WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

June 29, 2022

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

Attention: G. Cheryl Blundon
Director of Corporate Services
and Board Secretary

Dear Ms. Blundon:

Re: Newfoundland Power's 2023 Capital Budget Application

A. 2023 Capital Budget Application

Enclosed are the original and 10 copies of Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") *2023 Capital Budget Application* (the "Application").

The Application seeks approval of: (i) proposed single-year 2023 capital expenditures of $93,292,000; (ii) proposed multi-year projects with capital expenditures of $10,483,000 in 2023 and $10,645,000 in 2024; and (iii) 2021 rate base in the amount of $1,202,946,000.

The Application confirms there has been no change in the nature, scope or magnitude of ongoing multi-year projects previously approved in Order Nos. P.U. 37 (2020), P.U. 12 (2021), and P.U. 36 (2021), with expenditures of $19,688,000 in 2023 and $4,276,000 in 2024. Further approval of these expenditures is therefore not required.

B. Compliance Matters

B.1 The Guidelines

The Application complies with the spirit and intent of the Board's *Capital Budget Application Guidelines (Provisional)* effective January 2022 (the "Provisional Guidelines"). In correspondence dated December 20, 2021, the Board noted that strict adherence to the Provisional Guidelines may not be possible. Although the Application is broadly consistent with the requirements, there are areas where the Company was unable to fully comply, primarily due to the availability of asset data. Where the required information was not available, the Company has endeavoured to provide alternate information.

Complying with the Provisional Guidelines required substantive changes from prior capital budget applications to the format and content of the Application. For the assistance of the Board and other parties, the Company has provided a summary of the Application's compliance with the Provisional Guidelines, which is provided as Attachment A to this correspondence.

Newfoundland Power Inc.
55 Kenmount Road • P.O. Box 8910 • St. John's, NL A1B 3P6
PHONE (709) 737-5364 • **FAX** (709) 737-2974 • **lhollett@newfoundlandpower.com**

B.2 Board Orders

Compliance with previous orders of the Board can be found throughout the Application, including: (i) Order No. P.U. 12 (2021) directing the Company to report on the progress of the *Customer Service System Replacement* project;[1] (ii) Order No. P.U. 36 (2021) directing the Company to report on its 2022 capital expenditures;[2] (iii) Order No. P.U. 35 (2003) requiring a five-year capital plan;[3] (iv) Order No. P.U. 19 (2003) requiring evidence relating to deferred charges and a reconciliation of average rate base to invested capital;[4] and (v) Order No. P.U. 3 (2022) respecting changes to methodology for calculating General Expenses Capitalized.[5]

C. Filing Details and Circulation

The enclosed materials have been provided in binders with appropriate tabbing.

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

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

D. Concluding

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

Yours truly,

Lindsay Hollett
Senior Legal Counsel & Assistant
Corporate Secretary

Enclosures

c. Shirley Walsh
Newfoundland and Labrador Hydro

Dennis Browne, Q.C.
Browne Fitzgerald Morgan Avis & Wadden

1 See the *2023 Capital Budget Overview, Appendix E* filed with the Application.
2 See the *2022 Capital Expenditures Status Report* filed with the Application.
3 See the *2023-2027 Capital Plan* filed with the Application.
4 See report *6.1 Rate Base: Additions, Deductions and Allowances* filed with the Application.
5 See Schedule B to the Application.

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Attachment A:
Capital Budget Guidelines Compliance Summary

Capital Budget Guidelines Compliance Summary

The Provisional Guidelines provide guidance with respect to the format and content of capital budget applications. This guidance is primarily provided via Appendix A to the Provisional Guidelines, which is divided into four parts: (i) General Context; (ii) Organization; (iii) Required Information; and (iv) Prioritization.

Table A-1 summarizes Newfoundland Power's compliance with *Part I. General Context* of the Provisional Guidelines.

Table A-1
Provisional Guidelines Compliance Summary
Part I. General Context

Part	Requirement	Reference
I.A. Application Summary	A summary of the capital budget application and a discussion of the major activity drivers in each of the investment classifications. A discussion of the process followed to determine the expenditures which would be proposed and to confirm that these expenditures could not or should not be modified, re-prioritized or deferred until a future year. This should include an explanation as to: 1. The expenditures which had been planned for the year but which were modified, reprioritized or deferred until a future year. 2. The expenditures which are proposed for the year after having been deferred in a previous year.	See the *2023 Capital Budget Overview* for: - A summary of the Application and major activity drivers (sections 1.0 and 3.0); - A description of Newfoundland Power's capital planning process (section 2.2); and - A list of the capital expenditures that have been deferred, modified or advanced as a result of this capital planning process (Appendix B).
I.B Reliability Information	Historic and forecast system reliability trend information, including: 1. System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") graphs and tables for the overall electrical system as a whole and any relevant sub-segments: 2. A list of the 10 worst performing feeders including relevant outage statistics compared to utility averages for the past 10 years.	See the *2023 Capital Budget Overview* for: - Historical reliability performance under normal operating conditions and a comparison to the Canadian average (section 2.3.1); - A comparison to the Atlantic Canadian average (section 2.3.4); and - A list of worst performing feeders (Appendix D). See the *2023-2027 Capital Plan* (section 2.3 Operations Outlook) for a discussion of reliability performance targets and system reliability performance including significant events.

Table A-1 Provisional Guidelines Compliance Summary Part I. General Context		
Part	Requirement	Reference
I.C Rate Impact Summary	Summary of rate impacts including: 1. Historical Rates: Actual electricity rates for the past 10 years. 2. Proposed Budget Impact: Revenue requirement impact and indicative electricity rates assuming that the proposed capital budget is approved in full.	See the *2023 Capital Budget Overview* (section 2.3.3).
I.D Capital Expenditure Summary	Summary of capital expenditures and capital budgets including: 1. Historic Capital: Actual capital for the past 10 years. 2. Current Capital Budget. 3. Forecast Capital: Forecast capital budgets for the next five years.	See the *2023 Capital Budget Overview* (section 2.3.2) for historical and proposed capital expenditures. See the *2023-2027 Capital Plan* for forecast expenditures over the next five years, including forecast expenditures by asset class and investment classification.
I.E Five-Year Capital Plan	A five-year capital plan which focusses on strategic spending priorities, addressing: 1. Shifts in the utilities spending priorities in the coming five years. 2. The circumstances contributing to shifts in priorities. 3. The alternative approaches being considered by the utility	See the *2023-2027 Capital Plan* for forecast expenditures over the next five years and a discussion of investment priorities over that period.

Table A-2 summarizes Newfoundland Power's compliance with *Part II. Organization* of the Provisional Guidelines.

Table A-2
Provisional Guidelines Compliance Summary
Part II. Organization

Part	Requirement	Reference
II.A Investment Classification II.B Projects and Programs II.C Materiality	The information included with an annual capital budget application should be organized by investment classification, by category as whether it is a project or program, and by materiality based on the "all in" capital cost.	See Schedule B for the investment classification, category and "all in" capital cost of each proposed capital expenditure. See the *2023 Capital Budget Overview* for: - A summary of the organization of capital expenditures (Appendix A); and - Breakdowns of the total 2023 Capital Budget by category, investment classification and materiality (sections 3.3, 3.4 and 3.5).

For information on compliance with *Part III. Required Information*, see Schedule B to the Application, in particular, pages i to iv.

For information on compliance with *Part IV. Prioritization*, see Appendix C of the 2023 Capital Budget Overview.

Newfoundland Power Inc.
2023 Capital Budget Application

Table of Contents

APPLICATION

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; 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 single-year 2023 capital expenditures in the amount of $93,292,000;
(b) approving multi-year projects with capital expenditures of $10,483,000 in 2023 and $10,645,000 in 2024; and
(c) fixing and determining a 2021 rate base of $1,202,946,000.

2023 Capital Budget Application

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; 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 single-year 2023 capital expenditures in the amount of $93,292,000;
(b) approving multi-year projects with capital expenditures of $10,483,000 in 2023 and $10,645,000 in 2024; and
(c) fixing and determining a 2021 rate base of $1,202,946,000.

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 includes a summary of Newfoundland Power's capital expenditures as follows:

   (a) proposed single-year 2023 capital expenditures in the amount of $93,292,000;

   (b) proposed multi-year projects commencing in 2023 with capital expenditures of $10,483,000 in 2023 and $10,645,000 in 2024; and

   (c) ongoing multi-year projects previously approved in Order No. P.U. 37 (2020), Order No. P.U. 12 (2021), and Order No. P.U. 36 (2021) with capital expenditures of $19,688,000 in 2023 and $4,276,000 in 2024 (the "Previously Approved Multi-Year Projects").

3. The 2023 Capital Budget proposed in Schedule A to this Application includes contributions toward the cost of improvements or additions to property that Newfoundland Power intends to demand from its customers in 2023 including:

   (a) an estimated amount of $2,500,000 in contributions in aid of construction which shall be calculated in a manner approved by the Board; and

(b) an estimated amount of $2,690,000 for the construction of redundant supply for the Corner Brook Acute Care Hospital which will be fully recovered from the customer.

4. There has been no change in the scope, nature, or magnitude of the Previously Approved Multi-Year Projects included in Schedule A to this Application.

5. Schedule B to this Application provides detailed descriptions of the projects and programs for which the proposed capital expenditures included in Newfoundland Power's 2023 Capital Budget are required.

6. The proposed expenditures as set out in Schedules A and B 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.

7. Schedule C to this Application shows Newfoundland Power's actual average rate base for 2021 of $1,202,946,000.

8. Communication with respect to this Application should be forwarded to the attention of Lindsay Hollett and Liam O'Brien, Counsel to Newfoundland Power.

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 2023 in the amount of $93,292,000 as set out in Schedules A and B to this Application;

   (b) pursuant to section 41 of the Act, approving Newfoundland Power's proposed multi-year construction and purchase of improvements and additions to its property in the amount of $10,483,000 in 2023 and $10,645,000 in 2024 as set out in Schedules A and B to this Application;

   (c) pursuant to section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2021 in the amount of $1,202,946,000 as set out in Schedule C to this Application.

DATED at St. John's, Newfoundland and Labrador, this 29th day of June, 2022.

NEWFOUNDLAND POWER INC.

Lindsay Hollett.

Lindsay Hollett and Liam O'Brien
Counsel to Newfoundland Power Inc.
P.O. Box 8910
55 Kenmount Road
St. John's, NL A1B 3P6

Telephone: (709) 737-5364
Telecopier: (709) 737-2974

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; 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 single-year 2023 capital expenditures in the amount of $93,292,000;
(b) approving multi-year projects with capital expenditures of $10,483,000 in 2023 and $10,645,000 in 2024; and
(c) fixing and determining a 2021 rate base of $1,202,946,000.

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

2. 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 June, 2022:

Lindsay Hollett.
Barrister, NL

Byron Chubbs

2023 CAPITAL BUDGET SUMMARY

Asset Class	**Budget ($000s)**
Distribution	54,265
Substations	20,672
Transmission	12,284
Generation - Hydro	9,476
Generation - Thermal	335
Information Systems	12,940
Telecommunications	1,268
General Property	2,505
Transportation	4,968
Unforeseen Allowance	750
General Expenses Capitalized	4,000
Total	**$ 123,463**

Expenditure Type	**Budget ($000s)**
Single-Year Projects and Programs	$93,292
Multi-Year Projects Commencing in 2023	10,483
Multi-Year Projects Approved in Previous Years	19,688
	$ 123,463

2023 CAPITAL BUDGET

SINGLE-YEAR PROJECTS AND PROGRAMS

Projects and Programs	**Budget ($000s)**
Distribution	
LED Street Lighting Replacement	5,453
Corner Brook Acute Care Hospital Redundant Supply	2,690
Distribution Feeder Automation	1,054
Feeder Additions for Load Growth	670
Electric Vehicle Charging Network	594
Distribution Feeder SLA-05 Refurbishment	565
Distribution Feeder PEP-02 Refurbishment	550
Allowance for Funds Used During Construction	247
Extensions	12,218
Reconstruction	6,699
Rebuild Distribution Lines	4,945
Relocate/Replace Distribution Lines for Third Parties	3,803
Replacement Transformers	3,345
New Transformers	2,967
New Services	2,916
New Street Lighting	2,618
Replacement Street Lighting	770
Replacement Meters	662
Replacement Services	546
New Meters	297
Total Distribution	**$53,609**
Substations	
Walbournes Substation Refurbishment and Modernization	4,955
Molloy’s Lane Substation Refurbishment and Modernization	4,827
Long Pond Substation Capacity Expansion	3,313
Substation Spare Transformer Inventory	1,500
Substation Protection and Control Replacements	667
Substation Ground Grid Upgrades	563
PCB Bushing Phase-Out	425
Substation Replacements Due to In-Service Failures	4,422
Total Substations	**$20,672**

2023 CAPITAL BUDGET

SINGLE-YEAR PROJECTS AND PROGRAMS

Projects and Programs	Budget ($000s)
Transmission	
Transmission Line Maintenance	2,610
Total Transmission	**$2,610**
Generation Hydro	
Sandy Brook Hydro Plant Generator Refurbishment	1,577
Hydro Facility Rehabilitation	877
Hydro Plant Replacements Due to In-Service Failures	662
Total Generation Hydro	**$3,116**
Generation Thermal	
Thermal Plant Replacements Due to In-Service Failures	335
Total Generation Thermal	**$335**
Information Systems	
Application Enhancements	1,538
Shared Server Infrastructure	1,176
System Upgrades	962
Cybersecurity Upgrades	882
Network Infrastructure	419
Personal Computer Infrastructure	600
Total Information Systems	**$5,577**
Telecommunications	
Communications Equipment Upgrades	118
Total Telecommunications	**$118**

2023 CAPITAL BUDGET

SINGLE-YEAR PROJECTS AND PROGRAMS

Projects and Programs	**Budget ($000s)**
General Property	
Company Building Renovations	741
Physical Security Upgrades	576
Additions to Real Property	654
Tools and Equipment	534
Total General Property	**$2,505**
Unforeseen Allowance	
Allowance for Unforeseen Items	750
Total Unforeseen Allowance	**$750**
General Expenses Capitalized	
General Expenses Capitalized	4,000
Total General Expenses Capitalized	**$4,000**
Total	**$93,292**

2023 CAPITAL BUDGET

MULTI-YEAR PROJECTS

Multi-Year Projects Commencing in 2023

Class	Project Description	2023	2024	Total
Distribution	Distribution Reliability Initiative	656	1,015	1,671
Transmission	Transmission Line 55L Rebuild	5,328	5,284	10,612
Generation Hydro	Mobile Hydro Plant Refurbishment	1,666	2,480	4,146
Transportation	Replace Vehicles and Aerial Devices 2023-2024	2,833	1,866	4,699
	Total	**$10,483**	**$10,645**	**$21,128**

Multi-Year Projects Approved in Previous Years

Class	Project Description	2021	2022	2023	2024	Total
Information Systems	Microsoft Enterprise Agreement[1]	245	245	245	-	735
Information Systems	Customer Service System Replacement[2]	9,903	15,826	5,917	-	31,646
Generation Hydro	Sandy Brook Plant Penstock Replacement[3]	-	400	4,694	-	5,094
Transmission	Transmission Line 94L Rebuild[4]	-	4,473	4,346	4,276	13,095
Transportation	Replace Vehicles and Aerial Devices 2022-2023[5]	-	3,089	2,135	-	5,224
Telecommunications	St. John's Teleprotection System Replacement[6]	-	450	1,150	-	1,600
Information Systems	Workforce Management System Replacement[7]	-	808	1,201	-	2,009
	Total	**$10,148**	**$25,291**	**$19,688**	**$4,276**	**$59,403**

1 Approved in Order No. P.U. 37 (2020). See the *2021 Capital Budget Application*, Volume 1, Schedule B, pages 82 to 83.
2 Approved in Order No. P.U. 12 (2021). See the *2021 Capital Budget Application*, Volume 1, Schedule B, pages 93 to 94.
3 Approved in Order No. P.U. 36 (2021). See the *2022 Capital Budget Application*, Schedule B, pages 5 to 6.
4 Approved in Order No. P.U. 36 (2021). See the *2022 Capital Budget Application*, Schedule B, pages 18 to 20.
5 Approved in Order No. P.U. 36 (2021). See the *2022 Capital Budget Application*, Schedule B, pages 70 to 72.
6 Approved in Order No. P.U. 36 (2021). See the *2022 Capital Budget Application*, Schedule B, pages 76 to 77.
7 Approved in Order No. P.U. 36 (2021). See the *2022 Capital Budget Application*, Schedule B, pages 94 to 95.

2023 CAPITAL PROJECTS AND PROGRAMS

2023 CAPITAL PROJECTS AND PROGRAMS

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 2023, 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 has also commenced a review of its asset management practices that, among other matters, will evaluate options to meet the information requirements contained in the Provisional Guidelines.

The following provides an overview of the information provided within Schedule B to the Application for each project and program proposed for 2023:

(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. New for this Application, the budgets for capital projects and programs have been adjusted to reflect a direct allocation of pension costs to the labour component of projects and programs, with a corresponding reduction in General Expenses Capitalized. This change was approved by the Board in Order No. P.U. 3 (2022).

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

(iii) Program Trend

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

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

(iv) Asset Background

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

(v) Assessment of Alternatives

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

(vi) Risk Assessment

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

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

Figure 1 shows the risk matrix.

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

Figure 1: Risk Matrix

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

A detailed description of the risk matrix methodology is provided in Appendix C to the *2023 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.

2023 CAPITAL BUDGET

SCHEDULE B TABLE OF CONTENTS

DISTRIBUTION

Title: **LED Street Lighting Replacement**
Asset Class: **Distribution**
Category: **Project**
Investment Classification: **Service Enhancement**
Budget: **$5,453,000**

PROJECT DESCRIPTION

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

Newfoundland Power adopted LED street lighting as its service standard in 2019 following Board approval in Order No. P.U. 2 (2019). In 2021, the Company commenced implementation of a plan to provide all Street and Area Lighting customers with LED fixtures within six years.[1] Expenditures proposed for 2023 represent the third year of this plan. Approximately 10,000 street light fixtures are forecast to be replaced with LED fixtures in 2023. Street light fixtures will be replaced on an ongoing basis throughout the year in response to street light trouble calls.

PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2023 for the *LED Street Lighting Replacement* project.

Table 1
LED Street Lighting
Replacement Project
2023 Budget
($000s)

Cost Category	2023
Material	4,128
Labour – Internal	1,325
Labour – Contract	-
Engineering	-
Other	-
Total	$5,453

1 See Newfoundland Power's *2021 Capital Budget Application, Volume 1, LED Street Lighting Replacement Plan.*

Proposed expenditures for the *LED Street Lighting Replacement* project total $5,453,000 for 2023.

ASSET BACKGROUND

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

(i) *Lower overall costs for customers* – The capital cost of installing a LED fixture is approximately twice that of a HPS fixture. However, LED fixtures require 60% less energy to provide equivalent lighting output and require far less maintenance. Current customer rates for LED street lights are between 12% and 44% lower than rates for HPS street lights.[2]

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

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

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

The *LED Street Lighting Replacement Plan* has received the support of the largest municipal organization in the province, Municipalities Newfoundland and Labrador.[3]

ASSESSMENT OF ALTERNATIVES

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

The first alternative was to maintain the status quo by continuing to complete maintenance of HPS street lights and installing an LED fixture when an HPS fixture cannot be repaired. The assessment showed that approximately 1,700 HPS street lights would be replaced with LED equivalents annually under this alternative. More than 30 years would be required to provide all customers with LED street lights.

The second alternative was to accelerate the installation of LED fixtures by discontinuing the maintenance program for HPS street lights and installing LED fixtures in response to all street lighting trouble calls received from customers. The assessment showed approximately 10,000

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2 Current rates are reflected in the *Schedule of Rates, Rules and Regulations* effective March 1, 2022.
3 See Newfoundland Power's *2021 Capital Budget Application, Volume 1, LED Street Lighting Replacement Plan*, Appendix D.

HPS street lights would be replaced with LED equivalents annually under this alternative. All customers would be provided with LED street lights in six years.

An economic analysis determined that accelerating the installation of LED street lights would reduce energy and maintenance costs to customers by approximately $52 million over 20 years, providing a positive net benefit to customers of approximately $4.9 million.[4]

The accelerated installation of LED street lights was therefore the recommended alternative.

RISK ASSESSMENT

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

Without continuing to execute the Company's *LED Street Lighting Replacement* plan, a maintenance program for HPS street lights would continue to be required or customers would be without service upon the failure of existing street lights. Under this scenario, customers would continue to pay the higher rates associated with HPS street lights and would not receive the $4.9 million net benefit associated with phasing out this technology.

By continuing to execute the *LED Street Lighting Replacement* project, customers will be provided with the lower rates of LED street lights immediately upon installation. It is estimated that customer rates for approximately 10,000 street lights will be reduced by between 12% and 44% in 2023 by executing this project.

Table 2 summarizes the risk assessment of the 2023 *LED Street Lighting Replacement* project.

Table 2
LED Street Lighting Replacement Project
Risk Assessment Summary

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

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

JUSTIFICATION

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

4 Ibid., Appendix B.

Title:	**Corner Brook Acute Care Hospital Redundant Supply**
Asset Class:	**Distribution**
Category:	**Project**
Investment Classification:	**Access**
Budget:	**$2,690,000**

PROJECT DESCRIPTION

The *Corner Brook Acute Care Hospital Redundant Supply* project will provide redundant electrical supply to the Corner Brook Acute Care Hospital (the "Corner Brook Hospital" or the "Hospital").

The Corner Brook Hospital is currently under construction with an anticipated completion date of November 2023. Due to the critical nature of the load and essential electrical system standards for health care facilities, the customer has requested a backup supply to provide redundant service to the Hospital.[5] In accordance with Clause 9(c) of Newfoundland Power's *Schedule of Rates, Rules and Regulations*, the redundant supply is considered a special facility and will be fully funded by the customer.

Providing redundant supply to the Hospital will require modifying Bayview ("BVS") Substation distribution feeder BVS-03. A portion of the load currently supplied by BVS-03 will require offloading to adjacent feeders from the BVS and Humber substations.

Modifications to distribution feeder BVS-03 will include:

(i) Upgrading 2.5 kilometres of distribution feeder from single-phase to three-phase;
(ii) Relocating 1.2 kilometres of feeder;
(iii) Constructing 400 metres of three-phase underground infrastructure;
(iv) Completing 1.0 kilometre of right-of-way widening and pole upgrades; and
(v) Extending 4.0 kilometres of new feeder along Confederation Drive and Crockers Road in Corner Brook, including pole upgrades for double circuit structures running parallel with distribution feeder BVS-04.

Pole installations will be completed by the end of the first quarter of 2023. Conductor upgrades and the remainder of the project will be completed by the end of the second quarter.

5 See standard *CAN/CSA-Z32-99 (R2004) Electrical Safety and Essential Electrical Systems in Health Care Facilities*.

PROJECT BUDGET

The budget for the *Corner Brook Acute Care Hospital Redundant Supply* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2023 for the *Corner Brook Acute Care Hospital Redundant Supply* project.

Table 1
Corner Brook Acute Care Hospital
Redundant Supply Project
2023 Budget
($000s)

Cost Category	2023
Material	747
Labour – Internal	657
Labour – Contract	918
Engineering	140
Other	228
Total	$2,690

Proposed expenditures for the *Corner Brook Acute Care Hospital Redundant Supply* project total $2,690,000 for 2023. The project will be fully funded by the customer.

ASSET BACKGROUND

Construction power for the Corner Brook Hospital is currently being supplied from Walbournes ("WAL") Substation distribution feeder WAL-07. This feeder will be the main supply to the Hospital when construction is complete.[6]

The customer has requested a redundant supply to the Hospital for backup purposes. The estimated demand of the Hospital is 7.8 MVA and distribution feeder BVS-03 has been selected as the source of redundant supply for the Hospital. Distribution feeder BVS-03 will require modification in 2023 to serve as the source of redundant supply.

[6] The *Application for Approval of a Contribution in Aid of Construction ("CIAC") for a Three-Phase Service for Corner Brook Acute Care Hospital* was approved by the Board in Order No. P.U. 13 (2022) to complete an extension and upgrade of distribution feeder WAL-07 in 2022.

Figure 1 shows a map of distribution feeder BVS-03 with the section requiring modifications shown in red.

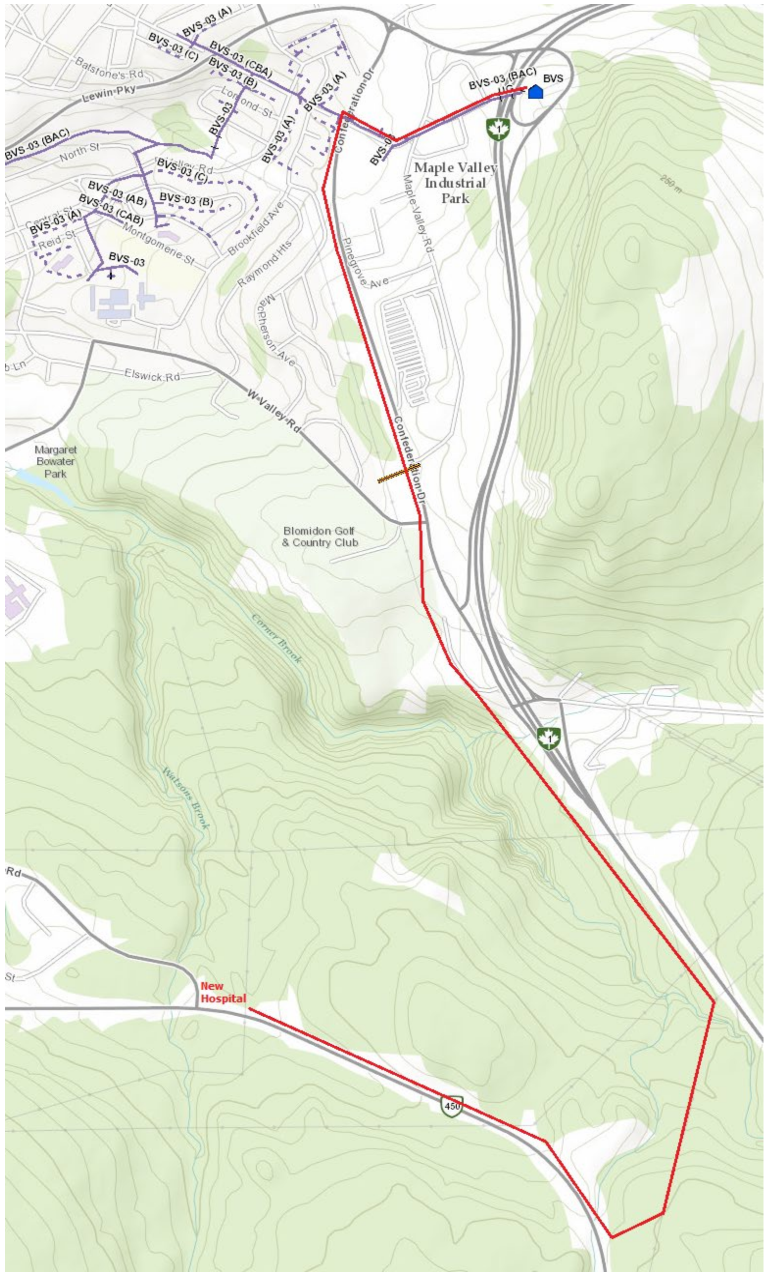

Figure 1: Proposed BVS-03 Redundant Supply

JUSTIFICATION

The *Corner Brook Acute Care Hospital Redundant Supply* project is required to meet the customer's request to provide a redundant supply to the Hospital. The project will be fully funded by the customer.

Title:	**Distribution Reliability Initiative**
Asset Class:	**Distribution**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$656,000 in 2023; and $1,015,000 in 2024**

PROJECT DESCRIPTION

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

Newfoundland Power has proposed a targeted refurbishment of Summerford ("SUM") Substation distribution feeder SUM-01 for 2023 and 2024, which will include:

(i) Replacing 6.5 kilometres of deteriorated conductor;
(ii) Replacing poles, structures and other components identified during inspection as being in poor condition, including crossarms and insulators;
(iii) Installing an automated downline recloser on the two-phase tap supplying the Virgin Arm/Moreton's Harbour area; and
(iv) Replacing the existing hydraulic-style downline recloser, SUM-01-R3, with a fully automated recloser.

The refurbishment of distribution feeder SUM-01 is proposed to be completed over two years commencing in 2023 and will address the poor service reliability currently experienced by customers on New World Island.

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 2023 and 2024 for the *Distribution Reliability Initiative*.

Table 1
Distribution Reliability Initiative Project
2023/2024 Budget
($000s)

Cost Category	2023	2024
Material	103	191
Labour – Internal	233	432
Labour – Contract	16	29
Engineering	153	82
Other	151	281
Total	$656	$1,015

Proposed expenditures for the *Distribution Reliability Initiative* total $1,671,000, including $656,000 in 2023 and $1,015,000 in 2024.

ASSET BACKGROUND

Newfoundland Power has been implementing the *Distribution Reliability Initiative* for over two decades. 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 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. The Company's approach to targeting its worst performing feeders for capital improvements is consistent with good utility practice.

Distribution feeder SUM-01 is one of two feeders supplying customers from the SUM Substation. The feeder serves 1,812 customers on New World Island. Customers served by this feeder experienced an average outage duration of 8.0 hours annually over the last five years, which is more than four times Newfoundland Power's corporate average. The frequency of outages experienced by these customers on New World Island is more than double the corporate average.

An engineering assessment determined the poor service reliability experienced by these customers is due to equipment failures including corroded or broken conductor, insulator failures, and deteriorated poles. Distribution feeder SUM-01 is a 25 kV feeder originally constructed in the 1960s with 2/0 Aluminum Conductor Steel Reinforced ("ACSR") conductor. This conductor has experienced performance issues in the past due to oxidation between the steel core and aluminum outer strands. The oxidation is particularly prevalent in coastal environments with frequent salt spray.

Newfoundland Power's outage management system, Responder, is able to pinpoint specific sections of feeders where high frequencies of outages occur. Data for distribution feeder SUM-01 indicates that there have been 153 outage incidents on the feeder between September 2019 and the end of 2021.[7] Of the 153 outage incidents, 124 events have been on the sections of feeder located northeast of SUM Substation along Route 340 towards Twillingate, including the two-phase tap to Virgin Arm/Moreton's Harbour. Further analysis identified 70 of the events were caused by component and conductor failure. Inspections identified 140 deficiencies on this section of feeder, including 79 deteriorated poles.

ASSESSMENT OF ALTERNATIVES

Customers served by distribution feeder SUM-01 are experiencing significantly worse service reliability than the average reliability experienced by Newfoundland Power's customers. An engineering assessment of distribution feeder SUM-01 identified deterioration on the section of feeder extending northeast from SUM Substation. Inspections have also identified other deterioration and deficiencies throughout the distribution feeder.

Newfoundland Power identified and evaluated two alternatives with respect to distribution feeder SUM-01: (i) complete a targeted refurbishment of a small section of the distribution feeder in 2023, including the installation of automated downline reclosers; or (ii) defer the refurbishment of the distribution feeder.

The assessment determined that completing a targeted refurbishment of SUM-01 would improve the poor service reliability currently experienced by customers on New World Island. Deferring the refurbishment of distribution feeder SUM-01 would result in customers continuing to experience poor service reliability. This would be inconsistent with maintaining acceptable and equitable levels of service reliability for customers throughout Newfoundland Power's service territory.

The targeted refurbishment of distribution feeder SUM-01 is therefore the recommended alternative.

RISK ASSESSMENT

The *Distribution Reliability Initiative* will mitigate risks to the delivery of reliable service to customers on New World Island.

A total of 1,812 customers on New World Island currently experience poor service reliability due the deteriorated condition of distribution feeder SUM-01, including deteriorated conductor, poles and hardware. The contribution of these deficiencies to the poor service reliability experienced by customers was confirmed through an engineering review, inspection and detailed analysis of outage data and equipment failures.

Customers on New World Island are expected to continue to experience worsening service reliability as distribution feeder SUM-01 has been among Newfoundland Power's worst performing feeders since 2014.

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7 Responder was implemented in September 2019.

Table 2 summarizes the risk assessment of the 2023 *Distribution Reliability Initiative* project.

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 on New World Island. Customers in this area currently experience service reliability that is significantly below the Company average. The multi-year project to refurbish a section of distribution feeder SUM-01 will address deficiencies identified during inspections and improve the service reliability experienced by customers in the area.

Title:	**Distribution Feeder Automation**
Asset Class:	**Distribution**
Category:	**Project**
Investment Classification:	**Service Enhancement**
Budget:	**$1,054,000**

PROJECT DESCRIPTION

The *Distribution Feeder Automation* project involves increasing automation of the distribution system through the installation of downline reclosers. Downline reclosers are pole-mounted devices that divide a distribution feeder into multiple segments. These devices are controlled remotely to: (i) isolate a fault so only a portion of customers on a feeder experience an outage, instead of all customers; and (ii) systematically restore power to customers following a prolonged outage.[8]

A total of 17 downline reclosers are planned for installation in 2023. These downline reclosers will be installed under three deployment scenarios:

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

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

(iii) *Scenario 3* – Deployment of downline reclosers at normally open tie locations on feeders that have downline reclosers installed.[9]

[8] For example, customers served by Doyles ("DOY") Substation feeder DOY-01 experienced an outage in December 2020. A downline recloser was operated to mitigate issues associated with cold load pick-up. The operation of this downline recloser avoided an additional outage to over 1,000 customers served by that feeder.

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

Table 1 lists the downline reclosers to be installed in 2023 and the associated deployment scenario.

Table 1
2023 Downline Recloser Installations

Feeders	Number of Devices	Deployment Scenario
MOL-05	1	Scenario 2
GDL-07	2	Scenario 2
GDL-09	1	Scenario 1
GDL-05/GDL-07 TIE	1	Scenario 3
GOU-02/MOL-05 TIE	1	Scenario 3
GDL-04/MOL-05 TIE	1	Scenario 3
GDL-04/GDL-05 TIE	1	Scenario 3
GDL-08/GDL-09 TIE	1	Scenario 3
NCH-02	1	Scenario 1
VIC-02	1	Scenario 1
SPF-01	1	Scenario 1
ISL-01	2	Scenario 1
WAL-02/WAL-04 TIE	1	Scenario 3
GFS-07	1	Scenario 1
BVS-04	1	Scenario 2

Design work for this project is expected to be completed by the end of the second quarter of 2023. Installation of the downline reclosers will commence in the third quarter with all downline reclosers installed by year-end.

PROJECT BUDGET

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

Table 2 provides a breakdown of expenditures proposed for 2023 for the *Distribution Feeder Automation* project.

Table 2
Distribution Feeder Automation Project
2023 Budget
($000s)

Cost Category	2023
Material	536
Labour – Internal	242
Labour – Contract	77
Engineering	88
Other	111
Total	$1,054

Proposed expenditures for the *Distribution Feeder Automation* project total $1,054,000 for 2023.

ASSET BACKGROUND

Newfoundland Power established a long-term approach to increasing automation of its distribution system in report *4.5 Distribution Feeder Automation* included with its *2020 Capital Budget Application.*

Automation of the distribution system through the installation of downline reclosers provides operational benefits during customer outages, particularly significant events. Downline reclosers are operated remotely to restore service to customers without the requirement to dispatch field crews. By sectionalizing distribution feeders, portions of feeders no longer need to be patrolled to identify the cause and location of outages.[10] Avoiding the need to dispatch field crews and decreasing patrol times reduces costs to customers.

The 2023 *Distribution Feeder Automation* project is consistent with the approach Newfoundland Power adopted in 2020 and Recommendation 2.4 of The Liberty Consulting Group's *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power*.

The 17 downline reclosers to be installed in 2023 will provide operational benefits in responding to customer outages throughout Newfoundland Power's service territory. Nine of the 17 devices will be installed on the Northeast Avalon on distribution feeders supplying customers in

[10] Given the size of Newfoundland Power's service territory, long drives to identify the cause of outages are not uncommon. Reducing the length of distribution feeder to be patrolled reduces the time necessary to locate faults and provides cost benefits.

the Mount Pearl and St. John's areas. The remainder will be installed in more rural areas of the Company's service territory.

ASSESSMENT OF ALTERNATIVES

Newfoundland Power identified two alternatives for the *Distribution Feeder Automation* project: (i) continue the installation of downline reclosers in a manner consistent with the approach adopted in 2020; or (ii) accept current levels of distribution system automation and defer the installation of additional downline reclosers.

Continuing to automate the distribution system will provide operational benefits by ensuring a prompt and efficient response to customer outages in the Company's largest load centre on the Northeast Avalon and in rural areas of the province. Accepting current levels of distribution system automation would defer the operational benefits associated with continuing to install downline reclosers.

Past experience indicates the benefits of downline reclosers can be substantial. Downline reclosers are routinely operated to restore service to customers following equipment failures.[11] The operational benefits of downline reclosers are most pronounced during significant events.[12] For example, the operation of five downline reclosers during a severe blizzard in January 2020 avoided approximately 3.5 million customer outage minutes without the assistance of field crews. This allowed field crews to focus on restoring service to customers who were affected by the blizzard. The operation of 12 downline reclosers during Hurricane Larry in September 2021 avoided approximately 3.8 million customer outage minutes, allowing field crews to focus on restoration efforts for customers who were affected by the storm.

Given the operational benefits provided by downline reclosers during normal operations and significant events, continuing to automate the distribution system is the recommended alternative.

RISK ASSESSMENT

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

Major components on Newfoundland Power's distribution system are aging beyond the industry average expected service lives, including overhead conductor and wooden support structures. Equipment failures on the distribution system are trending upward, with an increase of

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[11] As examples, the operation of a downline recloser in May 2019 quickly restored service to 665 customers served by Chamberlains Substation distribution feeder CHA-01 following an equipment failure. The operation of a downline recloser on Hardwoods Substation distribution feeder HWD-08 avoided over 96,000 customer outage minutes in April 2020. In both cases, customer outages were reduced or avoided without dispatching field crews.

[12] The term *"significant events"* refers to external events that exceed the design parameters or operational limits of the electrical system.

approximately 29% over the last decade.[13] At the same time, significant events due to severe weather are becoming more frequent throughout the Company's service territory.[14]

These conditions pose a risk to the delivery of reliable service to Newfoundland Power's customers going forward. Continuing to automate the distribution system through the installation of downline reclosers will help mitigate this increasing risk by supporting an efficient and effective response to customer outages. The benefits of downline reclosers can be substantial, particularly during severe weather, and are routinely observed each year as the devices automatically operate to avoid customer outages.

Table 3 summarizes the risk assessment of the 2023 *Distribution Feeder Automation* project.

Table 3
Distribution Feeder Automation Project
Risk Assessment Summary

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

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

JUSTIFICATION

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

13 See the *2023-2027 Capital Plan, Section 2.4 - Asset Condition Outlook.*
14 See the *2023-2027 Capital Plan, Section 2.3 - Operations Outlook.*

Title: **Feeder Additions for Load Growth**
Asset Class: **Distribution**
Category: **Project**
Investment Classification: **System Growth**
Budget: **$670,000**

PROJECT DESCRIPTION

The *Feeder Additions for Load Growth* project involves addressing overload conditions and providing additional capacity to address system load growth. For 2023:

(i) A section of Pulpit Rock ("PUL") Substation distribution feeder PUL-01 will be upgraded from single-phase to three-phase to address an overload condition that has developed as a result of customer connection growth in the area of Marine Drive. The cost of completing the required upgrades is $312,000.

(ii) A section of PUL Substation distribution feeder PUL-04 will be upgraded from single-phase to three-phase to address an overload condition that has developed as a result of customer connection growth in the Forest Landing subdivision. The cost of completing the required upgrades is $358,000.

Design work for the *Feeder Additions for Load Growth* project will be completed in the first quarter of 2023. Construction will begin in the second quarter and will be completed by the end of the third quarter of 2023.

Additional information on this project is included in report *1.2 Feeder Additions for Load Growth*.

PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2023 for the *Feeder Additions for Load Growth* project.

Table 1
Feeder Additions for Load Growth Project
2023 Budget
($000s)

Cost Category	2023
Material	180
Labour – Internal	219
Labour – Contract	256
Engineering	15
Other	-
Total	$670

Proposed expenditures for the *Feeder Additions for Load Growth* project total $670,000 for 2023.

ASSET BACKGROUND

Distribution feeder PUL-01 serves approximately 1,300 customers in the Torbay area. A 1.0 kilometre section of distribution feeder extending south along Marine Drive and then west along Torquay Place is overloaded. Load growth on this single-phase line can be attributed to customer connection growth in the Jones Pond Park Subdivision as well as large home renovations and electrical service upgrades in the area of Marine Drive. The number of customers supplied by this single-phase line has increased by 76% over the last 15 years.

Distribution feeder PUL-04 serves approximately 1,300 customers in the Torbay area. A 1.2 kilometre section of distribution feeder extending south on Western Island Pond Drive and then east on Forest River Road is overloaded. Load growth on this single-phase line can be attributed to customer connection growth in the Forest Landing Subdivision. The number of customers supplied by this single-phase line has increased by more than 600% over the last 15 years.

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 resulting from customer growth in the Torbay area in order to provide customers with adequate service.

Title:	**Electric Vehicle Charging Network**
Asset Class:	**Distribution**
Category:	**Project**
Investment Classification:	**General Plant**
Budget:	**$594,000**

PROJECT DESCRIPTION

The *Electric Vehicle Charging Network* project is part of Newfoundland Power's *Electrification, Conservation and Demand Management Plan: 2021-2025* (the "2021 Plan").[15] The *Electric Vehicle Charging Network* aims to provide access to public fast charging, which is a primary barrier to customers' adoption of electric vehicles.

Three electric vehicle charging stations are proposed for 2023. Each charging station will include a Direct Current Fast Charger ("DCFC") and a Level 2 Charger.

Design work and construction for this project will be completed by the third quarter of 2023.

PROJECT BUDGET

The budget for the *Electric Vehicle Charging Network* project is based on a detailed engineering estimate.

Table 1 provides a breakdown of expenditures proposed for 2023 for the *Electric Vehicle Charging Network* project.

Table 1
Electric Vehicle Charging Network Project
2023 Budget
($000s)

Cost Category	2023
Material	553
Labour – Internal	-
Labour – Contract	-
Engineering	12
Other	29
Total	$594

[15] See Newfoundland Power's *2021 Electrification, Conservation and Demand Management Application.*

Proposed expenditures for the *Electric Vehicle Charging Network* project total $594,000 for 2023.

ASSET BACKGROUND

The 2021 Plan proposes a portfolio of customer electrification programs primarily aimed at increasing the province's adoption of electric vehicles. A net present value analysis determined that execution of the electrification programs included in 2021 Plan will provide a rate mitigating benefit for customers of approximately 0.5 cents/kWh by 2034.

A lack of public fast charging infrastructure is currently a barrier to electric vehicle adoption in Newfoundland and Labrador and private sector investment in fast charging infrastructure is currently constrained by a weak business case.[16]

The *Electric Vehicle Charging Network* project aims to establish the minimum geographic coverage necessary to enable travel across the Island of Newfoundland in an electric vehicle. The Board approved the construction of 10 electric vehicle charging sites by Newfoundland Power in Order No. P.U. 30 (2021).[17] A proposal to construct an additional 10 charging sites in 2022 is currently under review by the Board.

Three charging sites are proposed for 2023. These charging sites will be installed in areas where existing charging stations are experiencing high customer usage rates, resulting in additional charging ports being required to meet customer demand.

RISK ASSESSMENT

The *Electric Vehicle Charging Network* project will provide an economic benefit to Newfoundland Power's customers.

Charging stations proposed for 2023 comprise approximately 11% of the total chargers planned to be installed as part of Newfoundland Power's *Electric Vehicle Charging Network* project.[18] The benefits associated with increasing electric vehicle adoption, including the benefits of increasing access to public fast charging, have been confirmed through a net present value analysis based on a detailed market potential study.

Customers continue to indicate through annual surveys that the limited access to public fast charging infrastructure in Newfoundland and Labrador is a barrier to electric vehicle adoption. Private sector investment in public fast charging infrastructure continues to lag behind in this province compared to the rest of Canada. Based on local market research, the limited access to public fast charging is likely to impede achieving the customer benefits of electric vehicle adoption if not addressed through the *Electric Vehicle Charging Network* project.

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[16] Ibid., Volume 1, Exhibit 2.

[17] Each charging site includes a DCFC and Level 2 charger. DCFCs charge an electric vehicle in approximately 30 minutes to one hour. This compares to an average of nine hours for a Level 2 charger.

[18] A total of 28 charging stations are planned to be installed as part of Newfoundland Power's *Electric Vehicle Charging Network*, including three in 2023.

Table 2 summarizes the risk assessment of the 2023 *Electric Vehicle Charging Network* project.

Table 2
Electric Vehicle Charging Network Project
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Electric Vehicle Charging Network* project would pose a Medium-High (12) risk to the delivery of least-cost service to customers.

JUSTIFICATION

The *Electric Vehicle Charging Network* project is required to provide a rate mitigating benefit for customers that is consistent with the delivery of reliable service at the lowest possible cost. The project will support increasing the province's adoption of electric vehicles and the successful delivery of customer electrification programs outlined in the 2021 Plan.

Title: **Distribution Feeder SLA-05 Refurbishment**
Asset Class: **Distribution**
Category: **Project**
Investment Classification: **Renewal**
Budget: **$565,000**

PROJECT DESCRIPTION

The *Distribution Feeder SLA-05 Refurbishment* project involves replacing deteriorated poles, conductor and hardware on Stamp's Lane ("SLA") Substation distribution feeder SLA-05. In addition, a portion of distribution feeder SLA-05 will also be converted from 4.16 kV to 12.5 kV to alleviate existing overload conditions. The project includes:

(i) Replacing 789 metres of 60-year-old, rear lot, single-phase primary #4 copper ("Cu") conductor with 1/0 aluminum alloy stranded conductor ("AASC");
(ii) Extending 200 metres of rear lot, single-phase primary distribution line and installing three additional transformers to address existing overloaded transformers;
(iii) Replacing existing deteriorated and overloaded transformers;
(iv) Replacing 23 deteriorated rear lot poles; and
(v) Converting a section of distribution feeder SLA-05 near Oxen Pond Road from 4.16 kV to 12.5 kV and transferring load to SLA-08 to alleviate overload conditions on two single-phase sections of distribution feeder SLA-05.

Design work for the *Distribution Feeder SLA-05 Refurbishment* project is expected to be completed in the first quarter of 2023. Construction will begin in the second quarter of 2023 and is expected to be completed by the end of the third quarter of 2023.

PROJECT BUDGET

The budget for the *Distribution Feeder SLA-05 Refurbishment* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2023 for the *Distribution Feeder SLA-05 Refurbishment* project.

Table 1
Distribution Feeder SLA-05
Refurbishment Project
2023 Budget
($000s)

Cost Category	2023
Material	98
Labour – Internal	235
Labour – Contract	214
Engineering	18
Other	-
Total	$565

Proposed expenditures for the *Distribution Feeder SLA-05 Refurbishment* project total $565,000 for 2023.

ASSET BACKGROUND

Distribution feeder SLA-05 was constructed in the early 1960s to 4.16 kV standards. The feeder serves 409 customers near Memorial University in St. John's, including 136 residential customers in the area of Oxen Pond Road.

Figure 1 is a map showing the location of distribution feeder SLA-05.

Figure 1: Location of Distribution Feeder SLA-05

The sections of single-phase distribution line supplying Dundas, Dorset and Wexford streets near Oxen Pond Road, are primarily constructed of 1960s vintage infrastructure including #4 Cu conductor.

This section of distribution feeder SLA-05 was inspected in accordance with Newfoundland Power's *Distribution Inspection and Maintenance Practices*. The inspection identified a significant number of deficiencies on the single-phase sections of the feeder along Dundas, Dorset and Wexford streets including deteriorated poles, crossarms and overhead conductor. Of 31 rear lot mainline poles installed in the 1960s, 23 require replacement due to deterioration. A number of pole-top transformers were also identified to be in poor condition.

Figures 2 to 4 show examples of deteriorated and substandard infrastructure on distribution feeder SLA-05.

