformer in a state of good health, while a rise in coding values signifies a progressive deterioration in the transformer's health.

Company:	NP	**Region:**	Burin
Station:	LAU	**Designation:**	T1
Equipment ID:	200298	**Serial Number:**	W64566
Manufacturer:	Federal Pioneer	**Manufacture Date:**	3/1/1976
Energize Date:		**Repair Date:**	
Retire Date:		**Voltage Rating:**	66/12.5
Top MVA:	13.3	**Cooling Type:**	ONAF
Number of Phases:	3	**Core Type:**	Core
Is Autotransformer:	False	**Failure Consequence Index:**	0.39

PTX Result Summary

Normal Degradation Index:	0.58	**Oil Quality Index:**	0.01
Abnormal Thermal Index:	0.00	**Bushing Index:**	0.00
Abnormal Electrical Index:	0.00	**LTC Index:**	0.60
Abnormal Core Index:	0.00	**Throughfault Failure Index:**	

Diagnosis Summary:

Figure A-2: EPRI LAU-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, during which the paper insulation is subject to 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 A-2, the Normal Degradation Index of LAU-T1 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. Inspections have continually shown signs of physical deterioration. In 2025, a metal box was welded to the tank to contain a valve leak.

Figures A-3 and A-4 show physical deterioration from the 2017 and 2025 inspections.

Figure A-3: 2017 Inspections on various components

Figure A-4: 2025 inspection on valve

See Attachment B for previously completed corrective maintenance of LAU-T1.

Site Condition

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.[2]

The existing circuit breakers and microprocessor-based digital relays at LAU provide acceptable protection and control for this type of power transformer.

2 Power transformer LAU-T1 contains approximately 9,400 liters of oil.

3.0 RISK ASSESSMENT

The *LAU-T1 Power Transformer Replacement* project will mitigate risks to the delivery of reliable service to approximately 700 customers in the St. Lawrence area.

In the case of a LAU-T1 failure there are no offloading capabilities available to supply the existing peak load of LAU Substation. System load forecasts indicate that 7.56 MVA would be exposed to an outage.[3] A portable substation or a spare transformer would need to be installed in the event of a LAU-T1 failure.

Newfoundland Power has three portable substations and three spare power transformers that can be used for emergency response to an in-service failure of LAU-T1. Failure of LAU-T1 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.[4] Current power transformer delivery times are estimated to be between 24 and 36 months.

Overall, an increased probability of power transformer failure due to the transformer's condition, 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 power transformer 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.

4.0 ASSESSMENT OF ALTERNATIVES

Newfoundland Power identified and assessed three alternatives to address the deteriorating condition of LAU-T1 power transformer. These are: (i) Condition Based Monitoring; (ii) Remove and Repair; or (iii) Replace Power Transformer. These alternatives are discussed below.

(i) Alternative 1 – Condition Based Monitoring

This alternative would involve deferring the replacement of LAU-T1 and continuing to monitor its condition.

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.

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3 A maximum peak load of 7.56 MVA is being forecasted over the next five years at LAU Substation.

4 Spare transformers 200219, 200220, or 200385 are suitable medium-term replacement for LAU-T1. 200219 is a 10 MVA, 56-year-old transformer with a de-energized tap changer. 200220 is a 13.3 MVA, 56-year-old transformer with a de-energized tap changer presently installed at SLA Substation. 200385 is a 2-year-old, 25 MVA transformer with an on-load tap changer. Since 200219 and 200220 have de-energized tap changers they are not suitable long-term replacements of LAU-T1.

Among these resources, there are three portable substations that can be installed as a short-term emergency response to offload LAU-T1. Following offload, there are three spare power transformers available that can then be installed for the medium-term replacement of LAU-T1.[5] If the remaining spare transformer, 200385, with a capacity of 25 MVA were utilized, there would be limited resources available to respond to future 25 MVA power transformer failures in the short- to medium-term since power transformer delivery times could range from 24 to 36 months.

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 such as LAU-T1. This approach would significantly increase risks to the delivery of safe and reliable service to approximately 700 customers in the St. Lawrence area. Deferral of the *LAU-T1 Power Transformer Replacement* project would increase the risk that LAU-T1 will fail in service.

(ii) Alternative 2 – Remove and Repair

This alternative would involve removing LAU-T1 from service, refurbishing the unit, and placing it back in service.

Under a typical repair or refurbishment approach, the original transformer tank would not be replaced. As a result, the tank would continue to be susceptible to corrosion over time. While corrosion is mitigated through routine maintenance by sandblasting and painting the tank, these activities progressively thin the tank material, increasing the likelihood of oil leaks and associated environmental risk. As a result, refurbished power transformers have a service life that is substantially less than that of a new power transformer.

LAU-T1 is exhibiting deterioration across multiple critical systems. Physical deterioration of the transformer is evident, the on-load tap changer has required repeated repairs, and the transformer has a weakened insulation system. These conditions indicate that the transformer has reached end of life and is operating with elevated operational and reliability risk.

Given the extent of deterioration, repairing LAU-T1 is not considered a practical or cost-effective option. Addressing the identified issues would require repair or replacement of most of the major transformer components while keeping the existing tank. This would result in high repair costs with minimal extension of service life.

(iii) Alternative 3 – Replace Power Transformer

This alternative would involve replacing LAU-T1 with a new unit.

The deteriorated condition of the power transformer justifies replacing it beginning in 2027. The TASA from oil samples has demonstrated the deterioration of the on-load tap changer. There are significant signs of physical deterioration on the unit. PTX indicates a moderate and increasing probability that the unit has insulating paper that is no longer capable of providing reliable service.

5 *Ibid.*

The planned replacement of LAU-T1 will manage the risk to an acceptable level by replacing the deteriorated power transformer with a newer, more reliable transformer.[6] Strategically replacing the power transformer in a planned manner avoids the additional cost and outages associated with unforeseen failures.[7] This will ensure the continued delivery of safe and reliable service to customers served by LAU Substation.

To address the risks outlined above, Newfoundland Power proposes a planned replacement of the deteriorated power transformer LAU-T1 based on the condition assessment outlined in this report.

5.0 PROJECT COST AND SCOPE

This project involves purchasing a new 10/13.3/16.6 MVA, 66-12.5/25 kV power transformer to replace LAU-T1 while the existing unit remains in service. A new spill containment foundation will be installed for the new power transformer. The project is proposed to be completed over two years. This would include design and procurement in 2027, followed by delivery, installation, testing and commissioning in 2028.

Table A-1 below provides a cost breakdown of the *LAU-T1 Power Transformer Replacement* project.

Table A-1
LAU-T1 Power Transformer Replacement Project
Project Cost
($000s)

Cost Category	2027	2028	Total
Material	-	2,854	2,854
Labour - Internal	-	105	105
Labour - Contract	-	-	-
Engineering	91	124	215
Other	8	103	111
Total	$99	$3,186	$3,285

The project to replace LAU-T1 is estimated to cost $99,000 in 2027, and $3,186,000 in 2028 for a total project cost of $3,285,000.

6 After the transformer has been replaced, it will be scrapped due to overall condition.

7 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 labour 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.

Attachment A:

TJ|H2b Transformer Condition Assessment History – Power Transformer LAU-T1

TJ | H2b ANALYTICAL SERVICES INCORPORATED

Tapchanger Activity Signature Analysis TASA ™

Sam Losinski	Location : LAURENTIAN	Date : 4/22/2025
Newfoundland Power	Bank & Phase : LAU-T1	Report Number : 5083745
P.O. Box 8910	Serial Number : W-64566-LTC	Purchase Order Number:
55 Kenmount Road	Ventilation : Sealed Tank	Manufacturer : FPE
St. John's, NF A1B 3P6	Compartment : Common	Model : TC 23-3

		Sample Date :	3/28/2025	10/8/2024	5/8/2024	11/23/2023	7/17/2023
		Laboratory No. :	5083745	5083063	5081818	5081383	5080559
		Container No. :	56856	55248	55261	53390	52211
		Temperature :	23	40	10	6	40
H2	Hydrogen	(ppm) :	12589	9607	8026	6283	9151
CH4	Methane	(ppm) :	2704	2720	2468	2362	2335
C2H6	Ethane	(ppm) :	540	197	74	362	347
C2H4	Ethylene	(ppm) :	6478	6281	5873	5474	5474
C2H2	Acetylene	(ppm) :	22097	22287	20217	15629	18129
CO	Carbon monoxide	(ppm) :	633	567	550	518	442
CO2	Carbon dioxide	(ppm) :	5599	5655	5400	5276	4201
N2	Nitrogen	(ppm) :	68137	67189	70898	66514	68896
O2	Oxygen	(ppm) :	4511	10074	8865	13767	12382
		Total (ppm) :	123288	124577	122371	116185	121357
		TDCG (ppm) :	45041	41659	37208	30628	35878
		SHL (%) :	3.89	3.86	3.85	3.87	3.87
		ETCG (% in blanket) :	26.06	21.32	18.08	15.22	19.57
Particles		5 to 15 um :	242621	223897	227067	200095	238897
Particles		15 to 25 um :	383	698	630	326	1266
Particles		25 to 50 um :	30	109	87	71	224
Particles		50 to 100 um :	1	1	6	2	12
Particles		> 100 um :	0	0	0	0	0
D1533	Moisture	(ppm) :	29	29	29	18	41
D1816	Dielectric BV	(kV) :	27	31	28	35	31
D974	Acid Number	(mg KOH/g) :	<0.02	0.02	<0.02	0.02	0.02
D971	Interfacial Tension	(dynes/cm) :	35.0	39.8	36.2	30.7	28.7
D1500	Color Number	:	4.5	5.0	>5.0	<3.5	5.5

Tapchanger Activity Signature Analysis Diagnostic Evaluation

TASA Assessment :	3 ID: 200298 Sampler: Terry Anstey Counter: 34995	3 ID: 200298 Sampler: Terry Anstey Counter: 33764	3 ID: 200298 Sampler: Terry Anstey Counter: 32773	2 ID: 200298 Sampler: Terry Anstey	2 ID: 200298 Sampler: Terry Anstey Counter: 30692

Sampling Interval : Recommend retest within in 90 days. Schedule overhaul within 6 months.

Operating Procedure : Monitor for increased arcing. Evaluate for worn or damaged components.

Comments : A moderately abnormal dissipation of energy is noted. This is an advancing indication of fault or wear activity.

Partial discharge is indicated.

Heating is indicated.

Abnormal arcing is indicated.

Follow guidelines for oils with high flammable gas content.

TJ|H2b Analytical Services Canada, Inc.
Bay #1, 2835 - 19th Street NE
Calgary, Alberta T2E 7A2

(403) 282-8542 Report Version 1.1.1.1 Page 1 of 2

TJ | H2b ANALYTICAL SERVICES INCORPORATED

Tapchanger Activity Signature Analysis TASA™

Sam Losinski
Newfoundland Power
P.O. Box 8910
55 Kenmount Road
St. John's, NF A1B 3P6

Location :	LAURENTIAN	Date :	4/22/2025
Bank & Phase :	LAU-T1	Report Number :	5083745
Serial Number :	W-64566-LTC	Purchase Order Number:	
Ventilation :	Sealed Tank	Manufacturer :	FPE
Compartment :	Common	Model :	TC 23-3

Approved by:

Michelle Kutzleb, PhD
Vice President of Operations

TJ | H 2 b
ANALYTICAL SERVICES INCORPORATED

Tapchanger Activity Signature Analysis TASA ™

Sam Losinski	Location :	LAURENTIAN	Date :	12-16-2025
Newfoundland Power	Bank & Phase :	LAU-T1	Report Number :	5085364
P.O. Box 8910	Serial Number :	W-64566-LTC	Purchase Order Number:	
55 Kenmount Road	Ventilation :	Sealed Tank	Manufacturer :	FPE
St. John's, NF A1B 3P6	Compartment :	Common	Model :	TC 23-3

		Sample Date :	11/25/2025	3/28/2025	10/8/2024	5/8/2024	11/23/2023
		Laboratory No. :	5085364	5083745	5083063	5081818	5081383
		Container No. :	57733	56856	55248	55261	53390
		Temperature :		23	40	10	6
H2	Hydrogen	(ppm) :	158	12589	9607	8026	6283
CH4	Methane	(ppm) :	12	2704	2720	2468	2362
C2H6	Ethane	(ppm) :	0	540	197	74	362
C2H4	Ethylene	(ppm) :	17	6478	6281	5873	5474
C2H2	Acetylene	(ppm) :	142	22097	22287	20217	15629
CO	Carbon monoxide	(ppm) :	18	633	567	550	518
CO2	Carbon dioxide	(ppm) :	504	5599	5655	5400	5276
N2	Nitrogen	(ppm) :	90860	68137	67189	70898	66514
O2	Oxygen	(ppm) :	37011	4511	10074	8865	13767
		Total (ppm) :	128722	123288	124577	122371	116185
		TDCG (ppm) :	347	45041	41659	37208	30628
		SHL (%) :	4.03	3.89	3.86	3.85	3.87
		ETCG (% in blanket) :	0.27	26.06	21.32	18.08	15.22
Particles		5 to 15 um :	23807	242621	223897	227067	200095
Particles		15 to 25 um :	133	383	698	630	326
Particles		25 to 50 um :	28	30	109	87	71
Particles		50 to 100 um :	0	1	1	6	2
Particles		> 100 um :	0	0	0	0	0
D1533	Moisture	(ppm) :	18	29	29	29	18
D1816	Dielectric BV	(kV) :	32	27	31	28	35
D974	Acid Number	(mg KOH/g) :	<0.02	<0.02	0.02	<0.02	0.02
D971	Interfacial Tension	(dynes/cm) :	49.2	35.0	39.8	36.2	30.7
D1500	Color Number	:	<0.5	4.5	5.0	>5.0	<3.5

Tapchanger Activity Signature Analysis Diagnostic Evaluation

TASA Assessment :	1 ID: 200298 Sampler: Terry Anstey Counter: N/A	3 ID: 200298 Sampler: Terry Anstey Counter: 34995	3 ID: 200298 Sampler: Terry Anstey Counter: 33764	3 ID: 200298 Sampler: Terry Anstey Counter: 32773	2 ID: 200298 Sampler: Terry Anstey

Sampling Interval : Recommend retest in one year or after specified number of operations if sooner.
Operating Procedure : LTC is operating satisfactorily. No special actions are recommended.
Comments : No abnormal dissipation of energy is indicated.

TJ | H2b ANALYTICAL SERVICES INCORPORATED

Tapchanger Activity Signature Analysis TASA ™

Sam Losinski	Location :	LAURENTIAN	Date :	12-16-2025
Newfoundland Power	Bank & Phase :	LAU-T1	Report Number :	5085364
P.O. Box 8910	Serial Number :	W-64566-LTC	Purchase Order Number:	
55 Kenmount Road	Ventilation :	Sealed Tank	Manufacturer :	FPE
St. John's, NF A1B 3P6	Compartment :	Common	Model :	TC 23-3

TJ|H2b Analytical Services issues reports in a simplified manner; not all ASTM and ISO/IEC 17025 requirements are addressed in this report; however, all required information is retained and available upon request. TJ|H2b does not perform sampling services and provides results for tests performed on samples as received; it is recommended that samples are collected according to ASTM D923 or equivalent. TJ|H2b assumes no responsibility for the quality or condition of the samples it receives or for the accuracy of any information provided with those samples. Test reports shall not be reproduced, except in full, without prior written consent of TJ|H2b.

Approved by: [signature]
Michelle Kutzleb, PhD
Vice President of Operations

Attachment B:

Transformer Maintenance History – Power Transformer LAU-T1

Transformer Maintenance History Power Transformer LAU-T1		
Year	Maintenance Level/Scope	Summary of Work Completed
2004	M4 – Transformer & Tapchanger maintenance	Completed transformer electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing); performed tapchanger maintenance including replacement of diverter arcing tips, oil replacement, installation and wiring of new pressure relief device, silica gel servicing, and calibration checks
2005	M3 – Protection devices	Inspected and completed insulation resistance testing on transformer protection devices; improved conduit sealing and weatherproofing; corrected control cabinet conduit entries
2006	M3 – Protection devices	Completed insulation resistance testing on transformer protection devices; updated drawings
2010	M4 – Transformer & Tapchanger maintenance	Completed major OLTC overhaul including replacement of collector rings, moving contacts on all phases, and transfer/arcing contacts; replaced tapchanger oil and filtered system; calibrated oil and winding temperature gauges; replaced silica gel system; Completed transformer electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing); painted transformer
2012	M5 – Alarm investigation / instrumentation	Investigated transformer general alarm; identified winding temperature gauge contact issue; disconnected and tagged alarm point pending further investigation
2013	M3 – Protection devices	Replaced winding temperature gauge; verified fan start, alarm, and trip settings
2015	Corrective / Forced outage	Replaced failed HV and LV bushing following animal contact fault; replaced gaskets; lowered oil; completed electrical testing; Rust inhibitor applied to tank.
2016	M3 – Protection devices	Inspected and completed insulation resistance testing on protection and alarm devices; identified degraded gas detector, temperature, and oil level instrumentation

Transformer Maintenance History Power Transformer LAU-T1 (continued)		
Year	Maintenance Level/Scope	Summary of Work Completed
2017	M4 – Transformer maintenance	Extensive mechanical, oil system, protection, and control upgrades including replacement of gas detector, oil and winding temperature gauges, oil level gauge, PRD, conservator piping and bolts, silica gel system; removed ladder due to corrosion; painted unit; Completed transformer electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing)
2017	M4 – Tapchanger maintenance	Disassembled OLTC; replaced collector contacts and arcing tips due to coking; cleaned rings and buses; filtered oil;
2017	M5 – Cooling system	Installed four new cooling fans and associated conductors
2018	M5 – Protection	Replaced gas detector relay; tested trip and alarm operation
2020	M5 – Instrumentation	Replaced conservator oil level gauge; verified alarm and trip contacts
2025	M4 – Transformer maintenance	Completed transformer electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing); replaced gas detector, steel box installed to contain valve leak, painted transformer,
2025	M4 – Tapchanger maintenance	Replaced diverter contacts on all phases replaced oil and PRD; confirmed acceptable ratio and mechanical performance

APPENDIX B:

LBK-T1 Power Transformer Replacement

TABLE OF CONTENTS

Page

1.0 LOOKOUT BROOK SUBSTATION POWER TRANSFORMER REPLACEMENT

1.1 Background

Lookout Brook Substation

Lookout Brook ("LBK") Substation was constructed in 1966 as a generation substation for the Lookout Brook Hydro Plant (the "Plant"). The Plant's 3 MVA generator G3 and 2.889 MVA generator G4 supply the LBK Substation. A 7.5 MVA generation power transformer, LBK-T1, interconnects the generating plant to Newfoundland Power's 66kV Transmission Line 403L to Robinsons ("ROB") Substation.

LBK-T1 Power Transformer

LBK-T1 is a 64-year-old, 7.5 MVA 66/33-2.4kV power transformer manufactured by English Electric. This transformer was installed in LBK Substation in 1997 after being relocated from Grand Falls Substation.

LBK-T1 is deteriorating and an assessment of alternatives determined that it should be replaced.

Figure B-1 shows power transformer LBK-T1.

Figure B-1: Power Transformer LBK-T1.

Newfoundland Power is proposing a capital project to replace power transformer LBK-T1 over three years commencing in 2027 at an estimated cost of $2,334,000.

2.0 ENGINEERING ASSESSMENT

Oil Analysis and Electrical Testing

Power transformer LBK-T1 undergoes regular maintenance and routine oil sampling in accordance with Newfoundland Power's maintenance program. The transformer has undergone annual oil sampling since at least 2002. The transformer last had full maintenance in August 2009.

In November 2025, oil samples were taken from LBK-T1 as part of routine testing. The Transformer Condition Assessments™ ("TCA") completed by TJ|H2b Analytic Services Incorporated ("TJ|H2b"), produced a Code 3 assessment in which arcing was indicated.[1] This is a sign 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 LBK-T1 based on information received as of December 31, 2025 is shown in Figure B-2 below.

Company:	NP	**Region:**	Stephenville
Station:	LBK	**Designation:**	T1
Equipment ID:	200112	**Serial Number:**	22P14598
Manufacturer:	English Electric	**Manufacture Date:**	3/1/1962
Energize Date:		**Repair Date:**	
Retire Date:		**Voltage Rating:**	66/2.4
Top MVA:	10	**Cooling Type:**	ONAF
Number of Phases:	3	**Core Type:**	Core
Is Autotransformer:	False	**Failure Consequence Index:**	0.30

PTX Result Summary

Normal Degradation Index:	0.29	**Oil Quality Index:**	0.00
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 B-2: EPRI LBK-T1 Summary

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1 See Attachment A. TJ| /H2b's Condition Assessment Diagnostic Evaluation ranges from Code 1 to a Code 4*. The code evaluation system is a measure of a transformer's health with Code 1 representing a transformer in a state of good health, while a rise in coding values signifies a progressive deterioration in the transformer's health.

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, during which the paper insulation is subject to 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 B-2, the Normal Degradation Index of LBK-T1 does not exceed the 0.60 threshold, but has exceeded the 0.25 threshold, prompting further scrutiny.

Physical Condition Assessment

The Company's power transformers are inspected annually to record any exterior physical defects that need to be addressed.

Previously repaired radiators on LBK-T1 exhibit signs of advanced corrosion and require replacement. The existing radiators are non-standard in design, requiring custom fabrication to accommodate spatial constraints. In addition, the radiators are welded directly to the main tank and are not equipped with isolation valves, which significantly increases replacement complexity. The replacement of the radiators would require an outage to the unit and controlled oil drawdown, followed by cutting and removal of the existing radiators, installation and welding of replacement radiators, and associated inspection and recoating of disturbed surfaces. The unit would require refilling and oil processing to restore dielectric integrity.

The deteriorated condition of the radiators from 2021 and 2023 inspections is shown in Figure B-3.

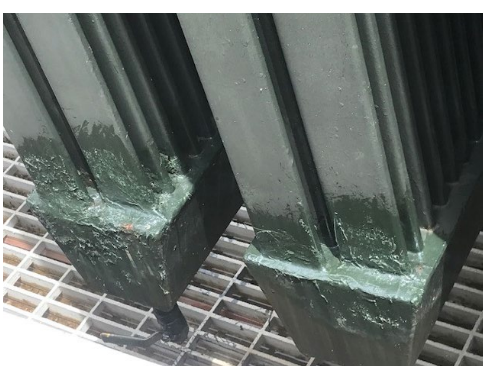

Figure B-3: 2021 radiator repair and 2023 Inspection on radiators

There is corrosion on the main tank and evidence of oil leakage at a bushing base. Remediation of corroded areas would require surface preparation involving chipping, scraping and recoating of impacted surfaces. Removal of protective coatings and base material during this process results in reduction of the remaining wall thickness, which increases the potential for future leaks. The presence of oil leakage further indicates deterioration of the sealing system and is contributing to accelerated coating breakdown.

Finally, there is mechanical damage on the high and low voltage bushings, including chipping of porcelain sheds. The damage reduces creepage distance and can compromise external insulation performance, particularly under contaminated or wet conditions. The degraded surfaces also promote the accumulation of moisture and contaminants, which increases the likelihood of surface tracking.

The corroded condition of the transformer tank and the porcelain insulator damage from a 2025 inspection are shown in Figure B-4.

Figure B-4: 2025 Inspection on top of transformer tank

Attachment B provides previously completed corrective maintenance of LBK-T1.

Site Condition

The existing transformer spill containment consists of a spill pan that is not large enough to accommodate the physical size of the new transformer. Replacement of LBK-T1 will include upgrading the spill containment to the current standard spill containment foundation to mitigate the risk of environmental damage in the event of an oil spill from the unit.[2]

The existing fused protection at LBK provides acceptable protection for this type of power transformer.