Figure 2: Heavy Cracking in Pole

Figure 3: Deteriorated Secondary Pole

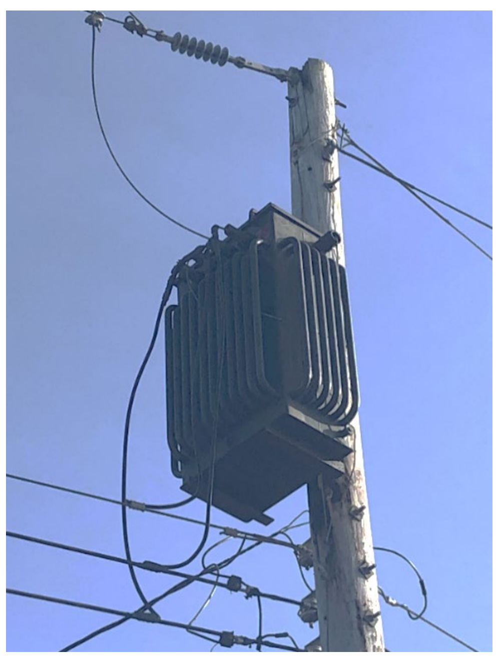


Figure 4: Deteriorated Pole and Vintage Transformer

An engineering assessment determined that the two single-phase sections supplying Dundas, Dorset and Wexford streets off of Oxen Pond Road are overloaded at approximately 135 amps each, which is outside of the Company's planning guidelines for a single-phase distribution line.[19] All six pole-top distribution transformers in the area are overloaded with each transformer having an average of 20 services.[20] These overload conditions are attributed to electrical upgrades in the area. The houses in this area are generally older and, at the time of connection, were mainly heated by oil furnaces. Over the past 10 years, approximately 30% of houses in the area have completed electrical upgrades including switching to electric heat. These upgrades have increased load on the feeder.

The least-cost alternative to address the overloaded conditions on distribution feeder SLA-05 is to complete a voltage conversion on a section of feeder and transfer the load to adjacent distribution feeder SLA-08, which operates at 12.5 kV.[21] The voltage conversion will reduce the current on each overloaded single-phase section of distribution feeder SLA-05 from approximately 135 amps to 45 amps.

Figure 5 provides details on the proposed scope of work to complete the refurbishment and voltage conversion of the identified section of distribution feeder SLA-05.

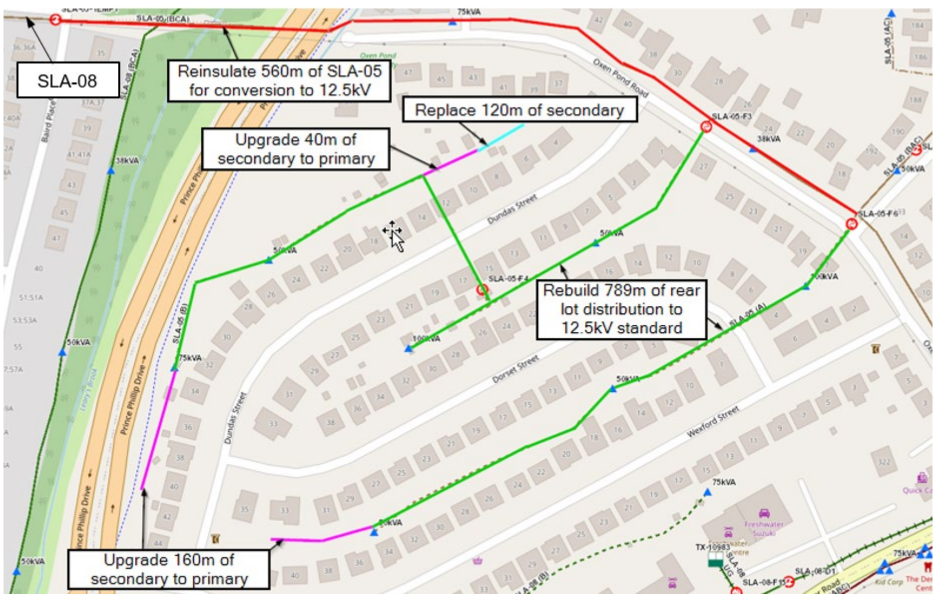


Figure 5: Proposed Refurbishment and Conversion of Distribution Feeder SLA-05

19 Newfoundland Power's planning criteria for maximum current on a single-phase distribution line is 85 amps. A heavily loaded single-phase tap can result in unbalanced loads on the three phases of a feeder and subsequent operation of feeder protection at the substation. This results in outages to customers and extended time to restore service. The unbalanced load condition can occur during peak load, cold load pick-up or when a protection fuse operates.

20 The largest pole mounted transformer that Newfoundland Power installs is a 100 kVA which is rated for a maximum of 12 services.

21 The voltage conversion will involve minimal additional cost to the project since the two overloaded single-phase sections of distribution line required refurbishment and will be rebuilt to current 12.5 kV standards.

RISK ASSESSMENT

The *Distribution Feeder SLA-05 Refurbishment* project will mitigate risks to the delivery of safe and reliable service to customers in the Oxen Pond Road area of St. John's.

A total of 136 customers in the Oxen Pond Road area of St. John's are served by distribution feeder SLA-05. This section of distribution feeder consists of rear lot construction in a predominantly residential area. These customers are exposed to risks of outages due to equipment failure as a result of the feeder's deteriorated condition and existing overload conditions. The deteriorated infrastructure and overload conditions pose a safety hazard as equipment failures can result in energized lines coming into contact with customers' premises. The probability of equipment failure on distribution feeder SLA-05 is likely given its age, existing overload conditions and the significant quantity of deterioration identified during inspection.

Table 2 summarizes the risk assessment of the *Distribution Feeder SLA-05 Refurbishment* project.

Table 2
Distribution Feeder SLA-05 Refurbishment Project
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Distribution Feeder SLA-05 Refurbishment* project would pose a Medium-High (12) risk to the delivery of safe and reliable service to customers.

JUSTIFICATION

The *Distribution Feeder SLA-05 Refurbishment* project is required to provide reliable service to customers at the lowest possible cost. A section of distribution feeder SLA-05 is experiencing overload conditions and has become heavily deteriorated. Addressing these deficiencies is necessary to mitigate risks of equipment failure and potential outages to customers in the Oxen Pond Road area of St. John's.

Title: **Distribution Feeder PEP-02 Refurbishment**
Asset Class: **Distribution**
Category: **Project**
Investment Classification: **Renewal**
Budget: **$550,000**

PROJECT DESCRIPTION

The *Distribution Feeder PEP-02 Refurbishment* project involves replacing deteriorated underground infrastructure on Loop 34 of Pepperrell ("PEP") Substation distribution feeder PEP-02. New primary and secondary conductor will be installed in underground conduit in conformance with current engineering design standards. The project will also include site work to restore sod, asphalt, and sidewalks. The detailed project scope includes the following:

(i) Install 1.2 kilometres of 103 mm primary conduit with new 1/0 XLPE primary conductor;
(ii) Install 1.0 kilometre of 103 mm secondary conduit and underground splice boxes;
(iii) Install a 10 metre section of 53 mm conduit from the splice boxes to each service location for future service replacements; and
(iv) Replace two padmount transformers.

Design work for the *Distribution Feeder PEP-02 Refurbishment* project is expected to be completed in the first quarter of 2023. Construction will begin in the second quarter and will be completed by the end of the third quarter of 2023.

PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2023 for the *Distribution Feeder PEP-02 Refurbishment* project.

Table 1
Distribution Feeder PEP-02
Refurbishment Project
2023 Budget
($000s)

Cost Category	2023
Material	404
Labour – Internal	88
Labour – Contract	-
Engineering	28
Other	30
Total	$550

Proposed expenditures for the *Distribution Feeder PEP-02 Refurbishment* project total $550,000 for 2023.

ASSET BACKGROUND

The underground infrastructure for Loop 34 of distribution feeder PEP-02 was installed in 1974 and provides service to 117 customers in the Virginia Park area of St. John's. Loop 34 is comprised of approximately 1.2 kilometres of direct buried XLPE insulated primary conductor. The primary underground conductor is connected in a looped configuration to padmount transformers, from which secondary cables are installed to provide service to customers.

Figure 1 shows a single line diagram illustrating Loop 34 of distribution feeder PEP-02.

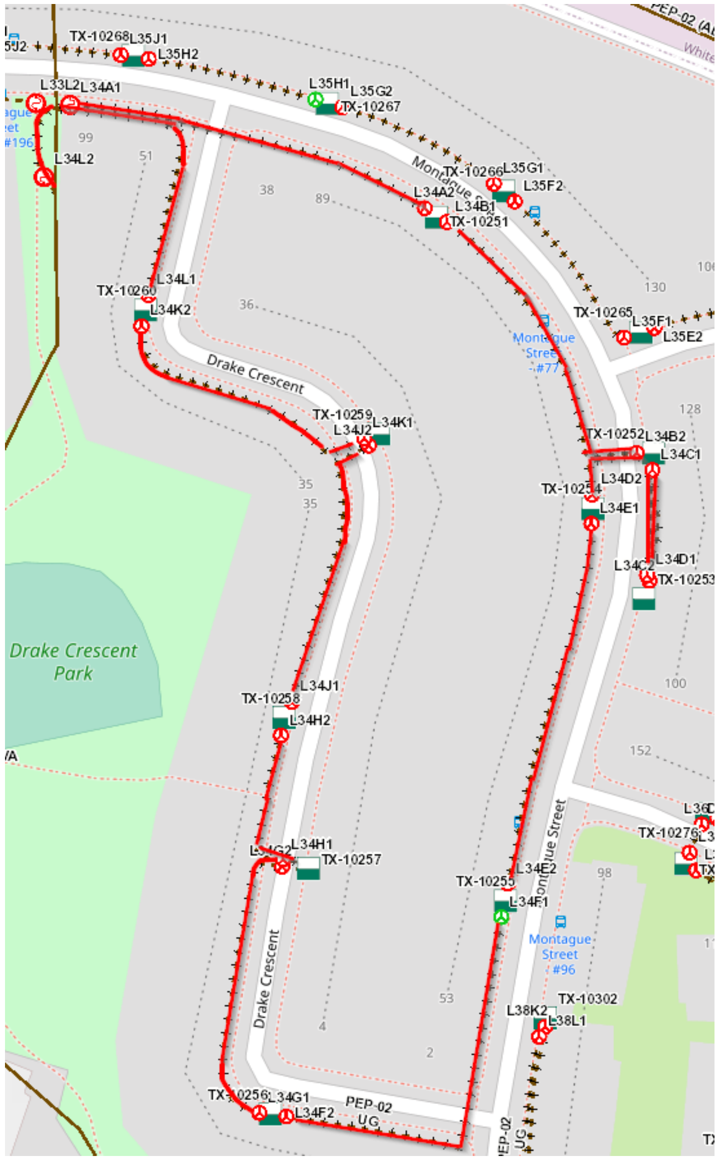


Figure 1: Loop 34

The primary conductor on Loop 34 has experienced numerous failures since the initial installation, with 20 primary conductor faults between 2004 and 2022. The primary conductor faults are becoming more frequent, with eight faults occurring since July 2020. Approximately $54,000 in maintenance costs to repair failed primary underground conductor have been incurred in the last 1.5 years.[22]

[22] Each cable fault repair requires excavation of the faulted cable location and the installation of a new piece of cable spliced into the existing cable. As a result, each cable fault repair requires two cable splices between new and existing cables which increases the likelihood of future faults at the splice locations.

Figures 2 and 3 show examples of the faulted primary conductor on Loop 34.

Figure 2: Loop 34 Primary Conductor Failure Repair

Figure 3: Loop 34 Primary Conductor Failure

An engineering assessment of the Loop 34 infrastructure, including failure frequency, asset age, condition assessment, and method of installation identified that the existing underground infrastructure has reached the end of its useful service life.

RISK ASSESSMENT

The *Distribution Feeder PEP-02 Refurbishment* will mitigate risks to the delivery of reliable service to customers in the Virginia Park area of St. John's.

Loop 34 of distribution feeder PEP-02 provides service to 117 customers in the Virginia Park area. These customers are exposed to risk of outages due to the deteriorated condition of the underground conductor on Loop 34. When the conductor fails, these 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 probability of equipment failure on Loop 34 is near certain given its age, deteriorated condition and the significant number of failures recently experienced.

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

Table 2 Distribution Feeder PEP-02 Refurbishment Project Risk Assessment Summary		
Consequence	Probability	Risk
Minor (2)	Near Certain (5)	Medium-High (10)

Based on this assessment, not proceeding with the *Distribution Feeder PEP-02 Refurbishment* project would pose a Medium-High (10) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Distribution Feeder PEP-02 Refurbishment* project is required to provide reliable service to customers at the lowest possible cost. Loop 34 of distribution feeder PEP-02 is deteriorated and is experiencing increased rates of equipment failure. Addressing these deficiencies is necessary to mitigate risks of equipment failure and potential outages to customers in the Virginia Park area of St. John's.

Title:	**Allowance for Funds Used During Construction**
Asset Class:	**Distribution**
Category:	**Project**
Investment Classification:	**Mandatory**
Budget:	**$247,000**

PROJECT DESCRIPTION

The *Allowance for Funds Used During Construction* ("AFUDC") is charged on distribution work orders with an estimated expenditure of less than $50,000 and a construction period in excess of three months. Newfoundland Power calculates AFUDC in a manner consistent with Order No. P.U. 32 (2007). This method of calculating AFUDC is standard practice for regulated Canadian utilities.

PROJECT BUDGET

The budget estimate for AFUDC is based on an estimated $1.0 million monthly average of distribution work in progress and capital materials upon which the interest rate will be applied. The AFUDC rate is applied each month in accordance with Order No. P.U. 32 (2007).

Table 1 provides a breakdown of expenditures proposed for 2023 for AFUDC.

Table 1
AFUDC
2023 Budget
($000s)

Cost Category	2023
Material	-
Labour – Internal	-
Labour – Contract	-
Engineering	-
Other	247
Total	$247

Proposed expenditures for AFUDC total $247,000 for 2023.

JUSTIFICATION

AFUDC is required to implement the Company's capital program and is justified on the same basis as the distribution capital expenditures to which it relates.

Title: **Extensions**
Asset Class: **Distribution**
Category: **Program**
Investment Classification: **Access**
Budget: **$12,218,000**

PROGRAM DESCRIPTION

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

PROGRAM BUDGET

The budget for the *Extensions* program is based on a forecast of new customer connections and an average cost per connection under this program. The average cost per connection is calculated based on historical data. Historical annual expenditures for this program over the most recent five-year period are expressed in current-year dollars ("Adjusted Costs"). The Adjusted Costs are divided by the number of new customers in each year to derive a cost per connection. The average of these costs is inflated by the GDP Deflator for Canada for non-labour costs and the Company's internal labour inflation rate for labour costs, and then multiplied by the forecast number of new customers for the budget year. Effective 2023, labour costs associated with this program include a direct allocation of amounts previously included in General Expenses Capitalized ("GEC"), as approved in Order No. P.U. 3 (2022).

Table 1 provides the cost per customer connection for the *Extensions* program from 2018 to 2023.

Table 1
Extensions Program
Cost per Customer

Year	2018	2019	2020	2021	2022F	2023F
Total (000s)	$11,274	$13,379	$10,561	$12,427	$11,879	$12,218
Adjusted Costs (000s)[1]	$12,606	$14,687	$11,386	12,725	$11,879	-
New Customers	2,781	2,379	2,062	2,448	2,343	2,185
Cost/Customer[1]	$4,533	$6,174	$5,522	$5,198	$5,070	$5,592

1 2022 dollars.

Newfoundland Power is forecasting 2,185 new customer connections in 2023 at a cost per connection under the *Extensions* program of $5,592.

Table 2 provides a breakdown of expenditures proposed for 2023 for the *Extensions* program.

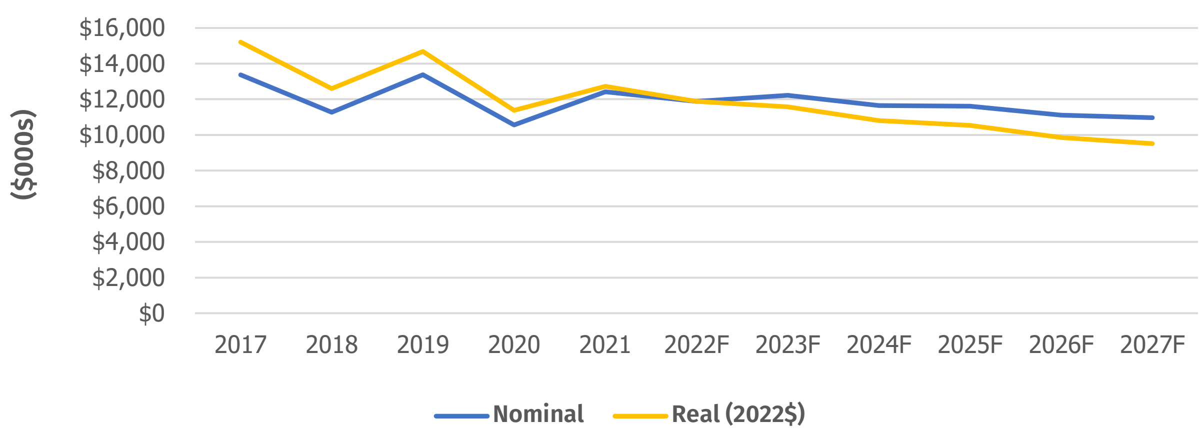
Table 2 Extensions Program 2023 Budget ($000s)	
Cost Category	2023
Material	3,926
Labour – Internal	4,102
Labour – Contract	2,582
Engineering	1,172
Other	436
Total	$12,218

Proposed expenditures for the *Extensions* program total $12,218,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Extensions* program from 2017 to 2027.[23]

Figure 1
Extensions Program Expenditures
(2017 - 2027F)



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

23 For forecast expenditures for the *Extensions* program, see the *2023-2027 Capital Plan,* Appendix A, page A-2.

approximately $12.1 million from 2017 to 2022, or approximately $13.1 million when adjusted for inflation. Annual expenditures under this program are forecast to average approximately $11.5 million over the next five years.

ASSET BACKGROUND

Newfoundland Power operates over 10,000 kilometres of distribution line. Extensions to distribution lines are constructed upon requests 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 requests and the locations 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: $6,699,000

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

Table 1 provides the annual expenditures for the *Reconstruction* program from 2018 to 2022.

Table 1
Reconstruction Program
Historical Expenditures
(000s)

Year	2018	2019	2020	2021	2022F
Total	$5,903	$5,579	$6,275	$5,959	$5,902
Adjusted Costs[1]	$6,599	$6,118	$6,753	$6,109	$5,902

[1] 2022 dollars.

The average annual adjusted cost for the *Reconstruction* program was approximately $6.3 million from 2018 to 2022.

Table 2 provides a breakdown of expenditures proposed for 2023 for the *Reconstruction* program.

Table 2
Reconstruction Program
2023 Budget
($000s)

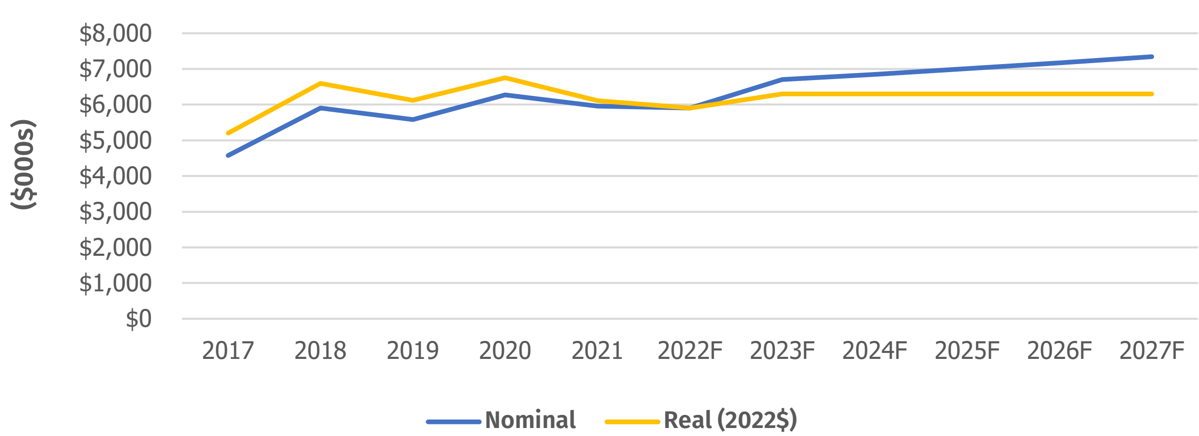
Cost Category	2023
Material	1,543
Labour – Internal	2,732
Labour – Contract	1,418
Engineering	781
Other	225
Total	$6,699

Proposed expenditures for the *Reconstruction* program total $6,699,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Reconstruction* program from 2017 to 2027.[24]

Figure 1
Reconstruction Program Expenditures
(2017 - 2027F)



[24] For forecast annual expenditures for the *Reconstruction* program, see the *2023-2027 Capital Plan,* Appendix A, page A-2.

Annual expenditures under this program averaged approximately $5.7 million from 2017 to 2022, or approximately $6.1 million when adjusted for inflation. Annual expenditures are forecast to average approximately $7.0 million over the next five years.

ASSET BACKGROUND

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

ASSESSMENT OF ALTERNATIVES

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

RISK ASSESSMENT

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

Newfoundland Power's distribution system has operated reliably over the last five years with an average of 1.4 outages per year and an average outage duration of 1.8 hours per year. The reliable operation of the distribution system is exposed to increased risk going forward due to the age of major line components.

The distribution system includes 228,000 wooden support structures and over 10,000 kilometres of overhead conductor. 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 15% of wooden support structures on Newfoundland Power's distribution system have exceeded 54 years in service. Approximately 23% of distribution overhead conductor has exceeded 50 years in service.[25]

The effect of age on Newfoundland Power's distribution system can be observed through its recent experience with equipment failures. Equipment failures on the distribution system are trending upward, with an increase of 29% over the last decade. This increase is primarily being driven by overhead conductor that has become deteriorated due to its age.

[25] For more information, see the *2023-2027 Capital Plan, Section 2.4.2 Distribution.*

An average of 533 deficiencies were corrected annually under the *Reconstruction* program from 2017 to 2021, ranging from 471 in 2019 to 616 in 2018. 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.

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

Table 3
Reconstruction Program
Risk Assessment Summary

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

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

JUSTIFICATION

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

Title:	**Rebuild Distribution Lines**
Asset Class:	**Distribution**
Category:	**Program**
Investment Classification:	**Renewal**
Budget:	**$4,945,000**

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 43 distribution feeders will undergo inspection in 2022 with planned preventative maintenance in 2023:

ABC-01	COL-02	HOL-02	PEP-01	SJM-09	SUM-01
BUC-01	GAM-01	KEN-01	PUL-03	SJM-11	VIR-08
BVS-05	GAN-03	KEN-02	ROB-01	SLA-06	WAL-01
CAT-01	GFS-07	MOL-05	SCT-01	SLA-11	
CAT-02	GFS-08	MOL-06	SCT-02	SLA-12	
CHA-02	GIL-01	MSY-03	SJM-06	SLA-13	
CHA-04	GLN-01	NCH-01	SJM-07	SPR-01	
CLV-01	GRH-02	NCH-02	SJM-08	SPR-02	

The specific deficiencies to be corrected on these distribution feeders will depend on the outcomes of the inspections completed throughout 2022, 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. 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 2018 to 2022.

Table 1 Rebuild Distribution Lines Program Historical Expenditures (000s)					
Year	2018	2019	2020	2021	2022F
Total	$4,429	$4,371	$4,477	$4,143	$4,333
Adjusted Costs[1]	$4,950	$4,794	$4,805	$4,250	$4,333

1 2022 dollars

The average annual adjusted cost for the *Rebuild Distribution Lines* program was approximately $4.6 million from 2018 to 2022.

Table 2 provides a breakdown of expenditures proposed for 2023 for the *Rebuild Distribution Lines* program.

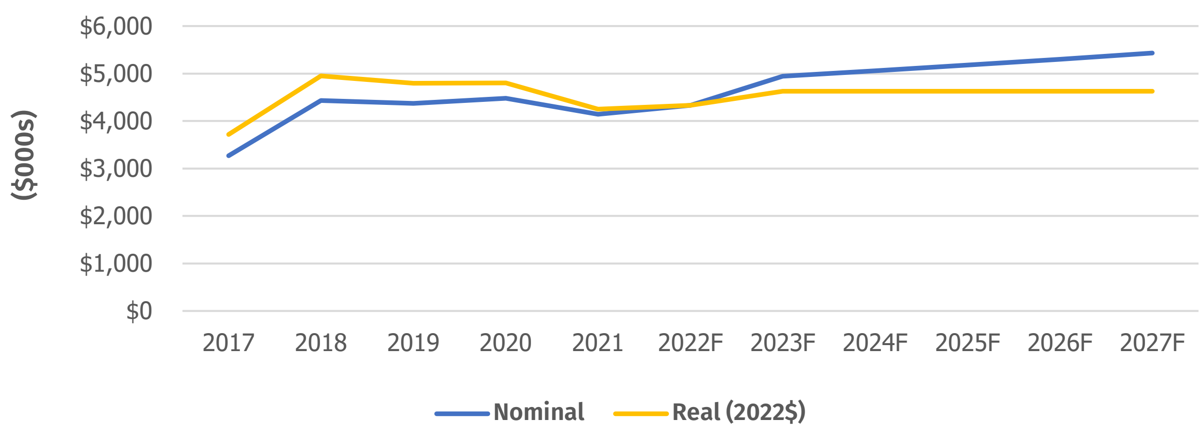
Table 2 Rebuild Distribution Lines Program 2023 Budget ($000s)	
Cost Category	2023
Material	1,476
Labour – Internal	2,488
Labour – Contract	509
Engineering	219
Other	253
Total	$4,945

Proposed expenditures for the *Rebuild Distribution Lines* program total $4,945,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Rebuild Distribution Lines* program from 2017 to 2027.[26]

Figure 1
Rebuild Distribution Lines Program Expenditures
(2017 - 2027F)



Annual expenditures under this program averaged approximately $4.2 million from 2017 to 2022, or approximately $4.5 million when adjusted for inflation. Annual expenditures are forecast to average approximately $5.2 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* project.

[26] For forecast annual expenditures for the *Rebuild Distribution Lines* program, see the *2023-2027 Capital Plan,* Appendix A, page A-2.

ASSESSMENT OF ALTERNATIVES

Newfoundland Power currently has over 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.

Newfoundland Power's distribution system has operated reliably over the last five years with an average of 1.4 outages per year and an average outage duration of 1.8 hours per year. The reliable operation of the distribution system is exposed to increased risk going forward due to the age of major line components.

The distribution system includes 228,000 wooden support structures and over 10,000 kilometres of overhead conductor. 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 15% of wooden support structures on Newfoundland Power's distribution system have exceeded 54 years in service. Approximately 23% of distribution overhead conductor has exceeded 50 years in service.[27]

The effect of age on Newfoundland Power's distribution system can be observed through its recent experience with equipment failures. Equipment failures on the distribution system are trending upward, with an increase of 29% over the last decade. This increase is primarily being driven by overhead conductor that has become deteriorated due to its age.

An average of 1,800 deficiencies were corrected annually under the *Rebuild Distribution Lines* program from 2017 to 2021, ranging from 1,017 in 2017 to 2,485 in 2020. These deficiencies were corrected through a combination of rebuilding sections of distribution feeders and the selective replacement of line components.

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27 For more information, see the *2023-2027 Capital Plan, Section 2.4.2 Distribution.*

The *Rebuild Distribution Lines* program will address deficiencies on 43 distribution feeders in 2023. These feeders serve an average of approximately 1,000 customers. The deficiencies to be addressed on these distribution feeders are likely to result in outages to these customers if not addressed.

Table 3 summarizes the risk assessment of the *Rebuild Distribution Lines* program.

Table 3
Rebuild Distribution Lines Program
Risk Assessment Summary

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

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

JUSTIFICATION

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

Title:	**Relocate/Replace Distribution Lines for Third Parties**
Asset Class:	**Distribution**
Category:	**Program**
Investment Classification:	**Access**
Budget:	**$3,803,000**

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.[28]

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. 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 relocation or replacement of distribution lines varies annually based on the nature of the request received from a third party. 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.

[28] 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 2018 to 2022.

Table 1
Relocate/Replace Distribution Lines for Third Parties Program
Historical Expenditures
(000s)

Year	2018	2019	2020	2021	2022F
Total	$2,496	$5,192	$2,745	$3,060	$3,370
Adjusted Costs[1]	$2,791	$5,703	$2,952	$3,136	$3,370

[1] 2022 dollars

The average annual adjusted cost for the *Relocate/Replace Distribution Lines for Third Parties* program was approximately $3.6 million from 2018 to 2022.

Table 2 provides a breakdown of expenditures proposed for 2023 for the *Relocate/Replace Distribution Lines for Third Parties* program.

Table 2
Relocate/Replace Distribution Lines for Third Parties Program
2023 Budget
($000s)

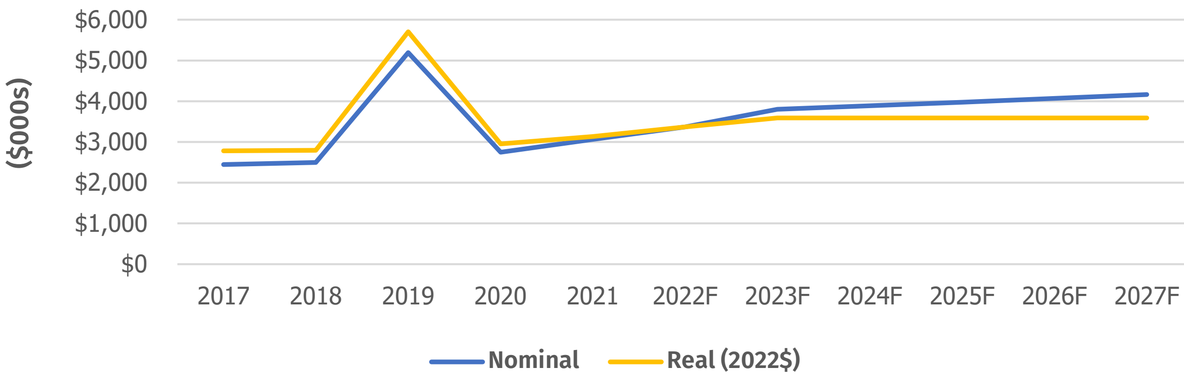
Cost Category	2023
Material	1,025
Labour – Internal	1,366
Labour – Contract	829
Engineering	410
Other	173
Total	**$3,803**

Proposed expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program total $3,803,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program from 2017 to 2027.[29]

Figure 1
Relocate/Replace Distribution Lines for Third Parties
Program Expenditures
(2017 - 2027F)



Annual expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program vary depending on the quantity and scope of the requests received.[30] Annual expenditures under this program averaged approximately $3.2 million from 2017 to 2022, or approximately $3.5 million when adjusted for inflation. Annual expenditures are forecast to average approximately $4.0 million over the next five years.

ASSET BACKGROUND

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

An average of 247 requests from third parties were received under the *Relocate/Replace Distribution Lines for Third Parties* program over the last four years, ranging from 120 in 2018 to 410 in 2021.[31]

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[29] For forecast annual expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program, see the *2023-2027 Capital Plan,* Appendix A, page A-2.

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

[31] Data for 2017 is not available.

JUSTIFICATION

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

Title: **Replacement Transformers**
Asset Class: **Distribution**
Category: **Program**
Investment Classification: **Renewal**
Budget: **$3,345,000**

PROGRAM DESCRIPTION

The *Replacement Transformers* program includes the cost of replacing or refurbishing distribution system transformers 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 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.

Table 1 provides annual expenditures for the *Replacement Transformers* program from 2018 to 2022.

Table 1
Replacement Transformers Program
Historical Expenditures
(000s)

Year	2018	2019	2020	2021	2022F
Total	$3,064	$3,019	$2,983	$3,356	$3,158
Adjusted Costs[1]	$3,434	$3,334	$3,270	$3,421	$3,158

[1] 2022 dollars.

The average annual adjusted cost for the *Replacement Transformers* program was approximately $3.3 million from 2018 to 2022.

Table 2 provides a breakdown of expenditures proposed for 2023 for the *Replacement Transformers* program.

Table 2
Replacement Transformers Program
2023 Budget
($000s)

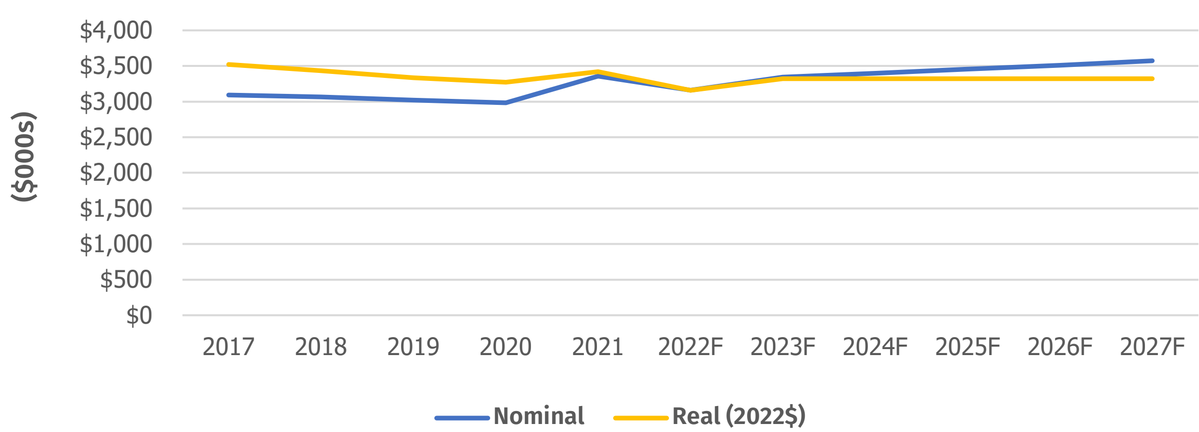
Cost Category	2023
Material	3,345
Labour – Internal	-
Labour – Contract	-
Engineering	-
Other	-
Total	$3,345

Proposed expenditures for the *Replacement Transformers* program total $3,345,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Replacement Transformers* program from 2017 to 2027.[32]

Figure 1
Replacement Transformers Program Expenditures
(2017 - 2027F)



[32] For forecast annual expenditures for the *Replacement Transformers* program, see the *2023-2027 Capital Plan,* Appendix A, page A-2.

Annual expenditures under this program averaged approximately $3.1 million from 2017 to 2022, or approximately $3.4 million when adjusted for inflation. Annual expenditures are forecast to average approximately $3.5 million over the next five years.

ASSET BACKGROUND

There are approximately 65,000 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 has 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.

Newfoundland Power changed its pole-mounted transformer specification to stainless steel tanks in 2001. This was the result of a significant number of premature steel transformer replacements due to rust. In coastal areas exposed to salt spray, rust was so significant that transformers were being replaced after 10 years or less. Newfoundland Power has replaced almost 80% of all distribution transformers with stainless steel units.

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

ASSESSMENT OF ALTERNATIVES

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

RISK ASSESSMENT

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

Transformers are replaced upon failure or imminent risk of failure. An average of 636 transformers were replaced annually from 2017 to 2021, ranging from 585 in 2017 to 704 in 2019. 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 liters of oil, while padmount transformers can contain up to 2,000 litres of oil. Failure and deterioration of transformers can result in oil leaks that lead to environmental contamination.

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

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

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

JUSTIFICATION

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

Title:	**New Transformers**
Asset Class:	**Distribution**
Category:	**Program**
Investment Classification:	**Access**
Budget:	**$2,967,000**

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 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.

Table 1 shows annual expenditures for the *New Transformers* program from 2018 to 2022.

Table 1
New Transformers Program
Historical Expenditures
(000s)

Year	2018	2019	2020	2021	2022F
Total	$2,718	$2,677	$2,645	$2,976	$2,800
Adjusted Costs[1]	$3,045	$2,956	$2,900	$3,033	$2,800

[1] 2022 dollars.

The average annual adjusted cost for the *New Transformers* program was approximately $2.9 million from 2018 to 2022.

Table 2 provides a breakdown of expenditures proposed for 2023 for the *New Transformers* program.

Table 2
New Transformers Program
2023 Budget
($000s)

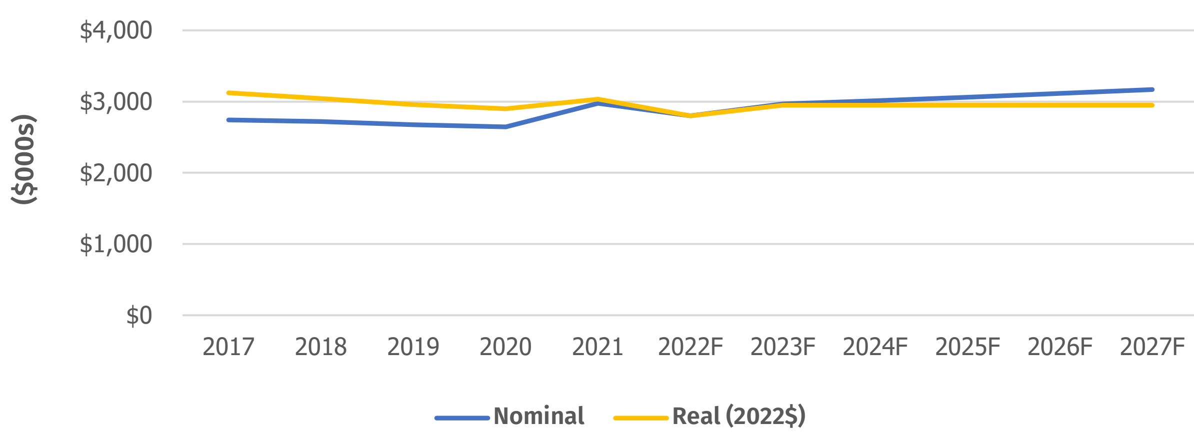
Cost Category	2023
Material	2,967
Labour – Internal	-
Labour – Contract	-
Engineering	-
Other	-
Total	$2,967

Proposed expenditures for the *New Transformers* program total $2,967,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *New Transformers* program from 2017 to 2027.[33]

Figure 1
New Transformers Program Expenditures
(2017 - 2027F)



33 For forecast annual expenditures for the *New Transformers* program, see the *2023-2027 Capital Plan,* Appendix A, page A-2.

Annual expenditures under this program averaged approximately $2.8 million from 2017 to 2022, or $3.0 million when adjusted for inflation. Annual expenditures under this program are forecast to average approximately $3.1 million over the next five years.

ASSET BACKGROUND

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

The number of new transformers required to be installed varies annually based on customer growth and load density on sections of distribution feeders. An average of 1,176 new transformers were installed annually from 2017 to 2021, ranging from 975 in 2019 to 1,373 in 2017.

JUSTIFICATION

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

Title: **New Services**
Asset Class: **Distribution**
Category: **Program**
Investment Classification: **Access**
Budget: **$2,916,000**

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

Table 1 provides annual expenditures for the *New Services* program from 2018 to 2023.

Table 1
New Services Program
Cost per Customer

Year	2018	2019	2020	2021	2022F	2023F
Total (000s)	$3,233	$2,769	$2,283	$2,936	$2,840	$2,916
Adjusted Costs (000s)[1]	$3,613	$3,032	$2,446	$3,013	$2,840	-
New Customers	2,781	2,379	2,062	2,448	2,343	2,185
Cost/customer[1]	$1,299	$1,274	$1,186	$1,231	$1,212	$1,334

[1] 2022 dollars.

Newfoundland Power is forecasting 2,185 new customer connections in 2023 at a cost per connection of $1,334.

Table 2 provides a breakdown of expenditures proposed for 2023 for the *New Services* program.

Table 2
New Services Program
2023 Budget
($000s)

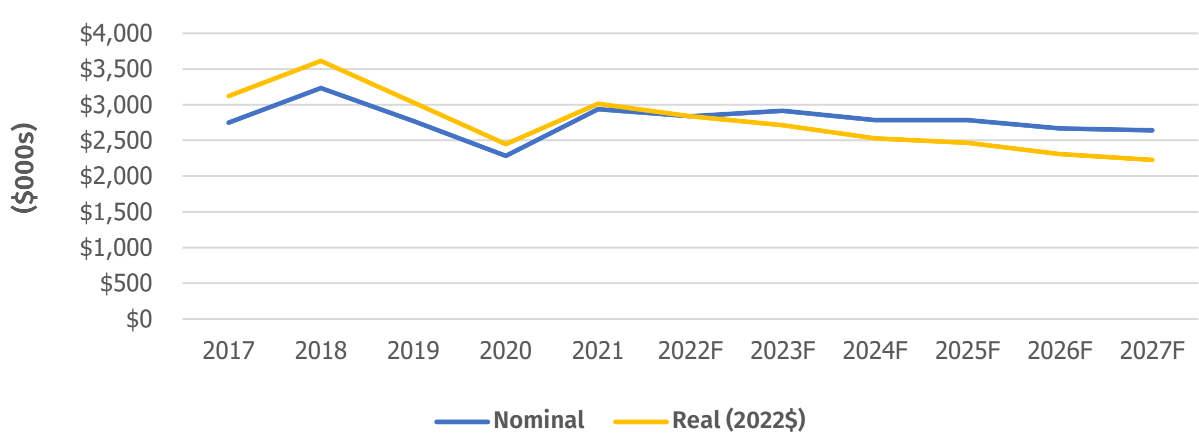
Cost Category	2023
Material	901
Labour – Internal	1,625
Labour – Contract	127
Engineering	220
Other	43
Total	$2,916

Proposed expenditures for the *New Services* program total $2,916,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *New Services* program from 2017 to 2027.[34]

Figure 1
New Services Program Expenditures
(2017 - 2027F)



[34] For forecast annual expenditures for the *New Services* program, see the *2023-2027 Capital Plan,* Appendix A, page A-2.

Annual expenditures under this program averaged approximately $2.8 million from 2017 to 2022, or $3.0 million when adjusted for inflation.[35] Annual expenditures under this program are forecast to average approximately $2.8 million over the next five years.

ASSET BACKGROUND

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

JUSTIFICATION

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

[35] Expenditures in 2018 were higher due to an increase in underground service installations, higher-cost general service connections, and front-lot hybrid construction configurations. See the *2018 Capital Expenditure Report,* Note 8.

Title: **New Street Lighting**
Asset Class: **Distribution**
Category: **Program**
Investment Classification: **Access**
Budget: **$2,618,000**

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

Table 1 provides the annual expenditures for the *New Street Lighting* program from 2018 to 2022.

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

Year	2018	2019	2020	2021	2022F
Total	$2,535	$2,678	$2,608	$1,494	$2,283
Adjusted Costs[1]	$2,833	$2,939	$2,820	$1,529	$2,283

1 2022 dollars.

The average annual adjusted cost for the *New Street Lighting* program was approximately $2.5 million from 2018 to 2022.

Table 2 provides a breakdown of expenditures proposed for 2023 for the *New Street Lighting* program.

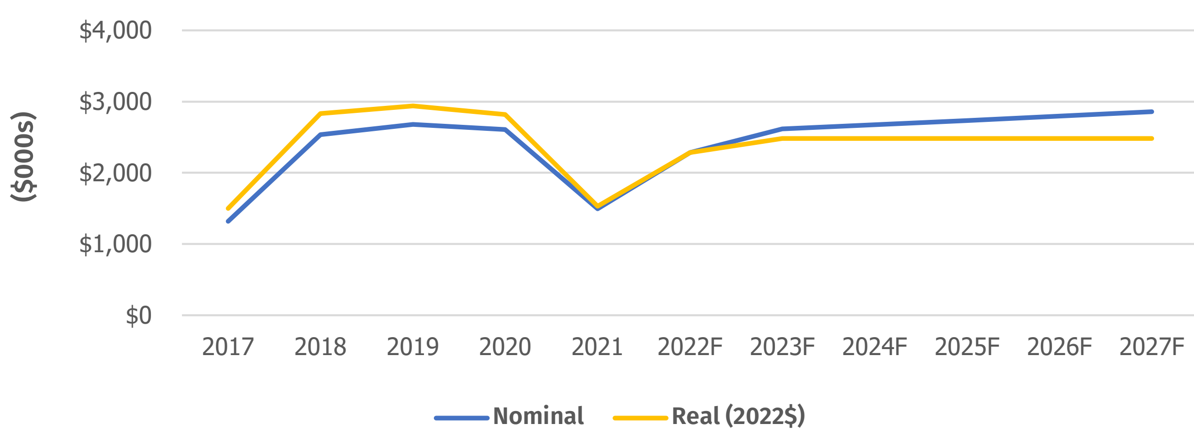
Table 2 New Street Lighting Program 2023 Budget ($000s)	
Cost Category	2023
Material	1,649
Labour – Internal	602
Labour – Contract	314
Engineering	26
Other	27
Total	$2,618

Proposed expenditures for the *New Street Lighting* program total $2,618,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast annual expenditures for the *New Street Lighting* program from 2017 to 2027.[36]

Figure 1
New Street Lighting Program Expenditures
(2017 - 2027F)



[36] For forecast annual expenditures for the *New Street Lighting* program, see *2023-2027 Capital Plan,* Appendix A, page A-2.

Annual expenditures for the *New Street Lighting* program vary depending upon the number and scope of requests received from customers. Annual expenditures under this program averaged approximately $2.2 million from 2017 to 2022, or approximately $2.3 million when adjusted for inflation. Annual expenditures under this program are forecast to average approximately $2.7 million over the next five years.

ASSET BACKGROUND

Newfoundland Power adopted LED street lighting as its service standard in 2019 following the approval of customer rates in Order No. P.U. 2 (2019). All new street lights installed under the *New Street Lighting* program are LED technology. A single Street and Area Lighting customer may request the installation of one or multiple street lights. An average of 607 new street lights were installed annually from 2017 to 2021, ranging from 491 in 2019 to 699 in 2018.

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: **$770,000**

PROGRAM DESCRIPTION

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

PROGRAM BUDGET

The budget for the 2023 *Replacement Street Lighting* program is based on actual expenditure history from 2021 and engineering estimates of forecast requirements.

Table 1 provides a breakdown of expenditures proposed for 2023 for the *Replacement Street Lighting* program.

Table 1
Replacement Street Lighting Program
2023 Budget
($000s)

Cost Category	2023
Material	485
Labour – Internal	177
Labour – Contract	92
Engineering	8
Other	8
Total	$770

Proposed expenditures for the *Replacement Street Lighting* program total $770,000 for 2023.

PROGRAM TREND

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. Information on historical trends in program costs is therefore not available.

Newfoundland Power is forecasting an average annual cost of approximately $805,000 for the *Replacement Street Lighting* program from 2023 to 2027.[37]

ASSET BACKGROUND

Newfoundland Power currently provides service to approximately 11,000 Street and Area Lighting customers. There are approximately 60,000 street lights in operation throughout the Company's service territory. Approximately 14,000 of these street lights have LED fixtures. The remainder have HPS fixtures, which are expected to be replaced in accordance with the *LED Street Lighting Replacement Plan.*[38]

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

RISK ASSESSMENT

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

The Company's Street and Area Lighting service is essential to public safety within communities. 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 all 60,000 street lights currently in service. Deficiencies are addressed under this program as identified during normal operations and upon the receipt of a trouble call from customers reporting a street light outage.

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[37] For forecast annual expenditures for the *Replacement Street Lighting* program, see the *2023-2027 Capital Plan,* Appendix A, page A-2.

[38] See the *2021 Capital Budget Application, LED Street Lighting Replacement Plan*.

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

Table 2
Replacement Street Lighting Program
Risk Assessment Summary

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

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

JUSTIFICATION

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

Title:	**Replacement Meters**
Asset Class:	**Distribution**
Category:	**Program**
Investment Classification:	**Renewal**
Budget:	**$662,000**

PROGRAM DESCRIPTION

The *Replacement Meters* program involves the replacement of deteriorated meters for existing customers and the sampling and replacement of meters in accordance with the requirements of the *Electricity and Gas Inspection Act (Canada)*. Newfoundland Power is forecasting a requirement to replace 4,877 meters in 2023.

PROGRAM BUDGET

The budget for the *Replacement Meters* program is calculated on the basis of 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 total replacement meter requirements in each year to derive the annual cost per meter in current-year dollars. The average of the 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 forecast meter replacements. 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 forecast quantity for replacement meters is based on historical data. Sampling and replacement requirements are governed by Compliance Sampling Orders ("CSOs") and Government Retest Orders ("GROs") issued in accordance with regulations under the *Electricity and Gas Inspection Act (Canada)*.

Table 1 provides annual expenditures for the *Replacement Meters* program from 2018 to 2023.