3.0 RISK ASSESSMENT

The *LBK-T1 Power Transformer Replacement* project will mitigate risks to the supply of approximately 5.889 MVA of generation from the Lookout Brook Hydro Plant.

In the case of a LBK-T1 failure, the Plant would be unable to supply any generation to the electrical system. This will decrease the supply of on-island generation by approximately 5.889 MVA during system peak.

Newfoundland Power has one portable substation that can be used for an emergency response to an in-service failure of LBK-T1. There are no spare power transformers that can be used. Failure of LBK-T1 would result in an unplanned, long-term installation of a portable substation to keep the Plant operational until a replacement could be procured. Current power transformer delivery times are estimated to be between 24 and 36 months.

Overall, an increased probability of power transformer failure due to the transformer's condition, 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 could also leave 5.889 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.[3] Additionally, extended transformer delivery times could further exacerbate these risks.

Based on this assessment, LBK-T1 should be replaced.

4.0 ASSESSMENT OF ALTERNATIVES

Newfoundland Power identified and assessed three alternatives to address the deteriorating condition of LBK-T1 power transformer. These are: (i) Condition Based Monitoring; (ii) Remove and Repair; or (iii) Replace Power Transformer. These alternatives are discussed below.

---

2 Power transformer LBK-T1 contains approximately 5,900 liters of oil.

3 With power transformer delivery times upwards of 36 months, it is estimated that a failure of LBK-T1 with no long-term portable substation availability could lead to additional energy and capacity costs. Based on the normal hydroelectric generation of the Lookout Brook Plant and the historical average seasonality of generation output, a 36-month Plant outage is predicted to result in approximately $9,500,000 in replacement energy and capacity costs. This estimate is based on the current marginal price of both energy and capacity.

(i) Alternative 1 – Condition Based Monitoring

This alternative would involve deferring the replacement of LBK-T1 and continuing to monitor its condition.

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 is one portable substation that can be installed as a short-term emergency response to offload LBK-T1. However, there are no spare transformers available that can then be installed for the long-term replacement of LBK-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 such as LBK-T1. This approach would significantly increase the risk to the supply of 5.889 MVA of electricity to the electrical system. Deferral of the *LBK-T1 Power Transformer Replacement* project would increase the risk that LBK-T1 will fail in service.

(ii) Alternative 2 – Remove and Repair

This alternative would involve removing LBK-T1 from service, refurbishing the unit, and placing it back in service.

Under a typical repair or refurbishment approach, the original power transformer tank is not replaced and would be reinstalled after refurbishment. 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.

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 LBK-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 repair of the 64-year-old LBK-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 5.889 MVA of generation. This would put additional pressure on the Company’s limited emergency response capabilities and the electrical system during peak load conditions. Furthermore, due to the age of LBK-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.

(iii) Alternative 3 – Replace Power Transformer

This alternative would involve replacing LAU-T1 with a new unit.

The deteriorated condition of the power transformer justifies replacing it over three years beginning in 2027. The unit shows signs of physical deterioration and the TCA from oil samples has indicated that there is arcing inside the unit.

The planned replacement of LBK-T1 will manage the risk to an acceptable level by replacing the deteriorated transformer with a newer, more reliable transformer.[4] Strategically replacing the power transformer in a planned manner avoids the additional cost and outages associated with unforeseen failures.[5] This will ensure the continued delivery of safe, reliable, low-cost generation to the electrical system.

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.

5.0 LIFECYCLE COST ANALYSIS

The LBK Substation serves the Plant by stepping the 2.4 kV plant generation voltage up to the 66 kV transmission voltage. Newfoundland Power’s hydro plants provide economic benefit for customers. Any capital investments related to the operation of these plants must be analyzed to ensure they remain economically in the best interest of customers. In the case of LBK Substation, the replacement of the generation power transformer LBK-T1 ensures that low-cost generation from the Plant continues to be available to displace more expensive purchase power costs. If the Plant was decommissioned and removed, this equipment would no longer be required.

---

4 After the transformer has been replaced, it will be scrapped due to overall condition.

5 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 labour 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.

A lifecycle cost analysis of the Plant including the necessary capital investment required for equipment in LBK Substation related to the Plant was completed as part of the *2024 Capital Budget Application*.[6] At that time, an estimate of $2,879,000 was forecasted for substation work in 2032.

As a result of the advancement of substation work to begin in 2027 due to the condition of the power transformer, Newfoundland Power revisited the lifecycle analysis completed in the *2024 Capital Budget Application*. The forecasted cost of the *Lookout Brook Power Transformer Replacement* project is now forecasted to be $2,334,000 over three years, commencing in 2027. The updated lifecycle cost analysis to account for the advancement of substation capital investment determined that it remains economically prudent to complete the work.

6.0 PROJECT SCOPE AND COSTS

This project involves purchasing a new 5/6.7/8.3 MVA, 66-2.4 kV power transformer to replace LBK-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 2027 and 2028, followed by delivery, installation, testing and commissioning in 2029.

Table B-1 below provides a cost breakdown of the *LBK-T1 Power Transformer Replacement* project.

Table B-1
LBK-T1 Power Transformer Replacement Project
Project Cost
($000s)

Cost Category	2027	2028	2029	Total
Material	-	-	2,025	2,025
Labour - Internal	-	-	5	5
Labour - Contract	-	-	-	-
Engineering	68	36	107	211
Other	5	50	38	93
Total	$73	$86	$2,175	$2,334

The project to replace LBK-T1 is estimated to cost $73,000 in 2027, $86,000 in 2028, and $2,175,000 in 2029 for a total project cost of $2,334,000.

6 See report *4.1 Lookout Brook Hydro Plant Refurbishment* filed as part of Newfoundland Power's *2024 Capital Budget Application*.

Attachment A:

TJ|H2b Transformer Condition Assessment History – Power Transformer LBK-T1

TJ | H2b ANALYTICAL SERVICES INCORPORATED

Transformer Condition Assessment ™

Date :	01-26-2026
Location :	LOOKOUT BROOK
Report Number :	5085323
Bank & Phase :	LBK-T1
Fluid volume :	1550 G
Serial Number :	22P14598
Fluid type :	Mineral Oil
Manufacturer :	ENG
Preservation :	Conservator
Date Mfgd :	1962
Cooling :	ONS/ONP
Size (kVA) :	10000
Core & coil wt. :	26700
Rating kV :	33
Impedance :	

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		Sample Date :	11/17/2025	4/23/2025	10/22/2024	4/12/2024	4/11/2024
		Laboratory No. :	5085323	5083825	5083177	5081822	5081750
		Container No. :	58740	57189	55222	55240	55215
		Temperature :	24	32	0	35	
H2	Hydrogen	(ppm) :	5	14	8	5	5
CH4	Methane	(ppm) :	3	3	3	2	2
C2H6	Ethane	(ppm) :	0	1	1	0	1
C2H4	Ethylene	(ppm) :	36	46	46	46	48
C2H2	Acetylene	(ppm) :	4	0	0	0	0
CO	Carbon monoxide	(ppm) :	265	409	288	284	324
CO2	Carbon dioxide	(ppm) :	2131	2455	2200	2428	2631
N2	Nitrogen	(ppm) :	72362	74511	72534	73102	74699
O2	Oxygen	(ppm) :	27459	3984	23606	21057	14019
		Total (ppm) :	102265	81423	98686	96924	91729
		TDCG (ppm) :	313	473	346	337	380
		SHL (%) :	11.06	10.54	10.70	11.14	11.26
		ETCG (% in blanket) :	0.23	0.42	0.26	0.26	0.30
Particles		5 to 15 um :	3865	1610	15698	2807	3005
Particles		15 to 25 um :	137	45	509	81	61
Particles		25 to 50 um :	18	0	66	14	11
Particles		50 to 100 um :	2	0	1	3	0
Particles		> 100 um :	0	0	0	0	0
D1533	Moisture	(ppm) :	12	15	11	14	10
D1816	Dielectric BV	(kV) :	34	42	33	30	28
D974	Acid Number	(mg KOH/g) :	0.07	0.06	0.07	0.06	0.07
D971	Interfacial Tension	(dynes/cm) :	30.1	33.4	33.6	30.3	29.8
D1500	Color Number	:	<2.0	<2.0	<2.0	<2.0	<2.0
D924	Power Factor	:	0.036	0.051	0.021	0.019	0.023
D2668	Oxidation Inhibitor	(%) :	0.173	0.267	0.231	0.237	0.231
5 HMF	5 hydroxymethyl-2-furaldehyde	(ppm) :	<0.010	<0.010	<0.010	<0.010	<0.010
2 FAL	2 furaldehyde	(ppm) :	0.037	0.037	0.039	0.033	0.038
2 ACF	2 acetylfuran	(ppm) :	<0.010	<0.010	<0.010	<0.010	<0.010
5 MEF	5 methyl-2-furaldehyde	(ppm) :	<0.010	<0.010	<0.010	<0.010	<0.010
2 FOL	2 furfurol	(ppm) :	<0.010	<0.010	<0.010	<0.010	<0.010
	Estimated DP	:	841	840	835	856	838

Transformer Condition Assessment Diagnostic Evaluation

TCA Assessment :	3 ID: 200112 Sampler: Alex Marche	1 ID: 200112 Sampler: Alex Marche	1 ID: 200112 Sampler: Alex Marche	1 ID: 200112 Sampler: Alex Marche	1 ID: 200112 Sampler: N/A

Sampling Interval : Retest in three months.

Operating Procedure : Continue normal operation.

Comments : Arcing is indicated. Paper condition is normal.

Field Comments : Fluid condition is within acceptable in-service parameters.

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Calgary, Alberta T2E 7A2
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TJ | H2b ANALYTICAL SERVICES INCORPORATED

Transformer Condition Assessment ™

		Date :	01-26-2026
Location :	LOOKOUT BROOK	Report Number :	5085323
Bank & Phase :	LBK-T1	Fluid volume :	1550 G
Serial Number :	22P14598	Fluid type :	Mineral Oil
Manufacturer :	ENG	Preservation :	Conservator
Date Mfgd :	1962	Cooling :	ONS/ONP
Size (kVA) :	10000	Core & coil wt. :	26700
Rating kV :	33	Impedance :	

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TJ|H2b Analytical Services issues reports in a simplified manner; not all ASTM and ISO/IEC 17025 requirements are addressed in this report; however, all required information is retained and available upon request. TJ|H2b does not perform sampling services and provides results for tests performed on samples as received; it is recommended that samples are collected according to ASTM D923 or equivalent. TJ|H2b assumes no responsibility for the quality or condition of the samples it receives or for the accuracy of any information provided with those samples. Test reports shall not be reproduced, except in full, without prior written consent of TJ|H2b.

Approved by: [signature]
Michelle Kutzleb, PhD
Vice President of Operations

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Attachment B:

Transformer Maintenance History –
Power Transformer LBK-T1

Transformer Maintenance History Power Transformer LBK-T1		
Year	Maintenance Level/Scope	Summary of Work Completed
1996	M4 – Transformer maintenance	Transformer untanked in shop; windings reconfigured from 66/33–4.16/2.4 kV to 66/3.3–2.4 kV; unit vacuum dried (dew point -32 °C), vacuum oil filled; bushings installed; Completed transformer electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing)
2009	M5 – Breather / moisture control	Installed new transformer breather kit with silica gel container and water guard due to frequent heating and cooling cycles
2009	M5 – Instrumentation	Replaced main oil level gauge with new unit equipped with two contacts

APPENDIX C:

HAR-T1 Power Transformer Replacement

TABLE OF CONTENTS

Page

1.0 HARMON SUBSTATION POWER TRANSFORMER REPLACEMENT

1.1 Background

Harmon Substation

Harmon ("HAR") Substation was constructed in 1968 as both a distribution and transmission substation. This substation is supplied by Newfoundland Power 66kV Transmission Lines 405L from Stephenville Gas Turbine ("STV") Substation and 406L from Gallants ("GAL") Substation. One 11.125 MVA distribution power transformer, HAR-T1, supplies two 12.5kV distribution feeders, serving approximately 1,400 customers in the Town of Stephenville.

HAR-T1 Power Transformer

HAR-T1 is a 57-year-old, 11.125 MVA, 66-12.5kV power transformer manufactured by General Electric. This transformer has remained at HAR Substation since its original installation in 1969.

HAR-T1 is deteriorating and an assessment of alternatives determined that it should be replaced.

Figure C-1 shows power transformer HAR-T1.

Figure C-1: Power Transformer HAR-T1.

Newfoundland Power is proposing a capital project to replace HAR-T1 over three years commencing in 2027 at an estimated cost of $2,904,000.

2.0 ENGINEERING ASSESSMENT

Oil Analysis and Electrical Testing

Power transformer HAR-T1 undergoes regular maintenance and routine oil sampling in accordance with Newfoundland Power's maintenance program. The transformer has undergone annual oil sampling since at least 2003. The transformer last had full maintenance in September 2010.

In November 2025, oil samples were taken from HAR-T1 as part of routine testing. The Transformer Condition Assessments™ ("TCA") completed by TJ|H2b Analytic Services Incorporated ("TJ|H2b") produced a Code 2 assessment score in which heating is indicated.[1] This is a sign 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 HAR-T1 based on information received as of December 31, 2025 is shown in Figure C-2 below.

Company:	NP	**Region:**	Stephenville
Station:	HAR	**Designation:**	T1
Equipment ID:	200208	**Serial Number:**	287279
Manufacturer:	General Electric	**Manufacture Date:**	3/1/1969
Energize Date:		**Repair Date:**	
Retire Date:		**Voltage Rating:**	66/12.5
Top MVA:	14.9	**Cooling Type:**	ONAF
Number of Phases:	3	**Core Type:**	Core
Is Autotransformer:	False	**Failure Consequence Index:**	0.58

PTX Result Summary

Normal Degradation Index:	0.65	**Oil Quality Index:**	0.30
Abnormal Thermal Index:	0.32	**Bushing Index:**	0.00
Abnormal Electrical Index:	0.00	**LTC Index:**	
Abnormal Core Index:	0.00	**Throughfault Failure Index:**	

Diagnosis Summary:

Figure C-2: EPRI HAR-T1 Summary.

[1] See Attachment A. TJ| /H2b's Condition Assessment Diagnostic Evaluation ranges from Code 1 to a Code 4*. The code evaluation system is a measure of a transformer's health with Code 1 representing a transformer in a state of good health, while a rise in coding values signifies a progressive deterioration in the transformer's health.

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, during which the paper insulation is subject to 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 C-2, the Normal degradation Index of HAR-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. Recent inspections of HAR-T1 do not indicate signs of corrosion.

See Attachment B for previously completed corrective maintenance of HAR-T1.

Site Condition

The current spill containment for the transformer is a spill pan. Replacement of HAR-T1 will include upgrading the spill containment to the current standard spill containment foundation to protect against environmental damage in the event of an oil spill from the unit.[2]

The existing fused protection at HAR will be upgraded in 2028 and 2029 as part of a planned refurbishment and modernization project as shown in the Five-Year Capital Plan.[3] The refurbishment and modernization project is associated with other deteriorating assets in HAR Substation and is planned to coordinate with the timing of the HAR-T1 power transformer replacement.

3.0 RISK ASSESSMENT

The *HAR-T1 Power Transformer Replacement* project will mitigate risks to the delivery of reliable service to approximately 1,400 customers in the Stephenville area.

In the case of a HAR-T1 failure, offloading capabilities can partially supply the existing peak load of HAR Substation. System load forecasts indicate that 6.28 MVA would be exposed to an outage in the event of a failure of HAR-T1.[4] A portable substation or a spare transformer would need to be installed in the event of a HAR-T1 failure.

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2 Power transformer HAR-T1 contains approximately 8,300 liters of oil.
3 See report *2.1 2027 Substation Refurbishment and Modernization,* Table 1.
4 A maximum peak load of 15.9 MVA is being forecasted over the next ten years at HAR Substation.

Newfoundland Power has three portable substations and two spare power transformer that can be used for emergency response to an in-service failure of HAR-T1. Failure of HAR-T1 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.[5] Current 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, HAR-T1 should be replaced.

4.0 ASSESSMENT OF ALTERNATIVES

Newfoundland Power identified and assessed three alternatives to address the deteriorating condition of HAR-T1 power transformer. These are: (i) Condition Based Monitoring; (ii) Remove and Repair; or (iii) Replace Power Transformer. These alternatives are discussed below.

(i) Alternative 1 – Condition Based Monitoring

This alternative would involve deferring the replacement of HAR-T1 and continuing to monitor its condition.

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 HAR-T1. Following offload, there are two spare power transformers available that can then be installed for the medium-term replacement of HAR-T1.[6] If the remaining spare power transformer, 200385, with a capacity of 25 MVA were utilized, there would be limited resources available to respond to future 25 MVA power transformer failures in the short- to medium-term since power transformer delivery times can range from 24 to 36 months.

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 HAR-T1. This approach would significantly increase risks to the delivery of safe and reliable service to

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5 Spare transformers 200220 or 200385 are suitable medium-term replacement for HAR-T1. 200220 is a 13.3 MVA, 56-year-old transformer with a de-energized tap changer presently installed at SLA. 200385 is a 2-year-old, 25MVA transformer with an on-load tap changer. 200220 is backup for 4.16 kV distribution systems and, as such, is not a suitable long-term replacement of HAR-T1.

6 *Ibid*.

approximately 1,400 customers in the Stephenville area. Deferral of the *HAR-T1 Power Transformer Replacement* project would increase the risk that HAR-T1 will fail in service.

(ii) Alternative 2 – Remove and Repair

This alternative would involve removing HAR-T1 from service, refurbishing the unit, and placing it back in service.

Under a typical repair or refurbishment approach, 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.

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 HAR-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 or spare transformer. This would put additional pressure on the Company's portable substation and spare transformer fleet creating an unacceptable risk to customers.

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 power transformers.

The repair of the 57-year-old HAR-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, requiring long-term installation of a portable substation. This would put additional pressure on the Company's limited emergency response capabilities and the electrical system during peak load conditions at the substation. Furthermore, due to the age of HAR-T1, shipment of the unit to a repair facility introduces the risk of 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 Power Transformer

This alternative would involve replacing HAR-T1 with a new unit.

The deteriorated condition of the power transformer justifies replacing over three years beginning in 2027. The TCA from oil samples has demonstrated the deterioration of the unit. 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 HAR-T1 will manage the risk to an acceptable level by replacing the deteriorated power transformer with a newer, more reliable power transformer.[7] Strategically replacing the power transformer in a planned manner avoids the additional cost and outages associated with unforeseen failures.[8] This will ensure the continued delivery of safe and reliable service to customers served by HAR Substation.

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.

5.0 PROJECT COST AND SCOPE

This project involves purchasing a new 15/20/25 MVA, 66-12.5/25 kV power transformer to replace HAR-T1 while the existing unit remains in service.[9] 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 2027 and 2028, followed by delivery, installation, testing and commissioning in 2029.

Table C-3 below provides a cost breakdown of the *HAR-T1 Power Transformer Replacement* project.

Table C-3
HAR-T1 Power Transformer Replacement Project
Project Cost
($000s)

Cost Category	2027	2028	2029	Total
Material	-	1	2,468	2,469
Labour - Internal	-	-	108	108
Labour - Contract	-	-	-	-
Engineering	69	39	115	223
Other	6	31	67	104
Total	$75	$71	$2,758	$2,904

The project to replace HAR-T1 is estimated to cost $75,000 in 2027, $71,000 in 2028 and $2,758,000 in 2029 for a total project cost of $2,904,000.

7 After the transformer has been replaced, it will be scrapped due to overall condition.
8 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 labour 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.
9 A larger power transformer was selected based on the maximum peak load forecast of 15.9 MVA forecasted over the next ten years.

Attachment A:

TJ|H2b Transformer Condition Assessment History – Power Transformer HAR-T1

TJ | H2b ANALYTICAL SERVICES INCORPORATED

Transformer Condition Assessment ™

		Date :	01-26-2026
Location :	Harmon Sub	Report Number :	5085260
Bank & Phase :	HAR-T1	Fluid volume :	1830 G
Serial Number :	287279	Fluid type :	Mineral Oil
Manufacturer :	GE	Preservation :	Conservator
Date Mfgd :	1969	Cooling :	ONAN
Size (kVA) :	11200	Core & coil wt. :	31110
Rating kV :	66	Impedance :	

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		Sample Date :	11/3/2025	4/23/2025	10/22/2024	4/11/2024	10/26/2023
		Laboratory No. :	5085260	5083824	5083176	5081749	5081194
		Container No. :	58736	57249	55239	55225	53402
		Temperature :	31	30	32	30	33
H2	Hydrogen	(ppm) :	6	16	14	16	6
CH4	Methane	(ppm) :	8	11	9	8	5
C2H6	Ethane	(ppm) :	1	2	1	1	1
C2H4	Ethylene	(ppm) :	92	83	74	70	61
C2H2	Acetylene	(ppm) :	0	0	0	0	0
CO	Carbon monoxide	(ppm) :	607	741	599	659	402
CO2	Carbon dioxide	(ppm) :	3521	3395	2951	3047	2516
N2	Nitrogen	(ppm) :	81301	88133	81948	89240	80899
O2	Oxygen	(ppm) :	22836	4054	19186	6872	26933
		Total (ppm) :	108372	96435	104782	99913	110823
		TDCG (ppm) :	714	853	697	754	475
		SHL (%) :	11.50	11.03	10.93	10.94	11.26
		ETCG (% in blanket) :	0.49	0.63	0.50	0.55	0.32
Particles		5 to 15 um :	6080	3643	13461	9797	25652
Particles		15 to 25 um :	185	163	310	260	521
Particles		25 to 50 um :	27	24	74	48	100
Particles		50 to 100 um :	0	1	1	1	3
Particles		> 100 um :	0	0	0	0	0
D1533	Moisture	(ppm) :	18	19	13	13	6
D1816	Dielectric BV	(kV) :	36	44	38	36	37
D974	Acid Number	(mg KOH/g) :	0.02	<0.02	0.02	0.02	<0.02
D971	Interfacial Tension	(dynes/cm) :	33.7	35.8	32.6	29.5	32.9
D1500	Color Number	:	1.5	1.5	1.5	1.5	1.5
D924	Power Factor	:	0.104	0.299	0.136	0.193	0.203
D2668	Oxidation Inhibitor	(%) :	<0.010	<0.010	<0.010	<0.010	<0.010
5 HMF	5 hydroxymethyl-2-furaldehyde	(ppm) :	<0.010	<0.010	<0.010	<0.010	<0.010
2 FAL	2 furaldehyde	(ppm) :	<0.010	<0.010	<0.010	<0.010	<0.010
2 ACF	2 acetylfuran	(ppm) :	<0.010	<0.010	<0.010	<0.010	<0.010
5 MEF	5 methyl-2-furaldehyde	(ppm) :	<0.010	<0.010	<0.010	<0.010	<0.010
2 FOL	2 furfurol	(ppm) :	<0.010	<0.010	<0.010	<0.010	<0.010
	Estimated DP	:	>1000	>1000	>1000	>1000	>1000

Transformer Condition Assessment Diagnostic Evaluation

TCA Assessment :	2 ID: 200208 Sampler: Alex Marche	1 ID: 200208 Sampler: Alex Marche	1 ID: 200208 Sampler: Alex Marche	1 ID: 200208 Sampler: Alex Marche	1 ID: 200208 Sampler: Alex Marche

Sampling Interval : Retest in six months.

Operating Procedure : Continue normal operation.

Comments : Heating is indicated. Paper condition is normal.

Field Comments : Fluid condition is within acceptable in-service parameters.

TJ | H 2 b
ANALYTICAL SERVICES INCORPORATED

Transformer Condition Assessment ™

		Date :	01-26-2026
Location :	Harmon Sub	Report Number :	5085260
Bank & Phase :	HAR-T1	Fluid volume :	1830 G
Serial Number :	287279	Fluid type :	Mineral Oil
Manufacturer :	GE	Preservation :	Conservator
Date Mfgd :	1969	Cooling :	ONAN
Size (kVA) :	11200	Core & coil wt. :	31110
Rating kV :	66	Impedance :	

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Approved by:

Michelle Kutzleb, PhD
Vice President of Operations

Attachment B:

Transformer Maintenance History – Power Transformer HAR-T1

Transformer Maintenance History Power Transformer HAR-T1		
Year	Maintenance Level/Scope	Summary of Work Completed
1996	M4 – Transformer maintenance	Radiators replaced due to seized and corroded valve stems; oil drained and transformer vacuum pulled; explosion vent replaced; valve stems lubricated and one valve stem replaced
2010	M3/M4 – Transformer maintenance	Transformer painted; completed insulation resistance testing on transformer protection devices; installed new gas detector gauge; installed new silica gel container and filter system; installed fall-arrest bracket; protection and insulation testing completed; Completed transformer electrical testing (Insulation Resistance testing, Power Factor testing)
2023	M3/M4 – Transformer maintenance	Completed insulation resistance testing on transformer protection devices; Installed new oil temperature gauge, winding temperature gauge, and oil level gauge; welded plate installed to stop oil leak; added four drums of new oil; installed petro filter and new silica gel; installed varmint guards and LV lead cover-ups; Completed transformer electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing); painted transformer

APPENDIX D:

RRD-T3 Power Transformer Replacement

TABLE OF CONTENTS

Page

1.0 RIDGE ROAD SUBSTATION POWER TRANSFORMER REPLACEMENT

1.1 Background

Ridge Road Substation

Ridge Road ("RRD") Substation was constructed in 1960 as both a distribution and transmission substation. This substation is supplied by Newfoundland Power 66kV Transmission Lines 30L from King's Bridge ("KBR") Substation, 32L from Oxen Pond ("OXP") Substation and 67L from OXP Substation. Two 20 MVA distribution power transformers, RRD-T2 and RRD-T3, supply eight 12.5kV distribution feeders, serving over 4,400 customers in the City of St. John's.

RRD-T3 Power Transformer

RRD-T3 is a 51-year-old, 20 MVA, 66-12.5 kV power transformer manufactured by Ferranti Packard. This transformer has remained at RRD since its original installation in 1977.

RRD-T3 is deteriorating and an assessment of alternatives determined that it should be replaced.

Figure D-1 shows power transformer RRD-T3.

Figure D-1: Power Transformer RRD-T3

Newfoundland Power is proposing a capital project to replace RRD-T3 over three years commencing in 2027 at an estimated cost of $2,695,000.

2.0 ENGINEERING ASSESSMENT

Oil Analysis and Electrical Testing

Power transformer RRD-T3 undergoes regular maintenance and routine oil sampling in accordance with Newfoundland Power's maintenance program. The transformer has undergone annual oil sampling since at least 2002. The power transformer last had full maintenance in November 2020.

In January 2025, oil samples were taken from RRD-T3 as part of routine testing. The Transformer Condition Assessments™ ("TCA") completed by TJ|H2b Analytic Services Incorporated ("TJ|H2b") indicated that the mechanical strength of paper for RRD-T3 is reduced to 70% tensile strength. The estimated degree of polymerization ("DP") is 661.[1] This information indicates that the paper insulation inside of the transformer is deteriorating.

While the transformer has not shown signs of internal arcing and high temperature heating, the TCAs completed on RRD-T3 have consistently indicated deterioration of the paper insulation. 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.

[1] 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.

A summary of the EPRI PTX results for RRD-T3 based on information received as of December 31, 2025 is shown in Figure D-2.

Company:	NP	**Region:**	St. John's
Station:	RRD	**Designation:**	T3
Equipment ID:	200272	**Serial Number:**	13908
Manufacturer:	Ferranti Packard	**Manufacture Date:**	3/1/1975
Energize Date:		**Repair Date:**	
Retire Date:		**Voltage Rating:**	66/12.5
Top MVA:	20	**Cooling Type:**	ONAF
Number of Phases:	3	**Core Type:**	Core
Is Autotransformer:	False	**Failure Consequence Index:**	0.76

PTX Result Summary

Normal Degradation Index:	0.57	**Oil Quality Index:**	0.39
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 D-2: EPRI RRD-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. Power transformers undergo normal aging or degradation due to operation of the power transformer under conditions that do not exceed the design criteria of the power 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 D-2, the Normal Degradation Index of RRD-T3 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 transformer has experienced leaks on the gas detector, current transformer ("CT") wiring block, radiator valves, and conservator tank piping.

Figures D-3 and D-4 show signs of physical deterioration on RRD-T3 from 2015 and 2023 inspections.

Figure D-3: 2015 Leak on top of tank

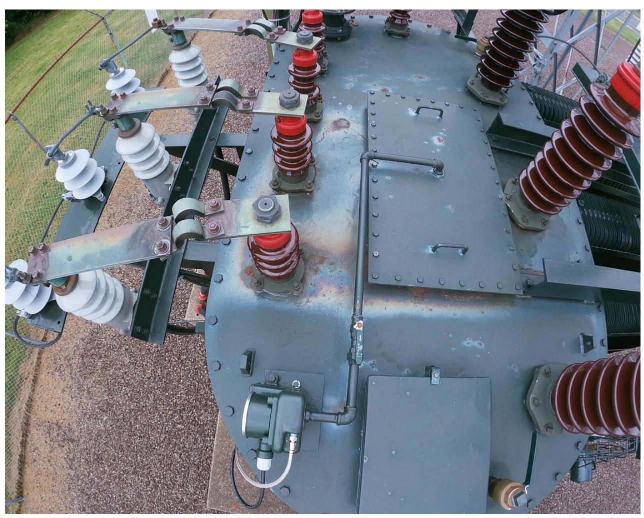

Figure D-4: 2023 Inspection on top of tank

See Attachment B for previously completed corrective maintenance of RRD-T3.

Site Condition

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.[2]

The existing circuit breakers and microprocessor-based digital relays at RRD provide acceptable protection and control for this type of power transformer. However, RRD substation is included in the Five-Year Capital Plan for a refurbishment and modernization project planned over two years beginning in 2028.[3] The refurbishment and modernization project is associated with replacing the deteriorated and obsolete switchgear and is planned to coordinate with the RRD-T3 power transformer replacement.

3.0 RISK ASSESSMENT

The *RRD-T3 Power Transformer Replacement* project will mitigate risks to the delivery of reliable service to over 4,400 customers in the St. John's area.

In the case of a RRD-T3 failure, RRD-T2 is unable to supply the existing peak load of RRD Substation. System load forecasts indicate that up to 15.26 MVA of RRD-T3 load can be transferred to either RRD-T4 or offloaded to adjacent feeders, while 3.1 MVA of load would be exposed to an outage.[4] A portable substation or a spare transformer would need to be installed in the event of a RRD-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 RRD-T3. Failure of RRD-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.[5] Current power transformer delivery times are estimated to be 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, power transformer RRD-T3 should be replaced.

---

2 Power transformer RRD-T3 contains approximately 9,500 liters of oil.
3 See report *2.1 2027 Substation Refurbishment and Modernization*, Table 1.
4 A maximum peak load of 34.7 MVA is being forecasted over the next five years at RRD Substation.
5 Spare transformer 200385 is a suitable medium-term replacement for RRD-T3. While it includes an on-load tap changer that is unnecessary for RRD-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 RRD Substation, a new spare transformer similar to transformer 200385 would need to be procured to maintain an adequate spare transformer inventory.

4.0 ASSESSMENT OF ALTERNATIVES

Newfoundland Power identified and assessed three alternatives to address the deteriorating condition of RRD-T3 power transformer. These are: (i) Condition Based Monitoring; (ii) Remove and Repair; or (iii) Replace Power Transformer. These alternatives are discussed below.

(i) Alternative 1 – Condition Based Monitoring

This alternative would involve deferring the replacement of RRD-T3 and continuing to monitor its condition.

Long delivery lead times of power transformers, limited emergency response capabilities, and the increased probability 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 RRD-T3. Following offload, there is one spare transformer available that can then be installed for the medium-term replacement of RRD-T3.[6] 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 such as RRD-T3. This approach would significantly increase risks to the delivery of safe and reliable service to over 4,400 customers in the St. John's area. Deferral of the *RRD-T3 Power Transformer Replacement* project would increase the risk that RRD-T3 will fail in service.

(ii) Alternative 2 – Remove and Repair

This alternative would involve removing RRD-T3 from service, refurbishing the unit, and placing it back in service.

Under a typical repair or refurbishment approach, 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.

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 RRD-T3 would require it to be removed from service for up to 18 to 24 months necessitating the long-term installation of a

6 *Ibid.*

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.

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 estimated cost to install a portable substation as well as to transport, assess, complete a three-phase rewind, test, and integrate the RRD-T3 transformer back into the system is approximately $2,900,000. This exceeds the cost to purchase and install a new transformer, with no guarantee of extended life compared to a new transformer.

The repair of the 51-year-old RRD-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 Power Transformer

This alternative would involve replacing RRD-T3 with a new unit.

The deteriorated condition of the power transformer justifies replacing it in 2027 to 2029. The TCA from oil samples has shown the deterioration of the Unit. 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 RRD-T3 will manage the risk to an acceptable level by replacing the deteriorated transformer with a newer, more reliable transformer.[7] Strategically replacing the power transformer in a planned manner avoids the additional cost and outages associated with unforeseen failures.[8] This will ensure the continued delivery of safe and reliable service to customers served by RRD Substation.

---

7 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.

8 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 labour 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.

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.

5.0 PROJECT COST AND SCOPE

This project involves purchasing a new 15/20/25 MVA, 66-12.5/25 kV power transformer to replace RRD-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 2027 and 2028, followed by delivery, installation, testing and commissioning in 2029.

Table D-1 below provides a cost breakdown of the *RRD-T3 Power Transformer Replacement* project.

Table D-1
RRD-T3 Power Transformer Replacement Project
Project Cost
($000s)

Cost Category	2027	2028	2029	Total
Material	-	-	2,404	2,404
Labour - Internal	-	-	5	5
Labour - Contract	-	-	-	-
Engineering	61	33	95	189
Other	5	31	61	97
Total	$66	$64	$2,565	$2,695

The project to replace RRD-T3 is estimated to cost $66,000 in 2027, $64,000 in 2028 and $2,565,000 in 2029 for a total project cost of $2,695,000.

Attachment A:

TJ|H2b Transformer Condition Assessment History – Power Transformer RRD-T3

TJ | H2b ANALYTICAL SERVICES INCORPORATED

Transformer Condition Assessment ™

		Date : 02-25-2025
	Location : RIDGE ROAD	Report Number : 5083547
	Bank & Phase : RRD-T3	Fluid volume : 9528 L
Sam Losinski	Serial Number : 13098	Fluid type : Mineral Oil
Newfoundland Power	Manufacturer : FPL	Preservation : Conservator
P.O. Box 8910	Date Mfgd : 1975	Cooling : ONAN/ONAF
55 Kenmount Road	Size (kVA) : 20000	Core & coil wt. : 30000
St. John's, NF A1B 3P6	Rating kV : 66	Impedance :

		Sample Date :	1/29/2025	11/10/2023	7/8/2020	6/10/2019	6/12/2018
		Laboratory No. :	5083547	5081282	5070957	5066660	5062999
		Container No. :	57222	54460	44900	41822	38494
		Temperature :	15	38	50	35	46
H2	Hydrogen	(ppm) :	12	6	11	5	5
CH4	Methane	(ppm) :	3	3	3	1	1
C2H6	Ethane	(ppm) :	1	1	0	0	0
C2H4	Ethylene	(ppm) :	36	37	24	18	18
C2H2	Acetylene	(ppm) :	0	0	0	0	0
CO	Carbon monoxide	(ppm) :	415	450	307	231	227
CO2	Carbon dioxide	(ppm) :	3172	3776	2576	2124	1738
N2	Nitrogen	(ppm) :	79576	73584	79946	78350	81033
O2	Oxygen	(ppm) :	28268	28136	32483	31415	29123
		Total (ppm) :	111483	105993	115350	112144	112145
		TDCG (ppm) :	467	497	345	255	251
		SHL (%) :	10.80	11.51	10.54	11.14	11.12
		ETCG (% in blanket) :	0.34	0.38	0.25	0.19	0.18
Particles		5 to 15 um :	1866	669	21610	26750	44500
Particles		15 to 25 um :	85	21	410	3850	6000
Particles		25 to 50 um :	17	2	290	950	1500
Particles		50 to 100 um :	1	0	40	100	150
Particles		> 100 um :	0	0	0	0	0
D1533	Moisture	(ppm) :	10	6	9	4	8
D1816	Dielectric BV	(kV) :	46	57	34	32	31
D974	Acid Number	(mg KOH/g) :	0.04	0.05	0.04	0.04	0.03
D971	Interfacial Tension	(dynes/cm) :	30.3	26.3	28.9	28.4	30.8
D1500	Color Number	:	2.5	2.5	<2.5	<2.5	<2.5
D924	Power Factor	:	0.084	0.089	0.005	0.147	0.088
D2668	Oxidation Inhibitor	(%) :	<0.010	<0.010	<0.010	<0.010	<0.010
5 HMF	5 hydroxymethyl-2-furaldehyde	(ppm) :	<0.010	<0.010	<0.010	<0.010	<0.010
2 FAL	2 furaldehyde	(ppm) :	0.157	0.122	0.126	0.136	0.092
2 ACF	2 acetylfuran	(ppm) :	<0.010	<0.010	<0.010	<0.010	<0.010
5 MEF	5 methyl-2-furaldehyde	(ppm) :	<0.010	<0.010	<0.010	<0.010	<0.010
2 FOL	2 furfurol	(ppm) :	<0.010	<0.010	<0.010	<0.010	<0.010
	Estimated DP	:	661	692	688	679	728

Transformer Condition Assessment Diagnostic Evaluation

TCA Assessment :	1 ID: 200272 Sampler: Doug Bartlett	1 ID: 200272 Sampler: David Warren	1 ID: 200272 Sampler: Brent Green	1 ID: 200272 Sampler: N/A	1 ID: 200272 Sampler: James Emberley

Sampling Interval : Retest in one year.

Operating Procedure : Continue normal operation.

Comments : No abnormal gas generation is indicated. Paper mechanical condition is reduced to approximately 70 % tensile strength.

Field Comments : Fluid condition is within acceptable in-service parameters.

TJ | H2b ANALYTICAL SERVICES INCORPORATED

Transformer Condition Assessment ™

		Date : 02-25-2025
	Location : RIDGE ROAD	Report Number : 5083547
	Bank & Phase : RRD-T3	Fluid volume : 9528 L
Sam Losinski	Serial Number : 13098	Fluid type : Mineral Oil
Newfoundland Power	Manufacturer : FPL	Preservation : Conservator
P.O. Box 8910	Date Mfgd : 1975	Cooling : ONAN/ONAF
55 Kenmount Road	Size (kVA) : 20000	Core & coil wt. : 30000
St. John's, NF A1B 3P6	Rating kV : 66	Impedance :

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Approved by: [signature]
Michelle Kutzleb, PhD
Vice President of Operations

Attachment B:

Transformer Maintenance History –
Power Transformer RRD-T3

Transformer Maintenance History Power Transformer RRD-T3		
Year	Maintenance Level/Scope	Summary of Work Completed
1992	M4 – Transformer maintenance	Transformer painted; corrosion and termination issues noted on LV potheads; general mechanical and condition maintenance completed
1997	M3 – Corrective maintenance	Investigated and repaired oil leak on piping between conservator tank and main tank; fittings tightened and leak resolved
2011	M5 – Corrective / minor repair	Repaired oil leak at CT junction box on top of transformer; oil lowered temporarily, fibre board tightened; silica gel container piping adjusted
2015	M3 – Protection inspections	Completed insulation resistance testing on transformer protection devices; oil level gauge replaced with new two-contact gauge; wiring to oil level gauge replaced
2015	M5 – Mechanical repair	Repaired leaks on gas detector and gas detector piping; oil level temporarily lowered to repair CT wiring block leak
2017	M3 – Protection inspections	Completed insulation resistance testing on transformer protection devices;
2020	M3 – Protection inspections	Protection device testing completed; fan control and temperature setpoints verified; explosion vent removed and replaced with new XPRD; new oil, winding temperature, oil temperature, oil level, and gas detector gauges installed with new wiring to transformer cabinet
2020	M3/M4 – Transformer maintenance	Completed insulation resistance testing on transformer protection devices; mechanical and electrical work including replacement of conservator piping, gas detector piping, oil level, oil temperature and winding temperature gauges; transformer painting, rust remediation, replacement of PRD with XPRD, addition of new oil; Completed transformer electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing); painted transformer

APPENDIX E:

Substation Power Transformer Strategy Five-Year Plan

Table E-1 shows the Power Transformer Strategy Five-Year Plan.

Table E-1 Power Transformer Strategy Five-Year Plan 2027-2031				
CBA Approval Year	Planned Transformer Replacements	Spare Power Transformers	Portable Substations	Costs ($000s)[1]
2027[2]	3	0	1	8,184
2028	3	0	0	12,757
2029	3	0	0	12,640
2030	3	1	0	8,123
2031	3	0	0	8,248

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 replacement GAN-T2 as part of the *Gander Substation Power Transformer Replacement* project, approved in Newfoundland Power's *2025 Capital Budget Application,* section *2.2 Substation Power Transformer Replacements*, have been excluded from this table.

May 2026

2.3 Portable Substation

Prepared by:
Tyler Stevens, P. Eng

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May 25, 2026
DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
A FORTIS COMPANY

TABLE OF CONTENTS

Page

1.0 INTRODUCTION

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") relies on portable substations as a critical component of its emergency response, substation maintenance and substation capital project execution. Portable substations enable the Company to maintain service to customers when substation equipment, such as power transformers, are removed from service for planned maintenance, capital projects, or following in-service equipment failures.

The Company's ability to deploy a portable substation in a timely manner can significantly reduce the duration of customer outages following a transformer failure. When a portable substation is readily available, service can typically be restored within 24 to 36 hours. Conversely, limited availability of portable substations increases the risk of prolonged outages and constrains the Company's ability to execute planned substation maintenance and capital programs.

Newfoundland Power's substation power transformer fleet is aging, with a significant portion of transformers operating beyond or approaching the upper range of typical industry service life. As outlined in Newfoundland Power's *Substation Power Transformer Strategy* filed as part of the *2026 Capital Budget Application*, the Company estimates that approximately three power transformers will need to be proactively retired each year to manage power transformer replacements in a controlled manner.[1] As a result of the increasing probability of power transformer failures due to age, together with increased procurement lead times, additional pressure is being placed on the Company's portable substation fleet.

In response to these risks, Newfoundland Power has assessed the adequacy of its portable substation fleet and determined that the procurement of an additional portable substation is required to support system reliability over the long term.

2.0 PORTABLE SUBSTATION BACKGROUND

2.1 Role of Portable Substations

Portable substations are deployed to maintain service to customers when substation equipment such as a power transformer is removed from service, and load cannot be transferred to another power transformer within the same substation or to another substation. Portable substations are typically used in three main scenarios:

1) Planned maintenance activities which typically require two to four weeks of deployment;
2) Capital projects at substations which typically require two to seven months of deployment; and
3) Emergency response to in-service equipment issues such as power transformer failures, which in some cases can require deployment up to 36 months.

[1] In 2027, the Company is proposing the replacement of LAU-T1, LBK-T1, HAR-T1, and RRD-T3. See report *2.2 Substation Power Transformer Strategy*.

Portable substations are not considered spare transformers. They are mobile installations that typically include a multi-winding power transformer, high voltage switches, low voltage breakers, protection and control systems, and cooling systems mounted on a trailer. This configuration allows flexibility across various substation sites.[2]

2.2 Portable Substation Fleet

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.[3] The Company also has access to one portable substation from Newfoundland and Labrador Hydro ("Hydro") through an equipment sharing agreement.[4]

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[5]	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 12 and 60 years. Combined, these units can provide emergency backup for most power transformers in Newfoundland Power's system.[6]

The Company's portable substations are inspected annually to assess their condition. Appendix B provides a summary of corrective maintenance completed on each portable substation over the past 5 years.

2 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.

3 Portable substations each have a multiple-winding power transformer, offering flexibility to connect portable substations 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.

4 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 also covered by a Newfoundland Power portable substation.

5 *Ibid.*

6 Appendix A provides the coverage by each of the portable substations included in Table 1.

3.0 HISTORICAL AND FORECAST PORTABLE UTILIZATION

3.1 Historical Utilization

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.

Figure 1 shows the utilization of Newfoundland Power's portable substations from 2021 to 2025.[7]

Figure 1
Portable Substation Utilitization
(2021-2025)

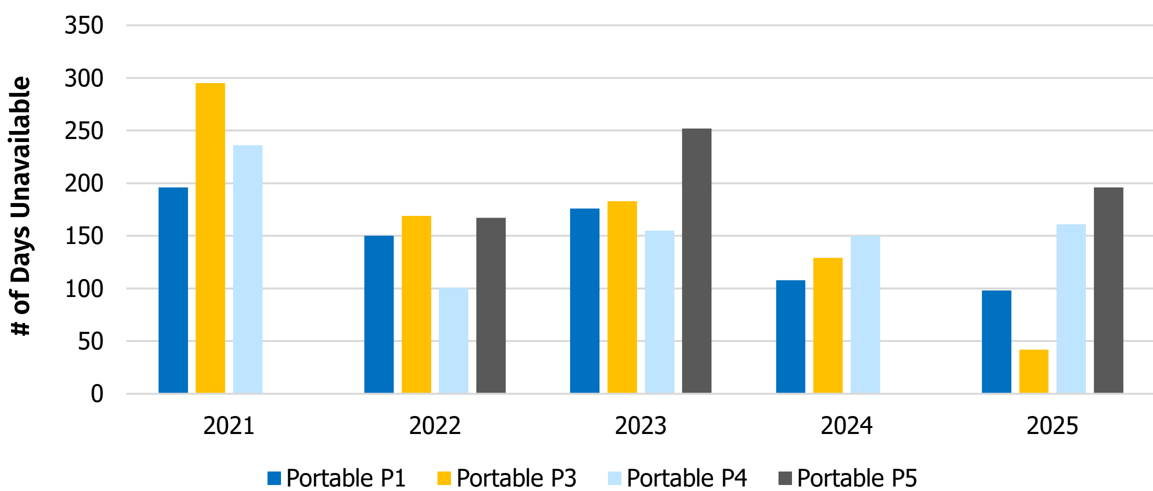


Figure 2 shows the breakdown of portable substation usage by activity type from 2021 to 2025. Usage is grouped into the following categories:

- Capital Project – Utilization to facilitate planned capital projects by temporarily maintaining customer supply during substation refurbishment and modernization projects.
- Transformer Maintenance – Utilization to support planned power transformer maintenance activities by temporarily bypassing in-service transformers.
- Others – Utilization to support other Utilities.
- Emergency Response – Utilization in response to unplanned events such as equipment failures to restore service or reduce outage duration.

---

[7] 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.

- Multipurpose – Utilization that supports multiple concurrent activities such as transformer maintenance, in-service failure work, or other work such as protection upgrades.