Table 1
Replacement Meters Program
Cost per Meter

Year	2018	2019	2020	2021	2022F	2023F
Meter Requirements						
GROs/CSOs	563	839	1,269	1,632	1,903	2,377
Replacements	2,021	1,204	1,224	1,320	2,500	2,500
Total	2,584	2,043	2,493	2,952	4,403	4,877
Meter Costs						
Actual (000s)	$310	$222	$319	$401	$534	$662
Adjusted[1] (000s)	$347	$244	$345	$410	$534	-
Cost/Meter[1]	$134	$119	$138	$139	$121	$136

1 2022 dollars.

Newfoundland Power is forecasting 4,877 meter replacements in 2023 at a cost per replacement of $136.

Table 2 provides a breakdown of expenditures proposed for 2023 for the *Replacement Meters* program.

Table 2
Replacement Meters Program
2023 Budget
($000s)

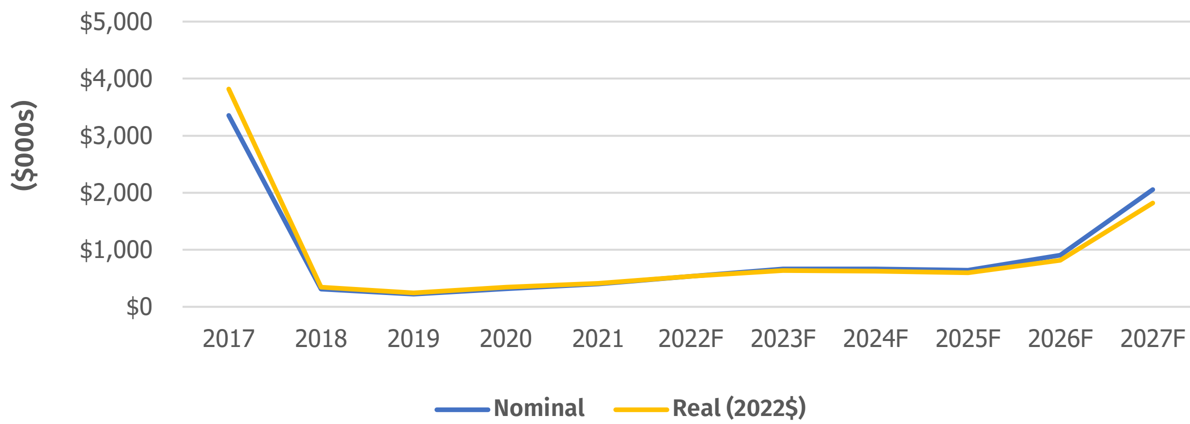
Cost Category	2023
Material	489
Labour – Internal	161
Labour – Contract	-
Engineering	-
Other	12
Total	$662

Proposed expenditures for the *Replacement Meters* program total $662,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Replacement Meters* program from 2017 to 2027.[39]

Figure 1
Replacement Meters Program Expenditures
(2017 - 2027F)



Annual expenditures for the *Replacement Meters* program decreased in 2018, reflecting the conclusion of Newfoundland Power's accelerated deployment of Automated Meter Reading ("AMR") technology. From 2018 to 2022, annual expenditures under this program averaged approximately $357,000, or approximately $376,000 when adjusted for inflation. Annual expenditures are forecast to average approximately $987,000 over the next five years. A forecast increase in expenditures in 2027 is due to an expected transition to Advanced Metering Infrastructure ("AMI") technology, with the installation of meters that are compatible with both AMR and AMI meter reading systems.

ASSET BACKGROUND

Virtually all meters in Newfoundland Power's service territory are AMR technology. AMR meters have provided efficiency benefits for customers through reduced meter reading costs.[40]

Revenue metering of electrical service is regulated under the *Electricity and Gas Inspection Act (Canada)*. Pursuant to these regulations, meters are required to be tested after eight years in service and periodically thereafter. The *Replacement Meters* program ensures compliance with this legislation and that deteriorated or failed meters are removed from service.

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[39] For forecast annual expenditures for the *Replacement Meters* program, see the *2023 Capital Budget Application, 2023-2027 Capital Plan,* Appendix A, page A-2.

[40] From 2012 to 2020, Newfoundland Power reduced its meter reading operating costs by approximately 81%. See Newfoundland Power's *2022/2023 General Rate Application, Volume 1, Section 2, page 2-8.*

The age profile of meters in Newfoundland Power's service territory reflects the Company's accelerated deployment of AMR meters, which concluded in 2017. Approximately 95% of all meters are under 10 years of age.

RISK ASSESSMENT

The *Replacement Meters* program will mitigate risks to the delivery of reliable service to customers by addressing the failure of meters on customers' premises.

Newfoundland Power forecasts a requirement to replace 2,500 meters in 2023. These meters are replaced upon failure. The failure of a meter on a customer's premises results in a loss of service to that customer. An additional 2,377 meters are also forecast to require replacement in 2023 to meet federal regulations.

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

Table 3
Replacement Meters Program
Risk Assessment Summary

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

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

Newfoundland Power has identified that its existing meters are exposed to risk of asset stranding due to the potential requirement to implement AMI technology. The deployment of AMI technology would require most existing AMR meters to be removed from service. The installation of replacement meters using AMI technology starting in 2027 is intended to help mitigate the risk of stranding AMR meters. Newfoundland Power will further evaluate options to mitigate risks of asset stranding in the development of a business case to deploy AMI technology.

JUSTIFICATION

The *Replacement Meters* program is required to provide reliable service to customers as it permits the replacement of deteriorated or failed meters. The program is also required to maintain compliance with government regulations.

Title: **Replacement Services**
Asset Class: **Distribution**
Category: **Program**
Investment Classification: **Renewal**
Budget: **$546,000**

PROGRAM DESCRIPTION

The *Replacement Services* 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.

PROGRAM BUDGET

The budget for the *Replacement Services* 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. Effective 2023, labour costs associated with this program include a direct allocation of amounts previously included in GEC, as approved in Order No. P.U. 3 (2022).

Table 1 provides annual expenditures for the *Replacement Services* program from 2018 to 2022.

Table 1
Replacement Services Program
Historical Expenditures
(000s)

Year	2018	2019	2020	2021	2022F
Total	$577	$321	$607	$311	$568
Adjusted Costs[1]	$644	$351	$653	$319	$568

1 2022 dollars.

The average annual adjusted cost for the *Replacement Services* program was approximately $507,000 from 2018 to 2022.

Table 2 provides a breakdown of expenditures proposed for 2023 for the *Replacement Services* program.

Table 2
Replacement Services Program
2023 Budget
($000s)

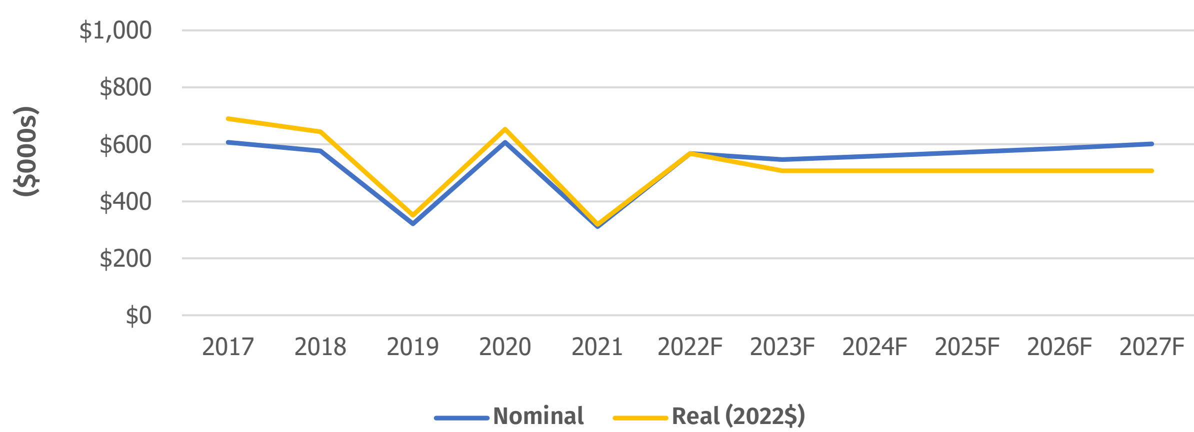
Cost Category	2023
Material	169
Labour – Internal	304
Labour – Contract	24
Engineering	41
Other	8
Total	$546

Proposed expenditures for the *Replacement Services* program total $546,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Replacement Services* program from 2017 to 2027.[41]

Figure 1
Replacement Services Program Expenditures
(2017 - 2027F)



[41] For forecast annual expenditures for the *Replacement Services* program, see the *2023-2027 Capital Plan,* Appendix A, page A-2.

Annual expenditures for the *Replacement Services* program vary based on failure rates and customers' service requests. Annual expenditures under this program averaged $499,000 from 2017 to 2022, or $538,000 when adjusted for inflation. Annual expenditures under this program are forecast to average $573,000 over the next five years.

ASSET BACKGROUND

Service wires are replaced upon the receipt of trouble calls from customers and subsequent follow-up that identifies a failure. Service wires are upgraded upon the receipt of a customer's request.

The number of service wires required to be replaced or upgraded varies annually. For example, service wire failures can be significantly affected by severe weather. The cost of replacing service wires also varies based upon the type of service wire to be replaced.

RISK ASSESSMENT

The *Replacement Services* program mitigates risks to the delivery of safe and reliable service to customers by replacing service wires that fail in service.

Newfoundland Power responded to an average of approximately 1,900 trouble calls from customers experiencing issues with the service connection to their premises from 2017 to 2021. Customers' trouble calls can result in the replacement of failed service wires. The failure of a service wire results in a loss of service to a customer's premises. The failure of a service wire can also pose a safety hazard when an energized wire becomes detached from a customer's premises, or when service wire insulation becomes deteriorated.

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

Table 3
Replacement Services Program
Risk Assessment Summary

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

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

JUSTIFICATION

The *Replacement Services* program is required to provide safe and reliable service to customers as it permits the replacement of failed service wires that are necessary to supply customers' premises.

Title: **New Meters**
Asset Class: **Distribution**
Category: **Program**
Investment Classification: **Access**
Budget: **$297,000**

PROGRAM DESCRIPTION

The *New Meters* program involves the purchase and installation of meters for new customers. Newfoundland Power is forecasting the requirement to install meters to serve 2,185 new customer connections in 2023.

PROGRAM BUDGET

The budget for the *New Meters* program is based on a forecast of new customer connections and 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 new customer connections in each year to derive the 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 meter installations for the budget year. Effective 2023, labour costs associated with this program include a direct allocation of amounts previously included in GEC, as approved in Order No. P.U. 3 (2022).

Table 1 provides the annual expenditures for the *New Meters* program from 2018 to 2023.

Table 1
New Meters Program
Cost per Customer

Year	2018	2019	2020	2021	2022F	2023F
Meter Requirements						
New Connections	2,781	2,379	2,062	2,448	2,343	2,185
Meter Costs						
Actual (000s)	$334	$259	$263	$332	$284	$297
Adjusted[1] (000s)	$374	$284	$285	$340	$284	-
Cost/customer[1]	$134	$119	$138	$139	$121	$136

1 2022 dollars.

Newfoundland Power is forecasting 2,185 new customer connections in 2023 at a cost per new meter installation of $136.

Table 2 provides a breakdown of expenditures proposed for 2023 for the *New Meters* program.

Table 2
New Meters Program
2023 Budget
($000s)

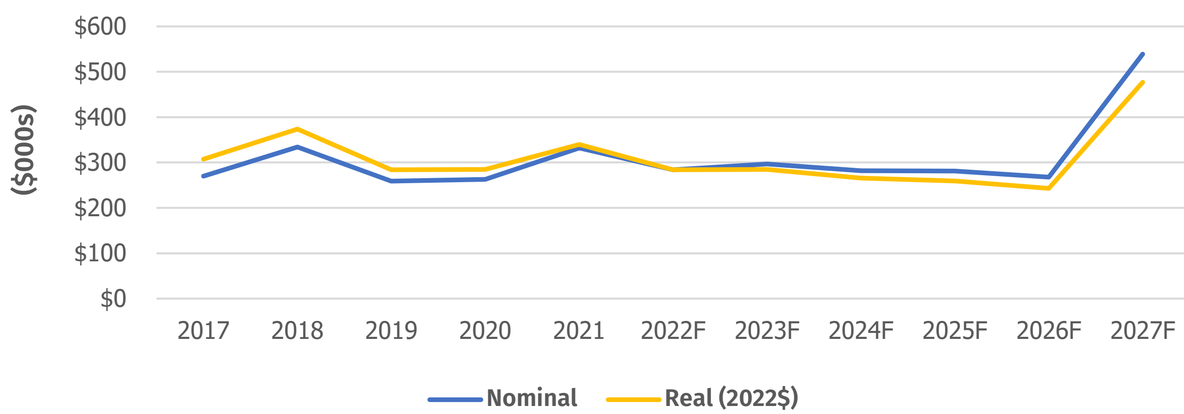
Cost Category	2023
Material	216
Labour – Internal	72
Labour – Contract	3
Engineering	-
Other	6
Total	$297

Proposed expenditures for the *New Meters* program total $297,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *New Meters* program from 2017 to 2027.[42]

Figure 1
New Meters Program Expenditures
(2017 - 2027F)



[42] For forecast annual expenditures for the *New Meters* program, see the *2023-2027 Capital Plan*, Appendix A, page A-2.

Annual expenditures for the *New Meters* program averaged approximately $290,000 from 2017 to 2022, or $312,000 on an inflation-adjusted basis. Annual expenditures are forecast to average approximately $333,000 over the next five years, with an increase in 2027 when a transition to AMI technology is expected to commence. The transition to AMI technology in 2027 reflects the installation of meters that are compatible with both AMR and AMI meter reading systems.

ASSET BACKGROUND

New meters are installed upon request from developers or contractors constructing new subdivisions, as well as individual customers who require electricity service. All new meters installed in Newfoundland Power's service territory currently use AMR technology.

RISK ASSESSMENT

Newfoundland Power has identified that its existing meters are exposed to risk of asset stranding due to the potential requirement to implement AMI technology. The deployment of AMI technology would require most existing AMR meters to be removed from service. The installation of replacement meters using AMI technology starting in 2027 is intended to help mitigate the risk of stranding AMR meters. Newfoundland Power will further evaluate options to mitigate risks of asset stranding in the development of a business case to deploy AMI technology.

JUSTIFICATION

The *New Meters* 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.

SUBSTATIONS

Title: **Walbournes Substation Refurbishment and Modernization**
Asset Class: **Substations**
Category: **Project**
Investment Classification: **Renewal**
Budget: **$4,955,000**

PROJECT DESCRIPTION

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

The 2023 scope of work for the *Walbournes Substation Refurbishment and Modernization* project includes:

(i) Dismantling the existing 12.5 kV switchgear;
(ii) Dismantling the existing switchgear building;
(iii) Constructing a new control building;
(iv) Replacing all deteriorated 66 kV switches;
(v) Installing two new 66 kV circuit breakers;
(vi) Installing new 12.5 kV distribution equipment including a steel bus structure, circuit breakers, switches, and potential transformers;
(vii) Constructing new spill containment foundations for WAL-T1 and WAL-T2;
(viii) Installing new digital relays and the associated communications equipment;
(ix) Extending the ground grid to cover substation equipment extension; and
(x) Installing standard varmint protection on all 12.5 kV equipment.

Design work for the *Walbournes Substation Refurbishment and Modernization* project will be completed by the end of the second quarter of 2023. Construction will commence in the third quarter and will be completed by the end of the fourth quarter.

Additional information on this project is provided in Appendix A of report *2.1 2023 Substation Refurbishment and Modernization* filed with the Application.

PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2023 for the *Walbournes Substation Refurbishment and Modernization* project.

Table 1
Walbournes Substation Refurbishment and Modernization Project
2023 Budget
($000s)

Cost Category	2023
Material	3,788
Labour – Internal	194
Labour – Contract	-
Engineering	818
Other	155
Total	$4,955

Proposed expenditures for the *Walbournes Substation Refurbishment and Modernization* project total $4,955,000 for 2023.

ASSET BACKGROUND

The refurbishment and modernization of individual substations is based on the condition of core infrastructure and equipment and was 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 24 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.[43] Continued execution of the *Substation Refurbishment and Modernization Plan* is therefore necessary to replace obsolete and deteriorated equipment and infrastructure.

43 For details of the assessment, see the *2023 Capital Budget Application, Report 2.1 2023 Substation Refurbishment and Modernization, Section 2.2*.

In 2023, Newfoundland Power is proposing to refurbish and modernize WAL Substation. The substation was built in 1966 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 the 12.5 kV switchgear, the 66 kV switches, and the electromechanical and vintage digital protection relays. Additionally, new transformer spill containment foundations are required and upgrades are required to the substation's ground grid.

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 WAL Substation, the number of components requiring preventative and corrective maintenance at this time justifies the requirement to refurbish and modernize the substation in 2023. The refurbishment and modernization of WAL Substation was planned to be completed in 2022, but was deferred to allow further engineering assessment of the components in the substation. Continued deferral of the refurbishment and modernization project would increase the risk that components will fail in service, which would result in an outage to thousands of customers in the Corner Brook area. Deferring this project further is therefore not a viable alternative.

RISK ASSESSMENT

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

WAL Substation provides service to approximately 6,900 customers in the Corner Brook area. Equipment failure in the substation would expose all 6,900 customers to the risk of outages. The time to restore service to customers would depend on the nature of the failure and could require several hours.

WAL Substation contains equipment that is deteriorated, obsolete and at end of life. A condition assessment determined the majority of switches on the 66 kV bus structure have deteriorated and aged beyond their expected useful service life. Switchgear within the substation is among the oldest in operation for the Company and has been discontinued by the vendor. The probability of equipment failure at WAL Substation is therefore likely.

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

Table 2
Walbournes Substation Refurbishment and Modernization Project
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Walbournes Substation Refurbishment and Modernization* project would pose a High (20) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Walbournes 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 6,900 customers in the Corner Brook area.

Title:	**Molloy's Lane Substation Refurbishment and Modernization**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget:	**$4,827,000**

PROJECT DESCRIPTION

The *Molloy's Lane Substation Refurbishment and Modernization* project involves the replacement and modernization of deteriorated equipment at the Molloy's Lane ("MOL") Substation in St. John's. Equipment to be replaced was identified through inspections, engineering assessments and operating experience.

The 2023 scope of work for the *Molloy's Lane Substation Refurbishment and Modernization* project includes:

(i) Completing a yard extension;
(ii) Constructing new 66 kV steel bus structure;
(iii) Installing new spill containment foundations for MOL-T1 and MOL-T2;
(iv) Dismantling the existing building;
(v) Constructing a new control building;
(vi) Installing two new 66 kV breakers;
(vii) Installing new 66 kV switches;
(viii) Installing one new 12.5 kV breaker;
(ix) Replacing deteriorated 12.5 kV switches;
(x) Installing 66 kV and 12.5 kV potential transformers;
(xi) Installing new digital relays;
(xii) Extending the ground grid to cover substation equipment extension; and
(xiii) Installing standard varmint protection on all 12.5 kV equipment.

The design work for the *Molloy's Lane Substation Refurbishment and Modernization* project will be completed by the end of the second quarter of 2023. Construction will commence in the third quarter and will be completed by the end of the fourth quarter.

Additional information on this project is provided in Appendix B of report *2.1 2023 Substation Refurbishment and Modernization* filed with the Application.

PROJECT BUDGET

The budget for the *Molloy's Lane Substation Refurbishment and Modernization* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2023 for the *Molloy's Lane Substation Refurbishment and Modernization* project.

Table 1
Molloy's Lane Substation Refurbishment and Modernization Project
2023 Budget
($000s)

Cost Category	2023
Material	3,731
Labour – Internal	182
Labour – Contract	-
Engineering	833
Other	81
Total	$4,827

Proposed expenditures for the *Molloy's Lane Substation Refurbishment and Modernization* project total $4,827,000 for 2023.

ASSET BACKGROUND

The refurbishment and modernization of individual substations is based on the condition of core infrastructure and equipment and was 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 24 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.[44] Continued execution of the *Substation Refurbishment and Modernization Plan* is therefore necessary to replace obsolete and deteriorated equipment and infrastructure.

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[44] For details of the assessment, see the *2023 Capital Budget Application, Report 2.1 2023 Substation Refurbishment and Modernization, Section 2.2*.

In 2023, Newfoundland Power is proposing to refurbish and modernize MOL Substation, which was built in 1960. A condition assessment has determined the substation contains a significant amount of deteriorated and obsolete equipment. Several pieces of equipment are at end of life, including: (i) the 66 kV wood pole structure; (ii) 66 kV and 12.5 kV switches; and (iii) the electromechanical and vintage digital protection relays. Additionally, new transformer spill containment foundations are required and upgrades are required to the substation's ground grid.

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 MOL Substation, the number of components requiring preventative and corrective maintenance at this time justifies the requirement to refurbish and modernize the substation in 2023. The refurbishment and modernization of MOL Substation was planned to be completed in 2021, but was deferred to allow further engineering assessment of the components in the substation. Continued deferral of the refurbishment and modernization project would increase the risk that components will fail in service, resulting in an outage to thousands of customers in St. John's. Deferring this project further is therefore not a viable alternative.

RISK ASSESSMENT

The *Molloy's Lane Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to customers in the St. John's area.

MOL Substation provides service to approximately 8,900 customers in the west end of St. John's. Equipment failure in the substation would expose all 8,900 customers to the risk of outages. The time to restore service to customers following an outage would depend on the nature of the equipment failure and could require several hours.

A condition assessment determined nearly all wood pole support structures and crossarms in the substation have deteriorated and require replacement. A circuit breaker and a significant quantity of switches require replacement based on their age and mechanical condition. Given the condition of the substation, the risk of failure of substation components is likely.

Table 2 summarizes the risk assessment of the *Molloy's Lane Substation Refurbishment and Modernization* project.

Table 2
Molloy's Lane Substation Refurbishment and Modernization Project
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Molloy's Lane Substation Refurbishment and Modernization* project would pose a High (20) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Molloy's 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 8,900 customers in the west end area of St. John's.

Title:	**Long Pond Substation Capacity Expansion**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Access**
Budget:	**$3,313,000**

PROJECT DESCRIPTION

The *Long Pond Substation Capacity Expansion* project involves increasing the capacity of electrical supply to Memorial University's St. John's campus. This increase in capacity is necessary to provide adequate electrical supply for Memorial University's boiler electrification project.

The electrification project at Memorial University is expected to add 25 MW of total load to Long Pond ("LPD") Substation through the installation of two new electric boilers. The boilers are expected to be ready for full load testing in early 2024. To meet this significant increase in electrical load, a second 25 MVA power transformer will be installed at LPD Substation ahead of the completion of the boiler electrification project.

The 2023 scope of work for the *Long Pond Substation Capacity Expansion* project includes:

(i) Constructing a 66 kV steel bus structure extension;
(ii) Constructing a 12.5 kV steel bus structure;
(iii) Installing a new 25 MVA power transformer and spill containment foundation;
(iv) Installing two new 66 kV breakers and new 66 kV switches;
(v) Installing one new 12.5 kV breaker and new 12.5 kV switches;
(vi) Installing new 12.5 kV potential transformers and current transformers;
(vii) Installing new transformer and bus differential protection digital relays; and
(viii) Installing standard varmint protection on all 12.5 kV equipment.

The design work for the *Long Pond Substation Capacity Expansion* project will be completed by the end of the second quarter of 2023. Construction will be completed by the end of the fourth quarter to meet the requirements of Memorial University's boiler electrification project schedule.

PROJECT BUDGET

The budget for the *Long Pond Substation Capacity Expansion* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2023 for the *Long Pond Substation Capacity Expansion* project.

Table 1
Long Pond Substation Capacity Expansion Project
2023 Budget
($000s)

Cost Category	2023
Material	2,692
Labour – Internal	89
Labour – Contract	-
Engineering	474
Other	58
Total	$3,313

Proposed expenditures for the *Long Pond Substation Capacity Expansion* project total $3,313,000 for 2023.

ASSET BACKGROUND

LPD Substation was constructed in 2019 and serves Memorial University's St. John's campus, including the Health Sciences Centre. LPD Substation consists of one 66 kV to 12.5 kV, 25 MVA power transformer (LPD-T1) to provide distribution voltage to Memorial University's distribution switchgear.

LPD Substation includes equipment owned by both Newfoundland Power and Memorial University. The Company owns all 66 kV infrastructure including power transformer LPD-T1 and a portion of the 12.5 kV equipment. The 12.5 kV distribution switchgear is owned and operated by Memorial University.

The 2021 peak load on LPD-T1 was 18 MVA. The addition of 25 MW of new load in 2024 will exceed the existing 25 MVA capacity of LPD Substation, as the forecast peak load in 2024 is 43 MVA.

The *Long Pond Substation Capacity Expansion* project is required to supply power to new services at Memorial University's St. John's Campus. Memorial University has a defined schedule associated with federal and provincial funding requirements to complete the electrification project. The new electric boilers must be fully in service by the end of March 2024. To meet this requirement, the *Long Pond Substation Capacity Expansion* project must be completed in 2023 to allow for start-up and commissioning of the new electric boilers.

JUSTIFICATION

The *Long Pond Substation Capacity Expansion* project is required to provide Memorial University with equitable access to an adequate supply of power. The capacity at LPD Substation will be insufficient to serve the increased load at Memorial University upon the installation of two electric boilers. Installing a second 25 MVA transformer will increase LPD Substation capacity to 50 MVA, enabling the substation to supply electricity for the additional load.

Title: **Substation Spare Transformer Inventory**
Asset Class: **Substations**
Category: **Project**
Investment Classification: **Renewal**
Budget: **$1,500,000**

PROJECT DESCRIPTION

The *Substation Spare Transformer Inventory* project involves the purchase of a 15/20/25 MVA, 66-25/12.5 kV power transformer in 2023 to serve as an emergency spare. This transformer specification will provide emergency backup for a significant portion of Newfoundland Power's fleet of substation power transformers.

Additional information on this project is provided in report *2.2 Substation Spare Transformer Inventory* filed with the Application.

PROJECT BUDGET

The budget for the *Substation Spare Transformer Inventory* project is based on a detailed engineering estimate.

Table 1 provides a breakdown of expenditures proposed for 2023 for the *Substation Spare Transformer Inventory* project.

Table 1
Substation Spare Transformer Inventory Project
2023 Budget
($000s)

Cost Category	2023
Material	1,475
Labour – Internal	-
Labour – Contract	-
Engineering	25
Other	-
Total	$1,500

Proposed expenditures for the *Substation Spare Transformer Inventory* project total $1,500,000 for 2023.

ASSET BACKGROUND

Newfoundland Power currently has 192 substation power transformers in service. Power transformers are essential to the delivery of reliable service to customers as the failure of a single transformer can result in a prolonged outage to thousands of customers.

The frequency of power transformer failures on the Company's system has increased over the last decade. A total of 11 power transformer failures occurred over the last five years. This compares to four power transformer failures over the previous five-year period.

Newfoundland Power's operations are exposed to increasing risk of power transformer failure going forward due to the age of the Company's power transformer fleet. Industry experience suggests the expected service life of a power transformer is typically between 30 and 50 years under ideal conditions and that failure rates increase with age. Approximately 32% of Newfoundland Power's power transformers are aged 50 years or older. An additional 33% of power transformers are between 45 and 49 years old.

When a power transformer fails, Newfoundland Power initiates emergency response to restore service to customers as quickly as possible. The length of time required to restore service to customers following the failure of a power transformer varies depending on whether it is possible to transfer load and whether a portable substation is nearby.

Newfoundland Power has typically had a small quantity of spare power transformers available to respond to a transformer failure. The Company's spares have historically been limited to power transformers that were removed from service due to system load growth. Newfoundland Power's inventory of spares currently consists of nine units. The coverage provided by these units is limited, at approximately 55% of Newfoundland Power's transformer fleet.

The emergency backup coverage provided by the Company's supply of spares is expected to diminish. Two-thirds of existing spare units are in excess of 45 years old. The Company is not forecasting any additional units to be removed from service due to load growth. As a result, existing spares will not be replaced once they are placed into service or reach the end of their useful service lives.

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

ASSESSMENT OF ALTERNATIVES

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

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

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

Maintaining an inventory of spare power transformers by purchasing units to act as emergency spares would provide the greatest degree of risk mitigation. The purchase of a 25 MVA transformer to act as a spare would improve the emergency backup coverage provided by the Company's existing inventory in 2023 from 55% to 75%. This would reduce expected pressures on the availability of portable substations and associated risks of customer outages.

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

RISK ASSESSMENT

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

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

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

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

Table 2 summarizes the risk assessment of the *Substation Spare Transformer Inventory* project.

Table 2 Substation Spare Transformer Inventory Project Risk Assessment Summary		
Consequence	Probability	Risk
Serious (4)	Likely (4)	Medium-High (16)

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

JUSTIFICATION

The *Substation Spare Transformer Inventory* project is required to provide reliable service to customers at the lowest possible cost. Purchasing a spare transformer will help mitigate risks of customer outages resulting from increasing power transformer failures.

Title:	**Substation Protection and Control Replacements**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget:	**$667,000**

PROJECT DESCRIPTION

The *Substation Protection and Control Replacements* project involves replacing substation protection and control systems, including Supervisory Control and Data Acquisition ("SCADA") system equipment and protection relay devices. The project includes: (i) replacing obsolete protection relays with industry standard digital relays; and (ii) upgrading protection and control equipment that does not meet current cybersecurity standards. The project also includes substation monitoring upgrades to effectively manage an increased volume of electrical system data collected by the Company's SCADA system, as well as to address the technical obsolescence of existing equipment and software.

In 2023, the *Substation Protection and Control Replacements* project will include modernizing the obsolete protection equipment at Oxen Pond ("OXP") Terminal Station and Hardwoods ("HWD") Terminal Station and the replacement of 14 communications gateways.[45]

Design work for the *Substation Protection and Control Replacements* project will be completed in the second quarter of 2023. Installation will commence in the second quarter and will be completed by the end of the fourth quarter.

PROJECT BUDGET

The budget for the *Substation Protection and Control Replacements* project is based on detailed engineering estimates of individual budget items.

[45] Recent inspections have determined that 36 of the Company's communication gateways require replacement.

Table 1 provides a breakdown of expenditures proposed for 2023 for the *Substation Protection and Control Replacements* project.

Table 1
Substation Protection and Control Replacements Project
2023 Budget
($000s)

Cost Category	2023
Material	287
Labour – Internal	133
Labour – Contract	-
Engineering	234
Other	13
Total	$667

Proposed expenditures for the *Substation Protection and Control Replacements* project total $667,000 for 2023.

ASSET BACKGROUND

Electromechanical relays were the original electrical protection used by Newfoundland Power. Starting in the early 2000s, the Company began modernizing its protection devices by replacing electromechanical relays with digital relays and controllers. The Company has upgraded most of its electromechanical protection devices to digital devices since that time.

Newfoundland Power currently has 35 substations where electromechanical relays are still in service.[46] Electromechanical relays have moving parts that can fail as they age, wear, and accumulate dirt and dust. A majority of the Company's electromechanical relays are over 30 years old, which is the upper limit of typical industry experience, and have become obsolete.

These obsolete relays are scheduled to be replaced in 70% of substations through *Substation Refurbishment and Modernization* projects. The *Substation Protection and Control Replacements* project covers the replacement of obsolete relays in the remaining 30% of substations that contain electromechanical relays. The *Substation Protection and Control Replacements* project also addresses digital relays and controllers that are now approaching 20 years in service and have started to fail.

[46] Approximately 10% of the protection devices currently in service at Company substations are still electromechanical. For information on the prevalence of electromechanical protection devices in Newfoundland Power's substations, see section 2.2 of the report *2.1 2023 Substation Refurbishment and Modernization*.

In addition to replacing electromechanical relays with digital relays, the Company has deployed other communications and control technologies that provide substation-based data to the Company's SCADA system. These technologies provide secure communication of the substation data across private and public networks. Periodic upgrades are required to effectively secure and manage increased volumes of electrical system data. These upgrades typically increase the functionality of the equipment and software while addressing errors in the manufacturer's software, known hardware defects and cybersecurity vulnerabilities to ensure continued effective electrical system control and operations.

RISK ASSESSMENT

The *Substation Protection and Control Replacements* project will mitigate risks to the delivery of reliable service to customers.

The consequences of keeping obsolete equipment in service without vendor support is an increased risk of extended outages to large numbers of customers until a suitable replacement is completed, as well as increased risk of cybersecurity incidents.[47]

Both OXP Terminal Station and HWD Terminal Station directly serve thousands of customers. OXP Terminal Station contains electromechanical relays that have been in service for over 30 years and are at end of life. HWD Terminal Station contains vintage digital relays that have been in service for approximately 20 years and are at end of life. The probability of failure is therefore likely.

Table 2 summarizes the risk assessment of the 2023 *Substation Protection and Control Replacements* project.

Table 2
Substation Protection and Control Replacements Project
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Substation Protection and Control Replacements* project would pose a Medium-High (16) risk to delivery of reliable service to customers.

JUSTIFICATION

The *Substation Protection and Control Replacements* project is required to provide reliable service to customers at the lowest possible cost as it permits the replacement of obsolete protection and controls systems at substations.

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[47] Replacing an electromechanical relay with a digital replay following an in-service failure will typically require engineering, configuration and rewiring work that may not be required for a simple like-for-like replacement.

Title: **Substation Ground Grid Upgrades**
Asset Class: **Substations**
Category: **Project**
Investment Classification: **Service Enhancement**
Budget: **$563,000**

PROJECT DESCRIPTION

The *Substation Ground Grid Upgrades* project involves the upgrade of substation ground grids to ensure compliance with *ANSI/IEEE Standard 80-2013 Guide for Safety in AC Substation Grounding*.

In 2023, Newfoundland Power will complete ground grid upgrades at three substations to ensure the ground grids are compliant with industry standards and to address identified deficiencies. Substation ground grids will be upgraded at the Company's Hardwoods ("HWD"), Cape Broyle ("CAB"), and Seal Cove ("SCV") substations.

Design work for the *Substation Ground Grid Upgrades* project will be completed in the second quarter of 2023. Construction will commence in the second quarter and will be completed by the end of the fourth quarter.

PROJECT BUDGET

The budget for the *Substation Ground Grid Upgrades* project is based on detailed engineering estimates of individual budget items.

Table 1 provides a breakdown of expenditures proposed for 2023 for the *Substation Ground Grid Upgrades* project.

Table 1
Substation Ground Grid Upgrades Project
2023 Budget
($000s)

Cost Category	2023
Material	460
Labour – Internal	3
Labour – Contract	-
Engineering	90
Other	10
Total	$563

Proposed expenditures for the *Substation Ground Grid Upgrades* project total $563,000 for 2023.

ASSET BACKGROUND

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.

Newfoundland Power completes engineering assessments of substation ground grids as part of its normal operations. The assessments include field testing and computer modeling to complete step and touch potential analysis to identify the upgrades required to comply with *ANSI/IEEE Standard 80-2013*.

Engineering assessments have been recently completed on HWD, CAB and SCV substations. Upgrades to the ground grids in these substations will include the addition of equipment bonding, grounding mats, below-grade conductor, and ground wells as required to improve ground impedance.

RISK ASSESSMENT

The *Substation Ground Grid Upgrades* project will mitigate risks to the safe delivery of service to customers by enhancing safety infrastructure in substations.

Engineering assessments have determined that HWD, CAB and SCV substations have deteriorated and substandard ground grids. This can result in unsafe conditions for employees working in the substations with the potential for serious injury or fatality. Given these substations are not in full compliance with industry standards for substation grounding, the probability of this hazard arising is considered possible.

Table 2 summarizes the risk assessment of the 2023 *Substation Ground Grid Upgrades* project.

Table 2
Substation Ground Grid Upgrades Project
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Substation Ground Grid Upgrades* project would pose a Medium-High (15) risk to the safe delivery of service to customers.

JUSTIFICATION

The *Substation Ground Grid Upgrades* project is required to maintain safe and adequate facilities as it will permit the correction of ground grid deficiencies identified at Newfoundland Power's substations.

Title:	**PCB Bushing Phase-out**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Mandatory**
Budget:	**$425,000**

PROJECT DESCRIPTION

The *PCB Bushing Phase-out* project is required to phase-out polychlorinated biphenyls ("PCB") with concentrations greater than 50 parts-per-million ("ppm") from breaker and substation transformer bushings. The phase-out of PCBs is mandated by *Government of Canada PCB Regulation (SOR/2008-273)*, and requires that transformer bushings, breakers and instrument transformers with PCB concentrations of greater than 50 ppm be removed from service by the end of 2025. Newfoundland Power will replace three potential transformers and three current transformers in 2023 that have PCB concentrations in excess of 50 ppm.

Design work for the *PCB Bushing Phase-out* project will be completed in the second quarter of 2023. Construction will commence in the second quarter and will be completed by the end of the fourth quarter.

PROJECT BUDGET

The budget for the *PCB Bushing Phase-out* project is based on detailed engineering estimates of individual budget items.

Table 1 provides a breakdown of expenditures proposed for 2023 for the *PCB Bushing Phase-out* project.

Table 1
PCB Bushing Phase-out Project
2023 Budget
($000s)

Cost Category	2023
Material	187
Labour – Internal	26
Labour – Contract	-
Engineering	205
Other	7
Total	$425

Proposed expenditures for the *PCB Bushing Phase-out* project total $425,000 for 2023.

ASSET BACKGROUND

Newfoundland Power is executing a phased approach to removing from service substation equipment with PCB concentrations prohibited by Government of Canada regulations. From 2011 to 2014, the Company removed from service the bushings on 68 power transformers and 28 bulk oil circuit breakers where bushings had PCB concentrations greater than 500 ppm.

In 2017, Newfoundland Power initiated an eight-year plan to remove from service equipment with PCB concentrations between 50 ppm and 500 ppm. The replacement of this equipment is required by 2025 to comply with Government of Canada regulations. A total of 24 power transformers and 42 bulk oil circuit breakers were identified as having bushings with PCB concentrations greater than 50 ppm and less than 500 ppm. The Company's execution of this plan was approximately 85% complete at year-end 2021.

JUSTIFICATION

The *PCB Bushing Phase-out* project is required to comply with Government of Canada regulations regarding the removal from service of substation equipment with PCB concentrations in excess of 50 ppm.

Title: **Substation Replacements Due to In-Service Failures**
Asset Class: **Substations**
Category: **Program**
Investment Classification: **Renewal**
Budget: **$4,422,000**

PROGRAM DESCRIPTION

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

PROGRAM BUDGET

The budget for the *Substation Replacements Due to In-Service Failures* program is based on a historical average. Historical annual expenditures under this program over the most recent five-year period are expressed in current-year dollars as Adjusted Costs. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada for non-labour costs and the Company's internal labour inflation rate for labour costs. Effective 2023, labour costs associated with this program include a direct allocation of amounts previously included in GEC, as approved in Order No. P.U. 3 (2022).

Table 1 provides the annual expenditures for the *Substation Replacements Due to In-Service Failures* program from 2018 to 2022.

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

Year	2018	2019	2020	2021	2022F
Total	$3,861	$4,532	$3,684	$4,113	$3,691
Adjusted Cost[1]	$4,319	$4,985	$3,986	$4,207	$3,691

[1] 2022 dollars.

The average annual adjusted cost for the *Substation Replacements Due to In-Service Failures* program was approximately $4.2 million from 2018 to 2022.

Table 2 provides a breakdown of expenditures proposed for 2023 for the *Substation Replacements Due to In-Service Failures* program.

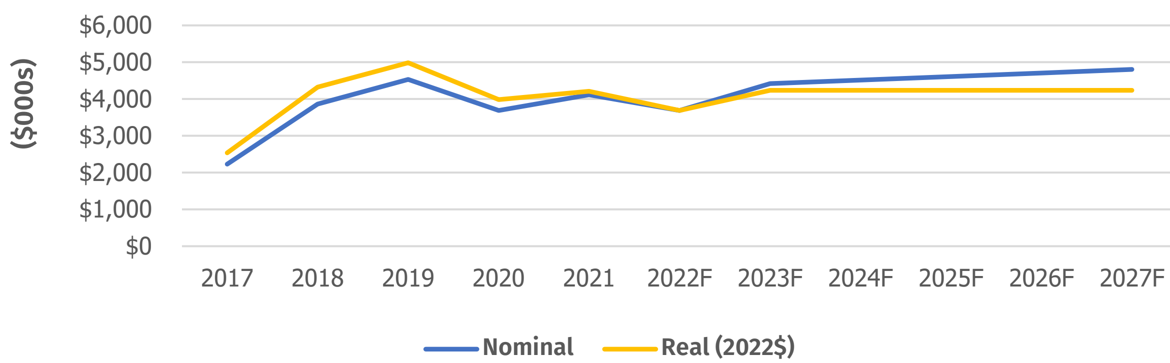
Table 2 Substation Replacements Due to In-Service Failures Program 2023 Budget ($000s)	
Cost Category	2023
Material	2,789
Labour – Internal	1,091
Labour – Contract	-
Engineering	262
Other	280
Total	$4,422

Proposed expenditures for the *Substation Replacements Due to In-Service Failures* program total $4,422,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Substation Replacements Due to In-Service Failures* program from 2017 to 2027.[48]

Figure 1
Substation Replacements Due to In-Service Failures
Program Expenditures
(2017 - 2027F)



[48] For forecast annual expenditures for the *Substation Replacements Due to In-Service Failures* program, see the *2023-2027 Capital Plan,* Appendix A, page A-3.

Annual expenditures under the *Substation Replacements Due to In-Service Failures* program averaged approximately $3.7 million from 2017 to 2022, or approximately $4 million when adjusted for inflation.[49] Annual expenditures are forecast to average approximately $4.6 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 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 part would have on the electrical system.

The volume of equipment required to be replaced under the *Substation Replacements Due to In-Service Failures* program varies annually. Historically, major equipment failures in substations have included power transformers, circuit breakers and reclosers, and switches. Five power transformers required replacement due to failure from 2017 to 2021. Over the same period, an average of eight circuit breakers and reclosers and eight switches also required replacement annually.

Newfoundland Power's operations are exposed to increasing risk of substation equipment failures as assets are aging beyond their expected useful service lives. This includes power transformers, bulk-oil circuit breakers, switches, and indoor switchgear. For more on the age and condition of substation assets, see report *2.1 2023 Substation Refurbishment and Modernization*.

ASSESSMENT OF ALTERNATIVES

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

RISK ASSESSMENT

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

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49 Expenditures in 2019 were higher as a result of two failed power transformers that required repair. See the *2019 Capital Expenditure Report*, Note 5.

Individual substations provide service to an average of 2,300 customers, with the largest substation providing service to over 10,000 customers. Substations are maintained to operate to a high standard of reliability and, as a result, have not had a material impact on the average service reliability provided to customers in recent years.[50] However, when substation failures occur they can result in significant customer outages. For example, a power transformer failure at Bonavista Substation in 2018 resulted in 3.7 million customer outage minutes. Equipment replaced under the *Substation Replacements Due to In-Service Failures* program has either failed or is at imminent risk of failure.

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.

50 Substation equipment failures have resulted in an annual average of less than 10 outage minutes per customer over the last five years.

TRANSMISSION

Title: **Transmission Line 55L Rebuild**
Asset Class: **Transmission**
Category: **Project**
Investment Classification: **Renewal**
Budget (Multi-Year): **$5,328,000 in 2023; and $5,284,000 in 2024**

PROJECT DESCRIPTION

The *Transmission Line 55L Rebuild* project involves rebuilding Transmission Line 55L from Blaketown ("BLK") Substation to Clarkes Pond ("CLK") Substation to address deterioration and deficiencies identified through inspection.

This project will be completed over two years. A 24.1 kilometre section of Transmission Line 55L will be rebuilt in 2023. A 21.2 kilometre section of Transmission Line 55L will be rebuilt in 2024. During both years, material procurement and brush clearing will be completed during the first quarter, followed by design work during the second quarter and construction during the third and fourth quarters.

Additional information on this project is provided in report *3.1 2023 Transmission Line Rebuild* filed with the Application.

PROJECT BUDGET

The budget for the *Transmission Line 55L Rebuild* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2023 and 2024 for the *Transmission Line 55L Rebuild* project.

Table 1
Transmission Line 55L Rebuild Project
2023/2024 Budget
($000s)

Cost Category	2023	2024
Material	934	1,042
Labour – Internal	315	300
Labour – Contract	2,747	2,709
Engineering	479	391
Other	853	842
Total	$5,328	$5,284

Proposed expenditures for the *Transmission Line 55L Rebuild* project total $10,612,000, with $5,328,000 in 2023 and $5,284,000 in 2024.

ASSET BACKGROUND

Newfoundland Power filed the *Transmission Line Rebuild Strategy* as part of its *2006 Capital Budget Application*. The strategy outlines a long-term plan to rebuild the Company's aging transmission lines. Rebuild projects are prioritized based on physical condition, risk of failure, and the potential impact on customers in the event of a failure. As part of executing this strategy, Transmission Line 55L is proposed to be rebuilt over two years starting in 2023.

Transmission Line 55L is a 66 kV radial line running between BLK Substation on the Trans-Canada Highway and CLK Substation. The line serves 3,419 customers in the Placentia area and was originally constructed in 1971, except for a small 1.0 kilometre section constructed in 1968. The tap to Quartz Substation was constructed in 1981. The line includes approximately 43.3 kilometres of original construction, consisting of 372 single-pole structures and 54 two-pole H-Frame structures.

Customers served by Transmission Line 55L have been subjected to outages due to significant weather systems over the last five years. Due to a wind storm in 2017, customers experienced an outage of approximately 4.5 hours, which resulted in approximately 891,000 customer outage minutes. Customers experienced a further outage in 2020 due to a wind storm, resulting in approximately 817,000 customer outage minutes. In total over the last two decades, customers served by Transmission Line 55L have experienced over 10 million customer outage minutes.

An inspection of Transmission Line 55L in 2022 identified that 253 of the 490 poles on the line have deteriorated and require replacement. Additionally, 61 structures were identified as having deteriorated insulators, deteriorated crossarms, or hardware deficiencies.

ASSESSMENT OF ALTERNATIVES

Transmission Line 55L was originally planned to be rebuilt in 2007, but was deferred through routine maintenance. Based on its condition, criticality in serving customers and operating experience, a capital project to address the deteriorated condition of Transmission Line 55L can no longer be deferred.

As discussed in report 3.1, three alternatives were evaluated to address the deteriorated condition of Transmission Line 55L: (i) address the existing deficiencies in 2023 and defer the replacement of other components; (ii) rebuild the line in its existing right of way; and (iii) rebuild the line in a new right of way. A net present value analysis determined that rebuilding Transmission Line 55L in a new right of way is the least cost alternative.

RISK ASSESSMENT

The *Transmission Line 55L Rebuild* project will mitigate risks to the delivery of reliable service to customers on the Avalon Peninsula.

Transmission Line 55L is a radial line that serves as the sole source of supply for 3,419 customers in the Placentia area. An equipment failure on Transmission Line 55L would result in outages to all customers served by the line. With sections of the transmission line located across country, significant time can be required to restore service to customers. This can be observed during past failures of the line during severe wind, as described above.

Inspections have identified that half of the poles on this line are deteriorated and a significant quantity of structures contain deficiencies. The probability of failure is therefore likely.

Table 2 summarizes the risk assessment of the *Transmission Line 55L Rebuild* project.

Table 2
Transmission Line 55L Rebuild Project
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Transmission Line 55L Rebuild* project would pose a High (20) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Transmission Line 55L Rebuild* project is required to provide reliable service to customers at the lowest possible cost. A net present value analysis confirmed that rebuilding Transmission Line 55L in a new right of way is the least-cost alternative to address existing deterioration and deficiencies and mitigate risks of equipment failures that result in customer outages.

Title:	**Transmission Line Maintenance**
Asset Class:	**Transmission**
Category:	**Program**
Investment Classification:	**Renewal**
Budget:	**$2,610,000**

PROGRAM DESCRIPTION

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

PROGRAM BUDGET

The budget for the *Transmission Line Maintenance* program is based on a historical average. Historical annual program expenditures over the most recent five-year period are expressed in current-year dollars as Adjusted Costs. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada for non-labour costs and the Company's internal labour inflation rate for labour costs. Effective 2023, labour costs associated with this program include a direct allocation of amounts previously included in GEC, as approved in Order No. P.U. 3 (2022).

Table 1 provides the annual expenditures for the *Transmission Line Maintenance* program from 2018 to 2022.

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

Year	2018	2019	2020	2021	2022F
Total	$2,747	$2,214	$2,139	$2,404	$2,398
Adjusted Cost[1]	$3,076	$2,438	$2,326	$2,455	$2,398

[1] 2022 dollars.

The average annual adjusted cost for the *Transmission Line Maintenance* program was $2.5 million from 2018 to 2022.