Figure 2
Portable Substation Usage
(2021 to 2025)

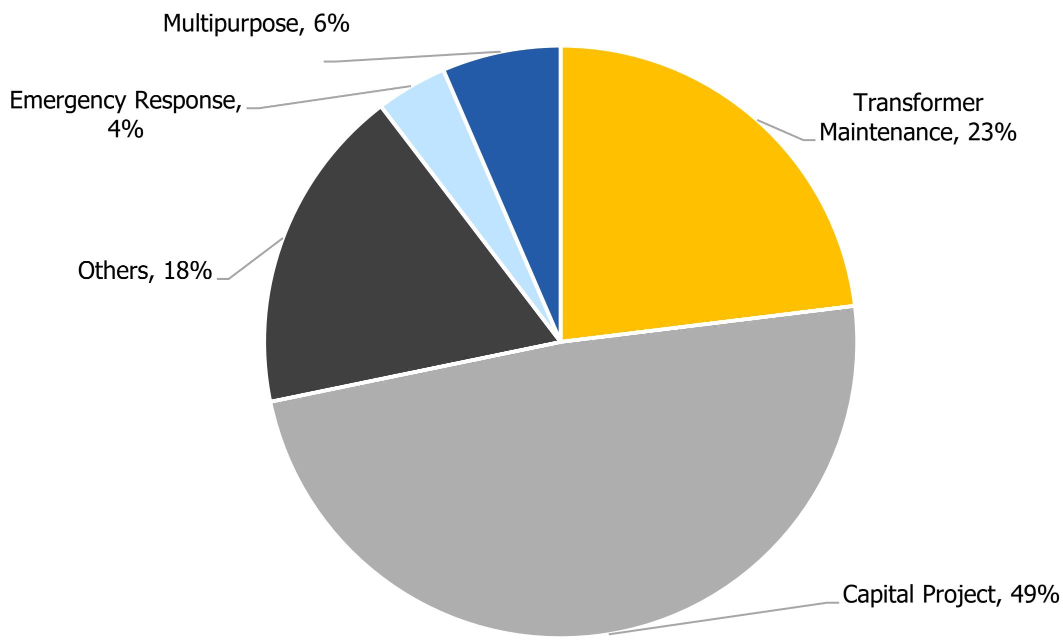
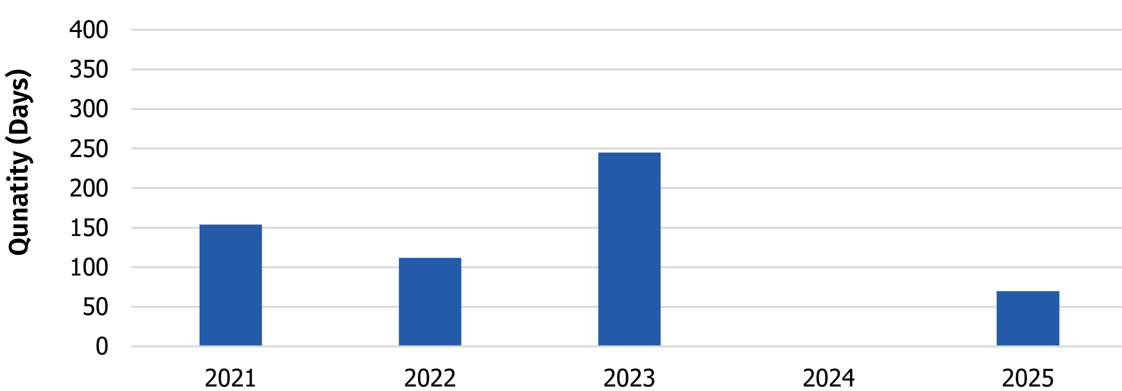


Figure 3 shows the number of days per year from 2021 to 2025 during which only one portable substation was available for deployment. During these periods, the remaining portable substations in the fleet were deployed for capital projects, planned maintenance, refurbishment or repair activity, under equipment-sharing arrangements, or in response to emergency events.

Figure 3
Periods of Single Portable Substation Availablity
(2021-2025)



Based on historical portable substation utilization, the Company's existing fleet of four portable substations has been adequate to meet operational requirements. However, during the May to November period, overlapping planned deployments have periodically reduced available fleet flexibility while maintaining emergency response coverage. During these peak activity months, the ability to respond to unplanned transformer failures was limited, increasing operational exposure that was managed through scheduling changes and risk mitigation measures.[8]

3.2 Forecast Utilization

The Company's *Power Transformer Strategy* identifies several trends that are expected to increase the utilization of the portable substation fleet:

- Over half of the Company's power transformers are aged 50 years or older. As transformers age, their risk of failure increases potentially requiring a portable substation deployment for emergency response.
- Average transformer delivery lead times have increased from approximately 34 weeks in 2019 to approximately 110 weeks in 2025. This increases the length of time portable substations are required to be deployed at a location to respond to an emergency.[9]
- Approximately 3 power transformers on average are expected to be proactively retired annually to manage replacements in a controlled manner.

The planned replacement of approximately three power transformers per year will place additional pressure on the availability of Newfoundland Power's portable substation fleet. Each power transformer replacement is expected to require a portable substation to remain in service for approximately four to ten weeks depending on the scope of work and offload capability. In addition to transformer replacement activities, the project scopes may include new spill containment systems and upgrades to the existing protection and control systems. These additional requirements can further extend the duration of portable substation deployment.

Based on recent operating experience and planned capital and maintenance activities, a reasonable estimate of future annual portable substation requirements includes:

- Two portable substations to support substation capital projects that may require deployment for up to seven months (May-November).
- One portable substation to support the replacement of three power transformers, requiring deployment for up to a combined total of approximately 30 weeks (May-November).
- One portable substation to support power transformer maintenance activities (April-December) while also maintaining emergency response capability for unplanned transformer and equipment failures throughout the year.

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8 For example, in four of the past five years, there were instances during this period when only one of the four portable substations was available to respond to emergencies due to project work, transformer maintenance, or portable substation maintenance.

9 These transformer lead time estimates are based on information provided by manufacturers currently utilized by the Company.

Figure 4 shows the maximum expected portable substation usage based on typical installation and deployment time frames with 4 portable substations.

Figure 4
Future Portable Substation Usage (4 Portable Substations)

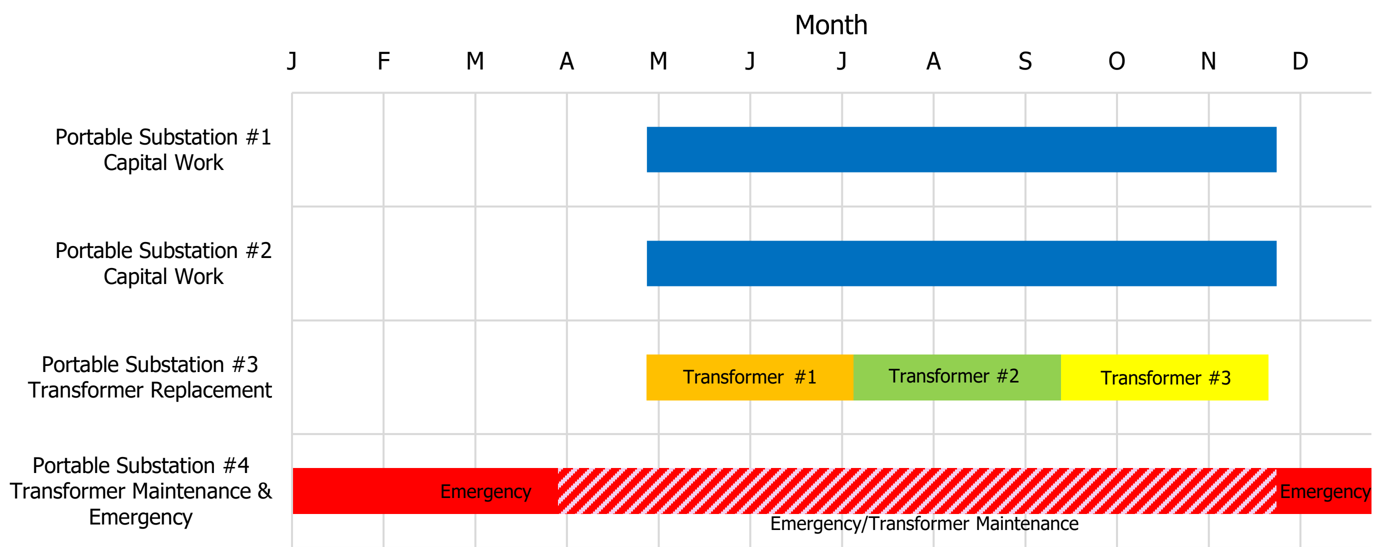
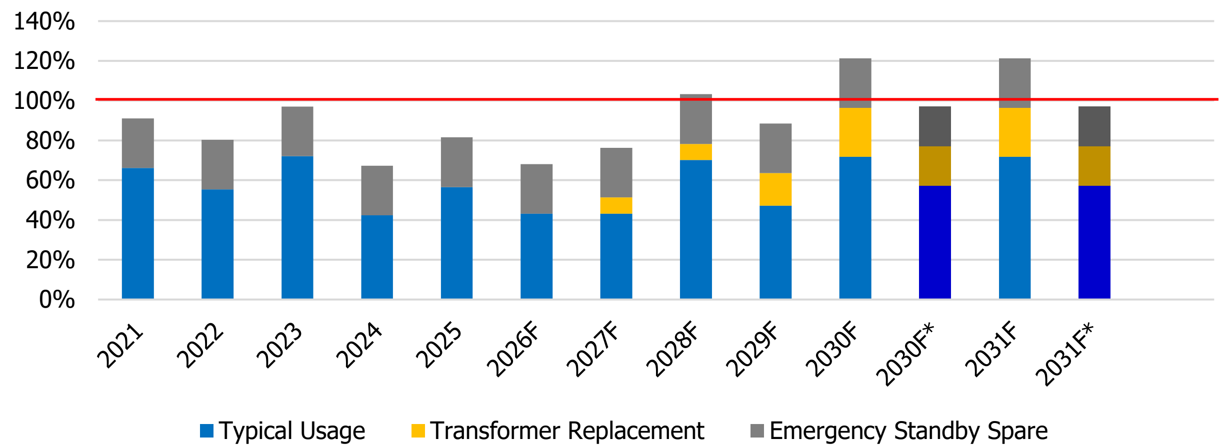


Figure 5 shows the historical and forecasted annual usage of Newfoundland Power's portable substation fleet during the May 1 to November 30 high-use time frame. Fleet usage has been separated into three main categories:

1. Typical Usage - Represents portable substation utilization associated with capital projects, in-service equipment failures, routine transformer and portable substation maintenance, and supply to third parties. Forecasted capital usage is based on the Company's five-year capital plan, while the remaining categories are derived from five-year historical averages.
2. Transformer Replacement – Represents the additional incremental demand placed on the portable substation fleet resulting from planned power transformer replacements under the Company's *Power Transformer Strategy*.
3. Emergency Standby Spare – Represents the portion of the year during which a portable substation is reserved and maintained on standby to respond to equipment failure.

Figure 5 represents portable substation usage with the existing fleet. Years 2030 and 2031, marked with an asterisk, indicate usage with a five-unit portable substation fleet.

Figure 5
Historical and Forecasted Portable Substation Fleet Usage
(May - November)



Looking forward, projected increases in planned transformer replacements, extended portable substation deployment durations due to long power transformer lead times, and sustained capital and maintenance activity indicate that the portable substation demand will increase. During the peak May to November period, multiple long duration planned deployments are expected to overlap with the ongoing requirement to retain emergency response capability.

Considering the Company's existing fleet of four portable substations, these forecasted requirements are expected to exceed the capability of the current fleet with the highest risk occurring in the May to November time frame. This increases the risk that a suitable portable substation may not be available during an emergency event.

4.0 RISK ASSESSMENT

The primary risk associated with Newfoundland Power's existing portable substation fleet is the potential for insufficient emergency response capability resulting from limited portable substation availability. As described in section 3.2, increasing utilization of the Company's portable substation fleet will be required due to an aging power transformer fleet, extended deployment durations following in-service failures, and growing demands associated with planned maintenance and capital programs. Collectively, these factors have increased the likelihood that portable substations will be deployed for planned and unplanned purposes. This reduces portable fleet availability and constrains the Company's ability to respond effectively to additional emergency events.

Where a suitable portable substation is readily available, service can typically be restored to customers within 24 to 36 hours following a power transformer failure. However, insufficient availability of portable substations can result in restoration delays of several days, particularly in substations where load transfers are not available. These delays expose customers to prolonged outages and increased reliability risk. As transformer failures can occur concurrently and portable substations are required to support planned maintenance and capital work, limited fleet availability increases the likelihood that customers will experience extended outages during emergency events.

The following assessment considers both the probability and consequence of this risk.

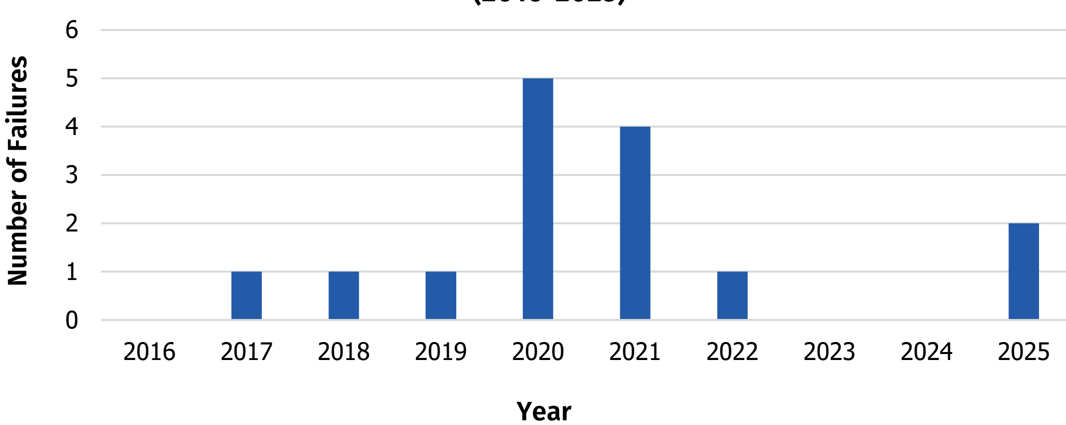
4.1 Probability of Insufficient Emergency Response Capability

The probability of insufficient emergency response capability is increasing due to a combination of asset condition, operational constraints, and planned capital activities. As documented in report *2.2 Substation Power Transformer Strategy*, the Company's power transformer fleet is aging, and it is reasonable to anticipate multiple transformer failures occurring concurrently, particularly as transformers continue to operate beyond typical industry service life.

The likelihood of insufficient emergency response capacity is further increased by the length of time that a portable substation is required following a transformer failure. Where a spare power transformer is not immediately available, or where repairs or replacement are delayed due to extended procurement lead times, a portable substation may be required to remain in service for extended periods. In some cases, deployments may last up to 18 to 36 months. Extended deployments materially reduce the number of portable substations available out of the Company's existing fleet of four units to respond to subsequent failures.

Figure 6 shows the number of power transformer failures experienced from 2016 to 2025 and illustrates that failures have not occurred uniformly over time but can cluster within a single year.[10] Multiple failures were experienced during 2020 and 2021, compared with years where no failures occurred. When multiple transformer failures occur within a short period, emergency requirements may overlap with planned outages required for maintenance and capital work. This can place additional pressure on the portable substation fleet or result in the deferral of planned capital work or maintenance.

Figure 6
Power Transformer Failure
(2016-2025)



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[10] See Appendix C for the list of substation power transformer failures experienced from 2016 to 2025.

In addition to emergency deployments, portable substations are required to support planned substation maintenance and capital projects. These planned activities typically require portable substations to be deployed for periods from one to seven months, reducing the pool of available units for emergency response during those periods. While routine maintenance on portable substations can often be advanced or deferred to accommodate system needs, long-term deployments associated with capital projects and transformer failures cannot be readily shortened without increasing the risk of customer outages.

An increase to three power transformer replacements per year introduces an additional constraint on portable substation availability. Each transformer replacement typically requires the removal of the in-service transformer for an extended period to accommodate de-energization, demolition of infrastructure such as concrete pads, installation of spill containment systems, installation of the transformer, commissioning, and cutover activities. Where load cannot be transferred to another transformer or adjacent substation, a portable substation is required to maintain service to customers for the duration of the replacement work.

As the number of annual transformer replacements increases, the probability that portable substations will be concurrently deployed for planned work also increases. This reduces the number of portable substations available to respond to unplanned transformer failures and increases the likelihood that an emergency event will occur while all suitable portable substations are already in service. Under such conditions, the Company's emergency response capability may be exceeded, resulting in prolonged customer outages or the deferral of critical planned work.

When considered collectively, an aging transformer fleet, anticipated increase in failure frequency, extended transformer procurement lead times, and the planned increase of transformer replacements under the *Substation Power Transformer Strategy*, the probability that existing portable substation resources will be insufficient to meet both planned and unplanned system needs is increased. This compounding effect represents a growing risk to system reliability if another portable substation is not added to the fleet.

4.2 Consequence of Insufficient Emergency Response Capability

Insufficient availability of portable substations resulting in insufficient emergency response capabilities would have significant consequences for customer reliability, system risk, and the execution of Newfoundland Power's maintenance and capital programs. Portable substations are a critical component of the Company's emergency response capability and play a central role in limiting the duration of customer outages following transformer failures.

When a suitable portable substation is readily available, service can typically be restored to customers within 24 to 36 hours following a transformer failure. In contrast, where no portable substation is immediately available, restoration time may be delayed by several days due to the time required to uninstall, transport, redeploy, and commission a unit that is already in service, or because there is no technically compatible unit available. These delays expose customers to significantly longer outage durations, particularly in areas where load transfers are not feasible.

Extended customer outages are a direct consequence of insufficient portable substation availability and have the greatest impact on customers served by substations with limited redundancy. In these locations, a single transformer failure can result in a complete loss of supply unless a portable substation can be deployed. Prolonged outages reduce overall system reliability.

In addition to customer impacts, insufficient portable substation availability presents significant risks to the execution of the Company's planned maintenance and capital programs. Portable substations are routinely required to maintain service during substation maintenance activities and capital projects. When portable substations are unavailable due to emergency deployments or extended use following transformer failures, planned work must be deferred.

Deferral of planned maintenance increases the risk of additional equipment failures by allowing known asset condition issues to remain unaddressed. Over time, this can lead to a compounding effect in which deferred maintenance contributes to increased unplanned outages, placing additional strain on the Company's emergency response resources and increasing overall system risk.

Insufficient portable substation availability also affects the Company's ability to execute its planned power transformer replacements. Transformer replacements typically require the removal of in-service transformers for extended periods to accommodate demolition, installation, and commissioning activities. Where portable substations are unavailable, the Company may be required to delay planned replacements, extending the time that aging transformers remain in-service and increasing the likelihood of in-service failures.

Insufficient portable substation availability directly impacts emergency response capabilities, increases the duration and severity of customer outages, constrains the execution of planned maintenance and capital programs, and elevates the overall risk to substation equipment. These consequences become more pronounced as the transformer failure frequency increases and portable substations are required to support a growing volume of planned transformer replacement work. Without an additional portable substation, these risks are expected to increase over time.

The probability and consequence of insufficient emergency response capability associated with limited portable substation availability represents a significant and increasing system risk. An aging power transformer fleet, higher anticipated power transformer failure rates, extended portable substation deployment following failures, and increasing reliance on portable substations to support planned maintenance and capital programs are placing increasing pressure on a portable fleet of four units. These conditions increase the likelihood that the entire portable substation fleet will be deployed, constraining emergency response capability and increasing the risk of prolonged customer outage and deferral of planned work.

5.0 ASSESSMENT OF ALTERNATIVES

As outlined in Section 4, Newfoundland Power must maintain a sufficient portable substation fleet to respond effectively to unplanned transformer and equipment outages while also supporting planned maintenance and capital activities. Portable substations are a critical component of the Company's emergency response capability and are often the only practical means of restoring service within 24 to 36 hours following a transformer failure when load transfers are not feasible. In response to the increasing risk that existing resources may be insufficient to meet future needs, the Company evaluated three alternatives to address the risk.

5.1 Alternative 1 – Maintain Existing Portable Substation Inventory

This alternative would involve maintaining the existing inventory of four portable substations, with access to one portable substation from Hydro through an equipment sharing agreement. These portable substations operate at different voltage and capacity ratings and are therefore not interchangeable across all substations. As a result, the availability of a technically compatible portable substation at the time of a transformer failure is not guaranteed, even when one or more units are not deployed. This alternative effectively represents a status quo approach.

Maintaining the existing portable substation inventory without additional investment would require the Company to accept an increasing level of operational and reliability risk. While the current inventory has historically provided adequate support for emergency response, maintenance, and capital execution, an assessment of future needs indicates that this approach is no longer sufficient to address future system needs.

Historical utilization data demonstrates that portable substations can be unavailable for extended periods due to a combination of emergency deployments, capital project requirements and refurbishment activities. A portable substation deployed in response to a transformer failure may remain in service for up to 18 to 36 months where spare transformers are unavailable or where repairs and replacements are delayed due to extended procurement lead times. Extended deployments reduce the number of portable substations available to respond to subsequent failures. This alternative also does not address the demand placed on portable substations by planned maintenance capital programs. Portable substations are critical to the effective execution of annual substation maintenance and capital work. When portable substations are unavailable due to emergency deployments, planned work must be deferred. Over time, deferral of maintenance increases the risk of additional equipment failures and further compounds system risk.

Under a status quo approach, increasing pressure from the aging transformer fleet and increasing failure frequency would result in a higher likelihood of concurrent portable substation deployments. Report *2.2 Substation Power Transformer Strategy* indicates that it is reasonable to anticipate multiple transformer failures occurring concurrently, which could potentially exceed the Company's emergency response capabilities. Maintaining the current portable substation inventory does not mitigate this risk and would increase the likelihood that multiple transformer failures would result in extended restoration times and prolonged customer outages. Maintaining the existing inventory does not account for the increased utilization of portable substations associated with the Company's planned power transformer replacements. Transformer replacements require the removal of in-service transformers, during which portable substations are often required to maintain customer service. As the number of planned replacements increase, the probability that portable substations will be concurrently deployed for planned work also increases, further reducing availability for emergency response. Maintaining the existing inventory would require accepting higher outage risk during these periods.

Maintaining the existing portable substation inventory without expansion increases pressure on the Company's emergency response resources. This alternative leaves customers increasingly exposed to prolonged outages and increases the prospect of deferred maintenance and elevated system risk as transformer failures, replacement activity, and procurement lead times increase. For these reasons, the status quo alternative of maintaining the existing portable substation inventory is not viable.

5.2 Alternative 2 – Increase Spare Transformer Inventory

This alternative would involve increasing the Company's spare power transformer inventory. Spare transformers are an essential component of Newfoundland Power's emergency response strategy and can reduce the duration a portable substation is required after a transformer failure. However, reliance on spare transformers alone does not adequately mitigate the risks associated with insufficient portable substation availability.

Spare transformers provide a medium to long term solution following a transformer failure but do not eliminate the need for a portable substation during the initial emergency response period. Following a failure, a portable substation is typically required to restore service to customers within 24 to 36 hours while damage assessment, site preparation, and spare transformer installation activities are completed. Even if a suitable spare transformer is available, installation and commissioning can require weeks or months, during which time a portable substation must remain in service.

Spare transformer coverage across the Company's system is incomplete. Transformers vary by voltage, MVA rating, impedance, and physical configuration. Spare transformers are not interchangeable across all substations. As documented in report *2.2 Substation Power Transformer Strategy*, a portion of the Company's power transformers do not have a directly compatible spare transformer available, limiting the effectiveness of increased reliance on spares as a standalone risk mitigation measure.