Table 2 provides a breakdown of expenditures proposed for 2023 for the *Transmission Line Maintenance* program.

Table 2
Transmission Line Maintenance Program
2023 Budget
($000s)

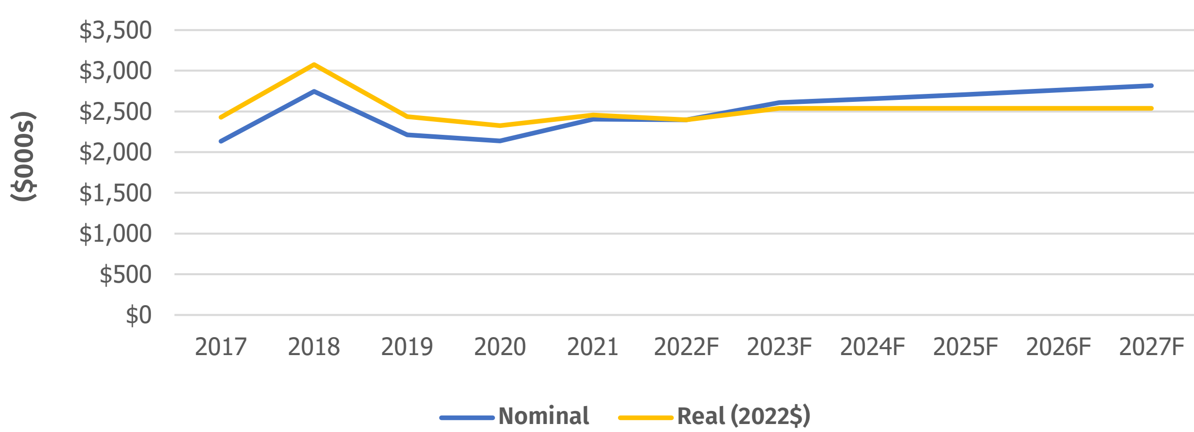
Cost Category	2023
Material	1,050
Labour – Internal	205
Labour – Contract	871
Engineering	188
Other	296
Total	$2,610

Proposed expenditures for the *Transmission Line Maintenance* program total $2,610,000 for 2023.

PROGRAM TREND

Figure 1 provides historical and forecast costs for the *Transmission Line Maintenance* program from 2017 to 2027.[51]

Figure 1
Transmission Line Maintenance Program Expenditures
(2017 - 2027F)



[51] For forecast annual expenditures for the *Transmission Line Maintenance* program, see the *2023-2027 Capital Plan,* Appendix A, page A-4.

Annual expenditures under this program averaged approximately $2.3 million from 2017 to 2022, or approximately $2.5 million when adjusted for inflation.[52] Annual expenditures are forecast to average approximately $2.7 million over the next five years.

ASSET BACKGROUND

Newfoundland Power owns and operates 110 transmission lines, which span approximately 2,000 kilometres. Virtually all of the Company's transmission lines operate at 66 kV or 138 kV.[53] Individual transmission lines range in length from two kilometres to 94 kilometres, with an average length of 19 kilometres.

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

The number of deficiencies addressed under the *Transmission Line Maintenance* program varies annually. From 2017 to 2021, an average of 100 poles, 109 framing structures and 1,176 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

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52 Expenditures in 2018 were higher as a result of a higher amount of maintenance work being required in comparison to the historical average. See the *2018 Capital Expenditure Report,* Note 6.

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

recent years.[54] However, while the transmission system operates reliably overall, equipment failures can result in significant customer outages. For example, an outage to transmission lines 94L and 95L during a severe wind storm in March 2017 resulted in approximately 3.2 million outage minutes to customers on the Avalon Peninsula.

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

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	60-65	Total
Kilometres	271	273	109	168	787	385	89	**2,082**
Percentage of Total	13%	13%	5%	8%	38%	19%	4%	**100%**

Approximately 23% of Newfoundland Power's transmission lines have been in service for over 50 years. An additional 38% of transmission lines have been in service for between 41 and 50 years. As transmission lines age, annual maintenance of these assets will continue to be critical to the provision of reliable service to customers.

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

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

Table 4
Transmission Line Maintenance Program
Risk Assessment Summary

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

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

[54] Transmission line outages have contributed to an annual average of less than 30 outage minutes per customer over the last five years.

JUSTIFICATION

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

GENERATION - HYDRO

Title:	**Mobile Hydro Plant Refurbishment**
Asset Class:	**Generation – Hydro**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$1,666,000 in 2023; and $2,480,000 in 2024**

PROJECT DESCRIPTION

The *Mobile Hydro Plant Refurbishment* project involves the refurbishment of the Mobile hydroelectric plant (the "Mobile Plant" or the "Plant"). The Mobile Plant is located on the Southern Shore of the Avalon Peninsula and has the second largest generating capacity of Newfoundland Power's 23 hydro plants.

The *Mobile Hydro Plant Refurbishment* project will be completed over two years and will include:

(i) Upgrading the powerhouse building and constructing a building extension;
(ii) Rehabilitating the powerhouse crane;
(iii) Upgrading the AC/DC distribution systems;
(iv) Upgrading protection and control systems and the governor;
(v) Replacing the switchgear; and
(vi) Overhauling the turbine and refurbishing the generator.

The design and procurement of replacement components will be completed in 2023. The Plant will be taken out of service in June 2024, at which point components to be replaced or refurbished will be removed. The Plant will be out of service for approximately 26 weeks while the new components are installed and commissioned.

Additional information on this project is provided in report *4.2 Mobile Hydro Plant Refurbishment* filed with the Application.

PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2023 and 2024 for the *Mobile Hydro Plant Refurbishment* project.

Table 1
Mobile Hydro Plant Refurbishment Project
2023/2024 Budget
($000s)

Cost Category	2023	2024
Material	1,331	1,714
Labour – Internal	115	448
Labour – Contract	-	-
Engineering	170	181
Other	50	137
Total	$1,666	$2,480

Proposed expenditures for the *Mobile Hydro Plant Refurbishment* project total $4,146,000, with $1,666,000 in 2023 and $2,480,000 in 2024.

ASSET BACKGROUND

The Mobile Plant was commissioned in 1951 with a capacity of 11.0 MVA. The Plant is connected to the Island Interconnected System at Mobile Substation and has provided 71 years of reliable energy production. The Plant provides normal annual production of approximately 40.32 GWh, or 9.2% of the total normal hydroelectric production of Newfoundland Power.[55]

The Mobile Plant is operated throughout the year as a source of low-cost energy for Newfoundland Power's customers. The Plant is routinely placed into service at the request of Newfoundland and Labrador Hydro. The Plant also provides a reliability benefit to approximately 4,500 customers on the Southern Shore of the Avalon Peninsula when Transmission Line 24L is out of service and the area operates as an isolated system.

Upgrades completed to the Mobile Plant have been limited over the last decade due to an arbitration process with the City of St. John's that placed into question future ownership and operation of the Mobile Plant. The upgrades completed over that time have largely focused on the replacement of systems that failed or were at imminent risk of failure. In 2020, the City of St. John's and Newfoundland Power entered into a new 50-year lease for the rights to the Mobile River watershed. The new lease ensures the Company's customers will continue to be supplied with low-cost production from the Plant until 2070.

[55] 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 Mobile Plant at 40.32 GWh.

Newfoundland Power conducted a detailed condition assessment of the Mobile Plant. The powerhouse building roof is leaking and existing heating and lighting systems are inadequate. The Mobile Plant is the largest plant in Newfoundland Power's system with obsolete protection and control systems that do not allow for modern water management to maximize efficient Plant production. The switchgear does not meet current arc flash ratings for this type of equipment and the turbine and generator both require refurbishment.

ASSESSMENT OF ALTERNATIVES

Two alternatives were evaluated to address the deteriorated condition of the Mobile Plant: (i) refurbish the Plant in 2023 and 2024; and (ii) defer refurbishment to future years.

As detailed in report 4.2, the assessment determined that the minimal benefit of deferring the Mobile Plant refurbishment is outweighed by the potential costs associated with responding to an in-service failure of the Plant if the project were to be deferred. In addition to these cost dynamics, deferring the refurbishment would not address current safety risks including arc flash hazards with the existing switchgear. It also would delay the realization of the operational efficiencies that can be achieved by modernizing the Plant and implementing a water management system to ensure efficient Plant production.

A lifecycle cost analysis confirmed that continued operation of the Mobile Plant will provide an economic benefit for Newfoundland Power's customers over the longer term.

RISK ASSESSMENT

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

The lifecycle cost analysis shows the Plant's production provides a net benefit for customers of between 5.14 ¢/kWh and 6.79 ¢/kWh. The present value of the cost of continued operation of the Mobile Plant is $17.6 million. This compares to the cost of replacing the Plant's production of between $51.2 and $62.0 million.

Capital upgrades to the Mobile Plant have been limited over the last decade. A condition assessment has identified numerous deficiencies within the Plant that could jeopardize the Plant's safe and reliable operation going forward, including obsolete protection and control systems and antiquated switchgear. The generator is the oldest original single generator plant remaining in service in the Company's fleet of generating plants and a statistical analysis of industry experience indicates that an in-service failure of the generator is likely based on its age.

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

Table 2 Mobile Hydro Plant Refurbishment Project Risk Assessment Summary		
Consequence	Probability	Risk
Critical (5)	Likely (4)	High (20)

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

JUSTIFICATION

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

Title:	**Sandy Brook Hydro Plant Generator Refurbishment**
Asset Class:	**Generation – Hydro**
Category:	**Project**
Investment Classification:	**Renewal**
Budget:	**$1,577,000**

PROJECT DESCRIPTION

The *Sandy Brook Hydro Plant Generator Refurbishment* project involves refurbishing the generator at the Sandy Brook hydroelectric plant (the "Sandy Brook Plant" or the "Plant"), located on a tributary of the Exploits River. The project will include rewinding the generator stator and re-insulating the generator rotor.

The *Sandy Brook Hydro Plant Generator Refurbishment* project will take approximately 24 weeks to complete. The project will be completed while the Plant is out of service for replacement of the penstock.[56] Procurement and design of the generator stator windings will occur in early 2023. The rotor and exciter will be removed from the generator in the second quarter, and reassembly will be completed by the end of the fourth quarter.

Additional information on this project is provided in report *4.1 Sandy Brook Hydro Plant Generator Refurbishment* filed with the Application.

PROJECT BUDGET

The budget for the *Sandy Brook Hydro Plant Generator Refurbishment* project is based on engineering estimates.

[56] The *Sandy Brook Plant Penstock Replacement* project was approved in Board Order No. P.U. 36 (2021).

Table 1 provides a breakdown of expenditures proposed for 2023 for the *Sandy Brook Hydro Plant Generator Refurbishment* project.

Table 1
Sandy Brook Hydro Plant Generator Refurbishment Project
2023 Budget
($000s)

Cost Category	2023
Material	1,241
Labour – Internal	147
Labour – Contract	-
Engineering	87
Other	102
Total	$1,577

Proposed expenditures for the *Sandy Brook Hydro Plant Generator Refurbishment* project total $1,577,000 for 2023.

ASSET BACKGROUND

The Sandy Brook Plant is located approximately 13 kilometres southwest of the Town of Grand Falls-Windsor. The Plant was placed into service in 1963 with a capacity of 6.31 MW and has provided 59 years of reliable energy production. The Plant has a normal annual production of approximately 29.41 GWh, or 6.7% of the total normal hydroelectric production of Newfoundland Power.[57]

The Sandy Brook Plant is operated throughout the year as a source of low-cost energy for Newfoundland Power's customers. The Plant is operated to maximize energy production in an efficient manner and is also routinely placed into service at the request of Newfoundland and Labrador Hydro.

The Sandy Brook Plant's generator, SBK-G1, was manufactured in 1963 and is original to the Plant. The generator was last dismantled in 2001 when the turbine runner and wicket gates were replaced. The stator and rotor were both cleaned at the time and the insulation resistance was verified.

[57] 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 29.41 GWh.

ASSESSMENT OF ALTERNATIVES

Newfoundland Power identified and assessed two alternatives for the *Sandy Brook Hydro Plant Generator Refurbishment* project. The alternatives included: (i) refurbishing the generator while completing the penstock replacement in 2023; and (ii) deferring refurbishment of the generator to a future year.

As detailed in report 4.1, the assessment determined that completing the generator refurbishment in 2023 during penstock replacement is the least-cost alternative. The assessment was based on the cost of purchasing more expensive replacement production if the Plant were to be out of service in a future year, as well as the potentially higher capital costs associated with an unplanned refurbishment if an in-service equipment failure were to occur.

An economic analysis was completed for the continued operation of the Plant as part of the Company's *2022 Capital Budget Application* for the replacement of the Sandy Brook Plant penstock. An updated analysis confirmed that operation of the Plant continues to provide an economic benefit for customers.

RISK ASSESSMENT

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

An economic analysis of the Sandy Brook Plant completed in 2021 as part of the penstock replacement showed that the benefits of the Plant's production exceed the cost of production.[58] An updated economic analysis was completed in 2022 and confirmed the net benefit of Plant production is still between 2.58 ¢/kWh and 4.61 ¢/kWh based on the most recent changes in marginal costs.[59]

The Sandy Brook Plant's generator stator windings and rotor pole insulation are original and will be 60 years old in 2023. The generator stator windings and rotor poles are amongst the oldest remaining in service in Newfoundland Power's fleet of generating plants. A statistical analysis of industry experience indicates that an in-service failure of the generator is likely based on its age. The frequent on/off cycling of the generator has led to thermal cycling and vibration, which contributes to the deterioration of the insulating components of the stator and rotor.

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58 Details on the benefits of the Plant's production are detailed in Table 3, Economic Evaluation Results on page A-5 of Appendix A of the *2022 Capital Budget Application* report *1.2 Sandy Brook Plant Penstock Replacement* and responses to Requests for Information CA-NP-078, NLH-NP-015, NLH-NP-019 and NLH-NP-022.

59 For the latest update on marginal costs, see *Marginal Cost Update - 2021 Summary Report, March 7, 2022, Appendix A*, filed in response to Request for Information TC-IC-NLH-001, Attachment 1, as part of the utilities' applications regarding the *Electrification, Conservation and Demand Management Plan: 2021-2025*.

Table 2 summarizes the risk assessment of the *Sandy Brook Hydro Plant Generator Refurbishment* project.

Table 2 Sandy Brook Hydro Plant Generator Refurbishment Project Risk Assessment Summary		
Consequence	Probability	Risk
Critical (5)	Likely (4)	High (20)

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

JUSTIFICATION

The *Sandy Brook Hydro Plant Generator Refurbishment* project is required to provide reliable service to customers at the lowest possible cost. The Sandy Brook Plant continues to provide low-cost energy to customers. Completing required upgrades to the Plant in 2023 will minimize plant downtime and ensure the continued provision of low-cost energy to customers.

Title:	**Hydro Facility Rehabilitation**
Asset Class:	**Generation – Hydro**
Category:	**Project**
Investment Classification:	**Renewal**
Budget:	**$877,000**

PROJECT DESCRIPTION

The *Hydro Facility Rehabilitation* project involves the replacement or refurbishment of deteriorated plant components that have been identified through routine inspections, operating experience and engineering studies. For 2023, the *Hydro Facility Rehabilitation* project includes:

(i) *West Country Pond Gatehouse Replacement* – Capital expenditures of $112,000 are required to replace the deteriorated gatehouse building structure at West Country Pond as part of the Pierre's Brook hydroelectric development. The building will be raised above the dam crest to mitigate the risk of flood waters entering the building. Deficiencies with existing steps and handrails will also be corrected. Design work will be completed by the end of the second quarter and the replacement will be completed by the fourth quarter of 2023.

(ii) *Lockston Access Road Bridge Replacement* – Capital expenditures of $306,000 are required to replace the deteriorated access road bridge for the Lockston hydroelectric development. Design work will be completed by the end of the second quarter and the replacement will be completed by the fourth quarter of 2023.

(iii) *Generation Control Systems Upgrades* – Capital expenditures of $459,000 are required to replace obsolete protection and control systems at the Seal Cove hydroelectric development.

PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2023 for the *Hydro Facility Rehabilitation* project.

Table 1
Hydro Facility Rehabilitation Project
2023 Budget
($000s)

Cost Category	2023
Material	605
Labour – Internal	38
Labour – Contract	-
Engineering	131
Other	103
Total	$877

Proposed expenditures for the *Hydro Facility Rehabilitation* project total $877,000 for 2023.

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.

Newfoundland Power maintains reliable operation of its hydro plants through a combination of annual inspections by plant operators, maintenance activities and replacement and refurbishment projects. The three items proposed for refurbishment in 2023 are:

(i) *West Country Pond Gatehouse ($112,000)*

The West Country Pond gatehouse houses the mechanical gate operator for the intake gate at the Pierre's Brook hydroelectric development. The West Country Pond gatehouse was constructed in 1980 using a timber frame, modified bitumen roofing system, vinyl cladding, timber door and a concrete foundation.

A condition assessment determined the building's timber framing is in poor condition with mould and rot present throughout the structure. The roofing system is original to the building and is severely deteriorated. The access step is constructed of timber and has deteriorated. Replacement of the gatehouse is required.

(ii) *Lockston Access Road Bridge ($306,000)*

The Lockston access road was constructed in 1958 to permit access to the Lockston hydroelectric development and Lockston Substation. The gravel roadway is approximately 550 metres long and crosses water bodies at two locations. The existing bridge structure was installed in 1980 and consists of timber beams and decking, metal guide rails and rock filled timber crib abutments.

A condition assessment determined the structural timber has degraded over time and is in poor condition. Additional midspan timber bracing has been added to avoid main beam failure. The bridge abutments are in poor condition. The abutments are constructed of rock filled timber cribs, which have failed and are partially crushed. The rock fill ballast has been removed by flowing water and displaced downstream. Replacement of the access bridge is required.

(iii) *Generation Control Systems ($459,000)*

Newfoundland Power began upgrading protection and control systems at its hydroelectric facilities in the early 2000s. This included modernizing the protection, governor, generator excitation system and unit controls by converting from older technology to modern digital systems.[60] Prior to the 2000s, the Company installed small Programmable Logic Controllers ("PLC") in hydroelectric facilities for dedicated functions like alarm annunciation and telemetry display. Currently, 22 of 23 hydroelectric facilities rely on some form of PLC technology.[61]

To maintain and support the legacy PLC technology, Newfoundland Power manages its own spare parts inventory. The inventory includes replacement modules purchased from the original equipment manufacturer when available and modules salvaged from PLCs that get replaced through the Company's capital upgrades.[62] As the inventory of specific modules and processors is depleted, the Company will need to replace the existing PLC hardware with current technology, and place the salvaged modules into the spare parts inventory.[63]

To ensure reliable operation of the Company's hydroelectric facilities, PLC modules and processors require replacement as they fail. In situations where the Company has been unable to obtain a replacement module from the original equipment manufacturer and the inventory of spare parts has depleted, the proactive replacement of that PLC technology becomes necessary.

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60 Replacement parts for the older electromechanical technology were no longer available to maintain this vintage of equipment. Additionally, the expertise necessary to work on the older technology was no longer being taught to the current generation of technologists, resulting in a technical skills gap.

61 Morris Plant, upstream on the Mobile watershed, does not have PLC technology. The plant was built in the early 1980s and includes other digital protection and control systems, but not PLC technology.

62 The existing modules will be salvaged and included in an inventory of spare parts to address equipment failures at other hydro plants that continue to use this obsolete equipment.

63 Replacing the existing PLC hardware with current technology will involve some engineering design effort, PLC programming and potentially other changes to generator equipment interfaces.

In 2023, the PLC system at the Seal Cove hydroelectric facility will be upgraded with current PLC technology and the existing PLC processors and modules will be placed into inventory.

RISK ASSESSMENT

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 *Hydro Facility Rehabilitation* project is an annual project that replaces 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 energy-related value of the production from Newfoundland Power's hydro plants is estimated at $12,938,000 annually, while the capacity-related value is estimated at $16,914,000 annually.[64] 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.

For 2023, the *Hydro Facility Rehabilitation* project will address deteriorated and obsolete components at three facilities. The components to be addressed under the project include the Lockston plant access bridge, West Country Pond plant gatehouse and Seal Cove plant PLC technology. Combined, these three hydro plants represent 10% of the normal annual production of Newfoundland Power. Failure of the components at these three 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 2023 *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.

64 Based on the most recent *Marginal Cost Update - 2021 Summary Report, March 7, 2022, Appendix A*, filed in response to Request for Information TC-IC-NLH-001, Attachment 1, *Electrification, Conservation and Demand Management Plan 2021-2025*.

JUSTIFICATION

The *Hydro Facility Rehabilitation* project is required to provide reliable service to customers at the lowest possible cost. Maintaining Newfoundland Power's hydro plants requires the replacement of deteriorated and failed equipment, components and systems. This includes the replacement of the Lockston access bridge, Western Country Pond gatehouse and Seal Cove PLC technology in 2023. Completing these upgrades will ensure the continued operation of these hydro plants and the continued provision of low-cost energy to customers.

Title:	**Hydro Plant Replacements Due to In-Service Failures**
Asset Class:	**Generation – Hydro**
Category:	**Program**
Investment Classification:	**Renewal**
Budget:	**$662,000**

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

Table 1 provides the annual expenditures for the *Hydro Plant Replacements Due to In-Service Failures* program from 2018 to 2022.

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

Year	2018	2019	2020	2021	2022F
Total	$578	$573	$594	$630	$610
Adjusted Costs[1]	$647	$629	$641	$643	$610

[1] 2022 dollars.

The average annual adjusted cost for the *Hydro Plant Replacements Due to In-Service Failures* program was approximately $634,000 from 2018 to 2022.

Table 2 provides a breakdown of the expenditures proposed for 2023 for the *Hydro Plant Replacements Due to In-Service Failures* program.

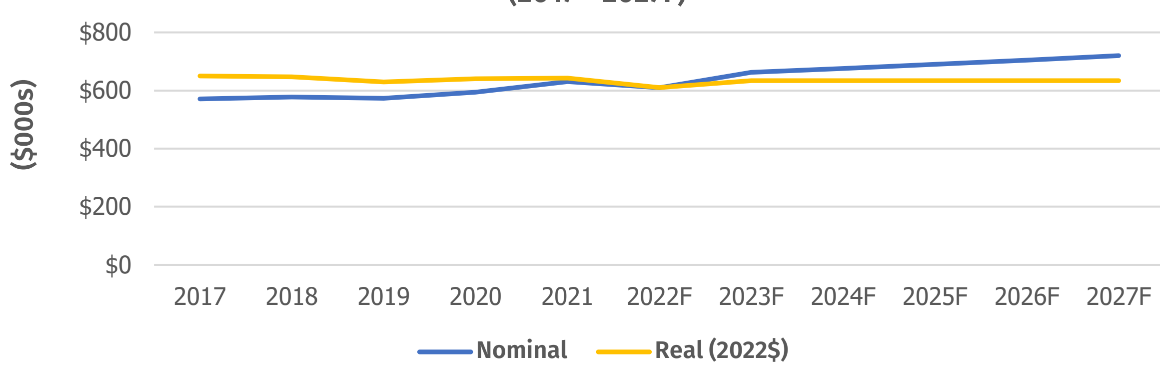
Table 2 Hydro Plant Replacements Due to In-Service Failures Program 2023 Budget ($000s)	
Cost Category	2023
Material	463
Labour – Internal	124
Labour – Contract	-
Engineering	18
Other	57
Total	$662

Proposed expenditures for the *Hydro Plant Replacements Due to In-Service Failures* program total $662,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Hydro Plant Replacements Due to In-Service Failures* program from 2017 to 2027.[65]

Figure 1:
Hydro Plant Replacements Due to In-Service Failures Program Expenditures (2017 - 2027F)



[65] For forecast annual expenditures for the *Hydro Plant Replacements Due to In-Service Failures* program, see the *2023-2027 Capital Plan,* Appendix A, page A-5.

Annual expenditures under this program averaged approximately $593,000 from 2017 to 2022, or approximately $637,000 when adjusted for inflation. Annual expenditures are forecast to average approximately $690,000 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.[66]

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 four 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 $12,938,000 annually, while the capacity-related value is estimated at $16,914,000 annually.[67] 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.

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66 The Company's hydro plants are routinely placed in service at the request of Newfoundland and Labrador Hydro. From 2017 through 2021, Newfoundland and Labrador Hydro requested operation of Newfoundland Power's generation on 352 occasions.

67 Based on the most recent *Marginal Cost Update - 2021 Summary Report, March 7, 2022, Appendix A*, filed in response to Request for Information TC-IC-NLH-001, Attachment 1, *Electrification, Conservation and Demand Management Plan 2021-2025*.

Hydro Plant Replacements Due to In-Service Failures 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 imminent risk of 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.

GENERATION - THERMAL

Title: **Thermal Plant Replacements Due to In-Service Failures**
Asset Class: **Generation – Thermal**
Category: **Program**
Investment Classification: **Renewal**
Budget: **$335,000**

PROGRAM DESCRIPTION

The *Thermal Plant Replacements Due to In-Service Failures* program involves the replacement or refurbishment of deteriorated thermal plant components that are identified through routine inspections, operating experience and engineering studies.

PROGRAM BUDGET

The budget for the *Thermal Plant Replacements Due to In-Service Failures* 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. 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 the annual expenditures for the *Thermal Plant Replacements Due to In-Service Failures* program from 2018 to 2022.

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

Year	2018	2019	2020	2021	2022F
Total	$408	$165	$333	$300	$307
Adjusted Cost[1]	$457	$182	$361	$307	$307

1 2022 dollars.

The average annual adjusted cost for the *Thermal Plant Replacements Due to In-Service Failures* program was approximately $323,000 from 2018 to 2022.

Table 2 provides the expenditures proposed for the *Thermal Plant Replacements Due to In-Service Failures* program for 2023.

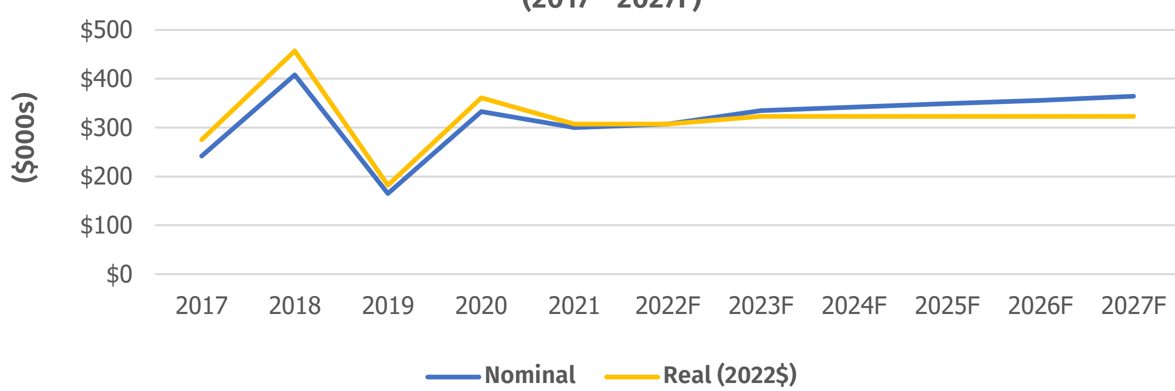
Table 2 Thermal Plant Replacements Due to In-Service Failures Program 2023 Budget ($000s)	
Cost Category	2023
Material	193
Labour – Internal	100
Labour – Contract	-
Engineering	23
Other	19
Total	$335

Proposed expenditures for the *Thermal Plant Replacements Due to In-Service Failures* program total $335,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Thermal Plant Replacements Due to In-Service Failures* program from 2017 to 2027.[68]

Figure 1
Thermal Plant Replacements Due to In-Service Failures Program Expenditures
(2017 - 2027F)



[68] For forecast annual expenditures for the *Thermal Plant Replacements Due to In-Service Failures* program, see the *2023-2027 Capital Plan,* Appendix A, page A-5.

Annual expenditures for the *Thermal Plant Replacements Due to In-Service Failures* program vary in response to failures experienced during a year.[69] Annual expenditures under this program averaged $293,000 from 2017 to 2022, or $315,000 when adjusted for inflation. Annual expenditures are forecast to average approximately $349,000 over the next five years.

ASSET BACKGROUND

Newfoundland Power operates six thermal generating facilities that provide a combined 44.5 MW of emergency capacity for the Island Interconnected System. These thermal plants are operated to supply customers during both planned and unplanned outages on the electrical system. These are:

(i) The Port Aux Basques Diesel Generator, which is a stationary unit that has been in service for 53 years.
(ii) The Wesleyville Gas Turbine, which is a stationary unit that has been in service for 53 years.
(iii) The Mobile Gas Turbine #1, which is a stationary unit that has been in service for 48 years.[70]
(iv) The Greenhill Gas Turbine, which is a stationary unit that has been in service for 47 years.
(v) The Mobile Diesel Generator #3, which is a mobile unit and that been in service for 18 years.
(vi) The Mobile Gas Turbine #2, which is a mobile unit that has been in service for three years.

The *Thermal Plant Replacements Due to In-Service Failures* program consists of the refurbishment or replacement of thermal plant structures and equipment due to damage, deterioration, corrosion and in-service failure. This equipment is critical to the safe and reliable operation of thermal generating facilities and must be replaced in a timely manner.

RISK ASSESSMENT

The *Thermal Plant Replacements Due to In-Service Failures* program will mitigate risks to the delivery of reliable service to customers by maintaining the condition of thermal plants that are operated to minimize customer outages.

Newfoundland Power's thermal plants are routinely operated to supply customers, including significant events resulting from severe weather. For example, the Mobile Gas Turbine operated during planned maintenance in Summer 2020 to avoid approximately 17 million customer outage minutes. Since 2017, the Company's thermal plants have also been dispatched over 100 times at the request of Newfoundland and Labrador Hydro to provide capacity support for the Island Interconnected System.

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[69] Expenditures were higher in 2018 due to in-service failures at the Wesleyville Gas Turbine and Mobile Gas Turbine #1 units. See the *2018 Capital Expenditure Report*, Note 5. Expenditures in 2019 were lower as a result of work requirements related to in-service failures being below the historical average. See the *2019 Capital Expenditure Report*, Note 3.

[70] Mobile Gas Turbine #1 is no longer considered mobile due to issues with the chassis and undercarriage as described in the *2018 Capital Budget Application, report 1.2 Purchase Mobile Generation*, page 4, Section 4.

Thermal plants must be maintained in adequate condition to ensure they are available to restore service to customers following outages. Equipment replaced under the *Thermal Plant Replacements Due to In-Service Failures* program has either failed or is at imminent risk of failure.

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

Table 3
Thermal 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 *Thermal Plant Replacements Due to In-Service Failures* program would pose a High (25) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Thermal Plant Replacements Due to In-Service Failures* program is required to provide reliable service to customers at the lowest possible cost. Thermal generating facilities are operated to provide reliable service to customers during planned and unplanned outages. The refurbishment or replacement of equipment that has failed in service or is at imminent risk of failure is necessary to ensure the continued operation of thermal generating facilities.

INFORMATION SYSTEMS

Title:	**Application Enhancements**
Asset Class:	**Information Systems**
Category:	**Project**
Investment Classification:	**General Plant**
Budget:	**$1,538,000**

PROJECT DESCRIPTION

The *Application Enhancements* project includes the enhancement or replacement of five software applications in 2023 to reduce costs to customers or improve customer service delivery. These include:

(i) Digital Forms Portfolio Enhancement;
(ii) Geographic Information System ("GIS") Enhancement;
(iii) Virtual Meeting System Replacement;
(iv) Environment, Health and Safety System Replacement; and
(v) takeCHARGE Website Enhancements.

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

Execution of the 2023 *Application Enhancements* project will better enable Newfoundland Power to meet customers' service expectations at the lowest possible cost.

Additional information on this project is provided in report *5.1 2023 Application Enhancements* filed with the Application.

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 2023 for the *Application Enhancements* project.

Table 1
Application Enhancements Project
2023 Budget
($000s)

Cost Category	2023
Material	-
Labour – Internal	1,141
Labour – Contract	-
Engineering	-
Other	397
Total	$1,538

Proposed expenditures for the *Application Enhancements* project total $1,538,000 for 2023.

ASSET BACKGROUND

The items included under the 2023 *Application Enhancements* project are:

(i) *Digital Forms Portfolio Enhancement ($163,000)*

Newfoundland Power routinely seeks to digitize paper-based forms through its Digital Forms Portfolio. The Digital Forms Portfolio Enhancement will digitize existing paper-based forms for underground wire location services and meter record keeping. Digitizing these forms will permit the creation of centralized databases, which will result in more efficient record keeping and a reduction in manual processes.

(ii) *GIS Enhancement ($335,000)*

Newfoundland Power currently pays annual subscription fees of approximately $35,000 to provide employees with a GIS online portal containing information on the location of electrical system assets. The Company's current service agreement with its vendor enables equivalent functionality to be delivered through an add-on to existing software, known as GIS Enterprise.

The software vendor has indicated that all clients will be required to upgrade to GIS Enterprise prior to their next system upgrade, which for Newfoundland Power is required by 2026. By implementing GIS Enterprise in 2023, annual subscription fees of approximately $35,000 will be eliminated and the mandatory software prerequisites for the next upgrade of the Company's GIS will have been completed.

(iii) *Virtual Meeting System Replacement ($214,000)*

Newfoundland Power has been using Cisco WebEx as its virtual meeting solution since 2018. Annual user fees for Cisco WebEx are currently $75,000. Newfoundland Power can implement Microsoft Teams as part of its existing Microsoft Enterprise Agreement with no added annual licensing costs from the vendor. Replacing the Company's existing virtual meeting system with Microsoft Teams will eliminate annual user fees associated with Cisco WebEx.

(iv) *Environment, Health and Safety System Replacement ($303,000)*

Costs to operate and maintain Newfoundland Power's existing Environment, Health and Safety System are expected to increase by approximately 25% in 2023. The Company conducted a market survey and determined that alternative solutions exist that provide comparable functionality with lower annual costs. The replacement of the existing Environment, Health and Safety System with another commercially available solution will result in lower costs to customers.

(v) *takeCHARGE Website Enhancement ($68,000)*

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, as well as energy conservation and electrification education and awareness resources. There were over 290,000 visits to the takeCHARGE website in 2021.

(vi) *Various Minor Enhancements ($455,000)*

Various Minor Enhancements allows Newfoundland Power to respond to unforeseen requirements that occur throughout the year, such as legislative and compliance changes, and employee-identified 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 efficiency and organizational effectiveness in serving customers. The process of estimating the budget for Various Minor Enhancements is based on the historical average cost of executing this work over the most recent three-year period.

ASSESSMENT OF ALTERNATIVES

The application enhancements identified for 2023 will advance operational efficiency and provide quantifiable cost savings for customers. Deferring the 2023 *Application Enhancements* project would defer realizing these cost savings and customer service benefits. Deferring this project is therefore not a viable alternative.

RISK ASSESSMENT

The *Application Enhancements* project provides an economic benefit to customers by enhancing software applications to reduce manual processes and by replacing software applications with lower-cost alternatives.

Combined, the Digital Forms Portfolio Enhancement, Virtual Meeting System Replacement, and Environment, Health and Safety System Replacement will provide a positive net present value for customers of approximately $283,000. The GIS Enhancement will eliminate annual subscription fees of $35,000. The takeCHARGE Enhancement will improve the information available to customers on energy conservation and electrification, and the Various Minor Enhancements item will provide flexibility to respond to opportunities to improve the Company's operating efficiency throughout the year. In addition to cost savings and customer service improvements, implementing these items in 2023 will also provide improved record keeping for auditing and regulatory compliance purposes and enhanced functionality to manage processes necessary to maintain employee safety.

These cost savings and customer benefits have been confirmed through detailed assessments, including net present value analyses. Newfoundland Power's practice is to reflect these cost savings in its revenue requirement as part of its general rate applications, thereby ensuring customers benefit from the identified efficiencies.

Table 2 summarizes the risk assessment of the 2023 *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 2023 *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: **Shared Server Infrastructure**
Asset Class: **Information Systems**
Category: **Project**
Investment Classification: **General Plant**
Budget: **$1,176,000**

PROJECT DESCRIPTION

The *Shared Server Infrastructure* project includes the addition, upgrade and replacement of computer hardware components and related technology associated with shared server infrastructure and peripheral equipment. For 2023, there are three items required to improve the functionality of Newfoundland Power's shared server infrastructure: (i) Backup and Disaster Recovery Infrastructure Replacement; (ii) Server Infrastructure Upgrades; and (iii) Customer Contact Centre Infrastructure Upgrade. Implementing this functionality will support the performance and security 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 2023 for the *Shared Server Infrastructure* project.

Table 1
Shared Server Infrastructure Project
2023 Budget
($000s)

Cost Category	2023
Material	495
Labour – Internal	376
Labour – Contract	-
Engineering	-
Other	305
Total	$1,176

Proposed expenditures for the *Shared Server Infrastructure* project total $1,176,000 for 2023.

ASSET BACKGROUND

Newfoundland Power uses a combination of information systems in the day-to-day provision of reliable and responsive service to customers. The availability and performance of these systems depends on the Company's shared server infrastructure and peripheral equipment.

The Company's shared server infrastructure is used for routine operation, testing, and disaster recovery of the Company's corporate applications. Newfoundland Power relies on these shared servers to ensure the efficient operation of systems and applications used in the day-to-day provision of service to customers. Management of these shared servers and their components is essential to ensuring these applications operate effectively at all times.

Three upgrades are proposed for 2023:

(i) *Backup and Disaster Recovery Infrastructure Replacement ($836,000)*

The replacement of the Company's backup infrastructure is necessary to ensure business continuity and recovery abilities are effective. The Company relies on computing systems to monitor and operate the electrical system, business systems, and to provide customer service. The current backup and recovery system was designed to meet industry practices of over a decade ago. The current system is not designed to provide the necessary recovery features required in light of new cybersecurity threats. By replacing the backup and recovery infrastructure with a modern system, the Company will maintain its ability to recover systems from failure and will ensure that business continuity is maintained in all scenarios.

(ii) *Server Infrastructure Upgrades ($270,000)*

Upgrades are required to extend the useful service life of existing server infrastructure. Infrastructure upgrades for 2023 include installing additional components to increase disk storage and expand processor and memory capacity to accommodate growth in information storage needs and improve the performance of Company applications.

(iii) *Customer Contact Centre Infrastructure Upgrade ($70,000)*

The addition and replacement of infrastructure is required to support continued operation of the Company's Customer Contact System. The current infrastructure is seven years old and at the end of its useful life. This item will ensure the Company can maintain application reliability and performance to continue to provide customer service.

ASSESSMENT OF ALTERNATIVES

Each year, an assessment is completed to determine shared server infrastructure 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.

Approximately 71% of proposed 2023 expenditures relate to the replacement of Newfoundland Power's Backup and Disaster Recovery Infrastructure. This critical infrastructure component underpins the Company's ability to recover from an infrastructure failure or a cybersecurity incident. Deferring this upgrade would hinder cybersecurity management.

The remaining 29% of proposed 2023 expenditures relate to routine upgrades and additions to Newfoundland Power's shared server infrastructure. These upgrades are necessary to accommodate growth in information storage needs, extend the service life of existing shared servers, improve performance of Company applications and maintain vendor support. Deferring these upgrades would threaten the secure and reliable operation of hardware and software used in providing service to customers.

RISK ASSESSMENT

The *Shared Server Infrastructure* project will mitigate risks to the delivery of safe and reliable service to customers.

Newfoundland Power's shared server infrastructure enables the operation of software applications used in providing service to customers, including the SCADA system, and the storage of customer and Company information necessary to run those applications. Instability within computing hardware could result in compromising customer or Company information, losing a software 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. has indicated that servers have a useful life of approximately five years.[71] 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 is extended beyond its expected useful service life.

[71] Gartner Inc. is a leading provider of research and analysis on the global information technology industry.

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 Service Infrastructure* project would pose a High (20) risk to the delivery of safe and reliable service to customers.

JUSTIFICATION

The *Shared Server Infrastructure* project is required to provide safe and reliable service to customers at the lowest possible cost. Management of server equipment through this project is essential to the secure and reliable operation of Company technologies used in the provision of service to customers.

Title: System Upgrades
Asset Class: Information Systems
Category: Project
Investment Classification: General Plant
Budget: $962,000

PROJECT DESCRIPTION

The *System Upgrades* project involves upgrades to third-party software products that comprise the Company's information systems. System upgrades proposed for 2023 involve the following:

(i) Quality Management module of the Company's Contact Management System ("CMS");
(ii) Human Resource Management System;
(iii) Financial Management System;
(iv) SCADA system; and
(v) Database Management Software.

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

PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2023 for the *System Upgrades* project.

Table 1
System Upgrades Project
2023 Budget
($000s)

Cost Category	2023
Material	-
Labour – Internal	687
Labour – Contract	-
Engineering	-
Other	275
Total	$962

Proposed expenditures for the *System Upgrades* project total $962,000 for 2023.

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 to 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 2023 are:

(i) *CMS Quality Management Module Upgrade ($285,000)*

This item involves upgrading the Quality Management module of the Company's CMS to a version that continues to be fully supported by the vendor.

Newfoundland Power's CMS was installed in 2017. This CMS is the primary information system used at the Company's Customer Contact Centre to respond to customer enquiries. On average, approximately 509,000 calls and 98,000 emails are received from customers each year. The CMS accepts and automatically routes all incoming calls and emails to Customer Service Representatives with the necessary skillsets to respond effectively.

The Quality Management module of the CMS includes call and screen recording capabilities. These capabilities are used for auditing customer interactions with Customer Service Representatives. Interactions are audited on a regular basis to ensure customers are receiving quality service and are also used for training and coaching purposes. This helps ensure customer communications are handled in the most efficient and effective manner.

Newfoundland Power's current version of the CMS Quality Management module will no longer be supported by the vendor as of December 2023. A system upgrade is required to ensure that the CMS continues to operate in a stable and supported environment. The project is anticipated to commence in February 2023 and will be completed in September 2023.

(ii) *Human Resource Management System Upgrade ($122,000)*

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

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

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

The project is anticipated to commence in January 2023 and will be completed in June 2023.

(iii) *Financial Management System Upgrade ($110,000)*

This item involves an upgrade to the Company's Financial Management System to a version that continues to be fully supported by the vendor.

Newfoundland Power's Financial Management System was implemented in 2002. It is used on a daily basis to manage the Company's financial resources, project accounting, and procurement and inventory processes. The Financial Management System communicates with other Company information systems to ensure the automatic flow of information relating to purchasing functions, electronic invoicing and warehouse management. This automation achieves efficiencies in the day-to-day management of financial processes.

The Financial Management System was last upgraded in 2020. Since the last upgrade, the vendor has introduced a new policy that requires upgrades on an annual cycle as opposed to the previous upgrade cycle of every two to three years. An annual upgrade is now required in order to receive vendor support, bug fixes and security updates necessary to keep pace with evolving cybersecurity threats.

The project is anticipated to commence in May 2023 and will be completed in September 2023.

(iv) *SCADA System Upgrade ($89,000)*

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 2023, 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 and vital control of the Island Interconnected System. The project is anticipated to commence in March 2023 and will be completed in July 2023.

(v) *Database Management Software Upgrade ($76,000)*

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

The Company operates multiple versions of Database Management Software to support over 80 database applications. The Database Management Software version selected for an application is typically the latest version available from the vendor at the time of implementation or upgrade.

One of Newfoundland Power's Database Management Software versions will no longer be supported by the vendor as of July 2024 and the underlying hardware reaches end of life in October 2023. This Database Management Software affects six different applications and databases that support applications in the operations, engineering and human resources areas of the Company.

An upgrade of the Database Management Software is required in 2023 to address the obsolete hardware and ensure continued vendor support of the software. Completing the necessary hardware and software upgrades simultaneously allows for data migration and testing to be completed concurrently. The upgrade will also apply the latest database security patches to minimize any potential vulnerabilities. The project is anticipated to commence in June 2023 and will be completed in September 2023.

(vi) *Various Minor Upgrades ($280,000)*

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 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.

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 alterative software product would be lower cost than upgrading existing software.

The upgrades proposed for 2023 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 $76,000 to $285,000 and do not constitute major product releases that warrant consideration of system replacement. Completing the required system upgrades in 2023 is therefore the only viable alternative.

RISK ASSESSMENT

The *System Upgrades* project is necessary to mitigate risks to the delivery of safe and reliable service to customers by maintaining the security and performance of Company information systems.

Each of the systems to be upgraded in 2023 is essential to Newfoundland Power's operations. The criticality of the SCADA system necessitates annual upgrades to maximize system performance and security. Upgrades of the Financial Management System, Database Management Software, Human Resource Management System and CMS Quality Management Module are necessary to ensure continued vendor support and to provide for the latest security patches and bug fixes for those systems. Ensuring continued vendor support mitigates risks associated with system failures.

Failure of these systems would have serious consequences to the delivery of safe and reliable service to customers. As examples, a security failure of the SCADA system could expose the electrical system to external interference, and a security failure of the Human Resource Management System could compromise employees' personal information.

System upgrades are becoming more frequent due to changes in vendor requirements and the need to manage cybersecurity risks. The system upgrades proposed for 2023 are necessary to mitigate risks of information system failure by implementing the latest bug fixes and cybersecurity patches and maintaining 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 2023 *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 2023 *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 ensure vendor support is maintained for those systems.

Title:	**Cybersecurity Upgrades**
Asset Class:	**Information Systems**
Category:	**Project**
Investment Classification:	**General Plant**
Budget:	**$882,000**

PROJECT DESCRIPTION

The *Cybersecurity Upgrades* project involves upgrades to the Company's cybersecurity infrastructure. Proposed 2023 capital expenditures include new technologies to reduce risk and enhance security in the areas of network and firewall security in operation technologies and SCADA environments, and endpoint/server security and hardening.

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 2023 for the *Cybersecurity Upgrades* project.

Table 1
Cybersecurity Upgrades Project
2023 Budget
($000s)

Cost Category	2023
Material	160
Labour – Internal	502
Labour – Contract	-
Engineering	-
Other	220
Total	$882

Proposed expenditures for the *Cybersecurity Upgrades* project total $882,000 for 2023.

ASSET BACKGROUND

Electrical system assets are operated using a combination of physical and technology infrastructure. Physical infrastructure includes components such as protection and control systems. Technology infrastructure includes components such as networks, software and data.

Protecting this infrastructure from threats, including cybersecurity threats, is critically important to the day-to-day provision of safe and reliable service to customers.

RISK ASSESSMENT

The *Cybersecurity Upgrades* project will mitigate risks to the delivery of safe and reliable service to customers by protecting Newfoundland Power's operations and the electrical system against cybersecurity threats.

The risk of cybersecurity incidents has increased materially for utilities as a result of the widespread use of technology. Worldwide spending on cybersecurity is forecast to grow. A 2021 global survey conducted by Gartner Inc., a leading technology advisory firm, indicated that cybersecurity is a top priority for new spending among corporations, with 61% of surveyed companies reporting increased investment.[72]

Newfoundland Power continually assesses its infrastructure to identify measures to improve the Company's cybersecurity. The cybersecurity measures identified for implementation in 2023 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.

[72] See Gartner Inc., *Gartner Forecasts Worldwide Security and Risk Management Spending to Exceed $150 Billion in 2021*, May 17, 2021.

Title: **Network Infrastructure**
Asset Class: **Information Systems**
Category: **Project**
Investment Classification: **General Plant**
Budget: **$419,000**

PROJECT DESCRIPTION

The *Network Infrastructure* project involves the addition of network components that provide employees with access to applications and data used in providing efficient and effective service to customers.

For 2023, this project includes the replacement of network and Voice over Internet Protocol ("VOIP") equipment that has reached the end of its service life and will no longer receive updates from the manufacturer to mitigate cybersecurity vulnerabilities. Devices to be replaced include routers and switches for the Company's offices, substations and mobile fleet.

PROJECT BUDGET

The budget for the *Network Infrastructure* project is based on cost estimates for the individual budget items.

Table 1 provides a breakdown of expenditures proposed for 2023 for the *Network Infrastructure* project.

Table 1
Network Infrastructure Project
2023 Budget
($000s)

Cost Category	2023
Material	100
Labour – Internal	189
Labour – Contract	-
Engineering	-
Other	130
Total	$419

Proposed expenditures for the *Network Infrastructure* project total $419,000 for 2023.

ASSET BACKGROUND

Network components, such as routers and switches, interconnect shared servers and personal computers throughout the Company's operations. These components enable the transport of SCADA, VOIP, corporate and customer service data. In addition to traditional wired network technologies, the Company has increased its use of wireless communications technologies in recent years in trucks and substations for mobile fleet and employees.

RISK ASSESSMENT

The *Network Infrastructure* project will mitigate risks to the delivery of safe and reliable service to customers by enabling the transport of data necessary for employees to communicate and use Company information systems.

The reliability and availability of network infrastructure is essential to providing service to customers. Failure or loss of this infrastructure could result in a loss of communication among employees or the loss of critical information, including visibility of the status of the electrical system. The failure of network components can require several hours to repair. Network components can also create cybersecurity vulnerabilities when they become obsolete.

The *Network Infrastructure* project replaces network components that have reached the end of their useful service lives and will no longer receive updates from the vendors. The probability of failure of network components replaced under this program is therefore likely.

Table 2 summarizes the risk assessment of the *Network Infrastructure* project.

Table 2
Network Infrastructure Project
Risk Assessment Summary

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

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

JUSTIFICATION

The *Network Infrastructure* project is required to provide reliable service to customers at the lowest possible cost as it permits the replacement of obsolete network equipment that is essential to the Company's day-to-day operations.

Title:	**Personal Computer Infrastructure**
Asset Class:	**Information Systems**
Category:	**Program**
Investment Classification:	**General Plant**
Budget:	**$600,000**

PROGRAM 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, mobile devices, and workgroup printers.

A total of 146 PCs are estimated to be replaced in 2023. Mobile units (e.g. laptops and tablets) currently account for nearly all PC replacements. The purchase of mobile units enables greater flexibility for Newfoundland Power's workforce to work remotely.

PROGRAM BUDGET

The cost for this program is estimated on the basis of historical expenditures and cost estimates for individual budget items. Historical annual program expenditures over the most recent three-year period are used to approximate costs per PC. These costs are then multiplied by the quantity of PC to be purchased.

Quantities are forecast by identifying the number of unit replacements resulting from lifecycle retirements and the number of new units required to accommodate new software applications or operational requirements. Once the unit price estimates and quantities have been determined, labour costs associated with procuring and installing the units are estimated based on experience and historical pricing.

Table 1 provides the annual expenditures for the *Personal Computer Infrastructure* program from 2018 to 2022.

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

Year	2018	2019	2020	2021	2022F
Total	$480	$500	$648	$531	$615

Expenditures for the *Personal Computer Infrastructure* program averaged approximately $555,000 annually from 2018 to 2022.

Table 2 provides a breakdown of expenditures proposed for 2023 for the *Personal Computer Infrastructure* program.

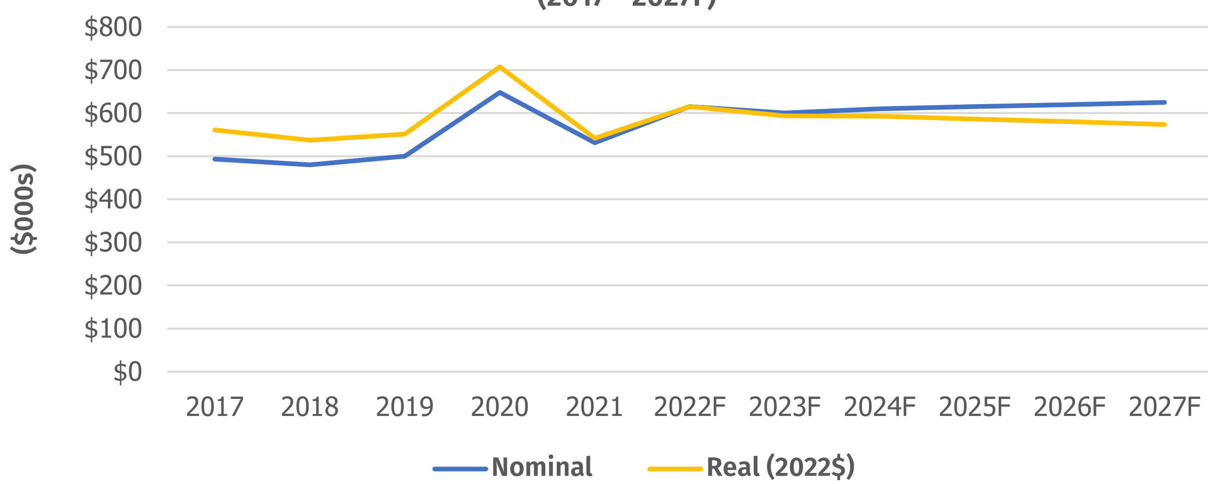
Table 2 Personal Computer Infrastructure Program 2023 Budget ($000s)	
Cost Category	2023
Material	440
Labour – Internal	120
Labour – Contract	-
Engineering	-
Other	40
Total	$600

Proposed expenditures for the *Personal Computer Infrastructure* program total $600,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Personal Computer Infrastructure* program from 2017 to 2027.[73]

Figure 1
Personal Computer Infrastructure Program Expenditures
(2017 - 2027F)



[73] For forecast annual expenditures for the *Personal Computer Infrastructure* program, see the *2023-2027 Capital Plan,* Appendix A, page A-6.

Annual expenditures under the *Personal Computer Infrastructure* program reflect a transition to mobile units in 2020 in response to the COVID-19 pandemic.[74] Annual expenditures averaged approximately $545,000 from 2017 to 2022. Annual expenditures are forecast to average approximately $614,000 over the next five years.

ASSET BACKGROUND

Newfoundland Power maintains a network of computers, servers, information systems and other hardware and software, including over 700 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.

[74] Expenditures in 2020 were higher as a result of the COVID-19 pandemic, which resulted in a requirement to purhase an increased quantity of mobile computers to facilitate work-from-home arrangements and an increase in the cost of units. See the *2020 Capital Expenditure Report,* Note 8.

Table 3 outlines the PC additions and retirements from 2017 to 2022, as well as the planned additions and retirements for 2023.

Table 3
PC Additions and Retirements
(2017-2023F)

Year	Unit	Additions	Retirements	Total
2017	Desktop	80	99	405
	Mobile	91	94	322
	Total	**171**	**193**	**727**
2018	Desktop	45	45	405
	Mobile	110	110	322
	Total	**155**	**155**	**727**
2019	Desktop	56	43	418
	Mobile	85	85	322
	Total	**141**	**128**	**740**
2020	Desktop	21	60	379
	Mobile	160	121	361
	Total	**181**	**181**	**740**
2021	Desktop	0	46	333
	Mobile	141	95	407
	Total	**141**	**141**	**740**
2022F	Desktop	10	78	265
	Mobile	136	68	475
	Total	**146**	**146**	**740**
2023F	Desktop	5	15	255
	Mobile	141	131	485
	Total	**146**	**146**	**740**

A total of 751 PCs were retired from 2018 to 2022, with 764 PC additions over that period. Approximately 83% of PC additions since 2018 were mobile units. Mobile units provide greater flexibility in managing Newfoundland Power's workforce, including work-from-home arrangements.

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 146 PCs are expected to require replacement in 2023, representing approximately 20% of Newfoundland Power's PC infrastructure used in providing service to customers. The replacement of PCs and associated equipment is necessary when it reaches the end of its useful service life. 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.[75] Extending PCs beyond the upper limit of typical industry experience would result in failure becoming likely.

Table 4 summarizes the risk assessment of the *Personal Computer Infrastructure* program.

Table 4
Personal Computer Infrastructure Program
Risk Assessment Summary

Consequence	Probability	Risk
Serious (4)	Likely (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.

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.

[75] See *Recommended Life Spans to Guide PC, Mobile and Other Device Replacement Strategies*, Gartner Inc., March 31, 2021.

TELECOMMUNICATIONS

Title: **Communications Equipment Upgrades**
Asset Class: **Telecommunications**
Category: **Program**
Investment Classification: **General Plant**
Budget: **$118,000**

PROGRAM DESCRIPTION

The *Communications Equipment Upgrades* program is necessary to ensure the continued integrity of the Company's operational voice systems and the remote monitoring and control of field devices. These voice, monitoring and control systems allow the Company to provide acceptable levels of customer service and achieve operational efficiencies.

The 2023 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.

PROGRAM BUDGET

The budget for the *Communications Equipment Upgrades* program is based on a historical average. Historical annual program expenditures over the most recent five-year period are expressed in current-year dollars ("Adjusted Cost"). 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. Effective 2023, labour costs associated with this program include a direct allocation of amounts previously included in GEC, as approved in Order No. P.U. 3 (2022).

Table 1 provides the annual expenditures for the *Communications Equipment Upgrades* program from 2018 to 2022.

Table 1
Communications Equipment Upgrades Program
Historical Expenditures
(000s)

Year	2018	2019	2020	2021	2022F
Total	$98	$112	$112	$74	$114
Adjusted Cost[1]	$109	$123	$119	$76	$114

[1] 2022 dollars.

The average adjusted annual cost for the *Communications Equipment Upgrades* program was approximately $108,000 from 2018 to 2022.

Table 2 provides a breakdown of expenditures proposed for 2023 for the *Communications Equipment Upgrades* program.

Table 2
Communications Equipment Upgrades Program
2023 Budget
($000s)

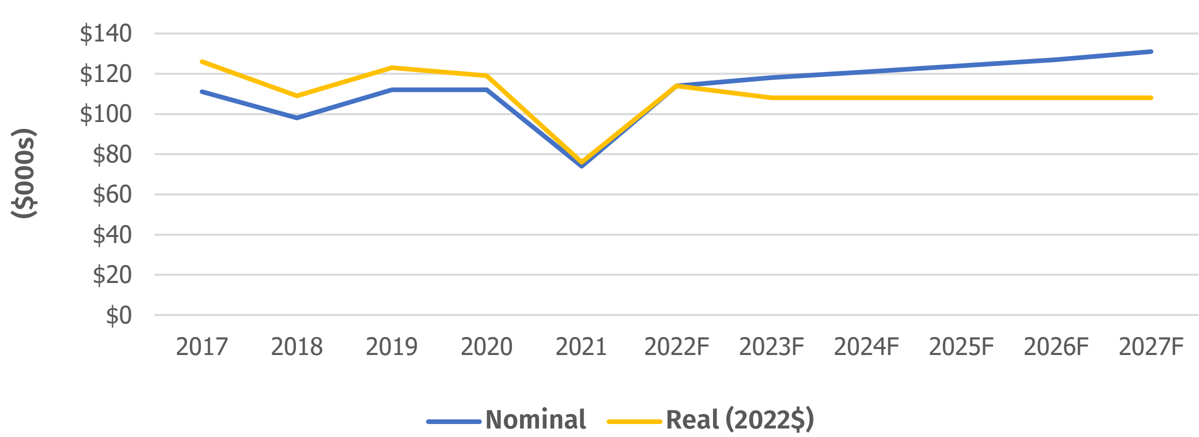
Cost Category	2023
Material	73
Labour – Internal	12
Labour – Contract	-
Engineering	23
Other	10
Total	$118

Proposed expenditures for the *Communications Equipment Upgrades* program total $118,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Communications Equipment Upgrades* program from 2017 to 2027.[76]

Figure 1
Communications Equipment Upgrades Program Expenditures
(2017 - 2027F)



[76] For forecast annual expenditures for the *Communications Equipment Upgrades* program, see the *2023-2027 Capital Plan,* Appendix A, page A-9.

Annual expenditures under this program averaged approximately $104,000 from 2017 to 2022, or approximately $111,000 when adjusted for inflation. Annual expenditures are forecast to average approximately $124,000 over the next five years.

ASSET BACKGROUND

The Company has mobile radio, portable radio, base station radio and radio console equipment in service providing operational voice communications for field staff. The radio equipment is used for communications between: (i) field staff working in multiple crews; (ii) field staff and operations centres; and (iii) field staff and the System Control Centre.

Data communications equipment is used to link the monitoring and control technologies on distribution lines, in substations, and in hydro plants to the SCADA system at the System Control Centre. A variety of different technologies are used to provide these data communication links depending on local conditions and available service offerings from telecommunications providers. The technologies used include land line communications, fibre optic communications and wireless communications.

Over time, this voice and data communications equipment fails in service, becomes obsolete or no longer supports the most cost-effective service offering from telecommunications providers. The criteria for replacing or upgrading communications equipment is based on: (i) in-service equipment failures as equipment deteriorates over time; (ii) obsolescence as technology evolves and is no longer supported; and (iii) manufacturers' recommendations for firmware upgrades or cybersecurity upgrades.

RISK ASSESSMENT

The *Communications Equipment Upgrades* program will mitigate risks to the delivery of safe and reliable service to customers resulting from the use of deteriorated or obsolete communications equipment.

Should communications equipment fail, Newfoundland Power would be required to dispatch employees to physically monitor and operate field devices. Since communications equipment allows these functions to be completed remotely in real time, dispatching employees to undertake the same function would increase costs to customers and increase the time required to respond to customer outages. Failure of communications equipment could also result in a loss of communication among employees working in the field, which can pose safety risks to employees working with energized equipment. The equipment identified for replacement under this program has failed, become obsolete or is deteriorated.

Table 3 summarizes the risk assessment of the *Communications Equipment Upgrades* program.

Table 3
Communications Equipment Upgrades Program
Risk Assessment Summary

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

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

JUSTIFICATION

The *Communications Equipment Upgrades* program is required to provide reliable service to customers at the lowest possible cost as it permits the replacement of failed, obsolete or deteriorated telecommunications equipment. Adequate telecommunications equipment is essential for the safe and efficient operation of field crews working to provide service to customers.

GENERAL PROPERTY

Title:	**Company Building Renovations**
Asset Class:	**General Property**
Category:	**Project**
Investment Classification:	**General Plant**
Budget:	**$741,000**

PROJECT DESCRIPTION

The *Company Building Renovations* project involves undertaking renovations of two Newfoundland Power facilities in 2023:

(i) *Port Aux Basques District Building* – Capital improvements are required to replace deteriorated and deficient building components. The building parking lot will be repaved and front and rear entrance systems will be replaced to address deterioration. A heat recovery ventilator, associated ductwork and a mini-split heat pump will be installed to address deficiencies with building ventilation and air conditioning. A new electrical panel and backup power supply will be installed to address capacity limitations and meet current standards.

(ii) *Kenmount Road Office Building* – Capital improvements are required to reconfigure a largely vacant server room to provide additional workspaces for personnel in the Technology Department. Reconfiguring the existing space will require removing a fire suppression system, wall and components specific to server operations. A new flooring system, lighting and electrical equipment will be installed and the existing heating, ventilation and air conditioning system will be modified to be suitable for a workspace. A dedicated space will be constructed to house the remaining server infrastructure.

The design work for both projects will be completed by the end of the first quarter of 2023. Procurement will occur during the second quarter. Construction will begin in the third quarter and will be completed by the end of the fourth quarter.

PROJECT BUDGET

The budget for the *Company Building Renovations* project is based on engineering estimates of individual budget items.

Table 1 provides a breakdown of expenditures proposed for 2023 for the *Company Building Renovations* project.

Table 1 Company Building Renovations Project 2023 Budget ($000s)	
Cost Category	2023
Material	490
Labour – Internal	11
Labour – Contract	-
Engineering	114
Other	126
Total	$741

Proposed expenditures for the *Company Building Renovations* project total $741,000 for 2023.

ASSET BACKGROUND

Newfoundland Power maintains 19 area and district office buildings throughout its service territory. These buildings serve as the base of operations for employees working to provide service to customers. As building components deteriorate and operational requirements evolve, there is an ongoing requirement to upgrade or replace equipment and systems at these facilities to extend their useful service lives.

(i) *Port Aux Basques District Building ($482,000)*

The Port Aux Basques District Building is a satellite site for Newfoundland Power's Stephenville area operations. The building was constructed in 1982 and is the base of operations for eight employees and equipment necessary to serve customers in the area.[77] Employees at the district building provide field service to approximately 5,300 customers from South Branch to Rose Blanche.

A condition assessment of the building was completed. The condition assessment showed the building parking lot has deteriorated. The asphalt parking lot was originally paved in 1990. Maintenance has been completed in the form of asphalt patches. The asphalt is now experiencing severe cracking and is in poor condition.

[77] Upgrades completed since building construction include improvements to the building envelope in 2011, a roof replacement in 2013, modifications to the door slab in the front entrance in 2016, and the construction of a new washroom and storage facility in 2019.

The building envelope consists of asphalt shingles, metal fascia, vinyl soffit, metal eavestrough, metal cladding and architectural brick. The majority of these components have been replaced since 2011. The architectural brick is original to the building. It is in poor condition and is showing signs of failure.

The condition assessment also identified deterioration of the entrance systems,[78] which are original to the building, and deficiencies with the building's ventilation and air conditioning systems.[79] The building's electrical panel is at capacity with no room for additions and is located in a non-fire separated room. The building's backup emergency power is supplied by a portable generator with no transfer switch or dedicated uninterruptible power supply ("UPS") panel. Therefore the unit does not comply with the *National Electrical Code*.

(ii) *Kenmount Road Office Building ($259,000)*

The Kenmount Road Office Building is Newfoundland Power's corporate headquarters in St. John's. The building was originally constructed in 1969 and was expanded in 1980 to include two additional floors. Various functions of the Company are located at the building, including Technology, Finance, Human Resources, and Engineering.

The basement floor of the building is original construction and is used by the Technology Department. Work requirements for the Technology Department have increased in recent years due to increasing support and maintenance requirements for operations technologies, including cybersecurity requirements. Additional staff have been added to meet these requirements, resulting in the need for additional office space. In 2023, the Department is forecast to increase by three full-time equivalent positions.

The basement floor of the building previously housed the main server infrastructure for the Company. This equipment was located in a large server room specifically constructed for that purpose. As technology evolved and became smaller, less space was required to store it. The existing server room is now largely vacant with a small number of servers remaining to support building operations.

A condition assessment of the space was completed in 2021 to identify capital improvements required to reconfigure the vacant server room into office space. The assessment determined that certain equipment specific to server rooms is not suitable for employee workspaces and must be removed. This includes the existing fire suppression system, electrical components, ventilated raised tile flooring system and heating, ventilation and air condition system. A wall separating the server room from the remainder of the Technology Department can be removed and the remaining servers can be relocated elsewhere in the building.

78 The entrance systems, with the exception of the door slab which was replaced in the front entrance in 2016, are in poor condition.

79 The ventilation system consists of exhaust fans for a bathroom and locker room. There is no ventilation provided throughout the rest of the building and no supply of fresh air. Air conditioning is provided by two wall mounted units. Both units have failed.

RISK ASSESSMENT

The *Company Building Renovations* project will mitigate risks associated with the safe and reliable delivery of service to customers by maintaining adequate workspaces for employees.

The Port Aux Basques District Building allows Newfoundland Power to maintain a reasonable response time to trouble calls received from customers on the southwest coast of the Province. The Company targets a two-hour response time to customer trouble calls. The time required to travel from the next closest operations centre in Stephenville to Rose Blanche during normal weather conditions is 2.5 hours. Correcting deteriorated and deficient equipment at the Port Aux Basques facility is necessary to maintain the facility as an adequate workspace for employees.

The basement floor of the Kenmount Road Office Building serves as the base of operations for the Company's Technology Department. The Technology Department supports the operation and maintenance of software and hardware essential to the provision of safe and reliable service to customers. Work requirements for the department have increased in recent years due to the increased use of technology and associated cybersecurity requirements. Reconfiguration of a largely vacant server room is necessary to create additional workspaces for personnel in the Technology Department.

Not proceeding with the renovations proposed for 2023 could expose employees to safety hazards due to deteriorated building components or hinder the Company's inability to meet current operational requirements due to space constraints. This could result in a deterioration in Newfoundland Power's response time to customers or reduced support for Company information systems. The deficiencies identified for correction have been verified through condition assessments and assessments of operational requirements and are therefore likely to result in disruptions to Newfoundland Power's operations if left unaddressed.

Table 2 summarizes the risk assessment of the *Company Building Renovations* project.

Table 2
Company Building Renovations Project
Risk Assessment Summary

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

Based on this assessment, deferring the *Company Building Renovations* project would pose a Medium-High (12) risk to the delivery of safe and reliable service to customers.

JUSTIFICATION

The *Company Building Renovations* project is required to maintain safe and adequate facilities necessary to provide service to customers. Components of the Port Aux Basques District Building are deteriorated or deficient and must be replaced to maintain the safety and adequacy of the facility for employees. The basement floor of the Kenmount Road Office Building requires reconfiguration to adequately meet increased operational requirements in the Technology Department.

Title: **Physical Security Upgrades**
Asset Class: **General Property**
Category: **Project**
Investment Classification: **General Plant**
Budget: **$576,000**

PROJECT DESCRIPTION

The *Physical Security Upgrades* project involves upgrading physical security infrastructure at Newfoundland Power's facilities throughout its service territory.

Security upgrades will be performed in 10 substations throughout 2023 to deter the entry of unauthorized persons and reduce the likelihood of copper theft. Substation security upgrades will include the installation of surveillance and alarm systems to deter theft and vandalism. Upgrades to security infrastructure will also be performed at three Company facilities and typically include improvements in public entrances, security fencing, access control gates and security surveillance systems. Security upgrades also include the installation of video streaming to monitor the security of eight hydro plant facilities.

PROJECT BUDGET

The budget for the *Physical Security Upgrades* project is based on engineering estimates of individual budget items.

Table 1 provides a breakdown of the proposed expenditures for the *Physical Security Upgrades* project for 2023.

Table 1
Physical Security Upgrades Project
2023 Expenditures
($000s)

Cost Category	2023
Material	460
Labour – Internal	18
Labour – Contract	-
Engineering	78
Other	20
Total	$576

Proposed expenditures for the *Physical Security Upgrades* project total $576,000 for 2023.

ASSET BACKGROUND

Newfoundland Power maintains 131 substations, 23 hydro plants and 19 office buildings throughout its service territory. Substations and hydro plants contain energized equipment which present safety hazards to the general public. Company facilities contain equipment and information that needs to be effectively secured from intrusion and theft.

In addition, Newfoundland Power has a number of sites where electrical equipment and hazardous materials are stored. These sites are vulnerable to theft, vandalism and trespassing and are secured by perimeter fencing and controlled access gates. Most of these sites require remote monitoring and alarming as they are not continuously staffed. As this security infrastructure ages, it requires refurbishment to ensure safe and secure operation of the sites.

RISK ASSESSMENT

The *Physical Security Upgrades* project will mitigate risks to the safe delivery of service to customers.

The unauthorized entry of personnel within Company facilities, including substations, can result in property damage and exposure to energized equipment or hazardous materials. This can create safety hazards for individuals entering the facilities, including employees, which can result in serious injuries occurring.

Theft and vandalism at substations continue to be a particular concern. There has been 37 substation break-ins since 2016. A significant increase in substation break-ins was observed in 2021, with 13 break-ins occurring. Given previous experience with substation break-ins, the probability of a security breach that poses a major safety risk is likely.

Table 2 summarizes the risk assessment for the *Physical Security Upgrades* project.

Table 2
Physical Security Upgrades Project
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Physical Security Upgrades* project would pose a Medium-High (16) risk to the safe delivery of service to customers.

JUSTIFICATION

The *Physical Security Upgrades* project 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.

Title: **Additions to Real Property**
Asset Class: **General Property**
Category: **Program**
Investment Classification: **General Plant**
Budget: **$654,000**

PROGRAM DESCRIPTION

The *Additions to Real Property* program involves upgrading, refurbishing and replacing equipment and facilities due to damage, deterioration, corrosion, in-service failure, and organizational changes.

PROGRAM BUDGET

The budget for the *Additions to Real Property* 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. Effective 2023, labour costs associated with this program include a direct allocation of amounts previously included in GEC, as approved in Order No. P.U. 3 (2022).

Table 1 provides the annual expenditures for the *Additions to Real Property* program from 2018 to 2022.

Table 1
Additions to Real Property Program
Historical Expenditures
(000s)

Year	2018	2019	2020	2021	2022F
Total	$759	$503	$485	$551	$716
Adjusted Cost[1]	$850	$555	$530	$562	$716

[1] 2022 dollars.

The average annual adjusted cost for the *Additions to Real Property* program was approximately $643,000 from 2018 to 2022.

Table 2 provides the expenditures proposed for the *Additions to Real Property* program for 2023.

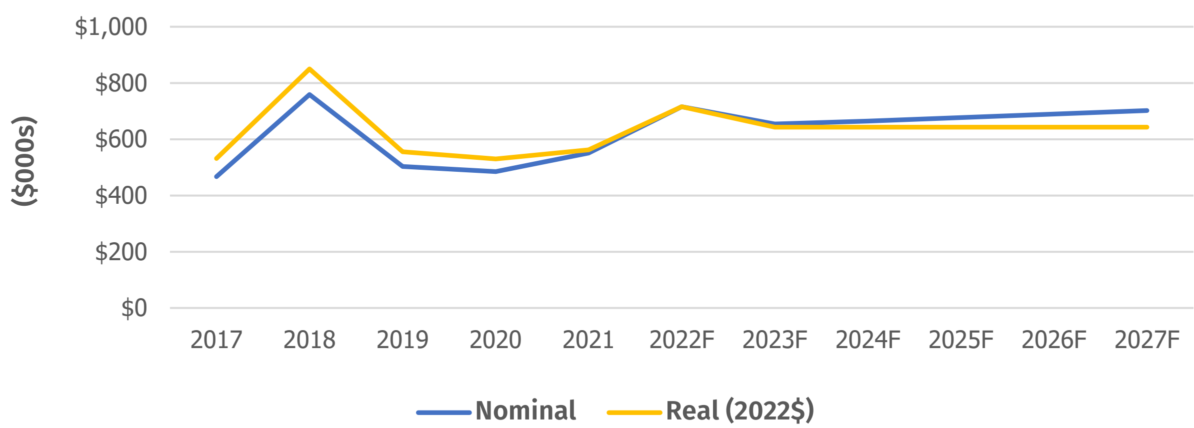
Table 2 Additions to Real Property Program 2023 Budget ($000s)	
Cost Category	2023
Material	560
Labour – Internal	17
Labour – Contract	-
Engineering	39
Other	38
Total	$654

Proposed expenditures for the *Additions to Real Property* program total $654,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Additions to Real Property* program from 2017 to 2027.[80]

Figure 1
Additions to Real Property Program Expenditures
(2017 - 2027F)



[80] For forecast annual expenditures for the *Additions to Real Property* program, see the *2023-2027 Capital Plan,* Appendix A, page A-8.

Annual expenditures under the *Additions to Real Property* program averaged $580,000 from 2017 to 2022, or $624,000 when adjusted for inflation.[81] Annual expenditures are forecast to average approximately $677,000 over the next five years.

ASSET BACKGROUND

Newfoundland Power maintains district and area offices throughout its service territory to ensure a prompt response to customer outages and other service requests as well as safe and adequate facilities for the Company's employees and customers.

Figure 2 shows the location of Newfoundland Power's office buildings.

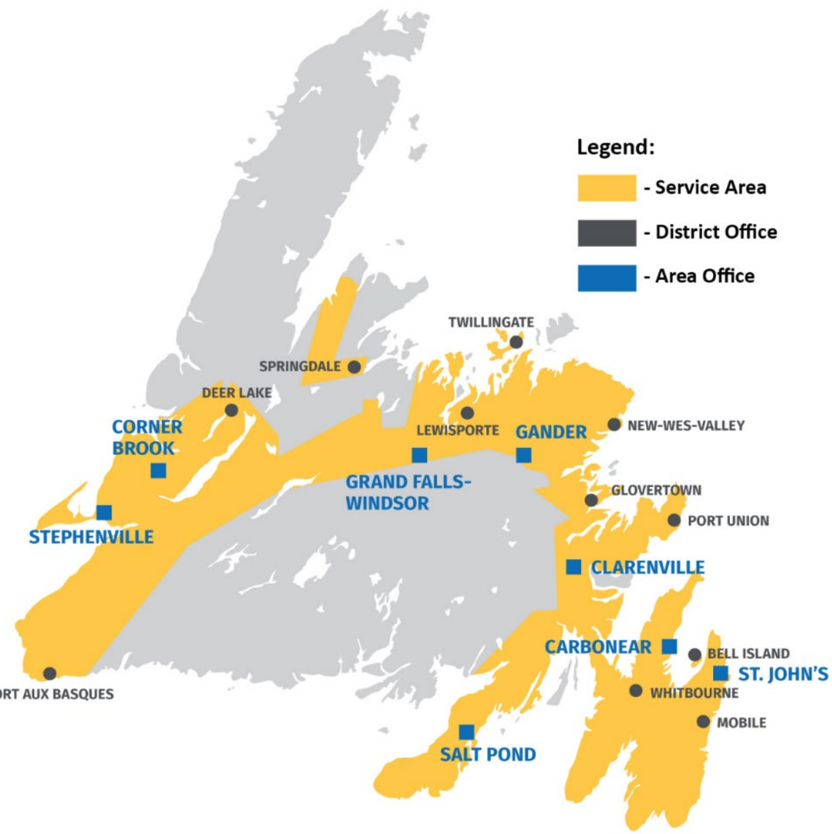


Figure 2: Newfoundland Power Building Locations

RISK ASSESSMENT

The *Additions to Real Property* program will mitigate risks to the safe delivery of service to customers by addressing equipment failure at Company office buildings.

Newfoundland Power's office buildings range in age from three years to 64 years, with an average age of 44 years. There is an ongoing requirement to upgrade or replace equipment

[81] Expenditures in 2018 were higher as a result of a project to install backflow prevention for water supply at the Duffy Place facility. See the *2018 Capital Budget Application, Schedule B,* page 56.

and facilities at these buildings due to failure or age-related deterioration. Past expenditures have included emergency water line replacement, sewer interceptor installation and correcting major drainage problems. Correcting such deficiencies in a timely manner is necessary to avoid the temporary closure of facilities and subsequent disruptions to Company operations.

Given the nature of the deficiencies addressed under this program and the age of Company buildings, the probability of failure is likely.

Table 3 summarizes the risk assessment of the *Additions to Real Property* program.

Table 3
Additions to Real Property Program
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Additions to Real Property* project would pose a Medium-High (12) risk to the safe delivery of service to customers.

JUSTIFICATION

The *Additions to Real Property* program is required to maintain safe and adequate facilities. Building components and systems addressed under this program have failed or are at imminent risk of failure.

Title:	**Tools and Equipment**
Asset Class:	**General Property**
Category:	**Program**
Investment Classification:	**General Plant**
Budget:	**$534,000**

PROGRAM DESCRIPTION

The *Tools and Equipment* program is necessary to add or replace tools and equipment used in day-to-day operations to provide safe and reliable service to customers. Most items within the *Tools and Equipment* program involve expenditures of less than $50,000. These items are consolidated into the following categories:

(i) Operations tools and equipment used by powerline technicians and field staff in day-to-day operations. These tools are maintained on a regular basis; however, over time they degrade and wear out, particularly hot line equipment which must meet rigorous safety requirements. Where appropriate, such tools are replaced with battery and hydraulic alternatives to improve working conditions.

(ii) Engineering tools and equipment used by electrical and mechanical maintenance personnel and engineering technologists. Engineering test equipment is required to perform system calibration, commissioning and testing of power system facilities and testing and analysis of associated data communications facilities.

(iii) Office furniture that has deteriorated through normal use and requires replacement.

PROGRAM BUDGET

The budget for the *Tools and Equipment* 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.

Table 1 shows the annual expenditures for the *Tools and Equipment* program from 2018 to 2022.

Table 1 Tools and Equipment Program Historical Expenditures (000s)					
Year	2018	2019	2020	2021	2022F
Total	$485	$451	$496	$458	$598
Adjusted Cost[1]	$543	$498	$544	$467	$598

[1] 2022 dollars.

The average annual adjusted cost for the *Tools and Equipment* program was approximately $530,000 from 2018 to 2022.

Table 2 provides the expenditures proposed for the *Tools and Equipment* program for 2023.

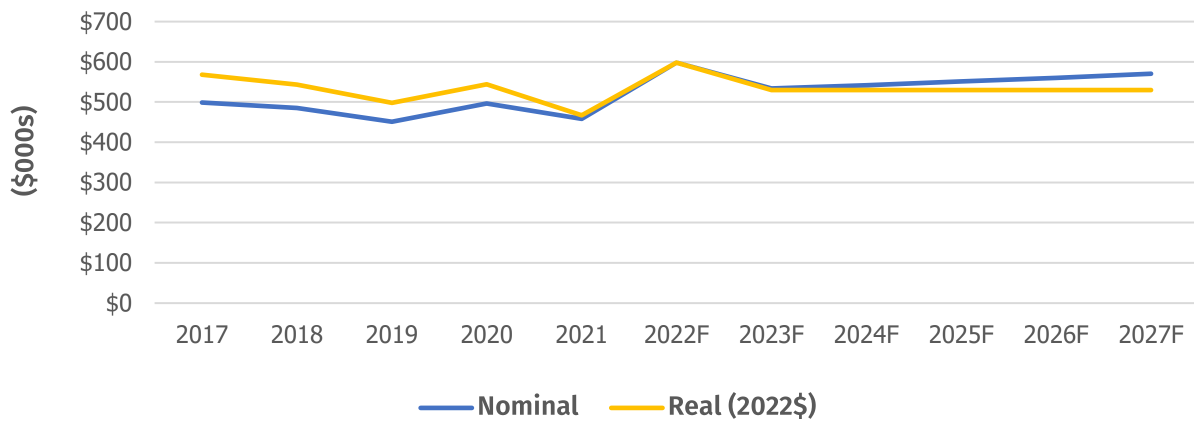
Table 2 Tools and Equipment Program 2023 Budget ($000s)	
Cost Category	2023
Material	534
Labour – Internal	-
Labour – Contract	-
Engineering	-
Other	-
Total	**$534**

Proposed expenditures for the *Tools and Equipment* program total $534,000 for 2023.

PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Tools and Equipment* program from 2017 to 2027.[82]

Figure 1
Tools and Equipment Program Expenditures
(2017 - 2027F)



Annual expenditures averaged approximately $498,000 from 2017 to 2022, or approximately $536,000 when adjusted for inflation. Annual expenditures are forecast to average approximately $551,000 over the next five years.

ASSET BACKGROUND

Tools and equipment are used by powerline technicians, engineering technologists, engineers and tradespersons during day-to-day operations. Specialized tools and equipment are required to maintain, repair, diagnose or commission system assets required to deliver service to customers. Office furniture deteriorates with use over time and eventually requires replacement.

RISK ASSESSMENT

The *Tools and Equipment* program will mitigate risks to the delivery of safe and reliable service to customers by replacing equipment that is essential during day-to-day operations.

The equipment, tools, and office furniture replaced under this program can result in hazardous working conditions for employees using unsafe equipment and decreased service reliability to customers due to delays in outage response. Likewise, the consequence of failure of office furniture is unsafe working environments and the potential for injury to employees and members of the public frequenting Newfoundland Power facilities.

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[82] For forecast annual expenditures for the *Tools and Equipment* program, see the *2023-2027 Capital Plan,* Appendix A, page A-8.

The tools and office furniture replaced under this program has become deteriorated or is obsolete. The probability of failure is therefore likely.

Table 3 summarizes the risk assessment of the *Tools and Equipment* program.

Table 3
Tools and Equipment Program
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Tools and Equipment* program would pose a Medium-High (16) risk to the delivery of safe and reliable service to customers.

JUSTIFICATION

The *Tools and Equipment* program is required to provide safe and reliable service to customers. Newfoundland Power requires an adequate supply of tools, equipment, and office furniture to provide service to customers. The replacement of deteriorated and obsolete equipment is necessary on an ongoing basis to ensure the safety of employees working in offices and the field and a prompt response to customer outages.

TRANSPORTATION

Title: **Replace Vehicles and Aerial Devices 2023-2024**
Asset Class: **Transportation**
Category: **Project**
Investment Classification: **General Plant**
Budget (Multi-Year): **$2,833,000 in 2023; and $1,866,000 in 2024**

PROJECT DESCRIPTION

The *Replace Vehicles and Aerial Devices 2023-2024* project involves the addition and replacement of heavy/medium duty fleet, light duty fleet, passenger and off-road vehicles. In 2022, due to long delivery times, Newfoundland Power initiated a multi-year approach to procuring heavy/medium duty fleet vehicles.

Table 1 summarizes the quantity of vehicles to be replaced in 2023 and 2024 under this project.

Table 1
2023-2024 Proposed Vehicle Replacements

Category	2023 No. of Units	2024 No. of Units
Passenger Vehicles	28	-
Light Duty Vehicles	4	-
Heavy/Medium Duty Vehicles	-	4
Total	32	4

Newfoundland Power has identified 28 passenger vehicles and four light duty vehicles for replacement in 2023 and four heavy/medium duty vehicles for replacement in 2024. An allowance of $350,000 has been allotted for the replacement of off-road vehicles in 2023.[83] 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 2023-2024* project is based upon the cost estimates of the quantity and types of units to be replaced.

83 The off-road vehicles category includes snowmobiles, ATVs, trailers and specialized mobile equipment.

Table 2 provides a breakdown of the proposed expenditures for the *Replace Vehicles and Aerial Devices 2023-2024* project for 2023 and 2024.

Table 2
Replace Vehicles and Aerial Devices
2023-2024 Project
2023/2024 Budget
($000s)

Cost Category	2023	2024
Material	2,701	1,866
Labour – Internal	127	-
Labour – Contract	-	-
Engineering	-	-
Other	5	-
Total	$2,833	$1,866

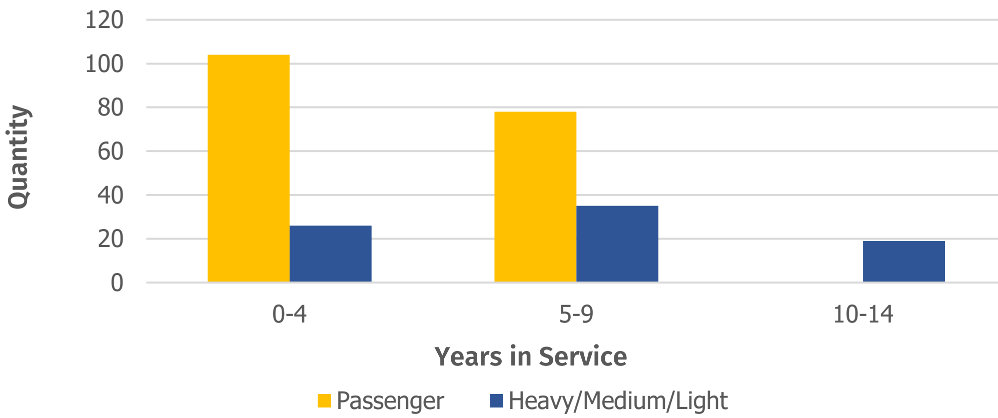
Proposed expenditures for the *Replace Vehicles and Aerial Devices 2023-2024* project total approximately $4,699,000, including $2,833,000 in 2023 and $1,866,000 in 2024.

ASSET BACKGROUND

Newfoundland Power maintains a fleet of over 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, customers' service requests and other operational requirements.

Figure 1 shows the age distribution of Newfoundland Power's vehicles.

Figure 1
Age Distribution of Vehicles



Approximately 24% of Newfoundland Power's heavy, medium and light duty vehicles have been in service for 10 years or more. Approximately 43% of the Company's passenger vehicles have been in operation for five years or more.

ASSESSMENT OF ALTERNATIVES

Newfoundland Power applies evaluation criteria to determine whether a vehicle requires replacement.[84] The criteria require that an evaluation be completed when individual vehicles reach a certain age or mileage. Heavy/medium and light duty vehicles are evaluated for replacement at 10 years of age or mileage of 250,000 kilometres. Passenger vehicles are evaluated for replacement at five years of age or mileage of 150,000 kilometres.

When these criteria are met, vehicles are inspected by a certified mechanic to assess their condition and any required repairs. The results of the inspection 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 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

[84] 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 2023-2024* project will mitigate risks to the delivery of safe and reliable service to customers.

Newfoundland Power responds to over 39,000 customer requests in the field annually, including 9,000 trouble calls from customers experiencing issues with their service. Ensuring a prompt response to customers' requests, including outages, requires an adequate fleet of vehicles. An adequate fleet of vehicles is also necessary for the deployment of engineers, technologists and other tradespersons responsible for inspecting and maintaining the electrical system.

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 in 2023 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 2023-2024* project.

Table 3
Replace Vehicles and Aerial Devices 2023-2024 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 2023-2024* project would pose a Medium-High (16) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Replace Vehicles and Aerial Devices 2023-2024* 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 in 2023 and 2024 are in poor condition and can no longer be economically maintained for additional service.

UNFORESEEN ALLOWANCE

Title:	**Allowance for Unforeseen Items**
Asset Class:	**Unforeseen Allowance**
Category:	**Project**
Investment Classification:	**Mandatory**
Budget:	**$750,000**

PROJECT DESCRIPTION

The *Allowance for Unforeseen Items* is necessary to permit unforeseen capital expenditures that have not been budgeted elsewhere. The purpose of the account is to permit the Company to act expeditiously to respond to events affecting the electrical system in advance of seeking specific approval of the Board. Examples of such expenditures are the replacement of facilities and equipment due to major storm damage or equipment failure.

While the contingencies for which this budget allowance is intended may be unrelated, it is appropriate that the entire allowance be considered as a single capital budget item.

PROJECT BUDGET

An allowance of $750,000 for unforeseen capital expenditures has been included in all of Newfoundland Power's capital budgets in recent years. If the *Allowance for Unforeseen Items* is exceeded in the year, the Company is required to file an application for approval of an additional amount in accordance with the Board's *Capital Budget Application Guidelines (Provisional).*

JUSTIFICATION

This project provides funds for timely service restoration in accordance with Section V.A.7 of the provisional *Capital Budget Application Guidelines – Allowance for Unforeseen Items*.

GENERAL EXPENSES CAPITALIZED

Title:	**General Expenses Capitalized**
Asset Class:	**General Expenses Capitalized**
Category:	**Project**
Investment Classification:	**Mandatory**
Budget:	**$4,000,000**

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. In Order No. P.U. 3 (2022), the Board approved a change in the calculation of GEC to remove pension costs. 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.*[85]

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.*

85 See Newfoundland Power's *2022/2023 General Rate Application, Volume 2, Report 6 Review of General Expenses Capitalized.*

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

	2021	2020
Net Plant Investment		
Plant Investment	2,104,248	2,020,501
Accumulated Depreciation	(869,423)	(828,004)
Contributions in Aid of Construction	(44,780)	(44,357)
	$1,190,045	$1,148,140
Additions to Rate Base		
Deferred Pension Costs	88,888	89,900
Credit Facility Costs	96	46
Cost Recovery Deferral – Hearing Costs	-	247
Cost Recovery Deferral – Conservation	16,421	17,049
Customer Finance Programs	1,755	2,098
Demand Management Incentive Account	1,342	1,002
	$108,502	$110,342
Deductions from Rate Base		
Weather Normalization Reserve	2,020	3,734
Other Post Employment Benefits	73,566	66,739
Customer Security Deposits	1,401	1,212
Accrued Pension Obligation	5,168	5,258
Accumulated Deferred Income Taxes	15,976	12,683
Cost Recovery Deferral	-	613
	$98,131	$90,239
Year End Rate Base	1,200,416	1,168,243
Average Rate Base Before Allowances	1,184,330	1,164,124
Rate Base Allowances		
Materials and Supplies Allowance	8,339	7,270
Cash Working Capital Allowance	10,277	10,503
Average Rate Base at Year End	$1,202,946	$1,181,897

2023 Capital Budget Overview

June 2022

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1.0 APPLICATION OVERVIEW

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") 2023 Capital Budget totals approximately $123.5 million. The 2023 Capital Budget includes:

(i) Proposed single-year projects and programs in the amount of $93,292,000;
(ii) Proposed multi-year projects with capital expenditures of $10,483,000 in 2023 and $10,645,000 in 2024; and
(iii) Previously approved multi-year projects with capital expenditures of $19,688,000 in 2023 and $4,276,000 in 2024.

Newfoundland Power's annual capital expenditures are essential to balancing the cost and reliability of the service provided to its customers. Over the last decade, the duration of customer outages has been approximately half the Canadian average and the Company's contribution to customer rates has decreased on an inflation-adjusted basis. Since 2011, Newfoundland Power has had plant investment levels consistent with other Atlantic Canadian utilities while maintaining the top service reliability of any distribution utility in Atlantic Canada.

The 2023 Capital Budget includes 20 recurring capital programs and 37 capital projects, seven of which have been previously approved and do not require further approval.

Approximately half of capital expenditures included in the 2023 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 2023 Capital Budget associated with the replacement and refurbishment of existing assets reflects the age and condition of Newfoundland Power's electrical system.

Approximately one quarter of capital expenditures included in the 2023 Capital Budget are associated with requirements to connect new customers and respond to system load growth. The Company is forecasting 2,185 new customer connections in 2023, as well as the requirement to address load growth on two distribution feeders due to residential development on the Northeast Avalon. Expenditures in 2023 also include the expansion of Long Pond Substation to accommodate the replacement of an oil-fired water boiler at Memorial University with two electrically powered boilers.

The remaining one quarter of capital expenditures included in the 2023 Capital Budget are associated with general plant, service enhancement and mandatory expenditures. The largest drivers of expenditures in these areas are: (i) the previously approved *Customer Service System Replacement* project with a budget of approximately $5.9 million in 2023; and (ii) the *LED Street Lighting Replacement* project which provides customers with lower rates for better quality lighting at a budget of approximately $5.5 million in 2023.

Overall, the 2023 Capital Budget represents the capital additions and improvements necessary to continue providing safe and reliable service to customers at the lowest possible cost.

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*.[1] The *Public Utilities Act* requires a public utility to provide services and facilities that are reasonably safe and adequate and just and reasonable.[2] The *Electrical Power Control Act, 1994* contains the provincial power policy, which requires that power be delivered to customers at the lowest possible cost consistent with reliable service.[3]

The Board provided updated provisional *Capital Budget Application Guidelines* (the "Provisional Guidelines") effective January 2022. In issuing the Provisional Guidelines, the Board noted that:

> *"… the provisional guidelines will require a new approach which may be challenging to implement fully in 2022. 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."*[4]

The capital expenditures proposed as part of Newfoundland Power's *2023 Capital Budget Application* (the "Application") are necessary to meet its 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 result of a comprehensive capital planning process. The Company's capital planning process applies sound engineering and objective data to determine which expenditures are required annually to provide customers with access to safe and reliable service at the lowest possible cost.

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1 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.

2 See section 37(1) of the *Public Utilities Act.*

3 See sections 3(b)(i), 3(b)(ii) and 3(b)(iii) of the *Electrical Power Control Act, 1994*.

4 See correspondence from the Board regarding *Provisional Capital Budget Application Guidelines*, dated December 20, 2021.

The capital planning process commences each year with an update of the Company's five-year capital plan. The capital plan provides a forecast of capital expenditures across all asset classes for the next five years, including the upcoming budget year. The capital plan is updated annually based on the most recent information of forecast customer requirements, asset condition, operational requirements and other factors.

Newfoundland Power's annual capital expenditures include a combination of recurring programs and specific projects. The capital planning process for programs and projects is described below.

2.2.2 Capital Program Planning

Programs include capital investments related to high-volume, repetitive work that is required on an ongoing basis. Programs include:

(i) Capital work required to connect new customers to the electrical system, such as the installation of services and meters;
(ii) Corrective and preventative maintenance programs necessary to maintain the electrical system, including the replacement of equipment that has failed or deteriorated; and
(iii) Capital expenditures necessary to replace or add specific materials used in providing service to customers, such as personal computers, tools and equipment.

Programs required to connect new customers to the electrical system are generally budgeted on the basis of forecast customer requirements. Each year, Newfoundland Power updates its capital plan to reflect its most recent Customer, Energy and Demand Forecast. The Customer, Energy and Demand Forecast estimates new customer connections that are expected over the next five years based on economic inputs from the Conference Board of Canada, such as forecast housing starts. This data is then used to determine forecast expenditures to connect new customers, including forecast expenditures for meters, services, and extensions to the distribution system.

Programs required to complete corrective and preventative maintenance of the electrical system are generally budgeted on the basis of historical expenditures and forecast inflation.[5] Capital requirements for corrective and preventative maintenance programs tend to be reasonably stable over time. Each year, the Company updates its forecast expenditures for these programs based on the most recent five-year average of expenditures and the latest forecast of inflation. This budgeting methodology helps to ensure forecast expenditures reflect the Company's most recent experience with maintaining the electrical system.

Capital expenditures for programs required to replace or add specific materials used in providing service to customers are generally budgeted based on a combination of historical

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

expenditures, forecast inflation, and identified operational requirements. For example, identified operational requirements could include the need to purchase a specific quantity of personal computers.