Furthermore, spare transformers cannot provide the same level of flexibility as portable substations. Portable substations are designed to operate across multiple voltage classes and can be rapidly deployed to a wide range of locations. Spare transformers, by contrast, are location specific assets that require site specific civil, electrical, and protection and controls work to be completed prior to energization. This limits their effectiveness as an immediate response tool during unplanned outages.

While spare transformers remain a critical component of the Company's overall transformer management strategy, increased reliance on spare transformers alone does not adequately mitigate the risk associated with aging assets, increased failure frequency, and growing demands on portable substation resources. While this alternative does provide a sufficient or timely response to emergency events, it does not reduce the probability or consequence of insufficient portable substation availability. For these reasons, the alternative of increasing the spare transformer inventory is not viable.

5.3 Alternative 3 – Procure an Additional Portable Substation

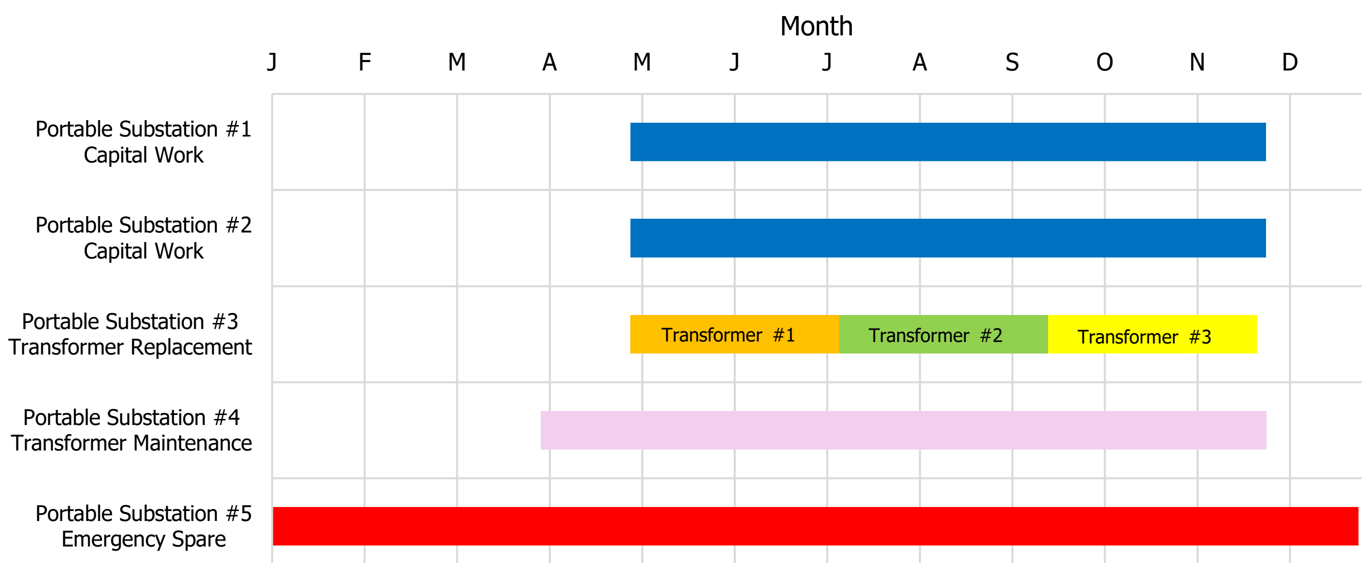
This alternative would involve the procurement of one additional portable substation to add to the Company's existing fleet. The procurement of an additional portable substation will address the increased probability of insufficient emergency response capacity. This alternative directly mitigates the risks associated with an aging transformer fleet, increasing transformer failure frequency, extended procurement lead times, and increasing demands placed on portable substations by planned maintenance and capital programs.

Portable substations are a critical component of Newfoundland Power's emergency response capability and represent the only practical means of restoring service to customers within 24 to 36 hours following a transformer failure when load cannot be transferred to adjacent substations. Increasing the number of available portable substations reduces the likelihood that emergency response capacity will be exceeded during periods of concurrent transformer failures or overlapping planned deployments.

The addition of a new portable substation improves system resilience by reducing the risk associated with extended deployments. Where a portable substation is required to remain in service for an extended duration due to delayed transformer repairs or replacement, the availability of an additional unit maintains the Company's ability to respond to subsequent emergencies without requiring the redeployment of an in-service unit. This reduces restoration delays and limits customer outage durations.

Figure 7 demonstrates the effect of an additional portable substation on deployment.

Figure 7
Future Portable Substation Usage (5 Portable Substations)



An additional portable substation also provides flexibility to support the Company's planned transformer replacement program, as shown in Figure 7. Transformer replacements typically require the removal of in-service transformers for extended periods to accommodate demolition, installation, and commissioning activities. Where load cannot be transferred, a portable substation is required to maintain service for the duration of the work. Increasing the portable substation fleet reduces the likelihood that planned replacements will compete with emergency response needs for limited resources, thereby supporting the timely execution of the transformer strategy.

The proposed portable substation will reduce exposure to prolonged customer outages and mitigates the risk associated with deferred maintenance and capital work. By limiting outage durations and supporting execution of planned programs, this alternative contributes to the delivery of reliable service to customers.

Procuring an additional portable substation is the recommended alternative and will address the identified risks to emergency response capability, system reliability, and capital program execution. This investment aligns with the *Substation Power Transformer Strategy* and supports the Company's ability to manage its substation assets in a controlled and proactive manner.

6.0 PROJECT SCOPE AND COST

6.1 Functional Requirements

The proposed portable substation will be designed to temporarily replace the functionality of a substation where a transformer is removed from service due to failure, planned maintenance, or capital replacement activities. Similar to existing portable substations, the unit will include:

- A 25 MVA, 138/66 to 12.5/25kV multi-winding power transformer with an On-Load Tap Changer;
- 138kV isolation equipment;
- 25kV circuit breaker;
- Instrument transformers;
- Auxiliary power;
- Protection, control and metering systems; and
- An integrated cooling system, all mounted on a transportable trailer.

This configuration will allow the portable substation to perform voltage transformation, switching, and protection functions necessary to maintain service to customers during extended outages of substation equipment.

6.2 Transformer Fleet Compatibility

Appendix A provides the coverage provided by each of the existing portable substations and the proposed portable substation. The configuration was selected to optimize compatibility with Newfoundland Power's existing substation power transformer fleet while considering physical size limitations.[11]

[11] The proposed portable substation will provide coverage for 141 of Newfoundland Power's 191 power transformers.

Voltage and MVA rating were selected to provide broad system coverage rather than targeting a single substation or transformer configuration. This approach ensures that the capacity provided by the new portable substation improves overall fleet flexibility and reduces the risk that a technically incompatible unit is the only one available at the time of a power transformer failure.

6.3 Intended Use Cases

The proposed additional portable substation will be deployed in support of the following activities:

- Emergency response to in-service transformer failures, enabling restoration of service to customers within 24 to 36 hours where load transfers are not possible.
- Planned substation maintenance, where transformers must be removed from service for inspection, repair, or condition-based maintenance.
- Capital projects, including power transformer replacements and substation refurbishment activities, where extended transformer or bus outages are required.

The unit may remain in service for short durations (weeks) or extended durations (months to years), depending on the nature of the deployment and the availability of spare transformers or replacement units.

6.4 Integration with Existing Fleet

The proposed portable substation will be integrated into the Company's existing portable substation program and managed using established operating, maintenance, and deployment practices. The addition of a new unit increases the total number of portable substations available for deployment, reducing the likelihood that all suitable units are concurrently in service or unavailable due to refurbishment.

The project does not replace any existing portable substations. Instead, it provides an additional unit to address the increasing demands placed on the fleet by aging transformers, extended deployment durations, and additional power transformer replacement activity.

6.5 Project Cost

Table 2 provides a detailed breakdown of the proposed *Portable Substation* multi-year project. The project is proposed to be completed over three years. This would include design and procurement in 2027 and 2028, followed by delivery, installation, testing and commissioning in 2029.

Table 2
Portable Substation Project
Project Cost
($000s)

Cost Category	2027	2028	2029	Total
Material	918	3,744	4,775	9,437
Labour - Internal	-	-	52	52
Labour – Contract	-	-	-	-
Engineering	52	68	118	238
Other	20	82	104	206
Total	$990	$3,894	$5,049	$9,933

The project to procure a portable substation is estimated to cost $990,000 in 2027, $3,894,000 in 2028, and $5,049,000 in 2029 for a total project cost of $9,933,000.

7.0 CONCLUSION

Newfoundland Power's substations are subject to increasing risks due to the aging profile of its power transformer fleet, forecasted increases in transformer failure frequency, and long procurement lead times for replacement transformers. As indicated in report *2.2 Substation Power Transformer Strategy*, these factors increase both the probability and consequence of transformer failures and place additional pressure on the Company's emergency response resources.

Portable substations are a critical component of Newfoundland Power's emergency response capability and play a central role in limiting customer outage durations following power transformer failures. When a suitable portable substation is readily available, service can typically be restored within 24 to 36 hours. Conversely, insufficient availability of portable substations exposes customers to an increased risk of prolonged outages and constrains the Company's ability to execute planned maintenance and capital programs, including the planned increase in power transformer replacements.

The assessment of alternatives demonstrates that maintaining the existing portable substation inventory or increasing reliance on spare power transformers does not adequately mitigate these risks. Maintaining the status quo would require acceptance of higher outage risk as power transformer failure frequency, portable substation deployment durations, and concurrently planned work all increase. While spare power transformers remain an essential component of the overall transformer strategy, they do not eliminate the need for portable substations during initial response periods and cannot address the constraints created by extended deployments.

Procuring an additional portable substation addresses the identified risks by increasing emergency response capacity and improving system resilience. The additional unit reduces the likelihood that concurrent emergency events or overlapping planned deployments will exceed available resources, thereby limiting outage durations and supporting timely execution of maintenance and capital programs.

The procurement of an additional portable substation aligns with the *Substation Power Transformer Strategy* and enhances the Company's ability to manage substation assets in a proactive, risk-based manner.

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	2026 Forecast MVA	P1	P3	P4	P5	P6	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	5.91	X	X	X	X	X				X		X		X
APT-T1	Dist.	66.0	25.0	25.00	16.72		X	X	X	X								X
BCV-T1	Dist.	66.0	25.0	25.00	19.79		X	X	X	X								X
BFS-T1	Dist.	138.0	25.0	20.00	8.47		X	X	X	X	X							
BHD-T1	Dist.	66.0	25.0	7.46	3.82	X	X	X	X	X							X	X
BIG-T1	Dist.	66.0	12.5	11.11	8.30	X	X	X	X	X				X		X		X
BLA-T1	Dist.	138.0	25.0	6.67	4.54		X	X	X	X	X							
BLK-T2	Dist.	138.0	25.0	20.00	16.21		X	X	X	X	X							
BOT-T1	Dist.	138.0	25.0	20.00	13.87		X	X	X	X	X							
BRB-T1	Dist.	138.0	12.5	20.00	11.54		X	X	X	X								
BRB-T4	Dist.	138.0	12.5	25.00	13.79		X	X	X	X								
BVA-T1	Dist.	138.0	12.5	25.00	13.81		X	X	X	X								
BVJ-T1	Dist.	138.0	25.0	2.67	0.29		X	X	X	X	X							
BVS-T1	Dist.	66.0	12.5	20.00	15.35		X	X	X	X								X
BVS-T2	Dist.	66.0	12.5	15.00	9.56	X	X	X	X	X				X		X		X
CAB-T2	Dist.	66.0	25.0	6.67	3.83	X	X	X	X	X							X	X
CAR-T1	Dist.	66.0	25.0	25.00	18.45		X	X	X	X								X
CAT-T2	Dist.	138.0	12.5	20.00	5.57		X	X	X	X								
CHA-T1	Dist.	66.0	25.0	50.00	35.34			X	X									
CHA-T2	Dist.	66.0	25.0	25.00	17.02		X	X	X	X								X
CLK-T1	Dist.	66.0	12.5	10.00	5.21	X	X	X	X	X				X		X		X
CLK-T2	Dist.	66.0	12.5	10.00	5.53	X	X	X	X	X				X		X		X
CLV-T2	Dist.	138.0	12.5	20.00	11.64		X	X	X	X								
CLV-T3	Dist.	138.0	12.5	25.00	13.01		X	X	X	X								
COB-T1	Dist.	138.0	12.5	20.00	15.15		X	X	X	X								
COB-T3	Dist.	138.0	12.5	25.00	19.22		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	2026 Forecast MVA	P1	P3	P4	P5	P6	200-299	200-185	200-358	200-219	200-352	200-220	200-328	200-385
COL-T1	Dist.	138.0	12.5	16.67	6.99		X	X	X	X								
DLK-T1	Dist.	66.0	25.0	25.00	22.14		X	X	X	X								X
DOY-T2	Dist.	66.0	25.0	6.67	5.13	X	X	X	X	X							X	X
DUN-T1	Dist.	66.0	25.0	25.00	7.98	X	X	X	X	X							X	X
FER-T1	Dist.	66.0	12.5	4.00	2.20	X	X	X	X	X		X		X		X		X
FRN-T1	Dist.	66.0	25.0	6.67	4.92	X	X	X	X	X							X	X
GAL-T1	Dist.	66.0	12.5	13.33	9.67	X	X	X	X	X				X		X		X
GAL-T2	Dist.	66.0	12.5	13.33	9.57	X	X	X	X	X				X		X		X
GAM-T1	Dist.	138.0	25.0	6.67	6.42		X	X	X	X	X							
GAN-T1	Dist.	138.0	12.5	20.00	18.10		X	X	X	X								
GAR-T1	Dist.	66.0	12.5	3.72	2.37	X	X	X	X	X				X		X		X
GBE-T1	Dist.	66.0	7.2	0.33	0.24	X	X		X	X			X					
GBS-T1	Dist.	66.0	25.0	25.00	8.78	X	X	X	X	X								X
GBY-T1	Dist.	66.0	25.0	13.33	8.48	X	X	X	X	X								X
GDL-T1	Dist.	66.0	25.0	25.00	17.48		X	X	X	X								X
GDL-T2	Dist.	66.0	25.0	25.00	17.78		X	X	X	X								X
GDL-T3	Dist.	66.0	25.0	25.00	18.08		X	X	X	X								X
GFS-T2	Dist.	138.0	25.0	20.00	13.50		X	X	X	X	X							
GFS-T3	Dist.	138.0	25.0	50.00	30.45			X	X									
GFS-T5	Dist.	66.0	4.2	11.17	6.27	X										X		
GIL-T1	Dist.	66.0	25.0	6.67	7.11	X	X	X	X	X							X	X
GLN-T1	Dist.	138.0	25.0	8.34	3.82		X	X	X	X	X							
GLV-T1	Dist.	138.0	25.0	20.00	12.92		X	X	X	X	X							
GOU-T2	Dist.	66.0	12.5	20.00	13.23		X	X	X	X						X		X
GOU-T3	Dist.	66.0	12.5	13.33	9.25	X	X	X	X	X				X		X		X
GPD-T1	Dist.	66.0	12.5	2.80	1.01	X	X	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	2026 Forecast MVA	P1	P3	P4	P5	P6	200-299	200-185	200-358	200-219	200-352	200-220	200-328	200-385
GRH-T2	Dist.	138.0	12.5	20.00	15.04		X	X	X	X								
HAR-T1	Dist.	66.0	12.5	14.90	12.84		X	X	X	X						X		X
HBS-T1	Dist.	66.0	25.0	6.67	4.02	X	X	X	X	X							X	X
HCT-T3	Dist.	66.0	12.5	2.24	1.59	X	X	X	X	X		X		X		X		X
HGR-T1	Dist.	66.0	25.0	25.00	9.54	X	X	X	X	X								X
HOL-T1	Dist.	138.0	12.5	20.00	15.04		X	X	X	X								
HOW-T3	Dist.	25.0	4.2	1.00	1.04	X												
HUM-T1	Dist.	66.0	12.5	25.00	16.58		X	X	X	X								X
HWD-T1	Dist.	66.0	12.5	20.00	16.62		X	X	X	X								X
HWD-T2	Dist.	66.0	12.5	20.00	16.52		X	X	X	X								X
HWD-T3	Dist.	66.0	25.0	50.00	44.16			X	X									
ILC-T1	Dist.	66.0	12.5	13.33	9.89	X	X	X	X	X				X		X		X
ISL-T1	Dist.	66.0	12.5	4.00	3.94	X	X	X	X	X				X		X		X
JON-T1	Dist.	66.0	12.5	0.33	0.10	X	X	X	X	X		X		X		X		X
KBR-T3	Dist.	66.0	25.0	25.00	19.64		X	X	X	X								X
KBR-T4	Dist.	66.0	25.0	25.00	20.32		X	X	X	X								X
KEL-T1	Dist.	66.0	25.0	25.00	21.47		X	X	X	X								X
KEN-T1	Dist.	66.0	25.0	25.00	20.04		X	X	X	X								X
KEN-T2	Dist.	66.0	25.0	50.00	41.93			X	X									
LAU-T1	Dist.	66.0	12.5	13.30	6.73	X	X	X	X	X				X		X		X
LET-T1	Dist.	66.0	25.0	16.67	8.90	X	X	X	X	X								X
LEW-T1	Dist.	138.0	25.0	25.00	19.98		X	X	X	X	X							
LGL-T1	Dist.	66.0	25.0	14.90	6.19	X	X	X	X	X							X	X
LLK-T1	Dist.	138.0	12.5	20.00	6.05		X	X	X	X								
LOK-T3	Dist.	66.0	12.5	4.00	3.45	X	X	X	X	X				X		X		X
LPD-T1	Dist.	66.0	12.5	25.00	20.00		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	2026 Forecast MVA	P1	P3	P4	P5	P6	200-299	200-185	200-358	200-219	200-352	200-220	200-328	200-385
LPD-T2	Dist.	66.0	12.5	25.00	20.00		X	X	X	X								X
MIL-T1	Dist.	66.0	25.0	16.67	12.85		X	X	X	X								X
MKS-T1	Dist.	138.0	25.0	14.90	8.00		X	X	X	X	X							
MMT-T1	Dist.	66.0	12.5	6.67	5.59	X	X	X	X	X				X		X		X
MOB-T2	Dist.	66.0	12.5	16.67	12.79		X	X	X	X						X		X
MOL-T1	Dist.	66.0	12.5	25.00	24.09		X	X	X	X								X
MOL-T2	Dist.	66.0	12.5	25.00	23.70		X	X	X	X								X
MSY-T1	Dist.	138.0	12.5	20.00	18.33		X	X	X	X								
MUN-T1	Dist.	66.0	12.5	14.96	3.87	X	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		X
NCH-T1	Dist.	66.0	12.5	6.67	4.17	X	X	X	X	X				X		X		X
NHR-T1	Dist.	66.0	12.5	13.33	7.60	X	X	X	X	X				X		X		X
NWB-T1	Dist.	138.0	25.0	11.20	5.85		X	X	X	X	X							
OPL-T1	Dist.	66.0	12.5	15.00	8.18	X	X	X	X	X				X		X		X
OXP-T1	Dist.	66.0	12.5	13.33	9.87	X	X	X	X	X				X		X		X
PAB-T5	Dist.	66.0	12.5	13.33	8.53	X	X	X	X	X				X		X		X
PAS-T1	Dist.	66.0	12.5	13.30	12.46		X	X	X	X						X		X
PBD-T1	Dist.	138.0	25.0	16.67	3.17		X	X	X	X	X							
PEP-T1	Dist.	66.0	25.0	25.00	11.70		X	X	X	X								X
PEP-T2	Dist.	66.0	25.0	25.00	12.39		X	X	X	X								X
PHR-T3	Dist.	33.0	4.2	4.00	2.35	X												
PJN-T1	Dist.	66.0	7.2	0.33	0.00	X	X		X	X			X					
PUL-T1	Dist.	66.0	25.0	25.00	18.79		X	X	X	X								X
PUL-T2	Dist.	66.0	25.0	25.00	19.09		X	X	X	X								X
QTZ-T1	Dist.	66.0	4.2	0.75	0.10	X						X				X		
RBK-T2	Dist.	66.0	25.0	6.67	3.43	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	2026 Forecast MVA	P1	P3	P4	P5	P6	200-299	200-185	200-358	200-219	200-352	200-220	200-328	200-385
ROB-T1	Dist.	66.0	25.0	6.67	3.92	X	X	X	X	X							X	X
RRD-T2	Dist.	66.0	12.5	20.00	15.57		X	X	X	X								X
RRD-T3	Dist.	66.0	12.5	20.00	17.54		X	X	X	X								X
RVH-T1	Dist.	66.0	25.0	8.33	3.36	X	X	X	X	X							X	X
SCR-T1	Dist.	138.0	25.0	8.30	5.97		X	X	X	X	X							
SCT-T1	Dist.	66.0	25.0	6.67	1.70	X	X	X	X	X							X	X
SCT-T2	Dist.	25.0	12.5	4.00	0.98	X												
SCV-T2	Dist.	66.0	25.0	11.20	8.69	X	X	X	X	X								X
SJM-T1	Dist.	66.0	25.0	25.00	15.84		X	X	X	X								X
SJM-T2	Dist.	66.0	12.5	25.00	17.19		X	X	X	X								X
SJM-T3	Dist.	66.0	25.0	25.00	11.25		X	X	X	X								X
SLA-T1	Dist.	66.0	4.2	13.30	3.75	X										X		
SLA-T2	Dist.	66.0	4.2	10.40	3.30	X										X		
SLA-T3	Dist.	66.0	12.5	25.00	19.86		X	X	X	X								X
SLA-T4	Dist.	66.0	12.5	25.00	20.49		X	X	X	X								X
SMV-T1	Dist.	66.0	25.0	4.00	2.87	X	X	X	X	X							X	X
SPF-T1	Dist.	138.0	12.5	20.00	13.77		X	X	X	X								
SPO-T1	Dist.	66.0	12.5	15.00	11.99		X	X	X	X						X		X
SPR-T1	Dist.	138.0	25.0	16.67	9.91		X	X	X	X	X							
STG-T1	Dist.	66.0	25.0	6.67	3.50	X	X	X	X	X							X	X
STX-T1	Dist.	66.0	12.5	6.67	4.97	X	X	X	X	X				X		X		X
SUM-T1	Dist.	66.0	25.0	13.33	7.41	X	X	X	X	X							X	X
SUN-T5	Dist.	138.0	25.0	25.00	9.64		X	X	X	X	X							
TNS-T1	Dist.	138.0	14.4	1.00	0.91		X		X	X								
TRN-T1	Dist.	66.0	25.0	6.67	3.78	X	X	X	X	X							X	X
TRP-T1	Dist.	66.0	12.5	15.00	2.49	X	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	2026 Forecast MVA	P1	P3	P4	P5	P6	200-299	200-185	200-358	200-219	200-352	200-220	200-328	200-385
TWG-T1	Dist.	66.0	12.5	13.33	9.24	X	X	X	X	X				X		X		X
VIC-T1	Dist.	66.0	12.5	13.33	8.71	X	X	X	X	X				X		X		X
VIR-T1	Dist.	66.0	12.5	25.00	20.20		X	X	X	X								X
VIR-T2	Dist.	66.0	25.0	25.00	22.53		X	X	X	X								X
VIR-T3	Dist.	66.0	25.0	25.00	11.94		X	X	X	X								X
WAL-T1	Dist.	66.0	12.5	20.00	20.74		X	X	X	X								X
WAL-T2	Dist.	66.0	12.5	25.00	21.16		X	X	X	X								X
WAV-T6	Dist.	66.0	12.5	13.30	6.78	X	X	X	X	X				X		X		X
WBC-T1	Dist.	66.0	25.0	8.33	4.03	X	X	X	X	X							X	X
WES-T1	Dist.	66.0	12.5	13.33	9.75	X	X	X	X	X				X		X		X
CAB-T1	Gen.	66.0	7.2	11.25	N/A	X	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	X								
HCT-T1	Gen.	66.0	4.2	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	X								
LOK-T2	Gen.	66.0	46.0	7.46	N/A	X	X		X	X								
LOK-T4	Gen.	46.0	6.9	2.50	N/A	X	X		X	X								
MOP-T1	Gen.	66.0	6.9	13.33	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	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	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	2026 Forecast MVA	P1	P3	P4	P5	P6	200-299	200-185	200-358	200-219	200-352	200-220	200-328	200-385
PHR-T1	Gen.	66.0	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									
ROP-T1	Gen.	66.0	6.9	5.33	N/A	X	X		X	X								
SBK-T1	Gen.	66.0	6.9	7.00	N/A	X	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	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	4.2	0.33	N/A	X												
WBK-T1	Gen.	12.5	4.2	0.33	N/A	X												
WBK-T1	Gen.	12.5	4.2	0.33	N/A	X												
WES-T2	Gen.	66.0	13.8	16.00	N/A													
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			