In forecasting program expenditures, Newfoundland Power reviews any recent variances in actual costs from approved budgets and the reasons for those variances. If significant variances are observed in consecutive years, an analysis is undertaken to determine whether a different budgeting methodology would be more reflective of forecast requirements.[6]

2.2.3 Capital Project Planning

Projects include capital investments for identifiable assets where the required work has a defined schedule, scope and budget based on detailed engineering estimates.

Forecast expenditures related to projects are updated annually to reflect the latest:

(i) Condition assessments of electrical system assets. Information on asset condition is obtained through annual inspection programs, engineering reviews and recent operating experience. This information identifies equipment that is deteriorated, deficient, or 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, that 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

[6] 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. For more information, see page 32 of Schedule B to that application.

alternatives for executing the required work. This includes both alternatives to the scope of a capital expenditure, such as a like-for-like replacement or upgrade, and alternatives that could result in the deferral of capital expenditures.

The 2023 Capital Budget includes seven capital projects that were previously deferred or modified and are now proposed for 2023, and one capital project that was planned for future years but was advanced to 2023. There are also five capital projects that were planned for 2023 but have been deferred to future years. Appendix B provides the list of the capital projects that were deferred, modified or advanced.

The prioritization or deferral of capital expenditures is assessed based on potential risks to customers. This includes engineering assessments of the likelihood that an asset will fail and the potential reliability, safety, environmental or economic consequences for customers if failure were to occur. In 2022 following the issuance of Provisional Guidelines, Newfoundland Power developed a risk matrix to standardize its approach to communicating risks associated with proposed capital expenditures. Appendix C provides the risk matrix methodology and a prioritized list of 2023 capital expenditures.

2.3 Balancing Cost and Service

2.3.1 Service Reliability

Newfoundland Power owns and operates over 10,000 kilometres of distribution line, approximately 2,000 kilometres of transmission line, 131 substations, 23 hydro generating plants and six thermal generating plants 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.[7] Long-term asset management strategies, such as the *Substation Refurbishment and Modernization Plan* and *Transmission Line Rebuild Strategy,* provide a structured approach to maintaining the condition of a large volume of electrical system assets. Annual inspections support routine preventative and corrective maintenance programs, with substations inspected eight times annually, transmission lines inspected annually, and distribution lines inspected on a seven-year cycle.

The service reliability experienced by customers also reflects the Company's response when outages occur. Newfoundland Power's operational response requires the deployment of a skilled workforce throughout its service territory, including powerline technicians, technologists and engineers. A combination of operational technologies and adequate tools and equipment are necessary to ensure the effective and efficient deployment of the Company's workforce.

Annual capital expenditures are essential to maintaining both electrical system condition and the Company's operational response. The most recent independent review of Newfoundland

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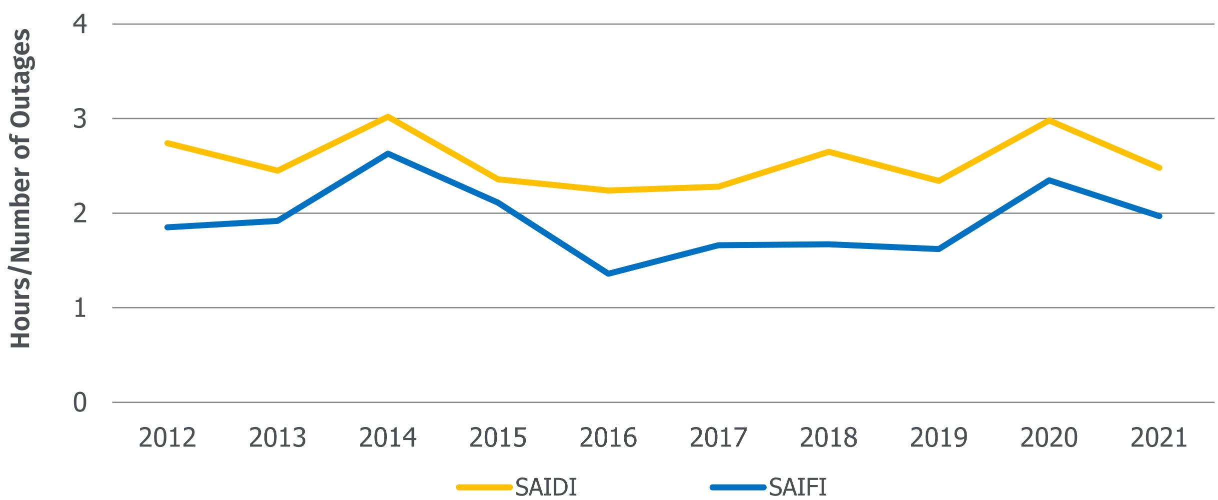
7 The primary engineering standard for distribution and transmission systems is Canadian Standards Association ("CSA") standard *C22.3 No.1-15 Overhead Systems*.

Power's engineered operations was conducted by The Liberty Consulting Group ("Liberty") in 2014 and found that the Company's asset management practices and operations conform to good utility practices.[8]

Figure 1 shows the average duration ("SAIDI") and frequency ("SAIFI") of outages to Newfoundland Power's customers from 2012 to 2021 under normal operating conditions.[9]

Figure 1
Newfoundland Power
SAIDI and SAIFI - Normal Operating Conditions
(2012-2021)



The frequency and duration of customer outages has been reasonably stable over the last decade under normal operating conditions. The average duration of customer outages has ranged from approximately 2.2 to 3.0 hours per year. The average frequency of customer outages has ranged from approximately 1.4 to 2.6 outages per year.

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8 The Liberty Consulting Group concluded that: *"Newfoundland Power's planning and design of its system, its asset management practices, its system operations, its outage management and emergency practices and its customer communications processes all conform to good utility practices."* See 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.

9 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 significant 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 2012 to 2021.[10]

Figure 2
Newfoundland Power vs. Canadian Average
SAIDI - Normal Operating Conditions
(2012-2021)

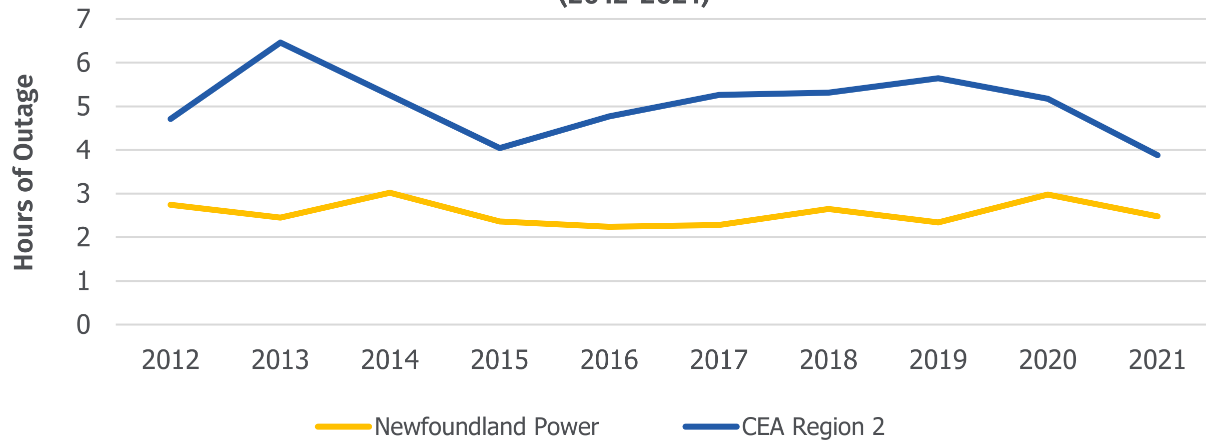
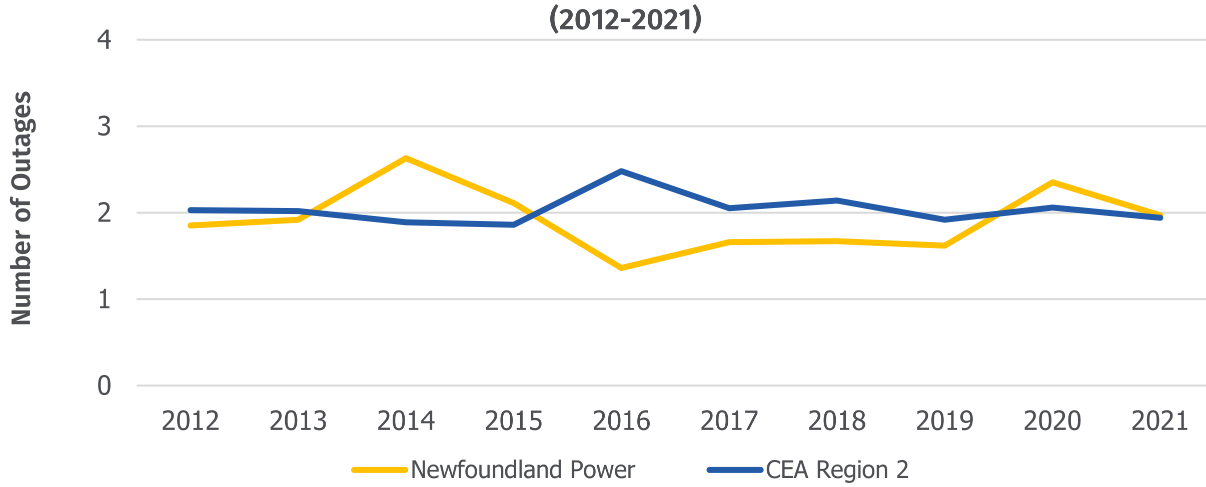


Figure 3
Newfoundland Power vs. Canadian Average
SAIFI - Normal Operating Conditions
(2012-2021)



[10] The Canadian Average reflects Region 2 utilities of the Canadian Electricity Association. Region 2 utilities include Canadian utilities that serve a mix of urban and rural markets. These are ATCO Electric, BC Hydro, FortisAlberta, FortisBC, Hydro One, Hydro Quebec, Manitoba Hydro, Maritime Electric, NB Power, Newfoundland and Labrador Hydro, Newfoundland Power, Newmarket-Tay Power Distribution, Nova Scotia Power, Northwest Territories Power Corporation, Sask Power, Veridian Connections, Waterloo North Hydro, Yukon Electrical Co. and Yukon Energy.

Newfoundland Power's reliability performance has been reasonable over the last decade in comparison to the Canadian average. The average duration of customer outages has been approximately half the Canadian average since 2012.[11] The average frequency of customer outages has been consistent with the Canadian average over this period.[12]

Newfoundland Power is focused on maintaining current levels of overall service reliability for its customers under normal operating conditions. The Company's annual targets for service reliability are based on the most recent five-year average.

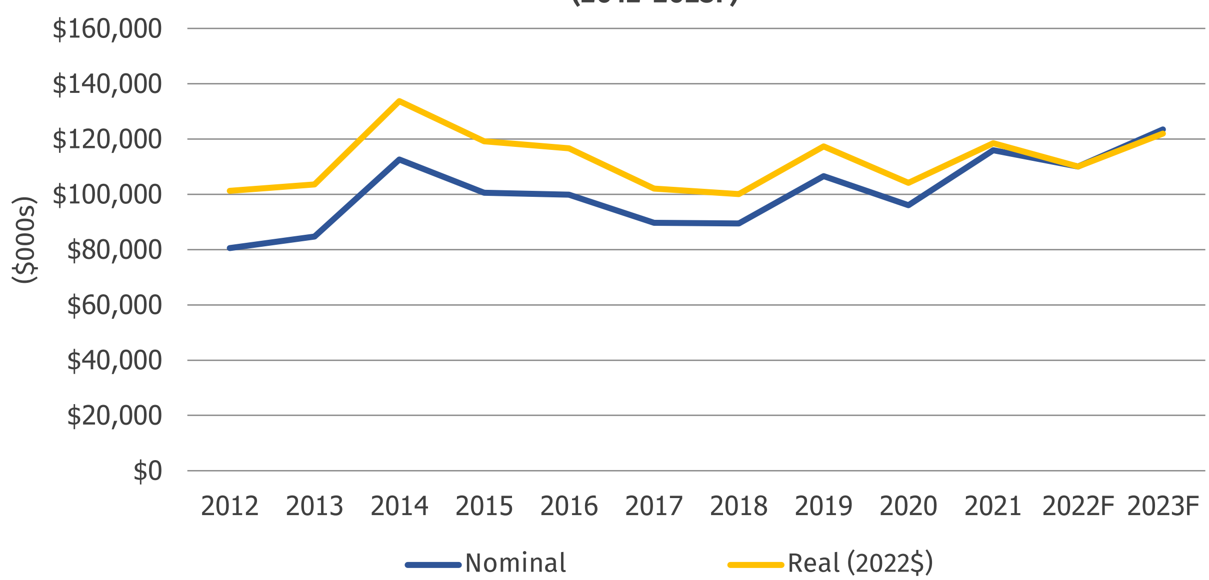
While overall levels of service reliability are viewed as acceptable, customers in certain areas experience service reliability that is considerably below Newfoundland Power's corporate average. Appendix D provides a list of the Company's worst performing feeders.

2.3.2 Capital Expenditures

Newfoundland Power's annual capital expenditures reflect the capital additions and improvements 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 2012 to 2022 and the 2023 Capital Budget.

Figure 4
Newfoundland Power Capital Expenditures
(2012-2023F)



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[11] Newfoundland Power's SAIDI averaged approximately 2.6 hours/year from 2012 to 2021. This compares to a CEA average SAIDI of 5.0 hours/year over the same period.

[12] Newfoundland Power's SAIFI averaged approximately 1.9 outages/year from 2012 to 2021. This compares to a CEA average SAIFI of 2.0 outages/year over the same period.

Newfoundland Power's capital expenditures have averaged approximately $99 million annually from 2012 to 2022, or $111 million when adjusted for inflation. On an inflation-adjusted basis, annual expenditures have ranged from approximately $100 million in 2018 to $134 million in 2014. The 2023 Capital Budget of approximately $123.5 million is within this range.

2.3.3 Customer Rates

A primary determinant of Newfoundland Power's customer rates is the Company's revenue requirement. Revenue requirement is the aggregate amount of forecast revenue required in a year to cover the Company's cost of serving customers, including operating costs, taxes, depreciation and allowed return on rate base.[13] Customer rates also reflect the Company's Customer, Energy and Demand forecasts and Board-approved rate structures.[14]

The Board has previously recognized the complex relationship between capital investments, revenue requirements and customer rates.[15] The Board has also recognized that fully justified capital expenditures contribute to the delivery of least-cost service to customers.[16]

The complex relationship between capital investments, revenue requirements and customer rates can be observed over the last decade. While the Company's annual capital expenditures averaged over $100 million since 2016, there has not been a customer rate increase resulting from a Newfoundland Power general rate application over that period.[17]

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

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

15 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."*

16 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."*

17 On July 1, 2016, customer rates increased by 1.2% as a result of Newfoundland Power's *2016/2017 General Rate Application*. Customer rates did not change as a result of its *2019/2020 General Rate Application* and decreased by approximately 1% as a result of its *2022/2023 General Rate Application*.

Table 1 shows Newfoundland Power's actual and inflation-adjusted contribution to revenue requirement in 2014 and 2023.[18]

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

	2014	2023[19]	Change
Actual	212.9[20]	239.3	12%
Inflation-Adjusted[21]	250.0	239.3	-4%

Since 2014, Newfoundland Power's contribution to revenue requirement increased by approximately 12%. On an inflation-adjusted basis, the Company's contribution to revenue requirement decreased by approximately 4%.

Newfoundland Power's revenue requirements and customer rates were most recently interrogated during its *2022/2023 General Rate Application.* The Company's proposed 2023 Capital Budget is reflected in its 2023 revenue requirement. Approval of the Company's 2023 revenue requirement resulted in a decrease in customer rates of approximately 1% effective March 1, 2022.

On a *pro forma* basis, the Company estimates that $4 million of the approved 2023 revenue requirement reflects the capital expenditures proposed for 2023. This *pro forma* estimate includes increases in depreciation, return on rate base and income tax, as well as reduced operating costs as a result of the *LED Street Lighting Replacement Plan*.[22] The *pro forma* analysis is practically limited as it does not include potentially higher revenues from growth-related

[18] Based on the Company's test year revenue requirements, excluding purchased power costs. Purchased power costs from Newfoundland and Labrador Hydro account for approximately 70% of the Company's overall revenue requirement.

[19] Newfoundland Power's 2023 revenue requirement was $699.2 million. Excluding purchased power costs of $459.9 million, it was $239.3 million. See the Company's *2022/2023 General Rate Application*, Exhibit 7 (Revised), page 2.

[20] Newfoundland Power's 2014 revenue requirement was $612.1 million. Excluding purchased power costs of $399.2 million, it was $212.9 million. See the Company's application filed in compliance with Order No. P.U. 13 (2013), Schedule 1, Appendix E, page 2.

[21] Inflation adjusted based on the GDP Deflator for Canada.

[22] The proposed *LED Street Lighting Replacement Plan* is forecast to reduce operating costs in 2023 by approximately $2 million on a *pro forma* basis. See the *2021 Capital Budget Application, Volume 1, LED Street Lighting Replacement Plan,* Appendix B, page B-5.

projects, or the long-term effect that fully justified capital expenditures have on minimizing revenue requirements.[23]

Table 2 compares Newfoundland Power's total contribution to average customer rates in cents per kWh in 2014 and 2023.

Table 2 Newfoundland Power Contribution to Customer Rates (¢/kWh)			
	2014	2023[24]	Change
Actual	3.65	4.23	16%
Inflation-Adjusted[25]	4.28	4.23	-1%

Newfoundland Power's contribution to average customer rates increased by approximately 16% from 2014 to 2023. On an inflation-adjusted basis, the Company's contribution to average customer rates decreased by 1%.

In Newfoundland Power's view, this is evidence of its ability to effectively manage costs while maintaining acceptable levels of service reliability for customers.

2.3.4 Atlantic Canadian Comparison

The four primary distributors of electricity in Atlantic Canada are: (i) Newfoundland Power; (ii) Nova Scotia Power; (iii) NB Power; and (iv) Maritime Electric. Each of these utilities serves customers in a mix of urban and rural areas.

23 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. Further, the proposed refurbishment of the Company's Mobile and Sandy Brook hydro plants included in the Application will result in the continued provision of low-cost energy to customers, thereby avoiding the need to purchase more expensive replacement production.

24 Based on Newfoundland Power's 2023 test year revenue requirement which is reflected in current customer rates, as approved in Order No. P.U. 3 (2022).

25 Inflation adjusted based on the GDP Deflator for Canada.

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 2011 to 2020; and (ii) the average duration of customer outages over the same period.

Table 3
Atlantic Canadian Comparison
Capital Investment and Service Reliability

	Capital Investment (T&D - Millions)[26]			Service Reliability (SAIDI)
Utility	2011	2020	Growth	(2011-2020)
Newfoundland Power	\$971	\$1,477	52%	2.6
Atlantic Canadian Utilities[27]	\$1,218	\$1,844	51%	4.0

Newfoundland Power's investment in T&D assets has increased at a rate consistent with the average of other Atlantic Canadian utilities over the 10-year period ending 2020, with investments among other Atlantic Canadian utilities ranging from 50% to 58%.

Over the same period, the Company's customers have experienced 35% fewer outage hours in comparison to customers of other Atlantic Canadian utilities.[28] The Company's average outage duration was the lowest of any Atlantic Canadian utility over this period.[29]

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

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26 Reflects the average Property, Plant and Equipment in T&D assets of NB Power, Nova Scotia Power and Maritime Electric. Property, Plant and Equipment is the gross cost of utility assets determined in accordance with generally accepted accounting principles. This information is based on the audited and publicly available financial statements of each utility.

27 The aggregate investment of NB Power, Nova Scotia Power and Maritime Electric was \$3,655 million in 2011 (\$3,655 million / 3 = \$1,218 million) and \$5,532 million in 2020 (\$5,532 million / 3 = \$1,844 million).

28 (2.6 – 4.0) / 4.0 = -0.35, or -35%.

29 The average SAIDI for the other Atlantic Canadian utilities ranged from 2.8 to 4.3.

3.0 SUMMARY OF 2023 EXPENDITURES

3.1 2023 Capital Budget Overall

Newfoundland Power's 2023 Capital Budget totals approximately $123.5 million, including approximately $19.7 million of expenditures in 2023 that were previously approved by the Board.[30] There has been no change in the scope, nature or magnitude of the previously approved capital expenditures.[31] Further Board approval is therefore not required for these expenditures. Appendix E provides an update on previously approved multi-year projects.

Net of previously approved expenditures, the Application is seeking approval of capital expenditures totalling approximately $103.8 million in 2023. Of this total, approximately $2.7 million relates to a project to provide redundant supply to the Corner Brook Acute Care Hospital. This project is considered a special facility under Newfoundland Power's *Schedule of Rates, Rules and Regulations* and will be fully funded by the customer.

Newfoundland Power's Application also proposes four new multi-year projects. The multi-year projects include commitments of approximately $10.6 million in 2024.

The following sections provide breakdowns of the 2023 Capital Budget by asset class, category, investment classification and materiality.

30 The previously approved multi-year projects also include expenditures of approximately $4.3 million in 2024.

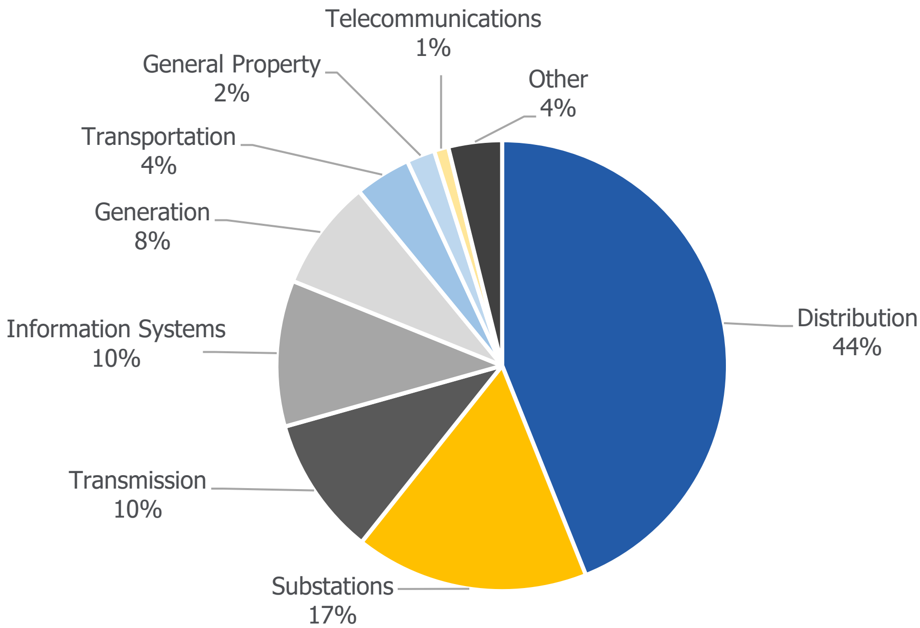
31 For expenditures incurred to date as part of these projects, see the *2022 Capital Expenditure Status Report* provided with the Application.

3.2 2023 Capital Budget by Asset Class

Newfoundland Power organizes its annual capital budget by asset class.

Figure 5 provides the 2023 Capital Budget by asset class, including previously approved multi-year projects.

Figure 5
2023 Capital Budget by Asset Class



The distribution asset class accounts for approximately 44% of capital expenditures for 2023. Over half of distribution expenditures are required to connect new customers to the electrical system. More than one third relate to preventative and corrective maintenance programs for the distribution system.

The substation asset class accounts for approximately 17% of capital expenditures for 2023. The majority of substation expenditures relate to the refurbishment and modernization of the Walbournes and Molloy's Lane substations at a combined cost of $9.8 million in 2023. Substation expenditures also include the purchase of a spare power transformer to manage increasing risks associated with the Company's aging fleet of power transformers.[32]

The transmission asset class accounts for approximately 10% of capital expenditures for 2023. The majority of transmission expenditures relate to the rebuilding of aging transmission lines constructed in the 1960s and 1970s. This includes a multi-year project to rebuild deteriorated

[32] For more information, see Newfoundland Power's *2023-2027 Capital Plan, Section 2.4 Asset Condition Outlook.*

Transmission Line 55L on the Avalon Peninsula at a cost of approximately $5.3 million in 2023 and $5.3 million in 2024. Transmission expenditures in 2023 also include approximately $4.3 million associated with a project to rebuild Transmission Line 94L on the Avalon Peninsula, as approved by the Board in Order No. P.U. 36 (2021).[33]

The information systems asset class continues to account for a large portion of capital expenditures as a result of the *Customer Service System Replacement* project approved by the Board in Order No. P.U. 12 (2021). Capital expenditures for 2023 include the final year of this multi-year project, at a cost of approximately $5.9 million.

The generation asset class accounts for approximately 8% of capital expenditures for 2023. This includes a multi-year project to refurbish the Mobile hydro plant at a cost of approximately $1.7 million in 2023 and $2.5 million in 2024. It also includes refurbishment of the Sandy Brook hydro plant generator in 2023 to coincide with replacement of the plant's penstock, as approved by the Board in Order No. P.U. 36 (2021).

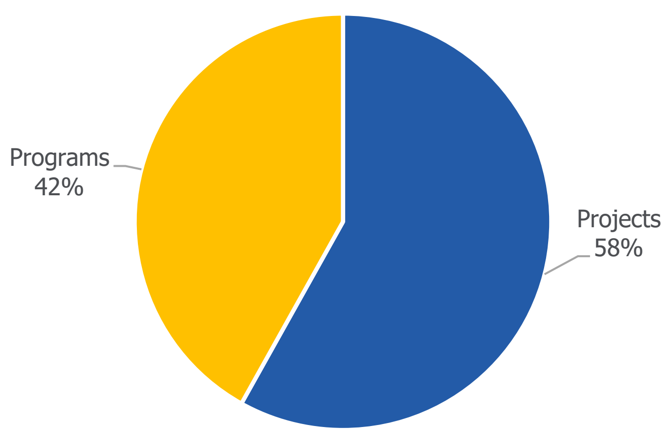
The remaining asset classes account for between 1% and 4% of capital expenditures for 2023.

3.3 2023 Capital Budget by Category

The Provisional Guidelines require the categorization of capital expenditures as: (i) projects that involve identifiable assets with defined schedules and budgets; or (ii) programs that involve ongoing, repetitive work where budgets are renewed annually.

Figure 6 provides a breakdown of Newfoundland Power's 2023 Capital Budget by category, including previously approved multi-year projects.

Figure 6
2023 Capital Budget by Category



[33] The previously approved project to rebuild Transmission Line 94L also includes expenditures of approximately $4.3 million in 2024.

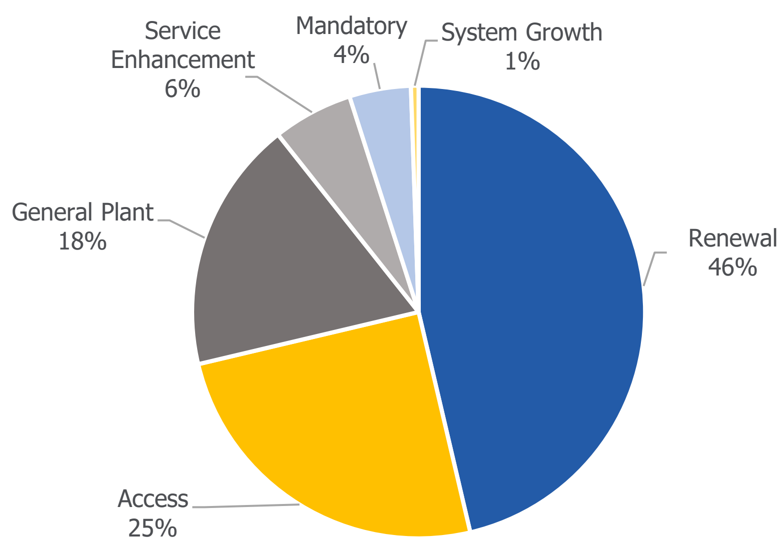
Newfoundland Power's 2023 Capital Budget includes 37 capital projects and 20 capital programs. Capital projects account for approximately 58% of capital expenditures for 2023, with the remaining 42% attributable to recurring programs.

3.4 2023 Capital Budget by Investment Classification

The Provisional Guidelines require capital expenditures be organized by investment classification.

Figure 7 shows Newfoundland Power's 2023 Capital Budget by investment classification, including previously approved multi-year projects.

Figure 7
2023 Capital Budget by Investment Classification



Renewal expenditures account for approximately 46% of capital expenditures for 2023. These expenditures are primarily driven by the age and condition of Newfoundland Power's electrical system. Preventative and corrective maintenance programs account for nearly half of Renewal expenditures in 2023. Capital work under the *Transmission Line Rebuild Strategy* and *Substation Refurbishment and Modernization Plan* account for an additional one third of Renewal expenditures in 2023.

Access expenditures account for approximately 25% of capital expenditures for 2023. 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 2,185 new customer connections in 2023.

General Plant expenditures account for approximately 18% of capital expenditures for 2023. Information systems expenditures, which include the *Customer Service System Replacement* project, account for over half of all General Plant expenditures. These expenditures are driven by the need to maintain the reliability and security of software and hardware that support the provision of service to customers. Expenditures within the transportation asset class are the next largest driver of General Plant expenditures, reflecting the routine replacement of vehicles that have reached the end of their useful service lives.

Service Enhancement expenditures account for approximately 6% of capital expenditures for 2023. The *LED Street Lighting Replacement* project accounts for the majority of Service Enhancement expenditures in 2023. This project is being completed as part of a six-year plan that commenced in 2021 to provide all Street and Area Lighting customers with LED fixtures. LED street light fixtures offer lower rates, better quality lighting and a more reliable street lighting service.

Mandatory expenditures account for approximately 4% of capital expenditures for 2023. The primary drivers within this classification are Federal Government regulations mandating the phase-out of polychlorinated biphenyls ("PCBs") and Board orders respecting *General Expenses Capitalized*, the *Allowance for Funds Used During Construction*, and the *Allowance for Unforeseen Items*.

System Growth expenditures account for approximately 1% of capital expenditures in 2023. There is one capital project proposed for 2023 to address localized load growth on two distribution feeders on the Northeast Avalon.

3.5 2023 Capital Budget by Materiality

The Provisional Guidelines require capital expenditures be organized by materiality based on three thresholds: (i) expenditures less than $1 million; (ii) expenditures between $1 million and $5 million; and (iii) expenditures greater than $5 million.

Table 4 provides an overview of the 2023 Capital Budget by materiality, including previously approved multi-year projects.[34]

Table 4
2023 Capital Budget by Materiality

Threshold	Quantity of Projects/Programs	Total Expenditures ($000s)	Percentage of Total Expenditures
Less than $1 million	26	14,911	12%
$1 million - $5 million	23	61,762	50%
Greater than $5 million	8	46,790	38%
Total	57	123,463	100%

Of the 57 total capital projects and programs included in the 2023 Capital Budget, 49 are less than $5 million in materiality. The eight capital projects and programs greater than $5 million include the previously approved *Customer Service System Replacement* project, *Transmission Line 94L Rebuild* project, *Sandy Brook Plant Penstock Replacement* project and *Replace Vehicles and Aerial Devices 2022-2023* project. There has been no change in the nature, scope or magnitude of these four projects.

The remaining four capital programs and projects greater than $5 million that are proposed for Board approval are:

(i) ***Extensions program***, which involves the construction of distribution lines to connect new customers to the electrical system. Capital expenditures for this program total approximately $12.2 million for 2023. The budget estimate is based on historical unit costs and forecast new customer connections.

(ii) ***Reconstruction program***, which involves corrective maintenance on the distribution system for high-priority deficiencies identified during inspections. Capital expenditures for this program total approximately $6.7 million for 2023. The budget estimate is based on historical expenditures over the most recent five-year period.

(iii) ***Transmission Line 55L Rebuild project***, which includes a multi-year project to rebuild Transmission Line 55L serving customers on the Avalon Peninsula. Capital expenditures for this multi-year project total approximately $5.3 million in 2023 and $5.3 million in 2024. The budget estimate is based on detailed engineering estimates.

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34 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.

(iv) ***LED Street Lighting Replacement project***, which involves the replacement of existing street lights with LED fixtures in order to provide customers with lower rates for a more reliable service. Capital expenditures for this project total approximately $5.5 million for 2023. The budget estimate is based on detailed engineering estimates.

Including previously approved expenditures, the eight capital projects and programs exceeding $5 million in materiality comprise approximately 38% of capital expenditures for 2023.

APPENDIX A:

Capital Expenditure Classification and Categorization Summary

Table A-1
2023 Capital Budget
Proposed Single-Year Projects and Programs

INVESTMENT CLASSIFICATION	BUDGET ($000)	ASSET CLASS	CATEGORY
Mandatory			
General Expenses Capitalized	4,000	GEC	Project
Allowance for Unforeseen Items	750	Unforeseen Allowance	Project
PCB Bushing Phase-Out	425	Substations	Project
Allowance for Funds Used During Construction	247	Distribution	Project
Total Mandatory	**$5,422**		
Access			
Extensions	12,218	Distribution	Program
Relocate/Replace Distribution Lines for Third Parties	3,803	Distribution	Program
Long Pond Substation Capacity Expansion	3,313	Substations	Project
New Transformers	2,967	Distribution	Program
New Services	2,916	Distribution	Program
Corner Brook Acute Care Hospital Redundant Supply	2,690	Distribution	Project
New Street Lighting	2,618	Distribution	Program
New Meters	297	Distribution	Program
Total Access	**$30,822**		
System Growth			
Feeder Additions for Load Growth	670	Distribution	Project
Total System Growth	**$670**		

Table A-1
2023 Capital Budget
Proposed Single-Year Projects and Programs

INVESTMENT CLASSIFICATION	BUDGET ($000)	ASSET CLASS	CATEGORY
Renewal			
Reconstruction	6,699	Distribution	Program
Walbournes Substation Refurbishment and Modernization	4,955	Substations	Project
Rebuild Distribution Lines	4,945	Distribution	Program
Molloy's Lane Substation Refurbishment and Modernization	4,827	Substations	Project
Substation Replacements Due to In-Service Failures	4,422	Substations	Program
Replacement Transformers	3,345	Distribution	Program
Transmission Line Maintenance	2,610	Transmission	Program
Sandy Brook Hydro Plant Generator Refurbishment	1,577	Generation – Hydro	Project
Substation Spare Transformer Inventory	1,500	Substations	Project
Hydro Facility Rehabilitation	877	Generation – Hydro	Project
Replacement Street Lighting	770	Distribution	Program
Substation Protection and Control Replacements	667	Substations	Project
Replacement Meters	662	Distribution	Program
Hydro Plant Replacements Due to In-Service Failures	662	Generation – Hydro	Program
Distribution Feeder SLA-05 Refurbishment	565	Distribution	Project
Distribution Feeder PEP-02 Refurbishment	550	Distribution	Project
Replacement Services	546	Distribution	Program
Thermal Plant Replacements Due to In-Service Failures	335	Generation – Thermal	Program
Total Renewal	**$40,514**		

Table A-1
2023 Capital Budget
Proposed Single-Year Projects and Programs

INVESTMENT CLASSIFICATION	BUDGET ($000)	ASSET CLASS	CATEGORY
Service Enhancement			
LED Street Lighting Replacement	5,453	Distribution	Project
Distribution Feeder Automation	1,054	Distribution	Project
Substation Ground Grid Upgrades	563	Substations	Project
Total Service Enhancement	**$7,070**		
General Plant			
Electric Vehicle Charging Network	594	Distribution	Project
Application Enhancements	1,538	Information Systems	Project
System Upgrades	962	Information Systems	Project
Shared Server Infrastructure	1,176	Information Systems	Project
Cybersecurity Upgrades	882	Information Systems	Project
Network Infrastructure	419	Information Systems	Project
Personal Computer Infrastructure	600	Information Systems	Program
Communications Equipment Upgrades	118	Telecommunications	Program
Company Building Renovations	741	General Property	Project
Additions to Real Property	654	General Property	Program
Physical Security Upgrades	576	General Property	Project
Tools and Equipment	534	General Property	Program
Total General Plant	**$8,794**		
TOTAL SINGLE-YEAR PROJECTS AND PROGRAMS	**$93,292**		

Table A-2
2023 Capital Budget
Proposed Multi-Year Projects

TITLE	ASSET CLASS	INVESTMENT CLASSIFICATION	PROJECT / PROGRAM	Budget ($000) 2023	2024	Total
Distribution Reliability Initiative	Distribution	Renewal	Project	656	1,015	1,671
Transmission Line 55L Rebuild	Transmission	Renewal	Project	5,328	5,284	10,612
Mobile Hydro Plant Refurbishment	Generation – Hydro	Renewal	Project	1,666	2,480	4,146
Replace Vehicles and Aerial Devices 2023-2024	Transportation	General Plant	Project	2,833	1,866	4,699
			Total	**$10,483**	**$10,645**	**$21,128**

Table A-3
2023 Capital Budget
Previously Approved Multi-Year Projects

TITLE	ASSET CLASS	INVESTMENT CLASSIFICATION	PROJECT/ PROGRAM	Budget ($000) 2021	2022	2023	2024	Total
System Upgrades (Microsoft Enterprise Agreement)[1]	Information Systems	General Plant	Project	245	245	245	-	735
Customer Service System Replacement[2]	Information Systems	General Plant	Project	9,903	15,826	5,917	-	31,646
Sandy Brook Plant Penstock Replacement[3]	Generation - Hydro	Renewal	Project	-	400	4,694	-	5,094
Transmission Line 94L Rebuild[4]	Transmission	Renewal	Project	-	4,473	4,346	4,276	13,095
Replace Vehicles and Aerial Devices 2022-2023[5]	Transportation	General Plant	Project	-	3,089	2,135	-	5,224
St. John's Teleprotection System Replacement[6]	Telecommunications	General Plant	Project	-	450	1,150	-	1,600
Workforce Management System Replacement[7]	Information Systems	General Plant	Project	-	808	1,201	-	2,009
		Total		**$10,148**	**$25,291**	**$19,688**	**$4,276**	**$59,403**

[1] Approved in Order No. P.U. 37 (2020). See the *2021 Capital Budget Application*, Volume 1, Schedule B, pages 82 to 83.
[2] Approved in Order No. P.U. 12 (2021). See the *2021 Capital Budget Application*, Volume 1, Schedule B, pages 93 to 94.
[3] Approved in Order No. P.U. 36 (2021). See the *2022 Capital Budget Application*, Schedule B, pages 5 to 6.
[4] Approved in Order No. P.U. 36 (2021). See the *2022 Capital Budget Application*, Schedule B, pages 18 to 20.
[5] Approved in Order No. P.U. 36 (2021). See the *2022 Capital Budget Application*, Schedule B, pages 70 to 72.
[6] Approved in Order No. P.U. 36 (2021). See the *2022 Capital Budget Application*, Schedule B, pages 76 to 77.
[7] Approved in Order No. P.U. 36 (2021). See the *2022 Capital Budget Application*, Schedule B, pages 94 to 95.

APPENDIX B:

Deferred, Modified and Advanced Capital Expenditures

Deferred, Modified and Advanced Capital Expenditures

The Board's Provisional Guidelines require an explanation of which capital expenditures had been planned for the year but were modified, re-prioritized or deferred until a future year. The Provisional Guidelines also require an explanation of which capital expenditures are proposed for the year after having been deferred in a previous year.

Table B-1 lists the capital expenditures proposed for 2023 that were deferred from previous years or modified through the Company's capital planning process.

Table B-1
2023 Capital Expenditures Deferred or Modified from Previous Years

Project	Description
Mobile Hydro Plant Refurbishment	The Mobile hydro plant requires refurbishment. The refurbishment of this plant was planned for 2022.[1] The project had been deferred to 2023 to allow further assessment of the condition of the plant and associated infrastructure. The assessment has now been completed and the refurbishment project is proposed for 2023.
Sandy Brook Hydro Plant Generator Refurbishment	The Sandy Brook hydro plant generator is original to the plant and approaching 60 years in service. The unit is at the age where the probability of failure is considered high. Refurbishment of the generator was planned for 2020.[2] The project was deferred to allow further engineering assessment. The assessment has now been completed and a rewind of the generator stator and re-insulation of the generator rotor poles are proposed to be completed in 2023 while the plant is out of service for penstock replacement.

[1] The five-year capital plan filed with the *2019 Capital Budget Application* included the refurbishment and modernization of the Mobile hydro plant in 2022.

[2] The five-year capital plan filed with the *2019 Capital Budget Application* included the refurbishment of the Sandy Brook hydro plant generator in 2020.

Table B-1
2023 Capital Expenditures Deferred or Modified from Previous Years

Project	Description
Molloy's Lane Substation Refurbishment and Modernization	Molloy's Lane Substation in St. John's requires refurbishment and modernization to replace and upgrade deteriorated equipment. Equipment to be replaced includes the control building, circuit breakers, switches, potential transformers, protective relaying and bus structures. The project also includes extending the substation yard and installing a new 66 kV steel bus structure. The project was most recently planned for 2021.[3] The project was deferred to allow further engineering assessment of the components in the substation. The assessment has now been completed and the project is proposed for 2023.
Walbournes Substation Refurbishment and Modernization	Walbournes Substation in Corner Brook requires refurbishment and modernization to replace and upgrade deteriorated equipment. Equipment to be replaced and modernized include the switchgear, control building, circuit breakers, switches, potential transformers, protective relaying and bus structures. The project was most recently planned for 2022.[4] The project was deferred to allow further engineering assessment of the components in the substation. The assessment has been completed and the project is proposed for 2023.
Transmission Line 55L Rebuild	Transmission Line 55L includes a 31 kilometre section of line that runs from Blaketown Substation to Quartz Substation on the Avalon Peninsula. The wood poles on this section of line are heavily deteriorated and require replacement. The project was most recently planned for 2022.[5] The project was deferred to allow an engineering assessment of the line components and to complete an analysis of the least cost approach to replacement. The assessment and analysis have been completed and the project is proposed for 2023.

3 The five-year capital plan filed with the *2019 Capital Budget Application* included the refurbishment and modernization of Molloy's Lane Substation in 2021.

4 The five-year capital plan filed with the *2018 Capital Budget Application* included the refurbishment and modernization of Walbournes Substation in 2022.

5 The five-year capital plan filed with the *2018 Capital Budget Application* included the rebuild of Transmission Line 55L in 2022.

Table B-1 2023 Capital Expenditures Deferred or Modified from Previous Years	
Project	Description
Application Enhancements	*Application Enhancements* is an annual capital project that seeks to improve Newfoundland Power's operating efficiency through the use of information systems. The project was originally planned for 2023, but the scope was modified to include additional efficiency opportunities identified through the Company's annual review process.
Shared Server Infrastructure	*Shared Server Infrastructure* is an annual capital project to replace existing computing hardware and related technologies based on age and risk of failure. The project was originally planned for 2023, but the scope was modified based on an assessment indicating replacement of the Company's backup infrastructure is necessary to ensure business continuity and recovery abilities are effective.

Table B-2 lists the capital expenditures that were planned for 2023 but have been deferred to subsequent years.

Table B-2 Capital Projects Deferred from 2023 to Subsequent Years	
Project	Description
Transmission Line 108L Rebuild	The rebuilding of Transmission Line 108L was originally planned for 2023. The project has been deferred to allow further assessment of the condition of the line and to complete a system planning study of the radial transmission system supplying Gander Bay and Boyd's Cove substations. The project is now planned for 2026 and 2027.
Memorial Substation Refurbishment and Modernization	Memorial Substation located at Memorial University in St. John's requires refurbishment and modernization to replace deteriorated equipment. The project was originally planned for 2023. The project has been deferred to allow further engineering assessment of the components in the substation and to coordinate with work planned by Memorial University on the equipment it owns in the substation. The project is now planned for 2024.

Table B-2 Capital Projects Deferred from 2023 to Subsequent Years	
Project	**Description**
Broad Cove Substation Refurbishment and Modernization	Broad Cove Substation located in Portugal Cove-St. Phillips requires refurbishment and modernization to replace deteriorated equipment. The project was originally planned for 2023. The project has been deferred to allow further engineering assessment of the components in the substation. The project is now planned for 2025.
Lockston Substation Refurbishment and Modernization	Lockston Substation on the Bonavista Peninsula requires refurbishment and modernization to replace and upgrade deteriorated equipment. The project was originally planned for 2023. The project has been deferred to allow further engineering assessment of the components in the substation. The project is now planned for 2024.
Kenmount Road Building Emergency Diesel and Main Electrical Upgrade	The electrical service and emergency diesel generator at the Kenmount Road Office Building requires upgrading. The project was originally planned for 2023. The project has been deferred to complete further analysis to determine the least cost approach to upgrading the existing systems. The project is now planned for 2024.

Table B-3 lists the capital expenditures that were planned for future years but have been advanced to 2023.

Table B-3 2023 Capital Projects Advanced from Future Years	
Project	**Description**
Long Pond Substation Capacity Expansion	Long Pond Substation in St. John's requires expansion in order to accommodate an increase in capacity to provide power for Memorial University's boiler electrification project. The project was originally planned for 2024. The project has been advanced to 2023 as a result of a request from the university for additional capacity by year-end 2023.

APPENDIX C:

Prioritized List of 2023 Capital Expenditures

Prioritized List of 2023 Capital Expenditures

Introduction

Part IV of Appendix A of the Provisional Guidelines requires that capital budget applications include a prioritized list of proposed projects and programs. The Provisional Guidelines stipulate that the prioritized list should be organized by investment classification as:

- Mandatory;
- Access;
- System Growth; or
- Renewal, Service Enhancement and General Plant.

The Provisional Guidelines direct that investments in the Renewal, Service Enhancement and General Plant classifications be ordered by risk mitigated per dollar spent and reliability improvement per dollar spent, and that previously approved multi-year projects within these investment classifications be at the top of the list without those values.

Newfoundland Power does not currently have the software or data necessary to calculate the risk mitigation or reliability improvement values of capital expenditures. Options to derive such values are among the matters being assessed by the Company as part of its ongoing asset management review.[1]

To comply with the spirit and intent of the Provisional Guidelines, Newfoundland Power conducted a review of Canadian utility practice to assess alternative options to evaluate risks in a manner that could produce a list identifying the relative priority of capital expenditures. The review determined that practices for assessing risks vary among utilities.[2] The review also determined that providing a ranking of the relative priority of capital expenditures as part of regulatory filings is relatively rare among utilities.[3]

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.

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1 Producing quantifiable risk and reliability values to prioritize capital expenditures would require the use of more advanced software. Newfoundland Power commenced an asset management review in 2022. The review is expected to take two years to complete and will include, among other matters, an assessment of options to calculate risk mitigation and reliability improvement values as required by the Provisional Guidelines.

2 The methodologies used by other utilities to assess risk include: (i) determining risk based on engineering judgment; (ii) using weighted formulas that apply risk-related criteria; (iii) risk matrices that assess probability and consequence; and (iv) advanced software, such as the CopperLeaf Portfolio.

3 Of 13 Canadian utilities surveyed, only two utilities indicate they provide prioritized lists of capital expenditures to their regulator. The two utilities identified as providing prioritized lists of capital expenditures to their regulators are Newfoundland and Labrador Hydro and Nova Scotia Power.

The risk matrix methodology and prioritized list of capital expenditures for 2023 are provided below. The Company expects its approach may evolve going forward as its asset management review is completed.

Risk Matrix Methodology

The risk matrix is used to evaluate: (i) the potential consequences of not completing an identified project or program; and (ii) the probability of those consequences occurring if the project or program did not proceed.

Figure C-1 shows the risk matrix.

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

Figure C-1: Risk Matrix

Using the risk matrix, capital projects and programs can receive a score of 1 to 25 based on the assessment of probability and consequence. Values of 1 to 4 are considered Low priority (shaded in green). Values of 5 to 9 are considered Medium priority (shaded in yellow). Values of 10 to 16 are considered Medium-High priority (shaded in orange). Values of 20 or 25 are considered High priority (shaded in red).

The assessment of consequences considered risks to four principal business objectives:

- *Reliability* – Maintain long-term reliable service.
- *Safety* – Protect safety of employees and the public.
- *Environment* – Avoid environmental degradation.
- *Economic* – Advance operational efficiency and effectiveness.

These business objectives are consistent with Newfoundland Power's statutory obligations.[4] 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.

[4] 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, to ensure its operations are not harmful to the environment.

Probability is assessed from the perspective of how likely the identified consequence is to occur if a capital project or program did not proceed.

Probability is based on engineering judgement using a scale of 0% to 100% as follows:

- *Near Certain (5)* – Probable within a range of 91% to 100%.
- *Likely (4)* – Probable within a range of 76% to 90%.
- *Possible (3)* – Probable within a range of 26% to 75%.
- *Unlikely (2)* – Probable within a range of 11% to 25%.
- *Rare (1)* – Probable within a range of 0% to 10%.

For Renewal and General Plant expenditures, the probability value is determined primarily based on asset condition. This includes the level of deterioration identified, obsolescence and other deficiencies. Assessments of probability also consider previous operating experience, including any history of equipment failure, and whether an asset has exceeded its expected useful service life.

For Service Enhancement expenditures, the probability value is determined based on whether the benefit is quantifiable through an economic analysis or can reasonably be expected based on past experience. Potential risks to achieving the benefit are considered in assessing probability, including the results of any associated sensitivity analyses.

Prioritized List of 2023 Capital Expenditures

Table C-2 provides the prioritized list of 2023 capital expenditures 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.[5]

Table C-2
Prioritized List of 2023 Capital Expenditures

Project/Program Name	Priority Score
Previously Approved Multi-Year Projects	
Customer Service System Replacement	-
Replace Vehicles and Aerial Devices 2022-2023	-
Workforce Management System Replacement	-
St. John's Teleprotection System Replacement	-
System Upgrades (Microsoft Enterprise Agreement)	-
Sandy Brook Plant Penstock Replacement	-
Transmission Line 94L Rebuild	-
Mandatory	
PCB Bushing Phase-Out	-
General Expenses Capitalized	-
Allowance for Unforeseen Items	-
Allowance for Funds Used During Construction	-
Access	
Extensions	-
New Transformers	-
New Meters	-
New Services	-
New Street Lighting	-
Corner Brook Acute Care Hospital Redundant Supply	-
Long Pond Substation Capacity Expansion	-
Relocate/Replace Distribution Lines for Third Parties	-

[5] An explanation of the priority score for each capital project and program within the Renewal, Service Enhancement and General Plant investment classifications can be found in the "Risk Assessment" sections of Schedule B to the Application.

Table C-2 Prioritized List of 2023 Capital Expenditures	
Project/Program Name	Priority Score
System Growth	
Feeder Additions for Load Growth	-
Renewal, Service Enhancement, General Plant	
Substation Replacements Due to In-Service Failures	25
Transmission Line Maintenance	25
Reconstruction	25
Thermal Plant Replacements Due to In-Service Failures	25
Hydro Plant Replacements Due to In-Service Failures	25
Molloy's Lane Substation Refurbishment and Modernization	20
Walbournes Substation Refurbishment and Modernization	20
Transmission Line 55L Rebuild	20
LED Street Lighting Replacement	20
Rebuild Distribution Lines	20
Distribution Reliability Initiative	20
Replacement Transformers	20
Replacement Meters	20
Replacement Services	20
Distribution Feeder Automation	20
Mobile Hydro Plant Refurbishment	20
Sandy Brook Hydro Plant Generator Refurbishment	20
Cybersecurity Upgrades	20
Shared Server Infrastructure	20
Substation Spare Transformer Inventory	16
Hydro Facility Rehabilitation	16
Substation Protection and Control Replacements	16
Physical Security Upgrades	16
Tools and Equipment	16
Replace Vehicles and Aerial Devices 2023-2024	16
System Upgrades	16
Personal Computer Infrastructure	16

Table C-2 Prioritized List of 2023 Capital Expenditures	
Project/Program Name	Priority Score
Network Infrastructure	16
Substation Ground Grid Upgrades	15
Replacement Street Lighting	15
Communications Equipment Upgrades	15
Application Enhancements	15
Distribution Feeder SLA-05 Refurbishment	12
Electric Vehicle Charging Network	12
Company Building Renovations	12
Additions to Real Property	12
Distribution Feeder PEP-02 Refurbishment	10

APPENDIX D:

List of Worst Performing Feeders

List of Worst Performing Feeders

The Board's Provisional Guidelines require a list of the 10 worst performing feeders, including relevant outage statistics compared to the utility average for the past 10 years. The Provisional Guidelines require the lists 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.[1]

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.[2] For this reason, Newfoundland Power does not rank the reliability performance of its over 300 distribution feeders including major events.

Newfoundland Power's annual assessment of its worst performing feeders applies five performance measures: (i) customer minutes of interruption; (ii) distribution System Average Interruption Frequency Index ("SAIFI"); (iii) distribution System Average Interruption Duration Index ("SAIDI"); (iv) distribution Customer Hours of Interruption per Kilometre ("CHIKM"); and (v) distribution Customers Interrupted per Kilometre ("CIKM").

For the purposes of compliance with the Provisional Guidelines, Tables D-1 through D-5 on the following pages provide the Company's worst performing feeders based on a 10-year average using the five reliability metrics applied as part of the *Distribution Reliability Initiative.* Tables D-1 through D-5 do not include outages related to major events as the Company has not historically tracked the performance of its distribution feeders according to this data.

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[1] Newfoundland Power's methodology for assessing its worst performing feeders and the results of its assessment can be found in report *1.1 Distribution Reliability Initiative* included with the Application.

[2] 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
(2012-2021)
Sorted by Customer Minutes of Interruption

Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
SUM-01	5,918	721,850	3.30	6.67
DUN-01	5,017	597,716	4.82	9.59
DOY-01	4,847	439,785	2.80	4.24
DLK-03	3,197	433,804	2.31	5.22
SCR-01	2,544	424,773	2.63	7.33
GLV-02	4,906	391,929	3.24	4.32
BOT-01	3,188	384,875	1.87	3.76
BVS-04	4,057	350,077	2.60	3.74
WAV-01	3,539	345,547	2.69	4.39
BLK-01	3,975	342,051	2.37	3.40
Company Average	**1,205**	**92,720**	**1.40**	**1.79**

Table D-2
Unscheduled Distribution-Related Outages
10-Year Average
(2012-2021)
Sorted by Distribution SAIFI

Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
BHD-01	4,668	317,827	4.94	5.61
DUN-01	5,017	597,716	4.82	9.59
TWG-03	1,368	63,650	4.67	3.55
SCT-01	3,319	213,215	4.67	4.96
SCT-02	1,139	103,520	4.47	6.82
TWG-02	3,130	178,705	4.46	4.26
SUM-02	1,700	312,916	3.85	8.60
ABC-02	3,733	252,330	3.67	4.15
TWG-01	2,591	143,049	3.51	3.23
SUM-01	5,918	721,850	3.30	6.67
Company Average	1,205	92,720	1.40	1.79

Table D-3
Unscheduled Distribution-Related Outages
10-Year Average
(2012-2021)
Sorted by Distribution SAIDI

Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
DUN-01	5,017	597,716	4.82	9.59
SUM-02	1,700	312,916	3.85	8.60
SBK-01[3]	3	1,355	1.12	7.53
RVH-02	499	70,136	3.22	7.49
SCR-01	2,544	424,773	2.63	7.33
TRP-01	1,421	258,865	2.75	7.18
SCT-02	1,139	103,520	4.47	6.82
SUM-01	5,918	721,850	3.30	6.67
BHD-01	4,668	317,827	4.94	5.61
LAU-01	1,912	228,840	2.72	5.41
Company Average	**1,205**	**92,720**	**1.40**	**1.79**

[3] Distribution feeder 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.

Table D-4
Unscheduled Distribution-Related Outages
10-Year Average
(2012-2021)
Sorted by Distribution CHIKM

Feeder	Annual Distribution CHIKM
GFS-02	325
KBR-09	253
MOL-04	230
SLA-10	209
KBR-10	200
SJM-06	199
MOL-09	194
SLA-13	193
TWG-02	170
KEN-03	170
Company Average	50

Table D-5 Unscheduled Distribution-Related Outages 10-Year Average (2012-2021) Sorted by Distribution CIKM	
Feeder	Annual Distribution CIKM
KBR-13[4]	196
KBR-10	158
HWD-07	111
SLA-10	109
KBR-12	102
KBR-15[5]	97
PAB-03	97
GOU-01	95
TWG-02	81
WAL-02	78
Company Average	22

4 Kings Bridge ("KBR") Substation distribution feeder KBR-13 was placed into service in 2017. Ten years of historical reliability data is not available for this feeder. The average is calculated on a five-year basis.

5 KBR Substation distribution feeder KBR-15 was placed into service in 2017. Ten years of historical reliability data is not available for this feeder. The average is calculated on a five-year basis.

APPENDIX E:

Previously Approved Multi-Year Projects

Previously Approved Multi-Year Projects

The Board's Provisional Guidelines require that each year of a multi-year capital project be considered in the initial year of application. The Provisional Guidelines stipulate that, where a utility confirms in its capital budget application in subsequent years that the scope, nature and magnitude of the project continues to be consistent with the original approval, further approval of the project is not required.

The 2023 Capital Budget includes seven capital projects that were previously approved by the Board. Capital expenditures for these project total approximately $19,688,000 in 2023 and $4,276,000 in 2024.

The following section provides an update on each multi-year project for 2023 that was previously approved by the Board. Newfoundland Power confirms that all projects are proceeding as approved and there has been no change in the scope, nature or magnitude of these projects that would require further approval of the Board.

Title: **Transmission Line 94L Rebuild**
Asset Class: **Transmission**
Category: **Project**
Investment Classification: **Renewal**
2023 Expenditures: **$4,346,000**

The rebuilding of Transmission Line 94L was included in the *Transmission Line Rebuild* project filed with Newfoundland Power's *2022 Capital Budget Application*.[1]

Transmission Line 94L was constructed in 1969 and serves 2,500 customers supplied via St. Catherine's, Riverhead and Trepassey substations on the Avalon Peninsula. Inspections completed in 2021 determined that this transmission line is heavily deteriorated. Approximately 83% of cribs, 68% of cross braces, and 62% of poles are experiencing deterioration, along with other identified deficiencies.

The Board approved the rebuilding of Transmission Line 94L as a three-year project in Order No. P.U. 36 (2021). The rebuilding of Transmission Line 94L is proceeding as approved. Brush clearing and vegetation management is being completed in the second quarter of 2022 and construction is expected to commence in the third quarter. A 21.5 kilometre section of line will be rebuilt in 2022, with 20 kilometres rebuilt in 2023 and 19.5 kilometres rebuilt in 2024.

Table E-1 provides the approved expenditures for the *Transmission Line Rebuild* project for 94L.

Table E-1
Transmission Line 94L Rebuild Project
Multi-Year Expenditures
($000s)

Cost Category	2022F	2023F	2024F
Material	1,579	1,486	1,482
Labour – Internal	90	86	86
Labour – Contract	2,050	1,970	1,970
Engineering	65	62	62
Other	689	742	676
Total	$4,473	$4,346	$4,276

Expenditures for the *Transmission Line 94L Rebuild* project total approximately $13,095,000, including $4,346,000 in 2023. For expenditures incurred to date, see the *2022 Capital Expenditure Status Report* filed with the Application.

[1] See Newfoundland Power's *2022 Capital Budget Application, report 3.1 2022 Transmission Line Rebuild.*

Title:	**Sandy Brook Plant Penstock Replacement**
Asset Class:	**Generation – Hydro**
Category:	**Project**
Investment Classification:	**Renewal**
2023 Expenditures:	**$4,694,000**

The *Sandy Brook Plant Penstock Replacement* project was included as a multi-year project in Newfoundland Power's *2022 Capital Budget Application.*[2]

The Sandy Brook hydro plant was placed into service in 1963. A condition assessment in 2020 determined the plant's penstock is in poor condition and requires replacement. The entire length of the penstock is experiencing joint leakage between stages and brooming at stave ends. The penstock's saddles and other components are in poor condition.

The Board approved the *Sandy Brook Plant Penstock Replacement* as a two-year project in Order No. P.U. 36 (2021). The replacement of the plant's penstock is proceeding as approved. Engineering design, procurement of the penstock and site preparation work is being completed in 2022. The installation of the replacement penstock will be completed in 2023.

Table E-2 provides the approved expenditures for the *Sandy Brook Plant Penstock Replacement* project.

Table E-2
Sandy Brook Plant Penstock Replacement Project
Multi-Year Expenditures
($000s)

Cost Category	2022F	2023F
Material	290	4,491
Labour – Internal	9	9
Engineering	71	54
Other	30	140
Total	$400	$4,694

Expenditures for the *Sandy Brook Plant Penstock Replacement* project total approximately $5,094,000, including $4,694,000 in 2023. For expenditures incurred to date, see the *2022 Capital Expenditure Status Report* filed with the Application.

[2] See Newfoundland Power's *2022 Capital Budget Application, report 1.2 Sandy Brook Plant Penstock Replacement.*

Title:	**Customer Service System Replacement**
Asset Class:	**Information Systems**
Category:	**Project**
Investment Classification:	**General Plant**
2023 Expenditures:	**$5,917,000**

The *Customer Service System Replacement* project was included as a multi-year project in Newfoundland Power's *2021 Capital Budget Application.*[3]

Newfoundland Power's Customer Service System supports all essential customer service functions, including program and service delivery and account management and billing. The system was implemented in 1993 with an expected service life of 20 years. The system now faces increased technical and functional risks and requires replacement with a modern solution.

The Board approved the *Customer Service System Replacement* project as a three-year project in Order No. P.U. 12 (2021). Replacement of the existing system is proceeding as approved.

The *Customer Service System Replacement* project is designed to be executed in three stages:

(i) *Procurement* of the replacement solution.
(ii) *Implementation* of the replacement solution, including initiation/planning, confirm/design, development, testing, training and deployment.
(iii) *Stabilization* of the replacement solution.[4]

An independent procurement advisor, Gartner Inc. ("Gartner"), was contracted in April 2021. Gartner's role was to provide expertise and best practices in undertaking competitive Request for Proposals ("RFP") processes during the procurement stage of the project.[5]

Gartner assisted Newfoundland Power in conducting two competitive RFP processes in 2021/2022. The first RFP process focused on the procurement of a software solution. The second RFP process focused on the procurement of implementation services.

Three proposals were received from vendors for software solutions. Proposals were evaluated to determine which solutions met the Company's technical and functional requirements. Product demonstrations were then completed, followed by an evaluation of proposed implementation, maintenance and support costs. Based on the evaluation, the Oracle Customer to Meter software was selected as the least-cost solution that met the necessary requirements.

Following the selection of a software vendor, a second RFP process was completed to obtain third-party implementation services. Five proposals were received from vendors for implementation services. The proposals were evaluated against criteria to determine which vendors demonstrated the experience, skills and resources necessary to execute the project,

3 See Newfoundland Power's *2021 Capital Budget Application, Volume 1, Customer Service Continuity Plan.*
4 *Ibid.,* Section 4.0 Project Scope.
5 *Ibid.,* page 14.

followed by an evaluation of proposed costs. Based on the evaluation, Ernst and Young LLP ("EY") was selected as the least-cost solution that met the necessary requirements.

With procurement complete, the project is currently in the implementation stage. The project team has been established and project initiation and planning has been completed. The project is currently in the confirm/design phase of implementation, which will be followed by development and testing. The replacement solution is expected to be implemented in 2023.

Table E-3 provides the approved expenditures for the *Customer Service System Replacement* project.

Table E-3
Customer Service System Replacement Project
Multi-Year Expenditures
($000s)

Cost Category	2021[6]	2022F	2023F
Material	7,186	10,358	3,685
Labour – Internal	1,934	4,132	1,237
Other	783	1,336	995
Total	$9,903	$15,826	$5,917

Expenditures for the *Customer Service System Replacement* project total approximately $31.6 million, including $5,917,000 for 2023. While the project is being executed as approved, the timing of project approval has resulted in expenditures being carried forward with a greater proportion of the project expected to be executed in 2022 and 2023. For expenditures incurred to date, see the *2021 Capital Expenditure Report* filed in February 2022 and the *2022 Capital Expenditure Status Report* filed with the Application.

Newfoundland Power will continue to provide quarterly updates to the Board on project execution as part of its *Quarterly Regulatory Report.*

[6] Includes a carryover of forecast expenditures of $7,093,000. See Newfoundland Power's *2021 Capital Expenditure Report,* page 1 of 14.

Title:	**Workforce Management System Replacement**
Asset Class:	**Information Systems**
Category:	**Project**
Investment Classification:	**General Plant**
2023 Expenditures:	**$1,201,000**

The *Workforce Management System Replacement* project was included as a multi-year project in Newfoundland Power's *2022 Capital Budget Application*.[4]

Newfoundland Power's existing Workforce Management System supports the scheduling, dispatching and monitoring of field crews responding to customer outages and other service requests. The existing system is being discontinued by its vendor. A net present value analysis determined that system replacement is least cost for customers.

The Board approved the *Workforce Management System Replacement* as a two-year project in Order No. P.U. 36 (2021). The project is proceeding as approved by the Board. The procurement of a replacement solution is being completed in 2022 through a competitive Request for Proposals process. The replacement system is expected to be implemented in 2023.

Table E-4 provides the approved expenditures for the *Workforce Management System Replacement* project.

Table E-4
Workforce Management System Replacement Project
Multi-Year Expenditures
($000s)

Cost Category	2022F	2023F
Material	150	250
Labour – Internal	418	266
Other	240	685
Total	$808	$1,201

Expenditures for the *Workforce Management System Replacement* project total approximately $2,009,000, including $1,201,000 in 2023. For expenditures incurred to date, see the *2022 Capital Expenditure Status Report* filed with the Application.

[4] See Newfoundland Power's *2022 Capital Budget Application, report 7.3 Workforce Management System Replacement.*

Title: **System Upgrades (Microsoft Enterprise Agreement)**
Asset Class: **Information Systems**
Category: **Project**
Investment Classification: **General Plant**
2023 Expenditures: **$245,000**

The Microsoft Enterprise Agreement was included as a multi-year *System Upgrades* project in Newfoundland Power's *2021 Capital Budget Application.*[5]

The Microsoft Enterprise Agreement covers the purchase of Microsoft software products and provides access to the latest versions of each product purchased under the agreement.

The Board approved the *System Upgrades* project, including the Microsoft Enterprise Agreement, in Order No. P.U. 37 (2020) as a three-year project. An agreement was established in 2021 and will continue into 2023.

Table E-5 provides approved expenditures for the *Microsoft Enterprise Agreement*.

Table E-5
System Upgrades (Microsoft Enterprise Agreement)
Multi-Year Expenditures
($000s)

Cost Category	2021	2022F	2023F
Material	245	245	245
Total	$245	$245	$245

Expenditures for the *Microsoft Enterprise Agreement* are $245,000 annually from 2021 to 2023. For expenditures incurred to date, see the *2022 Capital Expenditure Status Report* filed with the Application.

5 See Newfoundland Power's *2021 Capital Budget Application, report 6.2 2021 System Upgrades.*

Title:	**St. John's Teleprotection System Replacement**
Asset Class:	**Telecommunications**
Category:	**Project**
Investment Classification:	**General Plant**
Cost:	**$1,150,000**

The *St. John's Teleprotection System Replacement* project was included as a multi-year project in Newfoundland Power's *2022 Capital Budget Application.*[6]

Newfoundland Power's teleprotection system operates to protect the 66 kV transmission network serving substations in the St. John's area. The existing equipment platform for the system has become increasingly unreliable and has reached the end of its useful service life. The critical nature and continued need for the teleprotection functionality requires that the Company replace the existing system.

The Board approved the *St. John's Teleprotection System Replacement* as a two-year project in Order No. P.U. 36 (2021). The project is proceeding as approved. Procurement of the replacement system and associated engineering design work is being completed in 2022. Fibre optic cables builds and system configuration, testing and commissioning will occur in 2023.

Table E-6 provides the approved expenditures for the *St. John's Teleprotection System Replacement* project.

Table E-6
St. John's Teleprotection System Replacement Project
Multi-Year Expenditures
($000s)

Cost Category	2022F	2023F
Material	200	671
Labour – Internal	25	100
Labour – Contract	-	-
Engineering	150	240
Other	75	139
Total	$450	$1,150

Expenditures for the *St. John's Teleprotection System Replacement* project total approximately $1,600,000, including $1,150,000 for 2023. For expenditures incurred to date, see the *2022 Capital Expenditure Status Report* filed with the Application.

[6] See Newfoundland Power's *2022 Capital Budget Application, report 6.1 St. John's Teleprotection System Replacement.*

Title: **Replace Vehicles and Aerial Devices 2022-2023**
Asset Class: **Transportation**
Category: **Project**
Investment Classification: **General Plant**
Cost: **$2,135,000**

The *Replace Vehicles and Aerial Devices 2022-2023* project was included as a multi-year project in Newfoundland Power's *2022 Capital Budget Application.*[7]

The *Replace Vehicles and Aerial Devices 2022-2023* involves the addition and replacement of heavy/medium-duty, light-duty passenger and off-road vehicles. Due to long delivery times associated with the purchase of medium/heavy-duty vehicles, the Company shifted to a multi-year project for these vehicle purchases in 2022.

The Board approved the *Replace Vehicles and Aerial Devices 2022-2023* as a two-year project in Order No. P.U. 36 (2021). The project is proceeding as approved. A total of four light duty, 32 passenger and 14 off-road vehicles are being replaced in 2022. Five heavy/medium duty vehicles are being replaced in 2023.

Table E-7 provides the approved expenditures for the *Replace Vehicles and Aerial Devices 2022-2023* project.

Table E-7
Replace Vehicles and Aerial Devices 2022-2023 Project
Multi-Year Expenditures
($000s)

Cost Category	2022F	2023F
Material	2,979	2,059
Labour – Internal	106	73
Other	4	3
Total	$3,089	$2,135

Expenditures for the *Replace Vehicles and Aerial Devices 2022-2023* project total approximately $5,224,000 with $2,135,000 for 2023. For expenditures incurred to date, see the *2022 Capital Expenditure Status Report* filed with the Application.

[7] See Newfoundland Power's *2022 Capital Budget Application, Schedule B,* pages 70-72.

NEWFOUNDLAND POWER
A FORTIS COMPANY

2023-2027 Capital Plan

June 2022

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1.0 PLAN OVERVIEW

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") prepares a five-year capital plan to provide reasonable predictability of future investment priorities. The capital plan incorporates the best available information on future customer, operational and electrical system requirements. All planned investments undergo detailed engineering reviews prior to being submitted for approval to the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board").

The Company's current capital plan forecasts average annual investments of approximately $130.2 million from 2023 to 2027. This level of investment is expected to be required to continue providing customers with access to safe and reliable service at the lowest possible cost.

Newfoundland Power's operations are focused on maintaining current levels of overall service reliability for customers. While the Company is targeting stability in its reliability performance, the age of its electrical system poses an increasing risk to this objective.

The effect of age on the condition of Newfoundland Power's electrical system can be observed in recent trends with equipment failures. Equipment failures are trending upward on the distribution system, with an increase of approximately 29% over the last decade. This trend is primarily being driven by the failure of overhead conductor that has deteriorated due to its age. The risk of equipment failure is expected to increase as large quantities of assets approach the end of their expected useful service lives, including substation power transformers, distribution and transmission wooden support structures, and transmission overhead conductor.

Newfoundland Power's investment priorities over the next five years reflect an increased focus on the planned refurbishment of assets to extend their useful service lives and the replacement of assets that become deteriorated or fail in service. The refurbishment and replacement of existing assets is forecast to account for an average of approximately $70.5 million of annual capital expenditures from 2023 to 2027, or 54% of total annual expenditures.

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. Approximately 2,000 new customer connections are forecast annually from 2023 to 2027. System load growth is expected to be modest with increases driven by residential development in urban areas, government efforts to electrify provincial buildings, and electric vehicle adoption. Responding to customer and system growth is forecast to account for an average of approximately $29.2 million of annual capital expenditures from 2023 to 2027, or 22% of total annual expenditures.

Investment priorities over the next five years also reflect a continued focus on the management of Company information systems to mitigate increasing cybersecurity risks. Investment in cybersecurity is increasing globally, with third-party vendors requiring more frequent upgrades of computing hardware and software. Investments in general plant are forecast to account for an average of approximately $19.0 million of the Company's annual capital expenditures from 2023 to 2027, over half of which are attributable to investments in information systems.

2.0 PLANNING CONTEXT

2.1 General

Newfoundland Power's investment priorities and five-year capital plan reflect the capital expenditures necessary to meet its statutory obligations under the *Public Utilities Act* and *Electrical Power Control Act, 1994.* The capital plan is updated annually for the latest forecasts of customer and system load growth, anticipated operational requirements and electrical system condition. This section provides an overview of forecast requirements in these areas, which form the basis of the Company's investment priorities over the next five years.

2.2 Customer Outlook

Newfoundland Power has an obligation to provide customers with equitable access to an adequate supply of power.[1] Capital investments are required annually to connect new customers to the electrical system and to respond to increases in electrical system load.

The Company has experienced declining requests for new service connections in recent years due to a decrease in new home construction throughout its service territory. At the same time, system load growth has been concentrated in urban areas.[2] These trends are expected to continue.

Table 1 provides the forecast number of new customer connections from 2023 to 2027.

Table 1
Forecast New Customer Connections
(2023F-2027F)

	2023F	2024F	2025F	2026F	2027F
New Customer Connections	2,185	2,038	1,988	1,860	1,795

New customer connections are forecast to decline from 2,185 in 2023 to 1,795 in 2027. Approximately 39% of new customer connections over the next five years are forecast to occur in the province's largest urban centre, the Northeast Avalon.

System load growth is expected to continue to be driven by residential development in urban areas and government plans to electrify heating systems in provincial buildings. For example, in March 2022, the provincial and federal governments announced a $10.5 million project to replace an oil-fired water boiler at Memorial University with two electrically powered boilers.[3]

1 See Section 3(b)(ii) of the *Electrical Power Control Act, 1994.*

2 For example, of 19 *Feeder Additions for Load Growth* projects completed over the last five years, 17 projects have been on the Avalon Peninsula, including 12 on the Northeast Avalon.

3 See Provincial Government press release, *Provincial and Federal Governments Invest in Electrification Project at Memorial University*, March 25, 2022.

Efforts to electrify provincial buildings and other electrification opportunities are expected to be pursued as part of the Provincial Government's *Renewable Energy Plan.*[4]

System load growth is also expected to be affected by electric vehicle ("EV") adoption over the forecast period. Load growth associated with EVs is expected to increase annually, with the potential for approximately 140,000 EVs on the province's roads by 2034.[5] Newfoundland Power and Newfoundland and Labrador Hydro ("Hydro") have designed an *EV Demand Response Pilot Project* to study options for managing the impact of EVs on peak demand. The pilot project is being reviewed by the Board as part of the *Electrification, Conservation and Demand Management Plan: 2021-2025.*

Over the longer term, increased peak demand due to EV adoption is expected to result in dynamic rate structures becoming cost-effective for customers. A 2019 market potential study completed by Dunsky Energy Consulting determined that dynamic rates may become cost-effective for customers between 2030 and 2034.[6] Implementing dynamic rates will take several years and require investments in Advanced Metering Infrastructure ("AMI").[7] The Company expects to commence a transition to AMI technology in 2027 through the installation of meters that are capable of being read using both existing meter reading technology and AMI technology.

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.[8] Providing customers with reliable service requires capital investments to maintain the condition of the electrical system and the Company's operational response capabilities when outages occur.

Customers have indicated a reasonable level of satisfaction with Newfoundland Power's service delivery over the last decade.[9] The Company's operations are focused on maintaining current levels of overall service reliability for customers. Annual performance targets for service reliability are established based on the Company's performance over the most recent five-year period, excluding significant events.

For 2022, Newfoundland Power is targeting an average frequency of 1.9 outages per customer and an average duration of 2.5 outage hours per customer. Annual performance targets over

[4] See the Provincial Government's *Renewable Energy Plan,* section *1.4 Electrify Transportation and Space-Heating*.

[5] There are forecast to be approximately 41,000 EVs in Newfoundland and Labrador by 2034, with the potential to increase adoption to approximately 140,000 EVs by 2034 following implementation of the *Electrification, Conservation and Demand Management Plan: 2021-2025.*

[6] See *Schedule E – Potential Study Addendum Demand Response Potential Assessment – Further Analysis* filed as part of the *Electrification, Conservation and Demand Management Plan: 2021-2025*.

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

[8] See Section 3(b)(iii) of the *Electrical Power Control Act, 1994.*

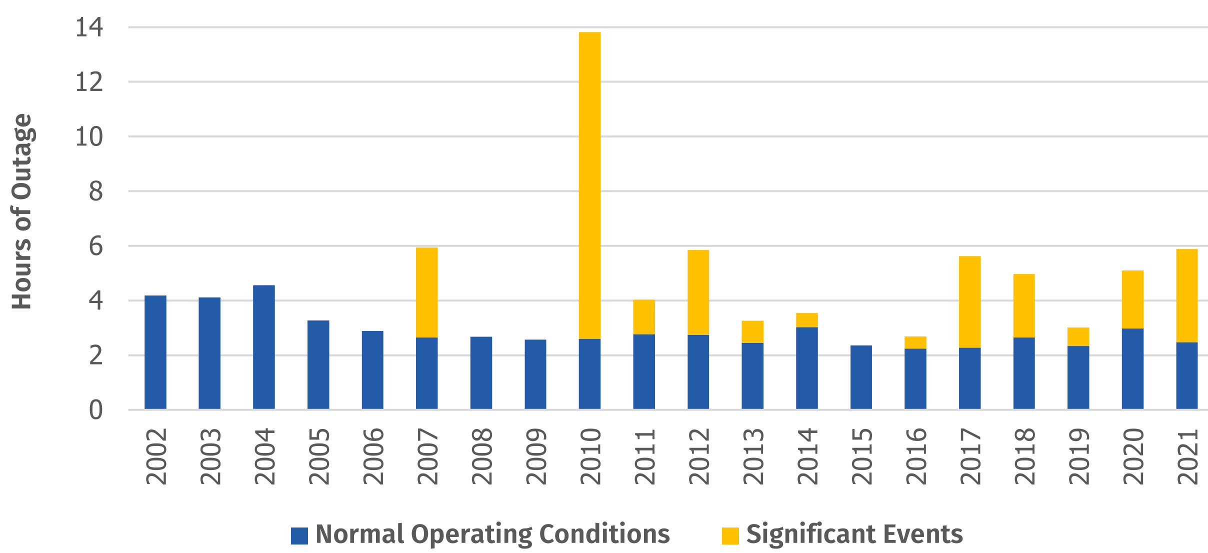
[9] Customer satisfaction with Newfoundland Power's service averaged approximately 86% from 2012 to 2021.

the ensuing five years are expected to be reasonably consistent with current targets, but may vary depending on actual results over this period.

While the Company aims to maintain a consistent level of service reliability for customers, severe weather events can have a significant impact on the service provided to customers. Such events exceed the design parameters of the electrical system and may result in widespread damage and extended customer outages. Recent examples include a severe blizzard in January 2020 and Hurricane Larry in September 2021.[10] Restoring service to customers following such events typically requires a robust operational response as well as capital investments to repair damage to the electrical system.[11]

Figure 1 shows the average duration of outages experienced by Newfoundland Power's customers from 2002 to 2021 including significant events.[12]

Figure 1
Newfoundland Power
Outage Duration Including Significant Events
(2002 to 2021)



Significant customer outages due to severe weather have become more frequent in the Company's service territory, causing customer outages in nine of the last 10 years compared to just three years in the prior decade.

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10 A severe blizzard in January 2020 resulted in over 90 centimeters of snow and wind gusts in excess of 170 kilometres per hour. Hurricane Larry in September 2021 resulted in wind gusts in excess of 180 kilometres per hour.

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 by the Board in Order Nos. P.U. 17 (2010) and P.U. 35 (2010).

12 Significant 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 2002 to 2021, significant events have resulted in an average SAIFI of 0.3, ranging as high as an average SAIFI of 1.2 in 2010.

The amount of capital investment required to restore service to customers following severe weather is highly variable and presents a risk to Newfoundland Power's customers and its forecast expenditures. This risk highlights the importance of ensuring the electrical system is 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]

The future reliability of supply to Newfoundland Power's customers is expected to be impacted by commissioning of the Muskrat Falls Project. Upon commissioning of the project, the Company's largest source of supply will be located off the island, approximately 1,100 kilometres from the province's load centre on the Avalon Peninsula. The reliability of supply from the Muskrat Falls Project is under review by the Board.[14] It is currently uncertain what effect, if any, the results of this review may have on the Company's operations and investment priorities.

Newfoundland Power's operations and capital investments must adapt to increasing cybersecurity risks. Cybersecurity risks have increased materially for critical infrastructure operators in recent years, including electric utilities. Worldwide spending on cybersecurity is forecast to grow over the near term. For example, a 2021 global survey indicated that cybersecurity is a top priority for new spending among corporations, with 61% of surveyed companies reporting increased investment.[15] Newfoundland Power expects that more frequent upgrades of its operations technologies and computing hardware will be required going forward to manage increasing cybersecurity risks.

Market conditions following the COVID-19 pandemic pose a risk to Newfoundland Power's *2023-2027 Capital Plan.* Supply chain disruptions have contributed to reduced availability and extended delivery times for certain materials, including heavy-duty vehicles, conductor and power transformers. Inflationary pressures on materials have also increased following the COVID-19 pandemic. The Company continues to monitor market conditions and assess potential impacts on its operations.

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[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 2 other provinces throughout Canada 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] In correspondence to Hydro dated March 25, 2021, the Board raised concerns regarding the findings of a report by Asim Haldar, PhD, P.Eng, titled *Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatalogical Loads* (the "Haldar Report"). The Board stated: *"The Haldar Report raises troubling concerns regarding the as-built design of the LIL with potential significant negative implications for the LIL's reliability."*

[15] See Gartner Inc., *Gartner Forecasts Worldwide Security and Risk Management Spending to Exceed $150 Billion in 2021*, May 17, 2021.

2.4 Asset Condition Outlook

2.4.1 General

Newfoundland Power's electrical system is maintained through a combination of preventative and corrective maintenance programs and long-term asset management strategies. The most recent independent review of Newfoundland Power's engineered operations was conducted by The Liberty Consulting Group in 2014. The review found that the Company's asset management conforms to good utility practice.[16]

A significant portion of Newfoundland Power's electrical system assets were constructed in the 1960s and 1970s following provincial electrification efforts in rural areas.[17] As a result, a high quantity of assets with expected useful service lives of between 50 and 60 years, such as conductor and wooden support structures, are now aging beyond their expected useful service lives. While age is not the primary determinant as to whether an asset requires refurbishment or replacement, it provides a reasonable indication of the probability that an asset may begin to fail.

The effect of age on the condition of Newfoundland Power's electrical system can be observed through its recent experience with equipment failures. An average of approximately 1,155 equipment failures per year were experienced on the distribution system from 2017 to 2021, which represents a 29% increase compared to the previous five-year period.[18] The upward trend in equipment failures is primarily being driven by overhead conductor that has become deteriorated due to its age.[19]

Newfoundland Power is exposed to increasing risk of equipment failure going forward due to the age of its electrical system. As detailed below, significant portions of major equipment in the distribution, transmission and substations asset classes have exceeded or are approaching the end of their useful service lives.

Maintaining the safe and reliable operation of the electrical system will require increased investments in the planned refurbishment and replacement of electrical system assets. The Company is currently undertaking an asset management review to ensure its practices continue to be adequate in light of the age and condition of its electrical system. This review is expected to take two years to complete.

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[16] See The Liberty Consulting Group, *Executive Summary of Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power Inc.*, December 17, 2014, page ES-1.

[17] In 1958, Newfoundland Power (then Newfoundland Light and Power), signed a rural electrification agreement with the Provincial Government to provide electricity in areas where it was not economical for the Company to build its own transmission lines. As part of this agreement, assets owned by the Newfoundland and Labrador Power Commission, which eventually became Hydro, were divested to the Company. Other entities, including municipal corporations, also divested assets to Newfoundland Power over this period.

[18] Includes failures of cutouts, primary conductor, insulators, poles, distribution transformers and other equipment. Does not include service wire failures, which are replaced upon failure and not inspected as part of Newfoundland Power's *Distribution Inspection and Maintenance Practices.*

[19] On average, 188 conductor failures occurred annually from 2012 to 2016. This compares to an average of approximately 327 conductor failures annually from 2017 to 2021.

2.4.2 Distribution

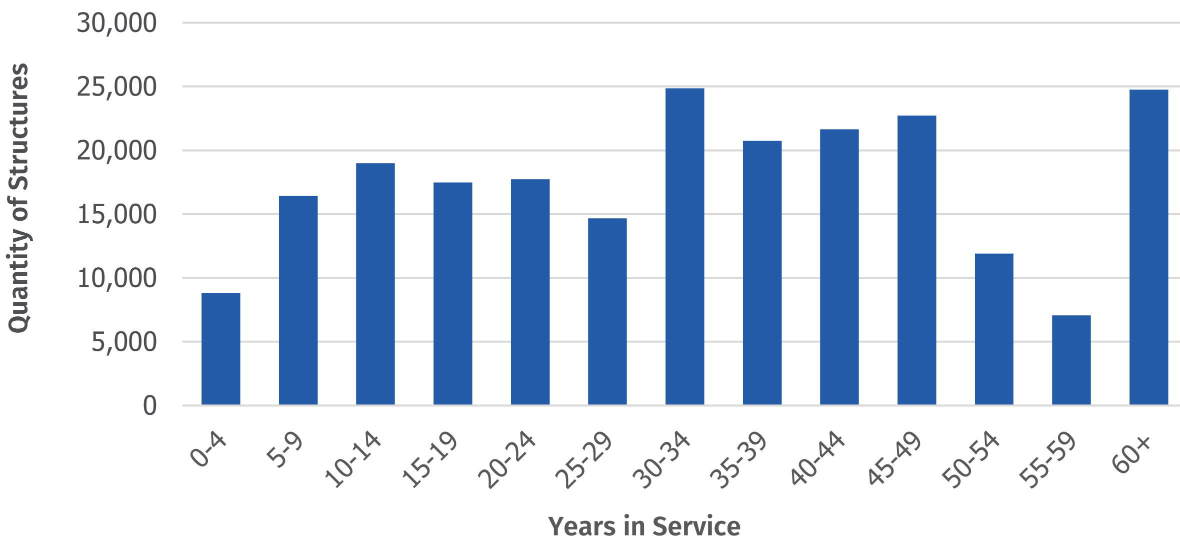
Newfoundland Power operates approximately 300 distribution feeders. Distribution feeders are inspected on a seven-year cycle to identify deficiencies. High-priority deficiencies are corrected during the year in which they are identified through the *Reconstruction* program. Other deficiencies are corrected in a planned manner through the *Rebuild Distribution Lines* program and individual refurbishment projects for feeders where deterioration is most pronounced. The distribution system is also maintained through the longstanding *Distribution Reliability Initiative*, which targets the worst performing feeders for capital investment.

Newfoundland Power's distribution system includes approximately 228,000 wooden support structures and over 10,000 kilometres of overhead conductor. Industry experience indicates an average expected useful service life of 54 years for distribution wooden support structures and 50 years for distribution overhead conductor.[20]

The risk of equipment failure on the Company's distribution system is currently high as large quantities of wooden support structures and overhead conductor have exceeded their expected useful service lives.

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

Figure 2
Distribution Wooden Support Structures
Asset Age

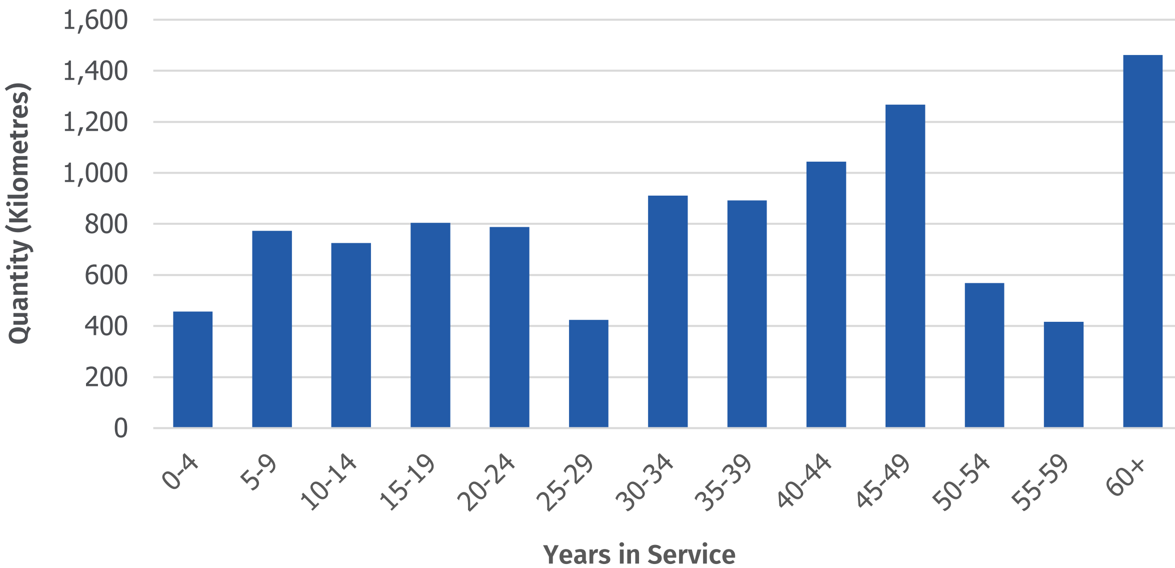


[20] The average industry expected useful service lives of distribution assets were derived from information published by the Federal Energy Regulatory Commission ("FERC"). Electric utilities subject to FERC's jurisdiction are required to file a Form 1 report annually. Form 1 reports are publicly available and provide financial and operational information for electric utilities. A total of 38 utilities were included in the analysis.

Approximately 15% of distribution wooden support structures have exceeded the average industry expected useful service life of 54 years. An additional 16% of distribution wooden support structures will reach 54 years in service over the next decade.

Figure 3 provides the age of overhead conductor on the Company's distribution system.

Figure 3
Distribution Overhead Conductor
Asset Age



Approximately 23% of distribution overhead conductor has currently exceeded the average industry expected useful service life of 50 years. An additional 22% of distribution overhead conductor will reach 50 years in service within the next decade.

2.4.3 Transmission

Transmission lines are the backbone of the electricity system serving customers. Transmission lines are inspected annually to identify deficiencies. Deficiencies are prioritized for correction based on severity through the annual *Transmission Line Maintenance* program. The condition of the transmission system is also maintained through planned rebuild projects completed in accordance with the *Transmission Line Rebuild Strategy*, which targets the Company's oldest and most deteriorated transmission lines.

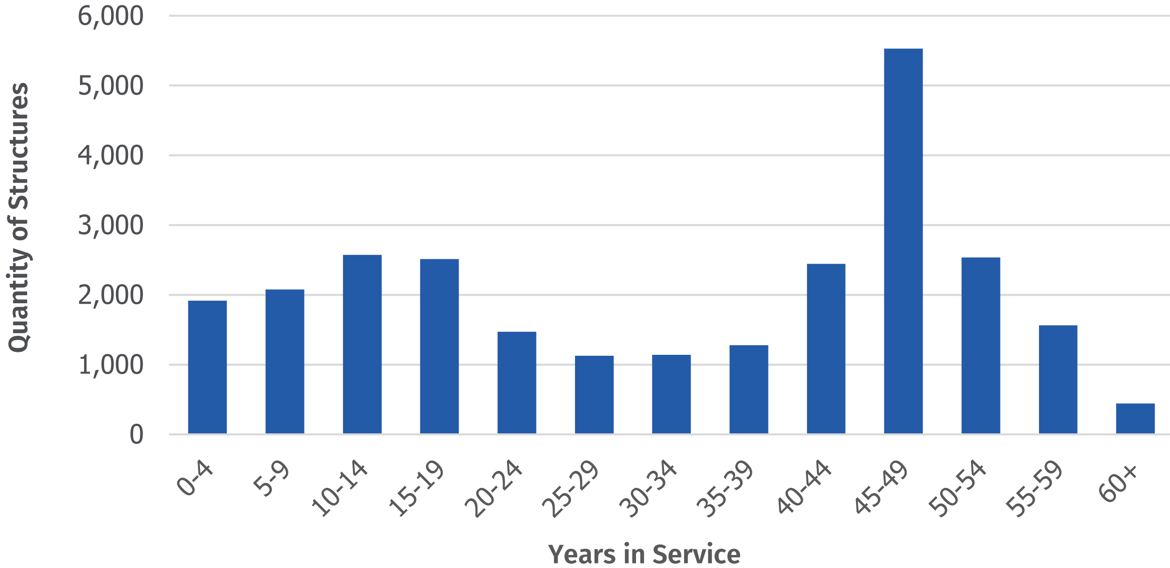
Newfoundland Power's transmission system includes approximately 27,000 wooden support structures and approximately 2,000 kilometres of overhead conductor. Industry experience indicates an average expected useful service life of 58 years for transmission wooden support structures and 63 years for transmission overhead conductor.[21]

[21] The average industry expected useful service lives of transmission assets were derived from information published by FERC. A total of 38 utilities were included in the analysis.

The Company's operations are exposed to an increasing risk of equipment failure on the transmission system going forward due to the age of wooden support structures and overhead conductor.

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

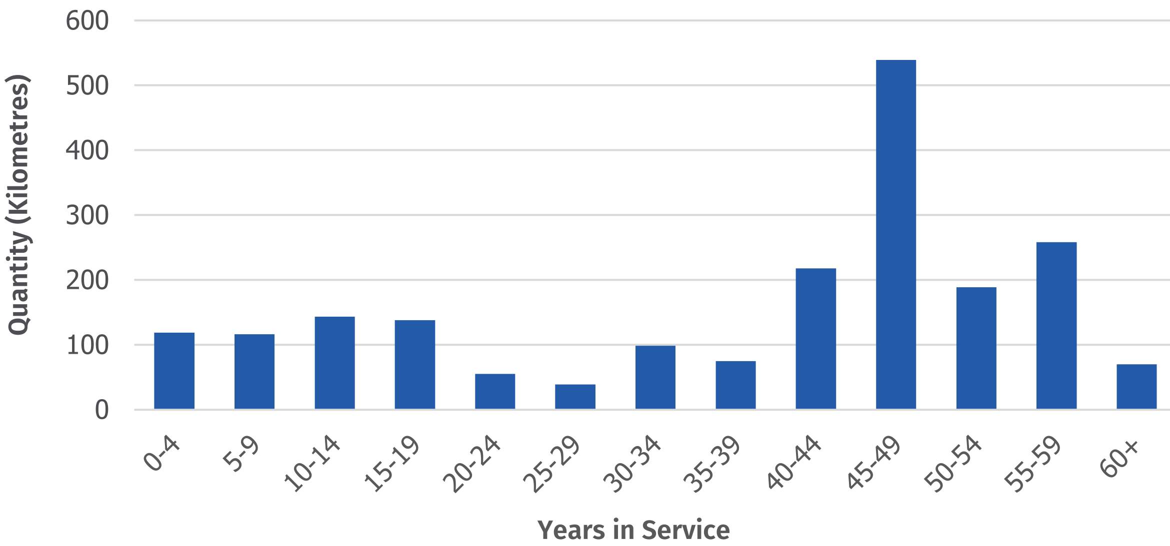
Figure 4
Transmission Wooden Support Structures
Asset Age



Approximately 2% of transmission wooden support structures have exceeded the average industry expected useful service life of 58 years. An additional 18% of transmission wooden support structures will reach 58 years in service over the next decade.

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

Figure 5
Transmission Overhead Conductor
Asset Age



Approximately 3% of transmission overhead conductor has currently exceeded the average industry expected useful service life of 63 years. An additional 17% 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 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 most critical equipment in substations are power transformers. There are currently 192 power transformers in operation at Newfoundland Power's substations. Industry experience suggests the service life of a power transformer is typically between 30 and 50 years under ideal conditions.[22] Based on the current age profile, the Company's power transformers are exposed to a high risk of equipment failure.