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	2026 Forecast MVA	P1	P3	P4	P5	P6	200-299	200-185	200-358	200-219	200-352	200-220	200-328	200-385
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		X	X	X									
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										

APPENDIX B:

Portable Substation Fleet Corrective Maintenance

P135

Year	Maintenance Level/ Scope	Summary of Work Completed
2021	M4 – Major Maintenance	• Oil system maintenance including conservator oil top-up and gas detector replacement • Replaced humidity control in cabinets and junction boxes • Performed electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing, demagnetization) • Cleaned, inspected, and retorqued HV transformer connections • Installed metal access platforms and safety railings • Completed structural reinforcement and corrosion repairs to trailer components • Removed, tested, and reinstalled grounding system • Repainted portable substation • Replaced humidity control in cabinets and junction boxes
2022	M4 – System-Wide Maintenance	• Completed M4 maintenance on power transformer, air-break switches, high-speed grounding switches, and 27 kV vacuum circuit breaker • Conducted transformer testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing, protection checks) • Serviced oil system and replaced gas detector • Tested cooling systems including pumps, fans, heaters, and control wiring • Maintained and adjusted protection and control systems (trip, alarm, limit switches, motor operators) • Refurbished 27 kV breaker including vacuum bottle hi-pot testing and motion analysis • Replaced humidity control in cabinets and junction boxes • Repaired structural cracks in breaker housing (welded, primed, painted) • Completed trailer, fender, and support repairs with new hardware • Continued humidity control, enclosure maintenance, and corrosion mitigation

P335

Year	Maintenance Level/Scope	Summary of Work Completed
2021	M3 / M4 Diagnostic Testing & Major Maintenance	• Changed LV tap configuration and verified transformer ratios • Performed electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing, demagnetization) • Serviced gas detector and protection devices • Identified and documented bushing oil leaks for future correction • Structural repair to cracked trailer welds • Replaced humidity control in cabinets and junction boxes
2022	M4 – System-Wide Maintenance	• Completed M4 maintenance on transformer and auxiliary systems • Changed internal tap configuration • Performed electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing, demagnetization) • Serviced and tested oil system and gas detector • Cleaned, inspected, and retorqued HV and LV transformer connections • Installed new varmint guards and upgraded grounding • Trailer, hydraulic, and structural inspections completed
2024	M3 / M4 Diagnostic Testing & Major Maintenance	• Serviced and tested oil system and replaced gas detector • Performed electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing, demagnetization) • Replaced humidity control in cabinets and junction boxes
2025	M3 / M4 Diagnostic Testing & Major Maintenance	• Replaced wiring associated with flow gauges due to poor insulation results • Serviced and tested protection devices • Performed electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing, demagnetization) • Changed HV links • Repaired cooling pump system • Repainted portable substation and refurbished cabinets.

P435

Year	Maintenance Level/Scope	Summary of Work Completed
2021	M4 – Major Maintenance	• Performed electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing, • Serviced and tested oil system • Removed, tested, and reinstalled grounding system • Cleaned, inspected, and retorqued HV connections • Serviced and tested protection devices • Repainted portable substation • Replaced humidity control in cabinets and junction boxes
2023	**M4 –** Major Maintenance	• Performed electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing, • Serviced and tested oil system • Removed, tested, and reinstalled grounding system • Cleaned, inspected, and retorqued HV connections • Serviced and tested protection devices • Repainted portable substation • Replaced humidity control in cabinets and junction boxes
2024	**M4 –** Major Maintenance	• Performed electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing, • Serviced and tested oil system • Removed, tested, and reinstalled grounding system • Cleaned, inspected, and retorqued HV connections • Serviced and tested protection devices • Replaced humidity control in cabinets and junction boxes • Air-break and high-speed ground switches inspected, cleaned, and lubricated
2025	M3 / M4 – Diagnostic Testing & Major Maintenance	• Performed electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing, • Serviced and tested oil system • Cleaned, inspected, and retorqued HV connections • Serviced and tested protection devices • Replaced humidity control in cabinets and junction boxes

P535

Year	Maintenance Level/Scope	Summary of Work Completed
2021	M3 / M4 – Diagnostic Testing & Major Maintenance	• Performed electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing, • Serviced and tested oil system • Removed, tested, and reinstalled grounding system • Cleaned, inspected, and retorqued HV connections • Serviced and tested protection devices • Hydraulic System Maintenance • Replaced humidity control in cabinets and junction boxes • Control cabinets inspected, cleaned, sealed, and humidity control improved
2023	M3 / M4 – Diagnostic Testing & Major Maintenance	• Performed electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing, • Serviced and tested oil system • Removed, tested, and reinstalled grounding system • Cleaned, inspected, and retorqued HV connections • Serviced and tested protection devices • Repainted portable substation • Replaced humidity control in cabinets and junction boxes • Tapchanger maintenance completed (mechanical inspection, oil testing, counter verification, functional checks) • Structural and mobile equipment repairs completed (platforms, doors, booster repairs)
2025	M4 – Comprehensive Transformer, Protection & Auxiliary Systems Maintenance	• Performed electrical testing (Insulation Resistance testing, Power Factor testing, Transformer Turns Ratio testing, • Serviced and tested oil system • Removed, tested, and reinstalled grounding system • Serviced and tested protection devices • Repainted portable substation • Replaced humidity control in cabinets and junction boxes • Hydraulic System Maintenance • SF_6 breaker, HGS, and auxiliary equipment cleaned, lubricated, torqued, and tested • Varmint guarding installed • Fans, pumps, generator, hydraulic systems, batteries, and control cabinets serviced and upgraded

APPENDIX C:

Power Transformer Failures: 2016 to 2025

Table C-1 lists Newfoundland Power's actual experience with respect to substation power transformer failures from 2016 to 2025.

Table C-1
Power Transformer Failures
(2016-2025)

Transformer	Voltage	Capacity (MVA)	Year Purchased	Year Failed	Action	Portable Required	Type of Failure
COB-T3	138 – 12.5	25	2012	2025	Repair	No	In-Service
VIR-T2	66 – 12.5	25	1990	2025	Repair	No	Imminent
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.

May 2026

3.1 Rose Blanche Hydro Plant Refurbishment

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NEWFOUNDLAND POWER
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TABLE OF CONTENTS

Page

1.0 INTRODUCTION

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") Rose Blanche Hydro Plant (the "Rose Blanche Plant" or the "Plant") is located on the southwest coast of the island of Newfoundland near the town of Rose Blanche – Harbour Le Cou. The Plant is accessed via a gravel access roadway off Route 470 and is located 51 kilometres east of the Town of Port aux Basques. The Rose Blanche Plant was commissioned in 1998 with a capacity of 6.0 MW under a net head of approximately 114 metres. The Plant contains one General Electric generator coupled to two Francis turbines on a common shaft.[1] The Plant is connected to the Island Interconnected System via distribution feeder LGL-02 and has provided 28 years of reliable energy production.[2]

Figure 1 shows the location of the Rose Blanche Plant.

Figure 1 - Rose Blanche Plant Location

In 2027 and 2028, the Company is proposing to refurbish obsolete components of the governor system, protection and control system, as well as replacement of the Plant's auxiliary power unit. The obsolete equipment has reached the end of its service life and investment is necessary to mitigate the risk associated with an in-service failure.

The project is estimated to cost $649,000 in 2027 and $1,079,000 in 2028.

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1 One turbine was refurbished in 2018 in response to damage sustained during an in-service failure.

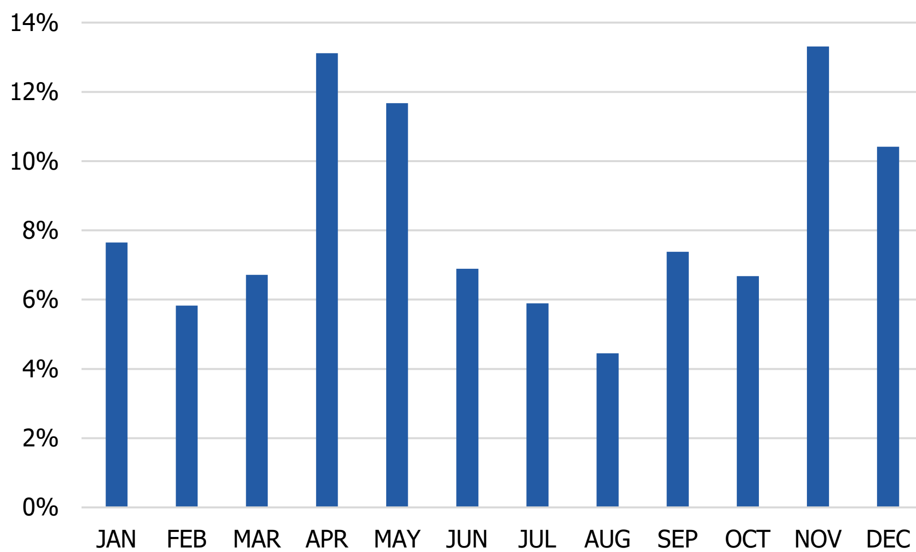
2 Distribution feeder LGL-02 connects the Plant and the communities of Burnt Islands, Diamond Cove and Rose Blanche - Harbour Le Cou to the Long Lake ("LGL") Substation which is located near the community of Burnt Islands.

2.0 BACKGROUND

The normal annual production of the Rose Blanche Plant is approximately 21.90 GWh, or 5.0% of the total normal hydroelectric production of Newfoundland Power.[3] The Plant is typically operated during all 12 months of the year.

Figure 2 shows the average production of the Plant by month based on the most recent five-year average from 2021 to 2025.

Figure 2
Rose Blanche Average Annual Production
(Percentage by Month)



The Rose Blanche Plant is operated throughout the year as a source of low-cost energy for Newfoundland Power's customers. The Plant is also routinely placed into service at the request of Newfoundland and Labrador Hydro ("Hydro"). These requests are most often received during the winter peak period, although non-peak operation is also requested. In addition, the Plant is often operated as a backup supply during periods when radial transmission lines TL214 and TL215 are unavailable. During these periods, the Plant operates along with thermal generation assets in the Port aux Basques area to supply the region as an isolated system until TL214 and TL215 are returned to service.

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[3] Newfoundland Power retained Hatch in 2020 to conduct an updated *Hydro Normal Production Review*. The review was completed in April 2021, setting the annual production for the Rose Blanche Plant at 21.90 GWh.

Table 1 lists the major upgrades that have been completed at the Rose Blanche Plant over the last 25 years.[4]

Table 1
Rose Blanche Plant Upgrades

Year	Upgrade
2009	Access Road Upgrades
2009	Increase Storage and Spillway Capacity
2017	Forebay Road Upgrades
2017	Penstock Burying
2017	Fish Compensation Valve Extension
2018	Generator Rotor Replacement
2018	G1 Runner Replacement
2019	Fishway Grating
2021	Plant Control System Upgrades

3.0 CONDITION ASSESSMENT

Newfoundland Power identified the obsolescence of the governor control system while completing plant control system upgrades in 2021. Observed conditions have indicated that during the warmest summer months, the governor oil cooler is not sufficiently sized to effectively cool the governor oil. The Plant protection and control system is also obsolete. During winter black start operations, the auxiliary power unit is undersized and cannot maintain sufficient temperature in the Plant to avoid freezing of plant components, rendering them unusable.[5] The below condition assessment summarizes information collected by Newfoundland Power during various inspections.

3.1 Governor System

The governor control system receives inputs from the Plant's supervisory programmable logic controller ("PLC") and controls the hydraulic pressure unit and wicket gate arms to maintain the desired generation output of the Plant. The Plants supervisory PLC was modernized in 2021 with Newfoundland Power's standard Allen Bradley PLC.[6]

The existing governor control system is original to the Plant and consists of a Sulzer SICOS compact control unit with a DTL595 controller and multiple analog and binary input/output modules. External communications from the controller are limited to either CANbus or ASCII messaging through legacy RS232 ports. All connections to the supervisory PLC are via hardwired signals which limit functionality in comparison to a modern PLC implementation.

4 Major upgrades are defined as upgrade work valued over $50,000.
5 A black start is the process of restoring the plant to operation from a complete shutdown without assistance from the larger power system.
6 The Plants supervisory PLC will not be replaced as part of the proposed work and will be incorporated into the new solution during installation of new components.

The main controller operates on the SICOS Access configuration software. The SICOS Access software, main controller and input/output modules are no longer manufactured or supported by the manufacturer with spare components unavailable for purchase. The SICOS Access software is only deployable on an obsolete MS DOS operating system. This is the only Sulzer governor control system in Newfoundland Power's fleet, with no opportunity to salvage parts existing in the Company's inventory.

Figure 3 shows the components of the governor control system.

Figure 3 - Governor Control System Controller and Modules

The governor hydraulic power unit ("HPU") provides mechanical energy to the wicket gate control arms such that the wicket gates can be correctly positioned to provide the required electrical generation from the Plant. The HPU also serves as a lubricating oil cooler for the Plant's various bearings. The hydraulic power unit contains a tube-in-tube style oil cooler where water from the penstock is used to cool the lubricating and hydraulic oil which has been warmed during operation of the generating unit.

Conditions observed during operation of the Plant have confirmed that, during the warmest months, the governor oil cooler does not provide sufficient cooling for the governor oil system. Excessive oil temperature results in oil degradation and the premature wear of system components.

Figure 4 shows the governor hydraulic power unit.

Figure 4 – Governor Hydraulic Power Unit

3.2 Protection and Control System

The Plant's protection and control system is entirely housed within the generator switchgear enclosure, installed in 1998, and is comprised of various electronic devices, many of which are obsolete. Generator protection is currently implemented using a Beckwith M-3420 protection relay. This relay is the only such relay in Newfoundland Power's fleet and is at the end of its useful life. Additionally, the Beckwith M-3420 does not facilitate remote network connection for troubleshooting and event analysis.[7]

Presently, transformer protection of the generator step-up ("GSU") transformer is achieved using ABB SPAD and SPAJ relays, both of which are obsolete as of 2012 and 2009, respectively. These relays also do not provide event analysis or metering.

[7] Remote network connection can mitigate the need to dispatch staff to the Plant for certain Plant trip scenarios, allowing for faster return to service after a system disturbance and reduced labour costs.

Figure 5 shows the protection and control system display.

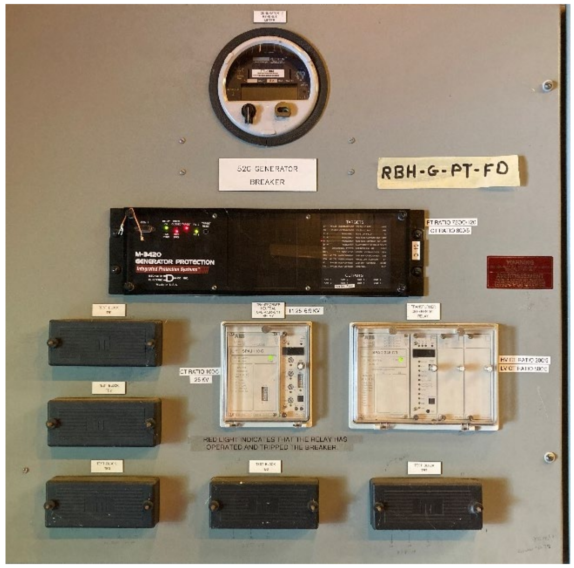

Figure 5 - Protection and Control System Display

The excitation control and synchronization system is currently controlled by a DECS-150 pilot excitation controller, BE1-25A auto-synchronizer, and a BE1-25 sync-check relay. All relays are now obsolete and do not facilitate remote connection for troubleshooting. These relays also no longer have replacement units or components available.

The 2021 control system upgrade work provided a new operator interface as well as upgraded connection between the Plant and Newfoundland Power's System Control Centre. The current control system uses SLC input/output racks to connect control equipment to the new operator interface. The modules in these SLC racks are obsolete.

The forebay monitoring system is implemented using a control microsystem 5000 series SCADAPack for monitoring and communication between the forebay and the Plant. This system provides critical monitoring for correct operation of Newfoundland Power's water management system, as well as for the protection of the Plant penstock from dewatering due to intake blockages. The forebay monitoring system is obsolete.

3.3 Auxiliary Power Unit

The auxiliary power unit ("APU") is original to the Plant and is used to provide station service power when distribution feeder LGL-02 is unavailable. The APU is required to support black start capabilities for the Plant. The unit consists of an 8.5 kW propane fuelled Kohler Power Systems generator complete with propane storage tank, fuel line, automatic transfer switch and distribution panel.

The generator is undersized for the load required to black start the Plant during prolonged periods of cold weather, and no vendor support is available.

Figure 6 shows the auxiliary power unit.

Figure 6 - Auxiliary Power Unit

4.0 RISK ASSESSMENT

Components of the Rose Blanche Plant, including the governor system, protection and control system, and auxiliary power unit are obsolete and require replacement.

The governor system, including the controller, input/output modules and software, are no longer manufactured or supported by the manufacturer. The governor system is unique in the Newfoundland Power fleet. As such, use of spare components from other governor systems is not possible. The governor system is a critical component of the Plant. Without a functioning governor system, the Plant cannot produce electricity. Due to the complexity of the design requirements and product lead times, an in-service failure of the governor control system is anticipated to result in a plant outage of approximately 18 months.

The governor oil cooler, which is an integral component of the hydraulic power unit, can no longer effectively cool the oil for safe operation of the governor control arms and unit bearings. The cooler does not provide sufficient cooling capacity to keep the oil from overheating during operation. Without effective cooling, the governor system cannot operate as originally designed and can result in unit outages.

The protection and control system is now obsolete with no replacement parts available. These components are critical to the safe operation of the Plant, and any failure of these components can lead to consequences which would require significant repairs to Plant components. Similar to the governor system, these repairs have the potential to result in lengthy Plant outages.

The auxiliary power unit provides electrical supply to black start the Plant. To complete Plant start-up when the distribution feeder supplying the Plant is unavailable, the auxiliary power unit is placed into service to provide energy required to place the Plant back into service. During prolonged winter periods of cold temperatures, the heating load required to maintain the Plant at a temperature whereby the cooling water lines do not freeze is not possible with the current unit. The Plant is remote, and during winter storms it takes considerable time for staff to access the Plant to place it back into service. During the time it takes staff to access the site, cooling water pipes are at risk of freezing. The Southwestern coast of Newfoundland is located at the end of radial transmission line 214L. During winter storms, this area can become disconnected from the Island Interconnected system and run as a local isolated electrical system. The ability to place the Plant back into service quickly is critical to restoring service to customers.

5.0 LIFECYCLE COST ANALYSIS

A lifecycle cost analysis has determined that continued operation of the Rose Blanche Plant will provide an economic benefit to customers over the longer term and that the risk of the Plant becoming stranded is very low. The analysis compared the cost of continued operation of the Plant to the cost of replacement production. The results are presented on a levelized cost of energy basis and are therefore expressed in terms of cents per kWh of production.

Table 2 summarizes the results of the lifecycle cost analysis of the Rose Blanche Plant.

Table 2
Rose Blanche Plant Lifecycle Cost Analysis Results

	50 Year Levelized Value	Net benefit
Lifecycle Cost of the Plant	4.36 ¢/kWh	-
Cost of Replacement Production (Run-of-River)	12.36 ¢/kWh	8.00 ¢/kWh
Cost of Replacement Production (Fully Dispatchable)	20.83 ¢/kWh	16.47 ¢/kWh

The analysis shows the Plant's production provides a net benefit for customers of between 8 ¢/kWh and 16.47 ¢/kWh. The significant differences between costs and benefits suggest any reasonable variance in the cost estimates will support the continued operation of the Plant.

The present value of the cost of continued operation of the Plant is $13.9 million. This compares to the cost of replacing the Plant's production of between $39.5 and $66.5 million.

Appendix A to this report provides the detailed lifecycle cost analysis.

6.0 ASSESSMENT OF ALTERNATIVES

6.1 General

A condition assessment and corresponding risk assessment determined that the Rose Blanche Plant contains deteriorated, obsolete and non-standard equipment that requires refurbishment or upgrade to ensure the continued safe and reliable operation of the Plant. A lifecycle cost analysis confirmed that continued operation of the Plant will provide an economic benefit for Newfoundland Power's customers over the longer term.

Newfoundland Power identified and assessed two alternatives to address the deteriorated condition of the Rose Blanche Plant: (i) refurbish the Plant in 2027 and 2028; and (ii) replace governor and protection and control systems after in-service failure. There are currently no alternatives for the governor oil cooler or auxiliary power unit as both do not currently effectively function as required for reliable Plant operation. The assessment of each alternative is detailed below.

6.2 Alternative 1: Refurbish Plant in 2027 and 2028

Alternative 1 involves replacing the governor control system, governor oil cooler and auxiliary power unit in 2027 and 2028. This alternative reduces the risk of failure and ensures the continued provision of low-cost generation to customer and mitigates risks to reliable service to the southwest coast of Newfoundland.

6.3 Alternative 2: Deferred Replacement Until In-Service Failure

The governor and protection and control systems have been in service for 28 years. An in-service failure would result in a Plant outage of approximately 18 months. The cost of a Plant outage as a result of an in-service failure is $2,037,000 annually. Due to the costs incurred, allowing the current system to fail in-service is not considered a viable alternative. In addition, these control systems provide protective functions for other plant equipment. An in-service failure of either system could result in significant damage to other plant equipment depending on the failure modes experienced.

7.0 PROJECT SCOPE

The assessment of alternatives determined that replacing the governor control system and the protection and control system in 2027 and 2028 is necessary to address deteriorated and obsolete equipment. Replacement of the governor oil cooler and auxiliary power unit is necessary as they do not meet the current requirements for reliable Plant operation.

Design and procurement will occur in 2027, with construction completed by year-end 2028.

8.0 PROJECT COST

Table 3 provides a breakdown by category of the cost of the *Rose Blanche Hydro Plant Refurbishment* project.

Table 3
Rose Blanche Hydro Plant Refurbishment Project
2027-2028 Budget
($000s)

Cost Category	2027	2028
Material	556	638
Labour – Internal	15	170
Labour – Contract	-	-
Engineering	44	148
Other	34	123
Total	$649	$1,079

The proposed *Rose Blanche Hydro Plant Refurbishment* project is estimated to cost $649,000 in 2027 and $1,079,000 in 2028 for a total project budget of $1,728,000.

9.0 CONCLUSION

Condition assessments and operational observations have confirmed that the governor control system at the Rose Blanche Plant is obsolete, the governor oil cooler and auxiliary power unit do not effectively function as required. The assessment of alternatives confirms that upgrading the governor control system, governor oil cooler and replacement of the Plant auxiliary power unit provide significant benefit to customers.

The governor and auxiliary power unit systems are critical to the operation of the Rose Blanche Plant. An updated lifecycle cost analysis confirms that continued operation of the Plant, including the cost of the work proposed in this application, will provide an economic benefit for customers over the longer term.

APPENDIX A:

Lifecycle Cost Analysis of the Rose Blanche Hydro Plant

TABLE OF CONTENTS

Page

1.0 INTRODUCTION

This lifecycle evaluation examines the future viability of generation at Newfoundland Power's Rose Blanche hydroelectric generating plant (the "Rose Blanche Plant" or the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2027, 2028 and beyond.

This evaluation compares the cost of continued operation of the Plant to the cost of replacing Plant production. The analysis includes a study period of 50 years and expresses the results in terms of the levelized cost of energy.

2.0 LIFECYCLE COSTS

2.1 Capital Costs

Table A-1 provides all significant capital expenditures for the Rose Blanche Plant over the next 25 years.

Table A-1
Rose Blanche Plant
Capital Expenditures
($000s)

Year	Expenditure
2027	649
2028	1,079
2033	25
2036	5,500
2048	1,700
2049	4,520
2051	750
Total	$14,223

The estimated capital expenditure for the Plant is $14,223,000 over the next 25 years.[1] These capital expenditures include the expenditures proposed for 2027 and 2028 and future capital expenditures commencing in 2033.

Attachment A provides a breakdown of capital costs.

[1] Capital expenditures beyond the initial 25 years are included in the analysis and are broadly indicative of the expenditures anticipated.

2.2 Operating Costs

Annual operating costs for the Plant, including water rental fees, are estimated to be approximately $222,000 per year.[2] The operating cost represents both direct charges for operations and maintenance at the Plant, as well as indirect costs such as those related to managing the environment, safety, dam safety inspections, and staff training. The annual water rental fee is approximately $72,000 for 2027.[3] This fee, adjusted for inflation, will be paid annually to the Provincial Government based on the Plant's production.

Attachment B provides a summary of operating costs.

2.3 Cost of Spill During Construction

Included in the lifecycle cost is the cost of reduced production from the Plant during the refurbishment project. During construction, the Plant will be out of service for a period of time. This will result in the spillage of water from its reservoirs and reduced Plant production. In 2028, it is expected that approximately 9.1 GWh of reduced production will occur, which will result in additional costs to replace lost production of approximately $256,000.

3.0 COST OF PLANT DOWNTIME

3.1 General

If the refurbishment project does not proceed as proposed, there is risk that the Plant will be out of service for a prolonged period due to equipment failure and potential safety hazards. Taking the Plant out of service will result in replacing its production with additional power from Newfoundland and Labrador Hydro ("Hydro"). The cost to replace the production from the Plant consists primarily of: (i) marginal energy costs; and (ii) the potential need to add generation capacity.

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2 Reflects 2025 dollars.

3 The water rental rate is the Provincial Government legislated water power rental charge. The charge in 2025 was $3.15/MWh and is increased annually by the Consumer Price Index (CPI) All Items for Canada. The additional cost is added to the annual operating cost.

Table A-2 provides a breakdown of the normal production of the Plant.

Table A-2
Normal Production from Rose Blanche Plant

Marginal Cost Period	Normal Production (GWh)	Production (%)
Non-Winter Period (All hours)	15.33	70
Winter Period		
On-Peak	3.07	14
Off-Peak	3.50	16
Annual Production	21.9	100

3.2 Marginal Energy Cost

The Island Interconnected System is connected to the North American power grid through the Labrador Island Link and the Maritime Link. An updated marginal cost study (the "Marginal Cost Update") completed by Hydro in 2025 provides estimates of the marginal energy cost as the opportunity cost of selling energy to other jurisdictions.[4] The marginal energy cost estimates vary by time of day and by season. To recognize these time-varying characteristics, the costs are summarized by winter on-peak, winter off-peak and non-winter peak periods.

Attachment C to this report provides the forecast marginal energy costs for the period 2026 to 2045.

3.3 Cost of Replacement Capacity

The Island Interconnected System's need for new capacity additions is being reviewed by the Board of Commissioners of Public Utilities. Removing the Plant from service would reduce the capacity available to supply customers and increase the need for new generation sources.[5]

The Marginal Cost Update provides estimates of the marginal cost of generation capacity for the Island Interconnected System in terms of cost per MWh and cost per kW of peak demand.

The Plant can provide 6.0 MW of capacity during the winter. The cost of replacement capacity is dependent on the extent to which this capacity is available to meet peak load conditions. This is impacted by the amount of storage, the timing of rainfall, how the Plant is dispatched, the volume of requests by Hydro to maximize generation and the potential that the Plant is out of service when required to meet increased customer demand.

[4] The most recent marginal cost study results are found in Hydro's Marginal Cost Update. The marginal cost study covers the period from 2026 to 2045.

[5] In its *Reliability and Resource Adequacy Study – 2022 Update* Hydro stated that "Regardless of the assumptions made for the Island Interconnected System load growth, the LIL capacity and bipole forced outage rate, the Island Interconnected System will be significantly capacity constrained once the Holyrood TGS and the Hardwoods Gas Turbine are retired." See *Reliability and Resource Adequacy Study – 2022 Update, Volume III, Long Term Resource Plan*, Page 51, lines 25-27.

To assess the cost of replacement capacity, Newfoundland Power completed an evaluation under two assumptions: (i) assuming the Plant's production reflects a *run-of-river* hydro plant; and (ii) evaluating the Plant as a *fully dispatchable* plant.

A *run-of-river* plant has little storage and provides minimum flexibility for the Company to schedule production for periods of greatest value.[6] The capacity from a run-of-river plant is dependent on the extent to which timing of the river flow will correspond to periods when the cost of capacity is the greatest. Evaluation of a run-of-river plant is completed by applying the production for each marginal cost time period to the appropriate marginal generation capacity cost.

Fully dispatchable generation, on the other hand, has sufficient storage to allow it to produce at its full rated capacity for all potential periods of need. This would be similar to a gas turbine, which can be dispatched at any time to provide its rated capacity to support customer demand. The capacity of a fully dispatchable plant is primarily reflective of its rated capacity and the likelihood it is not available for service.

Newfoundland Power's hydro generation facilities operate between being run-of-river and fully dispatchable generation plants. The Plant has total available storage of approximately 0.776 GWh. This level of storage represents approximately 5 days of production at a production rate of 6.0MW. However, storage levels are often not full, and there are practical limitations to managing the flow of water from storage to the forebay. These practical considerations limit the Company's ability to maintain continuous production at rated capacity for extended periods of time.[7]

4.0 LIFECYCLE ANALYSIS RESULTS

An analysis has been completed comparing the lifecycle costs of the Plant to the cost of replacement production over a 50-year study period. The Marginal Cost Update covers the period from 2026 to 2045. As a result, there is no forecast of marginal costs beyond this period. For the purposes of the 50-year study period, the Company has used the GDP Deflator to escalate marginal cost for the remaining years of the 50-year study period.

The costs are presented on a levelized cost of energy approach. The levelized cost of energy expresses the costs and benefits in terms of a ¢/kWh of production.

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6 As examples, periods of greatest value for production include during generation shortages and peak demand periods.

7 During periods of low water availability, such as during the summer months, generation capacity from the Plant will be limited and reflect a run-of-river system. During periods with greater water availability, such as during the spring and fall, generation capacity from the Plant will be high and reflect a fully dispatchable system. Since, at certain times of the year, the Plant operates as either a run-of-river system or a fully dispatchable system, the lifecycle analysis includes the value of capacity under both scenarios to assess the lowest and highest value of capacity from the Plant.

Table A-3 compares the estimated levelized costs of the Plant's production and the cost of replacement production.

Table A-3 Lifecycle Analysis Results		
	50 Year Levelized Value[8]	Net benefit
Lifecycle Cost of the Plant	4.36 ¢/kWh	
Cost of Replacement Production (Run-of-River)		
Energy Costs	5.05 ¢/kWh	
Capacity Costs	7.32 ¢/kWh	
Total	12.36 ¢/kWh	8.00 ¢/kWh
Cost of Replacement Production (Fully Dispatchable)		
Energy Cost	5.05 ¢/kWh	
Capacity Cost	15.78 ¢/kWh	
Total	20.83 ¢/kWh	16.47 ¢/kWh

The cost to replace the Plant's production will exceed the Plant's cost by between 8 ¢/kWh and 16.47 ¢/kWh. The significant difference between costs and benefits suggest any reasonable variance in the estimates of the costs and benefits will support the continued operation of the Plant.

This evaluation compares the cost of continued operation of the Plant to the cost of replacing Plant production. If the life extension of the Plant was determined to be costlier than the cost of replacing Plant production, then further analysis would be required.

Attachment D provides the detailed results of the calculated levelized costs and benefits.[9]

5.0 CONCLUSION

The results indicate that continued operation of the Rose Planche Plant is economically justified under current forecast capital, operating, marginal energy and capacity costs.

8 See Attachment D.
9 The financial assumptions used in the economic evaluation are provided in Attachment E.

Attachment A:

Summary of Capital Costs

Rose Blanche Plant Economic Analysis Summary of Capital Costs (2027-2051) ($000s)							
Description	2027	2028	2033	2036	2048	2049	2051
Civil							
Dam, Spillways and Gates	-	-	-	-	-	-	-
Penstock	-	-	-	5,500	-	-	-
Access Road and Bridges	-	-	-	-	500	-	-
Powerhouse	-	-	-	-	1,200	-	-
Mechanical							
Turbine	-	-	25	-	-	3,020	-
Powerhouse Systems	190	-	-	-	-	-	-
Electrical							
Generator Refurbishment	-	-	-	-	-	600	-
Switchgear	-	-	-	-	-	900	-
Protection and Control Systems	459	1,079	-	-	-	-	750
Other							
Substation Refurbishment	-	-	-	-	-	-	-
Total ($2023)	649	1,079	25	5,500	1,700	4,520	750

Attachment B:

Summary of Operating Costs

Rose Blanche Plant Economic Evaluation Summary of Operating Costs ($2026)	
	Amount
2021	$164,474
2022	$125,267
2023	$180,684
2024	$136,014
2025	$144,990
Average[1]	**$150,286**
Water Power Rental[2]	$71,832
Total Average Operating Cost	**$222,118**

1 Cost excludes the water power rental rate.
2 Calculated using the Provincial Government's current water rental rate ($3.15/MWh in 2025 escalated using CPI All Items for Canada) multiplied by the normal annual output of the plant.

Attachment C:

Marginal Costs Estimates

Marginal Cost Projections 2026-2045[1]
Island Interconnected System
At Hydro's Delivery Point to Newfoundland Power

Energy Supply Costs					
	Winter		Summer	Winter	Annual
	On-Peak	Off-Peak	All-Hours	All-Hours	All-Hours
Year	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
2026	106.62	90.01	39.19	97.39	58.49
2027	100.83	84.05	35.80	91.51	54.27
2028	85.88	69.58	28.17	76.82	44.29
2029	65.26	55.99	25.68	60.11	37.09
2030	63.93	55.58	25.34	59.29	36.60
2031	67.76	56.83	27.76	61.69	39.01
2032	71.74	59.62	28.94	65.00	40.90
2033	71.58	59.73	29.89	64.99	41.53
2034	71.94	62.43	29.20	66.65	41.61
2035	72.63	65.76	29.74	68.81	42.69
2036	70.37	62.99	30.67	66.27	42.47
2037	72.77	62.95	30.23	67.31	42.53
2038	77.31	67.08	30.89	71.62	44.39
2039	76.92	67.40	30.82	71.63	44.35
2040	79.83	74.17	33.85	76.68	48.05
2041	82.08	78.47	35.85	80.07	50.51
2042	84.20	77.00	37.69	80.20	51.78
2043	87.24	77.68	36.47	81.93	51.54
2044	94.60	84.63	36.63	89.06	54.01
2045	98.76	90.09	39.75	93.94	57.71

Capacity Costs				
	Winter		Summer	Winter
	On-Peak	Off-Peak	All-Hours	All-Hours
Year	$/MWh	$/MWh	$/MWh	$/MWh
2026	180.36	56.53	2.82	111.53
2027	135.85	42.49	2.07	83.96
2028	125.92	39.35	1.90	77.80
2029	157.60	49.33	2.43	97.43
2030	251.80	79.02	4.00	155.77
2031	467.19	146.91	7.62	289.18
2032	339.33	106.60	5.46	209.98
2033	372.95	117.19	6.02	230.80
2034	282.63	88.71	4.50	174.85
2035	203.08	63.62	3.16	125.57
2036	298.04	93.54	4.75	184.38
2037	306.79	96.29	4.89	189.80
2038	315.80	99.12	5.04	195.37
2039	325.07	102.04	5.19	201.12
2040	334.63	105.04	5.34	207.03
2041	344.48	108.14	5.50	213.12
2042	354.61	111.32	5.66	219.39
2043	365.05	114.60	5.83	225.85
2044	375.80	117.98	6.01	232.51
2045	386.87	121.46	6.19	239.36

1 2026-2045 based on the marginal cost projections provided by Hydro in the summary report Marginal Cost Update, dated December 2025.

Attachment D:

Calculation of Levelized Costs and Benefits

Calculation of Levelized Costs				
	PV Costs[1] ($000)	Levelized Annual Cost ($000)	Annual Production (GWh)	Levelized Unit Cost (¢/kWh)
Lifecycle Cost of Plant	13,928	955	21.9	4.36
Cost of Replacement Production (Run-of-River)				
Energy Cost	16,119	1,105	21.9	5.05
Capacity Cost	23,380	1,603	21.9	7.32
Total	39,499	2,708		12.36
Cost of Replacement Production (Fully Dispatchable)				
Energy Cost	16,119	1,105	21.9	5.05
Capacity Cost	50,429	3,457	21.9	15.78
Total	66,548	4,562		20.83

Notes:

1. See Cumulative Present Value at 50-year life on pages D-2 to D-5.

Present Worth Analysis of the Lifecycle Cost of the Plant											
Production Year	Year	Generation Hydro 65.7 yrs 8% CCA	Generation Hydro 65.7 yrs 100% CCA	Transmission 0 51.9 yrs 8% CCA	Substation 0 48.5 yrs 8% CCA	Capital Revenue Requirement	Operating Costs	Spillage Costs	Net Benefit	Present Worth Benefit	Cumulative Present Value Benefit
-1	2027	649,000	0	0	0	58,959	0	0	-58,959	-62,832	-62,832
0	2028	1,079,000	0	0	0	161,585	0	256,347	-417,932	-417,932	-480,764
1	2029	0	0	0	0	167,372	231,051	0	-398,423	-373,860	-854,624
2	2030	0	0	0	0	162,490	235,189	0	-397,679	-350,157	-1,204,781
3	2031	0	0	0	0	157,842	239,102	0	-396,944	-327,963	-1,532,744
4	2032	0	0	0	0	153,410	242,902	0	-396,312	-307,254	-1,839,997
5	2033	27,800	0	0	0	151,714	246,994	0	-398,708	-290,055	-2,130,052
6	2034	0	0	0	0	147,871	251,148	0	-399,019	-272,386	-2,402,438
7	2035	0	0	0	0	143,904	255,345	0	-399,249	-255,740	-2,658,178
8	2036	6,427,542	0	0	0	727,181	259,576	0	-986,757	-593,104	-3,251,282
9	2037	0	0	0	0	772,033	263,878	0	-1,035,910	-584,262	-3,835,543
10	2038	0	0	0	0	749,521	268,270	0	-1,017,791	-538,653	-4,374,196
11	2039	0	0	0	0	728,069	272,741	0	-1,000,810	-497,012	-4,871,208
12	2040	0	0	0	0	707,590	277,315	0	-984,905	-458,960	-5,330,169
13	2041	0	0	0	0	688,008	281,951	0	-969,959	-424,130	-5,754,298
14	2042	0	0	0	0	669,251	286,654	0	-955,904	-392,216	-6,146,514
15	2043	0	0	0	0	651,252	291,449	0	-942,701	-362,952	-6,509,466
16	2044	0	0	0	0	633,951	296,341	0	-930,291	-336,093	-6,845,559
17	2045	0	0	0	0	617,292	301,324	0	-918,616	-311,415	-7,156,974
18	2046	0	0	0	0	601,224	306,370	0	-907,593	-288,710	-7,445,684
19	2047	0	0	0	0	585,699	311,500	0	-897,199	-267,808	-7,713,493
20	2048	2,424,017	0	0	0	792,082	316,716	0	-1,108,798	-310,565	-8,024,058
21	2049	6,552,955	0	0	0	1,394,354	322,019	0	-1,716,373	-451,105	-8,475,163
22	2050	0	0	0	0	1,422,516	327,411	0	-1,749,927	-431,569	-8,906,732
23	2051	1,124,046	0	0	0	1,485,275	332,894	0	-1,818,169	-420,756	-9,327,488
24	2052	0	0	0	0	1,455,486	338,468	0	-1,793,954	-389,558	-9,717,046
25	2053	0	0	0	0	1,415,399	344,136	0	-1,759,535	-358,529	-10,075,574
26	2054	0	0	0	0	1,376,861	349,898	0	-1,726,759	-330,159	-10,405,733
27	2055	0	0	0	0	1,339,748	355,758	0	-1,695,506	-304,197	-10,709,930
28	2056	0	0	0	0	1,303,947	361,715	0	-1,665,661	-280,419	-10,990,349
29	2057	0	0	0	0	1,269,351	367,772	0	-1,637,123	-258,623	-11,248,972
30	2058	42,087	0	0	0	1,239,710	373,930	0	-1,613,640	-239,198	-11,488,170
31	2059	0	0	0	0	1,207,563	380,191	0	-1,587,754	-220,851	-11,709,022
32	2060	0	0	0	0	1,175,914	386,558	0	-1,562,471	-203,936	-11,912,957
33	2061	0	0	0	0	1,145,134	393,031	0	-1,538,165	-188,386	-12,101,343
34	2062	0	0	0	0	1,115,156	399,612	0	-1,514,768	-174,083	-12,275,427
35	2063	0	0	0	0	1,085,914	406,303	0	-1,492,217	-160,919	-12,436,346
36	2064	0	0	0	0	1,057,349	413,107	0	-1,470,456	-148,797	-12,585,143
37	2065	0	0	0	0	1,029,409	420,024	0	-1,449,433	-137,627	-12,722,770
38	2066	0	0	0	0	1,002,041	427,058	0	-1,429,099	-127,331	-12,850,101
39	2067	0	0	0	0	975,202	434,209	0	-1,409,411	-117,835	-12,967,936
40	2068	0	0	0	0	948,848	441,480	0	-1,390,327	-109,073	-13,077,009
41	2069	0	0	0	0	922,940	448,872	0	-1,371,813	-100,986	-13,177,995
42	2070	0	0	0	0	897,444	456,389	0	-1,353,832	-93,518	-13,271,513
43	2071	0	0	0	0	872,325	464,031	0	-1,336,356	-86,620	-13,358,133
44	2072	0	0	0	0	847,555	471,801	0	-1,319,356	-80,246	-13,438,379
45	2073	0	0	0	0	823,104	479,701	0	-1,302,805	-74,354	-13,512,734
46	2074	5,270,006	0	0	0	1,280,305	487,734	0	-1,768,039	-94,685	-13,607,419
47	2075	0	0	0	0	1,296,198	495,901	0	-1,792,099	-90,057	-13,697,476
48	2076	0	0	0	0	1,256,998	504,205	0	-1,761,203	-83,048	-13,780,525

Present Value of the Cost of Replacement Energy (Reduced Exports)					
Production Year	Year	Marginal Energy Costs	Total Present Worth	Cumulative Present Worth	Value of Export Sales (¢/kWh)
-1	2027	-	-	-	-
0	2028	-	-	-	-
1	2029	789,951	741,250	741,250	3.61
2	2030	779,224	686,108	1,427,358	3.56
3	2031	832,445	687,782	2,115,140	3.80
4	2032	872,514	676,445	2,791,585	3.98
5	2033	886,972	645,260	3,436,845	4.05
6	2034	886,959	605,471	4,042,317	4.05
7	2035	909,021	582,276	4,624,593	4.15
8	2036	906,642	544,950	5,169,542	4.14
9	2037	907,116	511,620	5,681,163	4.14
10	2038	945,624	500,460	6,181,623	4.32
11	2039	944,477	469,037	6,650,659	4.31
12	2040	1,023,571	476,978	7,127,637	4.67
13	2041	1,076,197	470,584	7,598,221	4.91
14	2042	1,105,753	453,700	8,051,921	5.05
15	2043	1,098,754	423,035	8,474,955	5.02
16	2044	1,148,125	414,791	8,889,747	5.24
17	2045	1,227,841	416,244	9,305,991	5.61
18	2046	1,248,401	397,123	9,703,113	5.70
19	2047	1,269,306	378,880	10,081,994	5.80
20	2048	1,290,560	361,476	10,443,469	5.89
21	2049	1,312,171	344,870	10,788,340	5.99
22	2050	1,334,143	329,028	11,117,368	6.09
23	2051	1,356,483	313,914	11,431,281	6.19
24	2052	1,379,197	299,493	11,730,775	6.30
25	2053	1,402,292	285,736	12,016,510	6.40
26	2054	1,425,774	272,610	12,289,120	6.51
27	2055	1,449,648	260,087	12,549,207	6.62
28	2056	1,473,922	248,139	12,797,347	6.73
29	2057	1,498,603	236,741	13,034,087	6.84
30	2058	1,523,697	225,865	13,259,952	6.96
31	2059	1,549,212	215,490	13,475,442	7.07
32	2060	1,575,153	205,591	13,681,033	7.19
33	2061	1,601,529	196,147	13,877,180	7.31
34	2062	1,628,347	187,136	14,064,316	7.44
35	2063	1,655,613	178,540	14,242,856	7.56
36	2064	1,683,337	170,338	14,413,194	7.69
37	2065	1,711,524	162,513	14,575,708	7.82
38	2066	1,740,184	155,048	14,730,756	7.95
39	2067	1,769,323	147,926	14,878,682	8.08
40	2068	1,798,950	141,130	15,019,812	8.21
41	2069	1,829,074	134,647	15,154,459	8.35
42	2070	1,859,702	128,462	15,282,921	8.49
43	2071	1,890,842	122,561	15,405,482	8.63
44	2072	1,922,504	116,931	15,522,413	8.78
45	2073	1,954,697	111,559	15,633,972	8.93
46	2074	1,987,428	106,435	15,740,407	9.08
47	2075	2,020,708	101,545	15,841,952	9.23
48	2076	2,054,544	96,881	15,938,833	9.38
49	2077	2,088,948	92,430	16,031,263	9.54
50	2078	2,123,927	88,184	16,119,448	9.70

Present Value of the Cost of Replacement Capacity (Run-of-River Assumption)					
Production Year	Year	Marginal Capital Costs ($)	Total Present Worth ($)	Cumulative Present Worth ($)	Avoided Generation Capacity (¢/kWh)
-1	2027	-	-	-	-
0	2028	-	-	-	-
1	2029	693,306	650,564	650,564	3.17
2	2030	1,110,225	977,555	1,628,118	5.07
3	2031	2,063,992	1,705,309	3,333,427	9.42
4	2032	1,497,614	1,161,074	4,494,502	6.84
5	2033	1,646,385	1,197,724	5,692,225	7.52
6	2034	1,246,368	850,818	6,543,043	5.69
7	2035	894,011	572,661	7,115,704	4.08
8	2036	1,314,372	790,021	7,905,726	6.00
9	2037	1,352,982	763,093	8,668,818	6.18
10	2038	1,392,822	737,133	9,405,952	6.36
11	2039	1,433,775	712,027	10,117,979	6.55
12	2040	1,475,898	687,760	10,805,739	6.74
13	2041	1,519,413	664,387	11,470,126	6.94
14	2042	1,564,067	641,750	12,111,876	7.14
15	2043	1,610,176	619,939	12,731,815	7.35
16	2044	1,657,738	598,903	13,330,718	7.57
17	2045	1,706,632	578,556	13,909,274	7.79
18	2046	1,735,210	551,979	14,461,253	7.92
19	2047	1,764,266	526,623	14,987,875	8.06
20	2048	1,793,808	502,431	15,490,307	8.19
21	2049	1,823,846	479,351	15,969,658	8.33
22	2050	1,854,386	457,331	16,426,989	8.47
23	2051	1,885,438	436,323	16,863,312	8.61
24	2052	1,917,009	416,279	17,279,591	8.75
25	2053	1,949,109	397,157	17,676,748	8.90
26	2054	1,981,747	378,913	18,055,661	9.05
27	2055	2,014,932	361,507	18,417,168	9.20
28	2056	2,048,672	344,900	18,762,068	9.35
29	2057	2,082,977	329,056	19,091,124	9.51
30	2058	2,117,856	313,941	19,405,065	9.67
31	2059	2,153,320	299,519	19,704,584	9.83
32	2060	2,189,377	285,760	19,990,344	10.00
33	2061	2,226,038	272,633	20,262,977	10.16
34	2062	2,263,313	260,109	20,523,087	10.33
35	2063	2,301,212	248,161	20,771,247	10.51
36	2064	2,339,746	236,761	21,008,008	10.68
37	2065	2,378,925	225,885	21,233,893	10.86
38	2066	2,418,760	215,508	21,449,401	11.04
39	2067	2,459,262	205,609	21,655,010	11.23
40	2068	2,500,443	196,164	21,851,173	11.42
41	2069	2,542,313	187,152	22,038,326	11.61
42	2070	2,584,884	178,555	22,216,881	11.80
43	2071	2,628,168	170,353	22,387,234	12.00
44	2072	2,672,176	162,527	22,549,761	12.20
45	2073	2,716,922	155,061	22,704,823	12.41
46	2074	2,762,417	147,938	22,852,761	12.61
47	2075	2,808,673	141,143	22,993,903	12.82
48	2076	2,855,705	134,659	23,128,562	13.04
49	2077	2,903,523	128,473	23,257,035	13.26
50	2078	2,952,143	122,571	23,379,607	13.48

Present Value of the Cost of Replacement Capacity (Fully Dispatchable Assumption)						
Production Year	Year	Effective Capacity[1] (MV)	Marginal Capacity Cost	Total Present Worth	Cumulative Present Worth	Avoided Generation Capacity (¢/kWh)
-1	2027	-	-	-	-	-
0	2028	-	-	-	-	-
1	2029	5.00	1,497,450	1,405,133	1,405,133	6.84
2	2030	5.00	2,391,600	2,105,807	3,510,940	10.92
3	2031	5.00	4,435,300	3,664,528	7,175,469	20.25
4	2032	5.00	3,223,050	2,498,775	9,674,244	14.72
5	2033	5.00	3,542,650	2,577,231	12,251,475	16.18
6	2034	5.00	2,686,550	1,833,940	14,085,415	12.27
7	2035	5.00	1,932,650	1,237,965	15,323,380	8.82
8	2036	5.00	2,834,100	1,703,474	17,026,854	12.94
9	2037	5.00	2,917,850	1,645,691	18,672,545	13.32
10	2038	5.00	3,004,100	1,589,881	20,262,426	13.72
11	2039	5.00	3,092,950	1,535,990	21,798,416	14.12
12	2040	5.00	3,184,450	1,483,935	23,282,351	14.54
13	2041	5.00	3,278,700	1,433,663	24,716,014	14.97
14	2042	5.00	3,375,800	1,385,119	26,101,133	15.41
15	2043	5.00	3,475,750	1,338,209	27,439,343	15.87
16	2044	5.00	3,578,700	1,292,903	28,732,245	16.34
17	2045	5.00	3,684,800	1,249,164	29,981,410	16.83
18	2046	5.00	3,746,502	1,191,781	31,173,191	17.11
19	2047	5.00	3,809,237	1,137,035	32,310,225	17.39
20	2048	5.00	3,873,023	1,084,803	33,395,028	17.69
21	2049	5.00	3,937,877	1,034,970	34,429,998	17.98
22	2050	5.00	4,003,816	987,427	35,417,425	18.28
23	2051	5.00	4,070,860	942,067	36,359,492	18.59
24	2052	5.00	4,139,027	898,792	37,258,284	18.90
25	2053	5.00	4,208,335	857,504	38,115,788	19.22
26	2054	5.00	4,278,803	818,113	38,933,901	19.54
27	2055	5.00	4,350,452	780,531	39,714,432	19.87
28	2056	5.00	4,423,300	744,676	40,459,108	20.20
29	2057	5.00	4,497,368	710,468	41,169,576	20.54
30	2058	5.00	4,572,677	677,831	41,847,407	20.88
31	2059	5.00	4,649,246	646,694	42,494,101	21.23
32	2060	5.00	4,727,098	616,987	43,111,088	21.58
33	2061	5.00	4,806,253	588,644	43,699,732	21.95
34	2062	5.00	4,886,734	561,604	44,261,335	22.31
35	2063	5.00	4,968,562	535,805	44,797,140	22.69
36	2064	5.00	5,051,761	511,192	45,308,332	23.07
37	2065	5.00	5,136,353	487,709	45,796,042	23.45
38	2066	5.00	5,222,361	465,305	46,261,347	23.85
39	2067	5.00	5,309,809	443,931	46,705,278	24.25
40	2068	5.00	5,398,722	423,538	47,128,816	24.65
41	2069	5.00	5,489,124	404,082	47,532,898	25.06
42	2070	5.00	5,581,039	385,520	47,918,417	25.48
43	2071	5.00	5,674,493	367,810	48,286,227	25.91
44	2072	5.00	5,769,513	350,914	48,637,141	26.34
45	2073	5.00	5,866,123	334,794	48,971,936	26.79
46	2074	5.00	5,964,352	319,415	49,291,350	27.23
47	2075	5.00	6,064,225	304,742	49,596,092	27.69
48	2076	5.00	6,165,770	290,743	49,886,835	28.15
49	2077	5.00	6,269,016	277,387	50,164,222	28.63
50	2078	5.00	6,373,991	264,645	50,428,866	29.10

Notes:

1. Effective Capacity reflects winter capacity and an allowance for a 5% forced outage rate and a 16% reserve margin.

Attachment E:

Economic Analysis Financial Assumptions

Economic Evaluation
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects a statutory income tax rate of 30%.

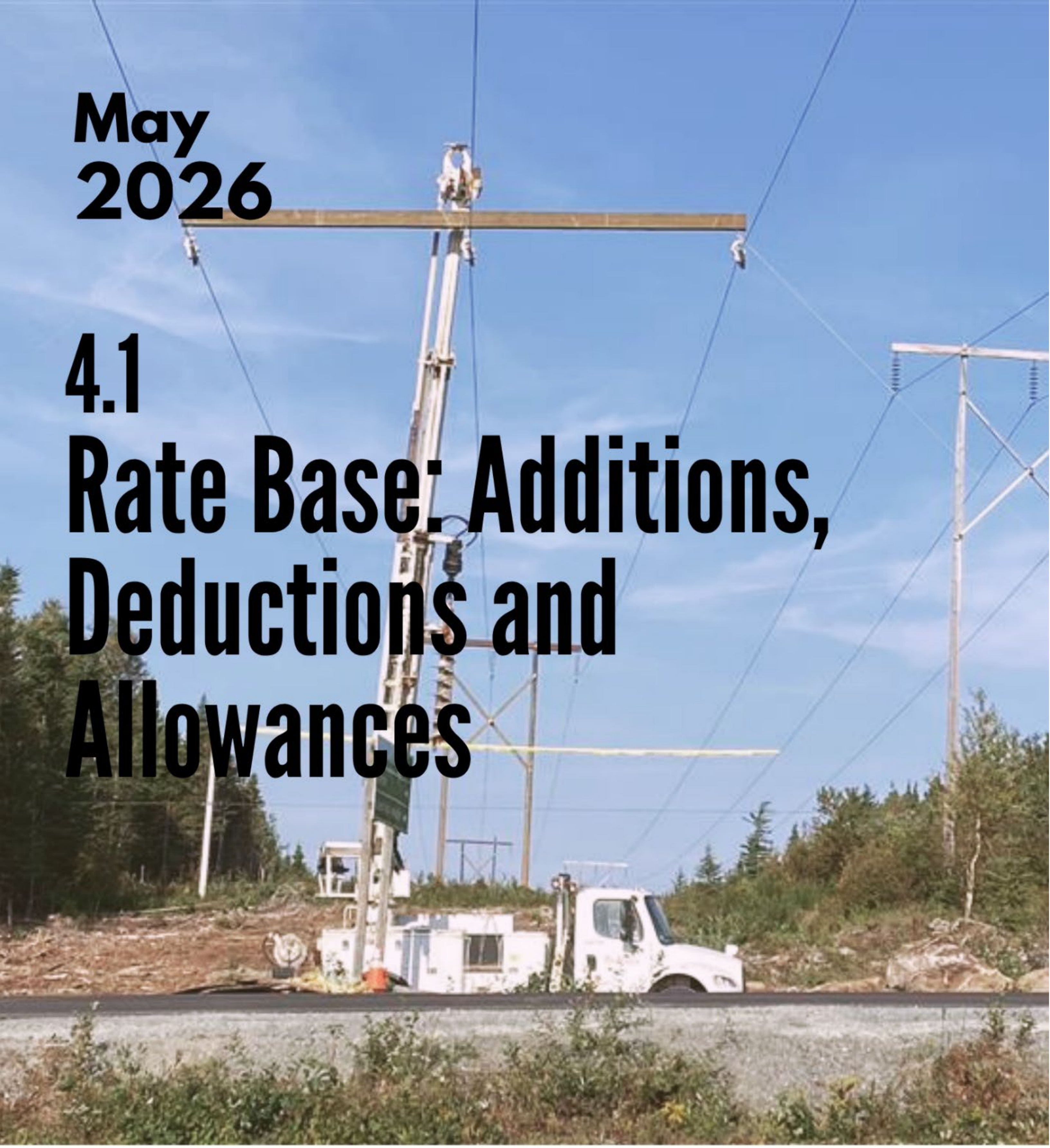
Operating Costs: Operating costs were assumed to be in 2026 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:		Capital Structure	Return	Weighted Cost
	Debt	55.00%	4.913%	2.70%
	Common Equity	45.00%	8.600%	3.87%
	Total	100.00%		6.57%

CCA Rates:	Class	Rate	Details
	17(a.1) & 47	8.00%	All generating, transmission, substation and distribution equipment not otherwise noted.
	43.2	100.00%	Expenditures related primarily to new generation or additions/alterations that increase the capacity of generating facilities.

Escalation Factors: Signal49 Research GDP deflator, medium term forecast dated February 6, 2026, and long term forecast dated March 27, 2026.

Supporting Documents: Newfoundland and Labrador Hydro's Marginal Cost Update, dated December 2025.



May
2026

4.1
Rate Base: Additions, Deductions and Allowances

NEWFOUNDLAND POWER
A FORTIS COMPANY

TABLE OF CONTENTS

Page

1.0 INTRODUCTION

In the *2027 Capital Budget Application* (the "Application"), Newfoundland Power Inc. ("Newfoundland Power" or the "Company") seeks final approval of its 2025 average rate base. This is consistent with current regulatory practice before the Board.

Newfoundland Power's 2025 average rate base of $1,419,718,000 is set out in Schedule D to the Application. This report provides a review of the 2024 and 2025 rate base additions, deductions and allowances to support the Company's 2025 average rate base set out in Schedule D to the Application.[1]

2.0 ADDITIONS TO RATE BASE

2.1 Summary

Table 1 summarizes Newfoundland Power's additions to rate base for 2024 and 2025.

Table 1
Additions to Rate Base
2024-2025
($000s)

	2024	2025
Deferred Pension Costs	108,293	109,843
Credit Facility Costs	167	161
Cost Recovery Deferral – Conservation	21,280	21,475
Cost Recovery Deferral – Revenue Shortfall	-	17,156
Cost Recovery Deferral – Load Research and Retail Rate Design Review	635	986
Cost Recovery Deferral – Hearing Costs	874	560
Cost Recovery Deferral – Pension Capitalization	1,198	849
Customer Finance Programs	1,049	1,101
Demand Management Incentive Account	1,545	-
Total Additions	$135,041	$152,131

[1] Further details associated with Newfoundland Power's 2025 average rate base are provided in the Company's *2025 Annual Report to the Board* which was filed with the Board on March 31, 2026. Return 3 provides the calculation of Newfoundland Power's 2025 average rate base.

Additions to rate base were approximately $152.1 million in 2025. This is approximately $17.1 million higher than 2024. The higher additions to rate base in 2025 primarily reflect the addition of a regulatory amortization for a revenue shortfall associated with the Company's *2025/2026 General Rate Application* as approved in Order No. P.U. 23 (2025).

This section outlines the additions to rate base in further detail.

2.2 Deferred Pension Costs

The difference between pension plan *funding* and pension plan *expense* associated with the Company's defined benefit pension plan is captured as a deferred pension cost in accordance with Order No. P.U. 17 (1987).[2]

Table 2 provides details of changes in the Company's deferred pension costs for 2024 and 2025.

Table 2
Deferred Pension Costs
2024-2025
($000s)

	2024	2025
Deferred Pension Costs, January 1st	101,430	108,293
Pension Plan Funding	1,269	1,039
Pension Plan Expense	5,594	511
Deferred Pension Costs, December 31st	$108,293	$109,843

2.3 Credit Facility Costs

In Order No. P.U. 1 (2005), the Board approved Newfoundland Power's issue of a $100 million committed revolving term credit facility.

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.

In August 2025, the committed credit facility was renegotiated to extend its maturity date to August 2030. Costs related to this amendment totalled $46,000 and are being amortized over the five-year life of the agreement, beginning in 2025.

The unamortized credit facility issue costs associated with credit facility amendments are included in rate base until they have been reflected in the Company's revenue requirement.

2 Deferred pension costs were approved for inclusion in average rate base in Order No. P.U. 19 (2003).

Table 3 provides details of Newfoundland Power's amortization of credit facility issue costs for 2024 and 2025.

Table 3
Credit Facility Costs
2024-2025
($000s)

	2024	2025
Balance, January 1st	105	167
Cost – Addition	101	46
Amortization	(39)	(52)
Balance, December 31st	$167	$161

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 2024 and 2025.

Table 4
Cost Recovery Deferral – Conservation
2024-2025
($000s)

	2024	2025
Balance, January 1st	20,708	21,280
Cost	3,966	3,874
Amortization	(3,394)	(3,679)
Balance, December 31st	$21,280	$21,475

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.

In Order No. P.U. 3 (2025), the Board approved (i) a forecast revenue shortfall for 2025 of $30.6 million ($21.4 million after-tax) resulting from the Company's *2025/2026 General Rate Application* and (ii) the subsequent amortization of the forecast revenue shortfall over a 30-month period beginning on July 1, 2025.

Table 5 provides details of the changes to the deferred cost recovery related to revenue shortfalls for 2024 and 2025.

Table 5
Cost Recovery Deferral – Revenue Shortfall
2024-2025
($000s)

	2024	2025
Balance, January 1st	229	-
Cost	6,300	21,445
Transfer to the RSA	(6,300)	-
Amortization	(229)	(4,289)
Balance, December 31st	-	17,156

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 2024 and 2025.

Table 6
Cost Recovery Deferral – Load Research and Retail Rate Design Review
2024-2025
($000s)

	2024	2025
Balance, January 1st	189	635
Cost	446	351
Balance, December 31st	$635	$986

2.7 Cost Recovery Deferral – Hearing Costs

In Order No. P.U. 3 (2025), the Board approved the Settlement Agreement recommendation for the amortization over a 30-month period of up to $1.0 million in estimated hearing costs related to the Company's *2025/2026 General Rate Application*. These costs will be amortized over the period of July 1, 2025 to December 31, 2027.[3]

Table 7 provides details of the changes in Newfoundland Power's deferred hearing costs for 2024 and 2025.[4]

Table 7
Cost Recovery Deferral – Hearing Costs
2024-2025
($000s)

	2024	2025
Balance, January 1st	-	874
Cost	874	-
Amortization	-	(314)
Balance, December 31st	$874	$560

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 increase to revenue requirement for 2024 was $1,069,000.

Charges to the account ceased effective December 31, 2024, as approved by the Board in Order No. P.U. 3 (2025).

3 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.

4 Deferred hearing cost balances are included in rate base on an after-tax basis consistent with the treatment of other regulatory assets and liabilities.

Table 8 provides details of the amortizations of the deferred cost recovery related to pension capitalization for 2024 and 2025.

Table 8 Cost Recovery Deferral – Pension Capitalization 2024-2025 ($000s)		
	2024	2025
Balance, January 1st	799	1,198
Cost	748	-
Amortization	(349)	(349)
Balance, December 31st	**$1,198**	**$849**

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 2024 and 2025.

Table 9 Customer Finance Programs 2024-2025 ($000s)		
	2024	2025
Balance, January 1st	1,199	1,049
Change	(150)	52
Balance, December 31st	**$1,049**	**$1,101**

2.10 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. In Order No. P.U. 3 (2025), the Board approved an amended DMI Account definition establishing a threshold of ±$500,000 effective January 1, 2025.

Table 10 provides details of the DMI Account for 2024 and 2025.

Table 10 DMI Account 2024-2025 ($000s)		
	2024	2025
Balance, January 1st	978	1,545
Transfers to the RSA	(978)	(1,545)
Operation of DMI	1,545	-
Balance, December 31st	$1,545	-

In 2025, the variance between actual and test year unit demand costs was within the ±$500,000 DMI Account threshold. As such, the Company absorbed the additional purchased power expense and there was no transfer to the RSA for recovery from customers.

3.0 DEDUCTIONS FROM RATE BASE

3.1 Summary

Table 11 summarizes Newfoundland Power's deductions from rate base for 2024 and 2025.

Table 11 Deductions from Rate Base 2024-2025 ($000s)		
	2024	2025
Other Post-Employment Benefits	86,308	88,543
Customer Security Deposits	618	688
Accrued Pension Obligation	5,512	5,671
Accumulated Deferred Income Taxes	33,287	34,678
Weather Normalization Reserve	2,896	(4,035)
Refundable Investment Tax Credits	294	33
Total Deductions	$128,915	$125,578

Deductions from rate base were approximately $125.6 million in 2025. Newfoundland Power's total deductions from rate base in 2025 were approximately $3.3 million lower than 2024.

The decreased deductions from rate base were primarily due to activity in the weather normalization reserve partially offset by (i) an increase in accumulated deferred income taxes reflecting continued investment in the electricity system, and (ii) an increase in Other Post-

Employment Benefits ("OPEBs") net liability reflecting the conclusion of the amortization of the OPEBs regulatory asset.[5]

This section outlines the deductions from rate base in further detail.

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 12 provides details of the changes related to the net OPEBs liability for 2024 and 2025.

Table 12
Other Post-Employment Benefits
2024-2025
($000s)

	2024	2025
Regulatory Asset	3,504	-
OPEBs Liability	89,812	88,543
Net OPEBs Liability	$86,308	$88,543

3.3 Customer Security Deposits

Customer security deposits are provided by customers in accordance with the *Schedule of Rates, Rules and Regulations*.

Table 13 provides details of the changes in customer security deposits for 2024 and 2025.

Table 13
Customer Security Deposits
2024-2025
($000s)

	2024	2025
Balance, January 1st	653	618
Change	(35)	70
Balance, December 31st	$618	$688

5 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 and ending in 2025.

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 14 provides details of changes related to the accrued pension obligation for 2024 and 2025.

Table 14
Accrued Pension Obligation
2024-2025
($000s)

	2024	2025
Balance, January 1st	5,397	5,512
Change	115	159
Balance, December 31st	$5,512	$5,671

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.[6,7,8]

Table 15 provides details of changes in the accumulated deferred income taxes for 2024 and 2025.

Table 15
Accumulated Deferred Income Taxes
2024-2025
($000s)

	2024	2025
Balance, January 1st	30,609	33,287
Change	2,678	1,391
Balance, December 31st	$33,287	$34,678

[6] 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.

[7] 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.

[8] 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).

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 16 provides details of changes in the balance of the Weather Normalization Reserve for 2024 and 2025.

Table 16
Weather Normalization Reserve
2024-2025
($000s)

	2024	2025
Balance, January 1st	(6,321)	2,896
Operation of the reserve	2,896	(4,035)
Transfers to the RSA	6,321	(2,896)
Balance, December 31st	$2,896	$(4,035)

The December 31, 2025 balance in the Weather Normalization Reserve account was approved by the Board in Order No. P.U. 10 (2026). The Company's Rate Stabilization Clause provides for the disposition of the year end balance to the RSA as of March 31, 2026.

3.7 Refundable Investment Tax Credits

Refundable Investment Tax Credits relate to provincial income tax credits for investment and in certain research and development activities. Refundable Investment Tax Credits 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 2024 and 2025.

Table 17
Refundable Investment Tax Credits
2024-2025
($000s)

	2024	2025
Balance, January 1st	292	294
Change	2	(261)
Balance, December 31st	$294	$33

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 18 provides details on changes in the cash working capital allowance for 2024 and 2025.

Table 18
Rate Base Allowances
Cash Working Capital Allowance[9]
2024-2025
($000s)

	2024	2025
Gross Operating Costs	595,523	601,654
Income Taxes	15,863	8,996
Municipal Taxes Paid	19,652	20,598
Non-Regulated Expenses	(2,511)	(3,937)
Total Operating Expenses	**$628,527**	**$627,311**
Cash Working Capital Factor	1.199%	0.466%
	$7,536	**$2,923**
HST Adjustment	15	(1,579)
Cash Working Capital Allowance	**$7,551**	**$1,344**

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.[10]

9 The cash working capital allowance for 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). The cash working capital allowance for 2025 is calculated based on the methodology used in the calculation of the 2025 Test Year average rate base approved by the Board in Order No. P.U. 23 (2025).

10 Financing costs for inventory related to the expansion of the electrical system are recovered through the use of an allowance for funds used during construction and are capitalized upon project completion.

Table 19 provides details on changes in the materials and supplies allowance for 2024 and 2025.

Table 19
Rate Base Allowances
Materials and Supplies Allowance
2024-2025
($000s)

	2024	2025
Average Materials and Supplies	18,219	19,969
Expansion Factor[11]	19.08%	13.27%
Expansion	3,476	2,650
Materials and Supplies Allowance	$14,743	$17,319

[11] The expansion factor is based on a review of actual inventories used for expansion projects. The calculation of the 2024 rate base included a materials and supplies allowance based upon an expansion factor of 19.08% as approved by the Board in Order No. P.U. 3 (2022). The calculation of the 2025 rate base included a materials and supplies allowance based upon an expansion factor of 13.27% as approved by the Board in Order No. P.U. 23 (2025).