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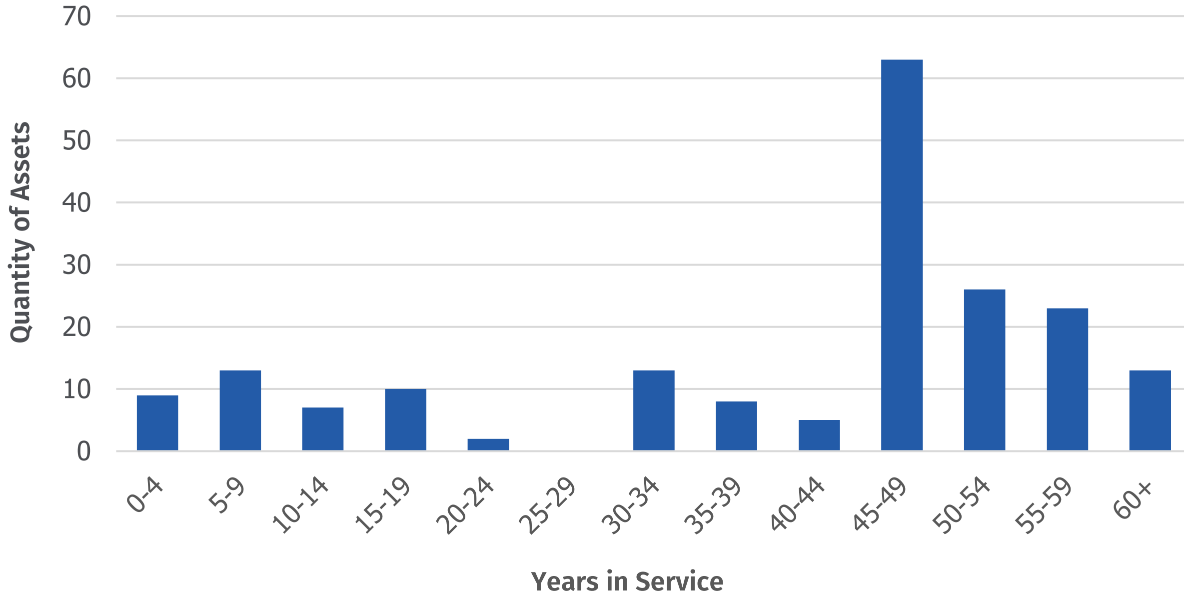
22 Practical conditions, such as ambient temperature, high loading and fault exposure, can reduce the expected service life of power transformers. High temperatures have an adverse effect on the insulating properties inside the transformer and cause the premature aging of power transformers. Insulation deterioration on the windings naturally occurs over time and is accelerated by exposure to high temperatures. Insulation that is found to be degraded is a major indicator that a power transformer has reached end of life. See International Council on Large Electric Systems ("CIGRE"), *Asset Management Decision Making Using Different Risk Assessment Methodologies*, 2013, page 94.

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

Figure 6
Substation Power Transformers
Asset Age



Approximately 32% of substation power transformers have exceeded the industry expected useful service life of 50 years. An additional 35% of substation power transformers will reach 50 years in service over the next decade.

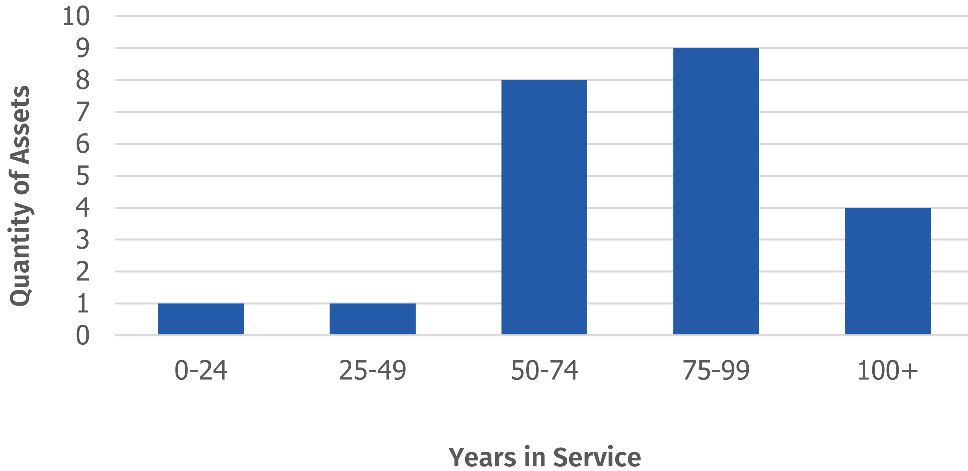
2.4.5 Generation

Newfoundland Power operates 23 hydro plants that collectively generate 438 GWh annually at a capacity of 98 MW. These plants provide low-cost electricity to customers. The Company also operates six thermal plants that supply customers experiencing localized outages and provide system support when requested by Hydro.

Generating plants are routinely inspected by plant operators to identify deficiencies. Equipment that fails or is at imminent risk of failure is addressed under the *Hydro Plant Replacements Due to In-Service Failures* program, *Thermal Plant Replacements Due to In-Service Failures* program and *Hydro Facility Rehabilitation* project. Major plant refurbishment projects, such as penstock replacements, are accompanied by economic analyses to confirm that continued operation of a plant is least-cost for customers.

Figure 7 provides the quantity of hydro plants in operation by age as of 2021.

Figure 7
Hydro Plants
Asset Age



Of Newfoundland Power's 23 hydro plants, 17 have been in service for between 50 and 100 years and four have been in service for over 100 years. Many of these plants have undergone refurbishment projects to extend their useful service lives, including generator refurbishments and penstock replacements. Based on the current age profile, refurbishment projects are expected to continue to be required to extend the useful service lives of these hydro plants when proven economic for customers.

Newfoundland Power's Greenhill and Wesleyville gas turbines have been in service for 46 years and 52 years, respectively. Inspections have identified that both gas turbines require refurbishment. A system planning study is being conducted to inform the long-term plan for these gas turbines.

3.0 SUMMARY OF PLANNED EXPENDITURES

3.1 General

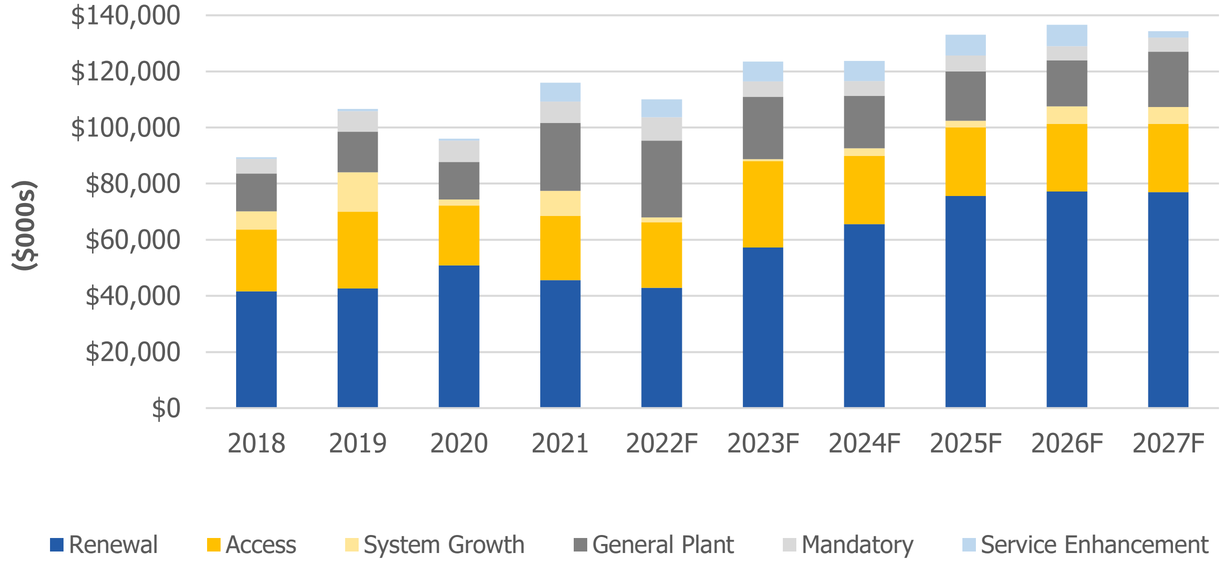
Newfoundland Power's *2023-2027 Capital Plan* forecasts annual capital expenditures of approximately $130.2 million from 2023 to 2027. This section provides a breakdown of forecast capital expenditures by investment classification and asset class.[23]

[23] 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 2018 to 2027 by investment classification.

Figure 8
Capital Expenditures by Investment Classification
(2018-2027F)



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. Renewal investments are forecast to account for approximately 54% of capital expenditures from 2023 to 2027, compared to approximately 43% over the previous five-year period.

Increases in Renewal investments reflect the age and condition of Newfoundland Power's electrical system. Renewal investments in the distribution asset class include the continuation of longstanding corrective and preventative maintenance programs, as well as an increase in distribution feeder refurbishment projects. Renewal investments in the substations and transmission asset classes reflect increases in the amount of work to be completed under the *Transmission Line Rebuild Strategy* and *Substation Refurbishment and Modernization Plan* over the forecast period. Renewal investments in the generation asset class reflect both an increase in refurbishment projects for hydro plants and the planned replacement of the Wesleyville and Greenhill gas turbines with a new mobile unit.

Expenditures in other investment classifications are expected to be reasonably stable over the forecast period.

Access and System Growth investments are forecast to account for approximately 22% of annual capital expenditures over the forecast period. This reflects the Company's relatively low growth outlook. Investments include approximately $3.3 million in 2023 for upgrades at Long Pond Substation resulting from an electrification initiative at Memorial University. Approximately $2.5 million of investments in 2027 relate to an upgrade at Kelligrews Substation to respond to load growth on the Northeast Avalon. Investments are also driven by EV adoption, with planned expenditures of approximately $4.1 million by 2027.

General Plant investments are forecast to account for approximately 15% of annual capital expenditures over the next five years. General Plant investments are expected to continue to be driven by expenditures in the information systems asset class. Information systems account for over 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 5% of annual capital expenditures over the next five years. Service Enhancement investments reflect continued automation of the distribution system and conclusion of the *LED Street Lighting Replacement Plan* in 2026.

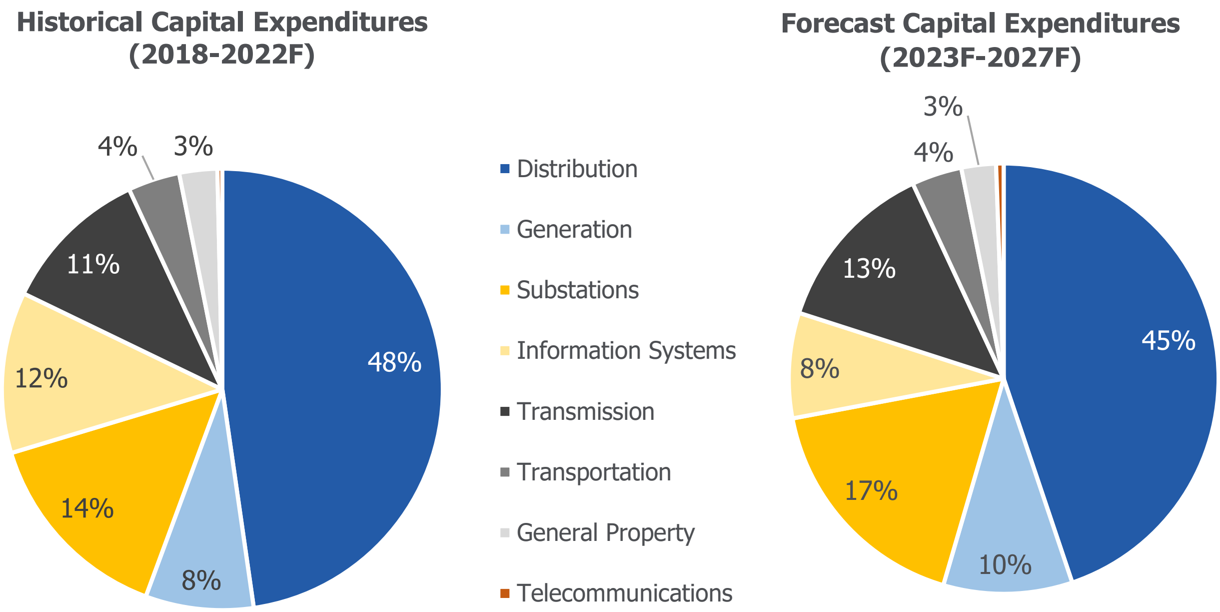
Mandatory investments are forecast to account for approximately 4% of annual capital expenditures over the next five years. Mandatory investments reflect conclusion of the *PCB Bushing Phase-Out* project in 2025. Expenditures after 2025 reflect capital expenditures resulting from Board orders, including *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.[24]

Figure 9
Capital Expenditures by Asset Class



The distribution asset class is forecast to continue to account for the largest proportion of capital expenditures from 2023 to 2027. Approximately 45% of forecast capital expenditures over the next five years relate to distribution assets. This includes expenditures to connect new customers to the electrical system and to replace or refurbish existing assets that have become deteriorated, deficient or fail in service.

The substations, transmission and generation asset classes are expected to account for a larger portion of capital expenditures over the forecast period in comparison to the last five years. This is primarily driven by major refurbishment and replacement projects within those asset classes, as described below.

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24 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 2018 to 2027.

Table 2
Distribution
Capital Expenditures
($000s)

Actual/Forecast					Average
2018	2019	2020	2021	2022F	2018-2022F
42,333	46,801	44,391	50,766	48,130	46,484

Plan					Average
2023F	2024F	2025F	2026F	2027F	2023F-2027F
54,265	56,104	56,689	57,406	56,829	56,259

Distribution capital expenditures are forecast to average approximately $56.3 million annually from 2023 to 2027. This compares to an average of approximately $46.5 million annually over the previous five-year period.

Increased distribution expenditures include the *LED Street Lighting Replacement Plan*, which commenced in 2021 and accounts for an average of approximately $5.5 million in annual capital expenditures from 2023 to 2026.[25]

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 $12.2 million annually. Refurbishment projects for individual distribution feeders are expected to increase over the forecast period, with annual expenditures increasing from approximately $1.1 million in 2023 to approximately $5.3 million in 2027.

Expenditures related to the *Distribution Reliability Initiative* are forecast to average approximately $1.9 million annually as the Company continues to target the worst performing feeders in its distribution system.[26]

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25 See Newfoundland Power's *2021 Capital Budget Application, Volume 1, LED Street Lighting Replacement Plan.*

26 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*. See the *2023 Capital Budget Application, report 1.1 Distribution Reliability Initiative.*

3.3.3 Substations

Table 3 provides historical and forecast substations capital expenditures from 2018 to 2027.

Table 3
Substations
Capital Expenditures
($000s)

Actual/Forecast					Average
2018	2019	2020	2021	2022F	2018-2022F
12,662	17,133	14,720	15,459	11,639	14,323
Plan					**Average**
2023F	2024F	2025F	2026F	202F7	2023F-2027F
20,672	20,824	21,832	21,387	25,128	21,969

Substations expenditures are forecast to average approximately $22.0 million annually from 2023 to 2027. This compares to an average of approximately $14.3 million annually over the previous five-year period.

Increased substations expenditures are driven by the Company's *Substation Refurbishment and Modernization Plan*. Forecast expenditures over the next five years reflect the refurbishment and modernization of 24 substations, including the Molloy's Lane and Walbournes substations in 2023. 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 $14.2 million from 2023 to 2027.

Forecast substation expenditures also include approximately $4.6 million annually to address equipment failures in substations, as well as other expenditures to upgrade or replace deficient equipment and respond to system load growth.

3.3.4 Transmission

Table 4 provides historical and forecast transmission capital expenditures from 2018 to 2027.

Table 4
Transmission
Capital Expenditures
($000s)

Actual/Forecast					Average
2018	2019	2020	2021	2022F	2018-2022F
7,806	11,940	10,069	10,395	12,892	10,620

Plan					Average
2023F	2024F	2025F	2026F	2027F	2023F-2027F
12,284	16,920	15,995	18,925	18,100	16,445

Transmission capital expenditures are forecast to average approximately $16.4 million annually from 2023 to 2027. This compares to an average of approximately $10.6 million annually over the previous five-year period.

Increased transmission expenditures are driven by an increase in the kilometres of transmission line to be rebuilt annually as part of the *Transmission Line Rebuild Strategy.*[27] As of 2022, execution of this strategy is 79% complete. Forecast expenditures from 2023 to 2027 include projects to rebuild seven transmission lines throughout the Company's service territory. The average annual cost of transmission line rebuild projects is approximately $12.9 million from 2023 to 2027.

Forecast transmission expenditures also include capital maintenance of transmission line structures at an annual average cost of approximately $2.7 million.

[27] The lines remaining to be completed in the 2022 to 2026 period include three lengthy 138 kV H-frame construction transmission lines. The extended line length for these rebuilds, and the 138 kV H-frame construction, are the primary drivers for the increase in transmission expenditures.

3.3.5 Generation

Table 5 provides historical and forecast generation capital expenditures from 2018 to 2027.

Table 5
Generation
Capital Expenditures
($000s)

Actual/Forecast					Average
2018	2019	2020	2021	2022F	2018-2022F
9,057	10,086	6,824	9,857	2,769	7,719

Plan					Average
2023F	2024F	2025F	2026F	2027F	2023F-2027F
9,811	7,026	16,623	17,640	9,780	12,176

Generation capital expenditures are forecast to average approximately $12.2 million annually from 2023 to 2027. This compares to an average of approximately $7.7 million annually over the previous five-year period.

Increased generation expenditures reflect a forecast requirement to undertake refurbishment projects at 10 hydro plants over the next five years. The average annual cost of hydro plant refurbishment projects is approximately $6.7 million from 2023 to 2027.

Increased generation expenditures also include the planned purchase of a second mobile gas turbine that will replace the existing Greenhill and Wesleyville gas turbines. The cost of purchasing a second mobile gas turbine is approximately $7.5 million in 2025 and $9.9 million in 2026.

3.3.6 Information Systems

Table 6 provides historical and forecast information systems capital expenditures from 2018 to 2027.

Table 6
Information Systems
Capital Expenditures
($000s)

Actual/Forecast					Average
2018	2019	2020	2021	2022F	2018-2022F
6,620	7,034	7,347	15,460	21,044	11,501

Plan					Average
2023F	2024F	2025F	2026F	2027F	2023F-2027F
12,940	7,122	9,276	8,332	11,955	9,925

Information systems capital expenditures are forecast to average approximately $9.9 million annually from 2023 to 2027. This compares to an average of approximately $11.5 million annually over the previous five-year period.

Information systems expenditures include the conclusion of the *Customer Service System Replacement* project in 2023. Expenditures beyond 2023 are expected to be driven by more frequent software and hardware upgrades required to manage cybersecurity risks and to meet vendor requirements. Forecast expenditures include upgrades to the Company's Geographic Information System and Outage Management System, among others.

3.3.7 Transportation

Table 7 provides historical and forecast transportation capital expenditures from 2018 to 2027.

Table 7
Transportation
Capital Expenditures
($000s)

Actual/Forecast					Average
2018	2019	2020	2021	2022F	2018-2022F
3,594	4,223	3,515	4,098	3,089	3,704
Plan					**Average**
2023F	2024F	2025F	2026F	2027F	2023F-2027F
4,968	4,935	4,211	4,647	4,971	4,746

Transportation capital expenditures are forecast to average approximately $4.7 million annually from 2023 to 2027. This compares to an average of approximately $3.7 million annually over the previous five-year period.

The increase in transportation capital expenditures from 2023 through 2027 primarily reflects inflation and the number of heavy-duty fleet and passenger vehicles forecast to be replaced over the period. In 2022, the Company moved to a multi-year approach to vehicle replacement as a result of long delivery times associated with the purchase of heavy-duty fleet vehicles experienced in recent years.[28]

28 Expenditures for 2022 do not include the purchase of any medium/heavy-duty fleet vehicles.

3.3.8 General Property

Table 8 provides historical and forecast general property capital expenditures from 2018 to 2027.

Table 8
General Property
Capital Expenditures
($000s)

Actual/Forecast					Average
2018	2019	2020	2021	2022F	2018-2022F
2,923	2,862	2,459	2,671	2,660	2,715

Plan					Average
2023F	2024F	2025F	2026F	2027F	2023F-2027F
2,505	4,596	3,308	3,189	2,712	3,262

General property capital expenditures are forecast to average approximately $3.3 million annually from 2023 to 2027. This compares to an average of approximately $2.7 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. The increase in expenditures over the 2023 to 2027 period is attributable to refurbishments required at the Company's head office in St. John's and area offices in Gander and Grand Falls-Windsor.

3.3.9 Telecommunications

Table 9 provides historical and forecast telecommunications capital expenditures from 2018 to 2027.

Table 9
Telecommunications
Capital Expenditures
($000s)

Actual/Forecast					Average
2018	2019	2020	2021	2022F	2018-2022F
325	312	112	424	564	347

Plan					Average
2023F	2024F	2025F	2026F	2027F	2023F-2027F
1,268	1,476	386	297	130	711

Telecommunications capital expenditures are forecast to average approximately $0.7 million annually from 2023 to 2027. This compares to an average of approximately $0.3 million annually over the previous five-year period.

The increase in telecommunications capital expenditures over the planning period is primarily driven by: (i) the conclusion of the *St. John's Teleprotection System Replacement* project in 2023 at a cost of approximately $1.2 million;[29] and (ii) the replacement of the Company's Very High Frequency ("VHF") mobile radio system in 2024 at a cost of approximately $1.0 million.[30]

[29] The multi-year *St. John's Teleprotection System Replacement* project was approved by the Board in Order No. P.U. 36 (2021).

[30] Newfoundland Power's VHF mobile radio communications use a system provided by Bell Mobility. Other users of this system include Hydro and some departments of the Provincial Government. The Provincial Government has started a process to transition away from the current VHF radio system to a new province-wide public safety radio system. Newfoundland Power is investigating options to provide its field staff with mobile radio communications in the event the current Bell Mobility VHF technology is retired.

APPENDIX A:

Capital Projects and Programs: 2023-2027

Table A-1
2023-2027 Capital Plan
By Asset Class
($000s)

Asset Class	2023F	2024F	2025F	2026F	2027F
Distribution	54,265	56,104	56,689	57,406	56,829
Substations	20,672	20,824	21,832	21,387	25,128
Transmission	12,284	16,920	15,995	18,925	18,100
Generation	9,811	7,026	16,623	17,640	9,780
Information Systems	12,940	7,122	9,276	8,332	11,955
Transportation	4,968	4,935	4,211	4,647	4,971
General Property	2,505	4,596	3,308	3,189	2,712
Telecommunications	1,268	1,476	386	297	130
Allowance for Unforeseen Items	750	750	750	750	750
General Expenses Capitalized	4,000	4,000	4,000	4,000	4,000
Total	$123,463	$123,753	$133,070	$136,573	$134,355

Table A-2 2023-2027 Capital Plan Distribution ($000s)					
	2023F	2024F	2025F	2026F	2027F
Project					
Feeder Additions for Load Growth	670	2,456	2,132	2,243	3,493
Distribution Reliability Initiative	656	2,015	2,000	2,250	2,500
Distribution Feeder Automation	1,054	1,085	1,098	1,101	1,111
Electric Vehicle Charging Network	594	610	425	0	0
LED Street Lighting Replacement	5,453	5,478	5,503	5,529	0
Corner Brook Acute Care Hospital – Redundant Supply	2,690	0	0	0	0
Distribution Feeder PEP-02 Refurbishment	550	0	0	0	0
Distribution Feeder SLA-05 Refurbishment	565	0	0	0	0
Distribution Feeder Refurbishments	0	2,606	3,165	3,718	5,288
Allowance for Funds Used During Construction	247	251	254	258	262
Program					
Extensions	12,218	11,643	11,611	11,103	10,962
Reconstruction	6,699	6,850	7,010	7,172	7,343
Rebuild Distribution Lines	4,945	5,060	5,181	5,303	5,432
New Services	2,916	2,785	2,783	2,667	2,639
Replacement Services	546	559	572	586	601
New Meters	297	282	281	268	539
Replacement Meters	662	666	644	904	2,058
New Transformers	2,967	3,013	3,063	3,113	3,169
Replacement Transformers	3,345	3,397	3,454	3,510	3,573
New Street Lighting	2,618	2,674	2,734	2,794	2,858
Replacement Street Lighting	770	787	804	822	841
Relocate/Replace Distribution Lines for Third Parties	3,803	3,887	3,975	4,065	4,160
Total	$54,265	$56,104	$56,689	$57,406	$56,829

Table A-3
2023-2027 Capital Plan
Substations
($000s)

	2023F	2024F	2025F	2026F	2027F
Project					
Substation Spare Transformer Inventory	1,500	0	0	0	0
PCB Bushing Phase-Out	425	200	631	0	0
Substation Ground Grid Upgrades	563	676	811	973	1,167
Molloy's Lane Substation Refurbishment & Modernization	4,827	0	0	0	0
Walbournes Substation Refurbishment & Modernization	4,955	0	0	0	0
Substation Refurbishment & Modernization	0	14,742	14,969	15,107	16,342
Long Pond Substation Capacity Expansion	3,313	0	0	0	0
Substation Feeder Termination	0	290	250	0	0
Additions Due to Load Growth	0	0	0	0	2,500
Substation Protection and Control Replacements	667	405	565	605	315
Program					
Substation Replacements Due to In-Service Failures	4,422	4,511	4,606	4,702	4,804
Total	$20,672	$20,824	$21,832	$21,387	$25,128

Table A-4 2023-2027 Capital Plan Transmission ($000s)					
	2023F	2024F	2025F	2026F	2027F
Project					
Transmission Line 94L Rebuild[31]	4,346	4,276	0	0	0
Transmission Line 55L Rebuild	5,328	5,284	0	0	0
Transmission Line Rebuild	0	4,702	13,286	12,164	15,283
Transmission Line Additions	0	0	0	4,000	0
Program					
Transmission Line Maintenance	2,610	2,658	2,709	2,761	2,817
Total	$12,284	$16,920	$15,995	$18,925	$18,100

31 Multi-year capital project approved in Order No. P.U. 36 (2021).

Table A-5
2023-2027 Capital Plan
Generation
($000s)

	2023F	2024F	2025F	2026F	2027F
Project					
Hydro Facility Rehabilitation	877	1,021	1,172	870	896
Sandy Brook Plant Penstock Replacement[32]	4,694	0	0	0	0
Sandy Brook Hydro Plant Generator Refurbishment	1,577	0	0	0	0
Mobile Hydro Plant Refurbishment	1,666	4,253	0	0	0
Cape Broyle Hydro Plant Refurbishment	0	0	660	2,925	0
Lawn Hydro Plant Refurbishment	0	0	0	0	2,632
Lookout Brook Hydro Plant Refurbishment	0	307	923	2,383	0
Morris Hydro Plant Refurbishment	0	0	0	513	750
Pitman's Pond Hydro Plant Refurbishment	0	0	0	0	3,087
Rose Blanche Hydro Plant Refurbishment	0	0	0	0	800
Tors Cove Hydro Plant Refurbishment	0	428	5,360	0	0
West Brook Hydro Plant Refurbishment	0	0	0	0	532
Gas Turbine Replacement	0	0	7,470	9,890	0
Program					
Hydro Plant Replacements Due to In-Service Failures	662	676	690	704	720
Thermal Plant Replacements Due to In-Service Failures	335	341	348	355	363
Total	$9,811	$7,026	$16,623	$17,640	$9,780

32 Multi-year capital project approved in Order No. P.U. 36 (2021).

Table A-6
2023-2027 Capital Plan
Information Systems
($000s)

	2023F	2024F	2025F	2026F	2027F
Project					
Customer Service System Replacement[33]	5,917	0	0	0	0
Workforce Management System Replacement[34]	1,201	0	0	0	0
System Upgrades[35]	1,207	2,056	3,960	2,741	5,109
Application Enhancements	1,538	2,360	960	867	990
Cybersecurity Upgrades	882	900	920	940	960
Network Infrastructure	419	400	475	500	525
Shared Server Infrastructure	1,176	796	846	1,496	1,746
Operations Technology	0	0	1,500	1,168	2,000
Program					
Personal Computer Infrastructure	600	610	615	620	625
Total	$12,940	$7,122	$9,276	$8,332	$11,955

33 Multi-year capital project approved in Order No. P.U. 12 (2021).
34 Multi-year capital project approved in Order No. P.U. 36 (2021).
35 Multi-year project for Microsoft Enterprise Agreement approved in Order No. P.U. 37 (2020).

Table A-7 2023-2027 Capital Plan Transportation ($000s)					
	2023F	2024F	2025F	2026F	2027F
Project					
Replace Vehicles and Aerial Devices 2022 - 2023[36]	2,135				
Replace Vehicles and Aerial Devices 2023 - 2024	2,833	1,866			
Replace Vehicles and Aerial Devices 2024 - 2025		3,069	1,898		
Replace Vehicles and Aerial Devices 2025 - 2026			2,313	2,371	
Replace Vehicles and Aerial Devices 2026 - 2027				2,276	1,880
Replace Vehicles and Aerial Devices 2027 - 2028					3,091
Total	$4,968	$4,935	$4,211	$4,647	$4,971

36 Multi-year capital project approved in Order No. P.U. 36 (2021).

Table A-8
2023-2027 Capital Plan
General Property
($000s)

	2023F	2024F	2025F	2026F	2027F
Project					
Physical Security Upgrades	576	660	440	440	440
Company Building Renovations	741	2,729	1,640	1,500	1,000
Program					
Additions to Real Property	654	665	677	689	702
Tools and Equipment	534	542	551	560	570
Total	$2,505	$4,596	$3,308	$3,189	$2,712

Table A-9
2023-2027 Capital Plan
Telecommunications
($000s)

	2023F	2024F	2025F	2026F	2027F
Project					
St. John's Teleprotection System Replacement[37]	1,150	0	0	0	0
Fibre Optic Cable Build	0	355	262	170	0
Radio System Replacement	0	1,000	0	0	0
Program					
Communications Equipment Upgrades	118	121	124	127	130
Total	$1,268	$1,476	$386	$297	$130

[37] Multi-year capital project approved in Order No. P.U. 36 (2021).

Table A-10
2023-2027 Capital Plan
Allowance for Unforeseen Items
($000s)

	2023F	2024F	2025F	2026F	2027F
Project					
Allowance for Unforeseen Items	750	750	750	750	750
Total	$750	$750	$750	$750	$750

Table A-11 2023-2027 Capital Plan General Expenses Capitalized ($000s)					
	2023F	2024F	2025F	2026F	2027F
Project					
General Expenses Capitalized	4,000	4,000	4,000	4,000	4,000
Total	$4,000	$4,000	$4,000	$4,000	$4,000

2022 Capital Expenditure Status Report

June 2022

Newfoundland Power Inc.

2022 Capital Expenditure
Status Report

Compliance Matter

This report is presented in compliance with the directive of the Board of Commissioners of Public Utilities (the "Board") contained in paragraph 6 of Order No. P.U. 36 (2021):

> *Unless otherwise directed by the Board, Newfoundland Power shall provide, in conjunction with the 2023 capital budget application, a status report on the 2022 capital budget expenditures showing for each project:*
> *(i) the approved budget for 2022;*
> *(ii) the expenditures prior to 2022;*
> *(iii) the 2022 expenditures to the date of the application;*
> *(iv) the remaining projected expenditures for 2022;*
> *(v) the variance between the projected total expenditures and the approved budget; and*
> *(vi) an explanation of the variance.*

Overview

Page 1 of the 2022 Capital Expenditure Status Report outlines the forecast variances from budget of the capital expenditures approved by the Board. The detailed tables on pages 3 to 13 provide additional detail on capital expenditures in 2022 which were approved in Order No. P.U. 36 (2021). The detailed tables also include information on those capital projects approved for 2020 and 2021 that were not completed prior to 2022. The carry forward projects were approved in Orders Nos. P.U. 5 (2020), P.U. 37 (2020), P.U. 10 (2021), P.U. 12 (2021) and P.U. 30 (2021).

Variances of more than 10% of approved expenditure and $100,000 or greater are explained in the notes contained in Appendix A, which immediately follows at the conclusion of the 2022 Capital Expenditure Status Report. These variance criteria are as outlined in the *Capital Budget Application Guidelines,* Policy No. 1900.6, October 2007.

The variances contained in Appendix A relate to better than expected contract pricing for the *Topsail Hydro Plant Refurbishment* project and a forecast increase in gross new customer connections for 2022 by approximately 15% from 2,038 to 2,343.

Newfoundland Power will provide updated information to the Board in its regular reporting and upon request of the Board.

Newfoundland Power Inc.

2022 Capital Budget Variances
($000s)

Approved by Order No.
P.U. 36 (2021)

	Budget	Forecast	Variance
Generation – Hydro	2,462	2,462	-
Generation - Thermal	307	307	-
Substations	11,639	11,639	-
Transmission	12,892	12,892	-
Distribution	46,214	48,130	1,916[1]
General Property	2,660	2,660	-
Transportation	3,089	3,089	-
Telecommunications	564	564	-
Information Systems	21,044	21,044	-
Unforeseen Items	750	750	-
General Expenses Capitalized	6,500	6,500	-
Total	$108,121	$110,037	$1,916
Projects carried forward from prior years		$17,485[2]	

1 The increase is due to a forecast increase in customer connections. Details can be found in the notes provided in Appendix A.
2 Forecast 2022 expenditures associated with projects carried forward from prior years.

2022 Capital Expenditure Status Report
($000s)

	Capital Budget			Actual Expenditure			Forecast			
	2020 - 2021	2022	Total	2020 - 2021	YTD 2022	Total To Date	Remainder 2022	Total 2022	Overall Total	Variance
	A	B	C	D	E	F	G	H	I	J
2022 Projects	$ -	$ 108,121	$ 108,121	$ -	$ 25,329	$ 25,329	$ 84,708	$ 110,037	$ 110,037	$ 1,916
2020-2021 Projects	41,872	-	41,872	23,086	6,268	29,354	11,217	17,485	40,571	(1,301)
Grand Total	**$ 41,872**	**$ 108,121**	**$ 149,993**	**$ 23,086**	**$ 31,597**	**$ 54,683**	**$ 95,925**	**$ 127,522**	**$ 150,608**	**$ 615**

Column A	Approved Capital Budget for 2020 and 2021
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2022 Capital Expenditure Status Report
($000s)

Category: Generation - Hydro

	Capital Budget			Actual Expenditure			Forecast				
	2020 - 2021	2022	Total	2020 - 2021	YTD 2022	Total To Date	Remainder 2022	Total 2022	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2022 Projects											
Hydro Facility Rehabilitation	$ -	$ 2,062	$ 2,062	$ -	$ 321	$ 321	$ 1,741	$ 2,062	$ 2,062	$ -	
Sandy Brook Plant Penstock Replacement	-	400	400	-	44	44	356	400	400	-	
Total 2022 Generation Hydro	**$ -**	**$ 2,462**	**$ 2,462**	**$ -**	**$ 365**	**$ 365**	**$ 2,097**	**$ 2,462**	**$ 2,462**	**$ -**	
2020-2021 Projects											
Petty Harbour Hydro Plant Refurbishment	$ 3,662	$ -	$ 3,662	$ 3,499	$ 58	$ 3,557	$ 142	$ 200	$ 3,699	$ 37	
Topsail Hydro Plant Refurbishment	$ 9,859	$ -	$ 9,859	$ 8,079	$ 97	$ 8,176	$ 203	$ 300	$ 8,379	$ (1,480)	1
Total Generation - Hydro	**$ 13,521**	**$ 2,462**	**$ 15,983**	**$ 11,578**	**$ 520**	**$ 12,098**	**$ 2,442**	**$ 2,962**	**$ 14,540**	**$ (1,443)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2020 and 2021
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2022 Capital Expenditure Status Report
($000s)

Category: Generation - Thermal

	Capital Budget			Actual Expenditure			Forecast				
	2021	2022	Total	2021	YTD 2022	Total To Date	Remainder 2022	Total 2022	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2022 Projects											
Thermal Plant Facility Rehabilitation	$ -	$ 307	$ 307	$ -	$ 60	$ 60	$ 247	$ 307	$ 307	$ -	
Total 2022 Generation - Thermal	**$ -**	**$ 307**	**$ 307**	**$ -**	**$ 60**	**$ 60**	**$ 247**	**$ 307**	**$ 307**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2021
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2022 Capital Expenditure Status Report
($000s)

Category: Substations

	Capital Budget			Actual Expenditure			Forecast				
	2021	**2022**	**Total**	**2021**	**YTD 2022**	**Total To Date**	**Remainder 2022**	**Total 2022**	**Overall Total**	**Variance**	**Notes***
2022 Projects	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	
Substation Refurbishment and Modernization	$ -	$ 7,049	$ 7,049	$ -	$ 706	$ 706	$ 6,343	$ 7,049	$ 7,049	$ -	
Replacements Due to In-Service Failures	-	3,691	3,691	-	1,746	1,746	1,945	3,691	3,691	-	
PCB Bushing Phase-out	-	899	899	-	34	34	865	899	899	-	
Total 2022 Substations	**$ -**	**$ 11,639**	**$ 11,639**	**$ -**	**$ 2,486**	**$ 2,486**	**$ 9,153**	**$ 11,639**	**$ 11,639**	**$ -**	
2021 Projects											
Additions Due to Load Growth	$ 4,997	$ -	$ 4,997	$ 2,508	$ 1,423	$ 3,931	$ 1,124	$ 2,547	$ 5,055	$ 58	
Total Substations	**$ 4,997**	**$ 11,639**	**$ 16,636**	**$ 2,508**	**$ 3,909**	**$ 6,417**	**$ 10,277**	**$ 14,186**	**$ 16,694**	**$ 58**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2021
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2022 Capital Expenditure Status Report
($000s)

Category: Transmission

	Capital Budget			Actual Expenditure			Forecast				
	2021	2022	Total	2021	YTD 2022	Total To Date	Remainder 2022	Total 2022	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2022 Projects											
Transmission Line Rebuild	$ -	$ 10,494	$ 10,494	$ -	$ 748	$ 748	$ 9,746	$ 10,494	$ 10,494	$ -	
Transmission Line Maintenance and 3rd Party Relocations	-	2,398	2,398	-	128	128	2,270	2,398	2,398	-	
Total 2022 Transmission	**$ -**	**$ 12,892**	**$ 12,892**	**$ -**	**$ 876**	**$ 876**	**$ 12,016**	**$ 12,892**	**$ 12,892**	**$ -**	
2021 Projects											
Transmission Line Extension - 35L	$ 1,343	$ -	$ 1,343	$ 106	$ 18	$ 124	$ 1,219	$ 1,237	$ 1,343	$ -	
Total Transmission	**$ 1,343**	**$ 12,892**	**$ 14,235**	**$ 106**	**$ 894**	**$ 1,000**	**$ 13,235**	**$ 14,129**	**$ 14,235**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2021
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2022 Capital Expenditure Status Report
($000s)

Category: Distribution

	Capital Budget			Actual Expenditure			Forecast				
	2021	**2022**	**Total**	**2021**	**YTD 2022**	**Total To Date**	**Remainder 2022**	**Total 2022**	**Overall Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	
2022 Projects											
Extensions	$ -	$ 10,333	$ 10,333	$ -	$ 3,696	$ 3,696	$ 8,183	$ 11,879	$ 11,879	$ 1,546	2
Meters	-	818	818	-	335	335	483	818	818	-	
Services	-	3,038	3,038	-	994	994	2,414	3,408	3,408	370	3
Street Lighting	-	2,507	2,507	-	885	885	1,622	2,507	2,507	-	
Street Lighting - LED Replacement Program	-	5,428	5,428	-	2,312	2,312	3,116	5,428	5,428	-	
Transformers	-	5,958	5,958	-	4,601	4,601	1,357	5,958	5,958	-	
Reconstruction	-	5,902	5,902	-	1,901	1,901	4,001	5,902	5,902	-	
Rebuild Distribution Lines	-	4,333	4,333	-	1,042	1,042	3,291	4,333	4,333	-	
Relocate/Replace Distribution Lines for Third Parties	-	3,370	3,370	-	771	771	2,599	3,370	3,370	-	
Trunk Feeders - Humber 4.16 kV Conversion	-	1,355	1,355	-	615	615	740	1,355	1,355	-	
Feeder Additions for Load Growth	-	1,690	1,690	-	289	289	1,401	1,690	1,690	-	
Distribution Reliability Initiative	-	350	350	-	-	-	350	350	350	-	
Distribution Feeder Automation	-	893	893	-	54	54	839	893	893	-	
Allowance for Funds Used During Construction	-	239	239	-	73	73	166	239	239	-	
Electric Vehicle Charging Network[1]	-	-	-	-	-	-	-	-	-	-	
Total 2022 Distribution	**$ -**	**$ 46,214**	**$ 46,214**	**$ -**	**$ 17,568**	**$ 17,568**	**$ 30,562**	**$ 48,130**	**$ 48,130**	**$ 1,916**	
2021 Projects											
Trunk Feeders	$ 800	$ -	$ 800	$ 7	3	$ 10	$ 789	$ 792	$ 799	$ (1)	
Feeder Additions for Load Growth	2,655	-	2,655	1,899	569	2,468	102	671	2,570	(85)	
Utility EV Charging Network[1]	1,538	-	1,538	51	1,146	1,197	341	1,487	1,538	-	
Total Distribution	**$ 4,993**	**$ 46,214**	**$ 51,207**	**$ 1,957**	**$ 19,286**	**$ 21,243**	**$ 31,794**	**$ 51,080**	**$ 53,037**	**$ 1,830**	

1. Expenditures related to the Utility Electric Vehicle Charging Network are recorded to the deferral account in accordance with Order No. P.U. 3 (2022).

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2021
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Column E	Actual Capital Expenditures for 2022 YTD
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2022 Capital Expenditure Status Report
($000s)

Category: General Property

	Capital Budget			Actual Expenditure			Forecast				
	2021	2022	Total	2021	YTD 2022	Total To Date	Remainder 2022	Total 2022	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2022 Projects											
Tools and Equipment	$ -	$ 598	$ 598	$ -	$ 146	$ 146	$ 452	$ 598	$ 598	$ -	
Additions to Real Property	-	716	716	-	94	94	622	716	716	-	
Clarenville Area Office Building Refurbishment	-	854	854	-	37	37	817	854	854	-	
Physical Security Upgrades	-	492	492	-	36	36	456	492	492	-	
									-		
Total 2022 General Property	**$ -**	**$ 2,660**	**$ 2,660**	**$ -**	**$ 313**	**$ 313**	**$ 2,347**	**$ 2,660**	**$ 2,660**	**$ -**	
2021 Projects											
Company Building Renovations	$ 1,392	$ -	$ 1,392	$ 1,038	$ 168	$ 1,206	$ 183	$ 351	$ 1,389	$ (3)	
Total General Property	**$ 1,392**	**$ 2,660**	**$ 4,052**	**$ 1,038**	**$ 481**	**$ 1,519**	**$ 2,530**	**$ 3,011**	**$ 4,049**	**$ (3)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2021
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Column H	Total of Columns E and G
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2022 Capital Expenditure Status Report
($000s)

Category: Transportation

	Capital Budget			Actual Expenditure			Forecast				
	2021	2022	Total	2021	YTD 2022	Total To Date	Remainder 2022	Total 2022	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2022 Projects											
Replace Vehicles and Aerial Devices 2022-2023	$ -	$ 3,089	$ 3,089	$ -	$ 102	$ 102	$ 2,987	$ 3,089	$ 3,089	$ -	
Total 2022 Transportation	**$ -**	**$ 3,089**	**$ 3,089**	**$ -**	**$ 102**	**$ 102**	**$ 2,987**	**$ 3,089**	**$ 3,089**	**$ -**	
2021 Projects											
Purchase Vehicles and Aerial Devices	$ 4,032	$ -	$ 4,032	$ 1,683	$ 1,022	$ 2,705	$ 1,393	$ 2,415	$ 4,098	$ 66	
Total Transportation	**$ 4,032**	**$ 3,089**	**$ 7,121**	**$ 1,683**	**$ 1,124**	**$ 2,807**	**$ 4,380**	**$ 5,504**	**$ 7,187**	**$ 66**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2021
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2022 Capital Expenditure Status Report
($000s)

Category: Telecommunications

	Capital Budget			Actual Expenditure			Forecast				
Project	**2021**	**2022**	**Total**	**2021**	**YTD 2022**	**Total To Date**	**Remainder 2022**	**Total 2022**	**Overall Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	
2022 Projects											
Replace/Upgrade Communications Equipment	$ -	$ 114	$ 114	$ -	$ 9	$ 9	$ 105	$ 114	$ 114	$ -	
St. John's Teleprotection System Replacement	-	450	450	-	25	25	425	450	$ 450	-	
Total 2022 Telecommunications	**$ -**	**$ 564**	**$ 564**	**$ -**	**$ 34**	**$ 34**	**$ 530**	**$ 564**	**$ 564**	**$ -**	
2021 Projects											
Fibre Optic Cable Builds	$ 350	$ -	$ 350	$ 238	$ 11	$ 249	$ 101	$ 112	$ 350	$ -	
Total Telecommunications	**$ 350**	**$ 564**	**$ 914**	**$ 238**	**$ 45**	**$ 283**	**$ 631**	**$ 676**	**$ 914**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2021
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2022 Capital Expenditure Status Report
($000s)

Category: Information Systems

	Capital Budget			Actual Expenditure			Forecast				
	2021	**2022**	**Total**	**2021**	**YTD 2022**	**Total To Date**	**Remainder 2022**	**Total 2022**	**Overall Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	
2022 Projects											
Application Enhancements	$ -	$ 1,007	$ 1,007	$ -	$ 358	$ 358	$ 649	$ 1,007	$ 1,007	$ -	
System Upgrades	-	802	802	-	204	204	598	802	802	-	
Personal Computer Infrastructure	-	615	615	-	87	87	528	615	615	-	
Shared Server Infrastructure	-	613	613	-	271	271	342	613	613	-	
Network Infrastructure	-	508	508	-	19	19	489	508	508	-	
Cybersecurity Upgrades	-	865	865	-	142	142	723	865	865	-	
Customer Service System Replacement	-	15,826	15,826	-	-	-	15,826	15,826	15,826	-	
Workforce Management System Replacement	-	808	808	-	88	88	720	808	808	-	
Total 2022 Information Systems	**$ -**	**$ 21,044**	**$ 21,044**	**$ -**	**$ 1,169**	**$ 1,169**	**$ 19,875**	**$ 21,044**	**$ 21,044**	**$ -**	
2021 Projects											
Application Enhancements	$ 978	$ -	$ 978	$ 852	$ -	$ 852	$ 186	$ 186	$ 1,038	$ 60	
Network Infrastructure	363	-	363	316	51	367	43	94	410	47	
Customer Service System Replacement	9,903	-	9,903	2,810	1,702	4,512	5,391	7,093	9,903	-	
Total - Information Systems	**$ 11,244**	**$ 21,044**	**$ 32,288**	**$ 3,978**	**$ 2,922**	**$ 6,900**	**$ 25,495**	**$ 28,417**	**$ 32,395**	**$ 107**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2021
Column B	Approved Capital Budget for 2022
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2021
Column E	Actual Capital Expenditures for 2022 YTD
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2022
Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2022 Capital Expenditure Status Report
($000s)

Category: Unforeseen Allowance

Project	Capital Budget 2022 A	Capital Budget Total B	Actual Expenditures YTD 2022 C	Actual Expenditures Total To Date D	Forecast Remainder 2022 E	Forecast Total 2022 F	Forecast Overall Total G	Variance H	Notes*
2022 Projects									
Allowance for Unforeseen Items	$ 750	$ 750	$ -	$ -	$ 750	$ 750	$ 750	$ -	
Total Unforeseen Allowance	**$ 750**	**$ 750**	**$ -**	**$ -**	**$ 750**	**$ 750**	**$ 750**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2022
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2022 YTD
Column D	Total of Column C
Column E	Forecast for Remainder of 2022
Column F	Total of Columns C and E
Column G	Total of Columns D and E
Column H	Column G less Column B

2022 Capital Expenditure Status Report
($000s)

Category: General Expenses Capitalized

	Capital Budget		Actual Expenditures		Forecast				
Project	**2022**	**Total**	**YTD 2022**	**Total To Date**	**Remainder 2022**	**Total 2022**	**Overall Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
2022 Projects									
General Expenses Capitalized	$ 6,500	$ 6,500	$ 2,356	$ 2,356	$ 4,144	$ 6,500	$ 6,500	$ -	
Total General Expenses Capitalized	**$ 6,500**	**$ 6,500**	**$ 2,356**	**$ 2,356**	**$ 4,144**	**$ 6,500**	**$ 6,500**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2022
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2022 YTD
Column D	Total of Column C
Column E	Forecast for Remainder of 2022
Column F	Total of Columns C and E
Column G	Total of Columns D and E
Column H	Column G less Column B

Generation - Hydro

1. *Topsail Hydro Plant Refurbishment (2020 – 2021 Project):*

   Budget: $9,859,000 Forecast: $8,379,000 Variance: ($1,480,000)

   The *Topsail Hydro Plant Refurbishment* project was a multi-year project that commenced in 2020. The forecast expenditure is expected to be approximately 15% below the budgeted amount. The reduction in expenditure associated with the *Topsail Hydro Plant Refurbishment* project was largely due to better than expected contract pricing through the tendering process.

Distribution

2. *Extensions:*

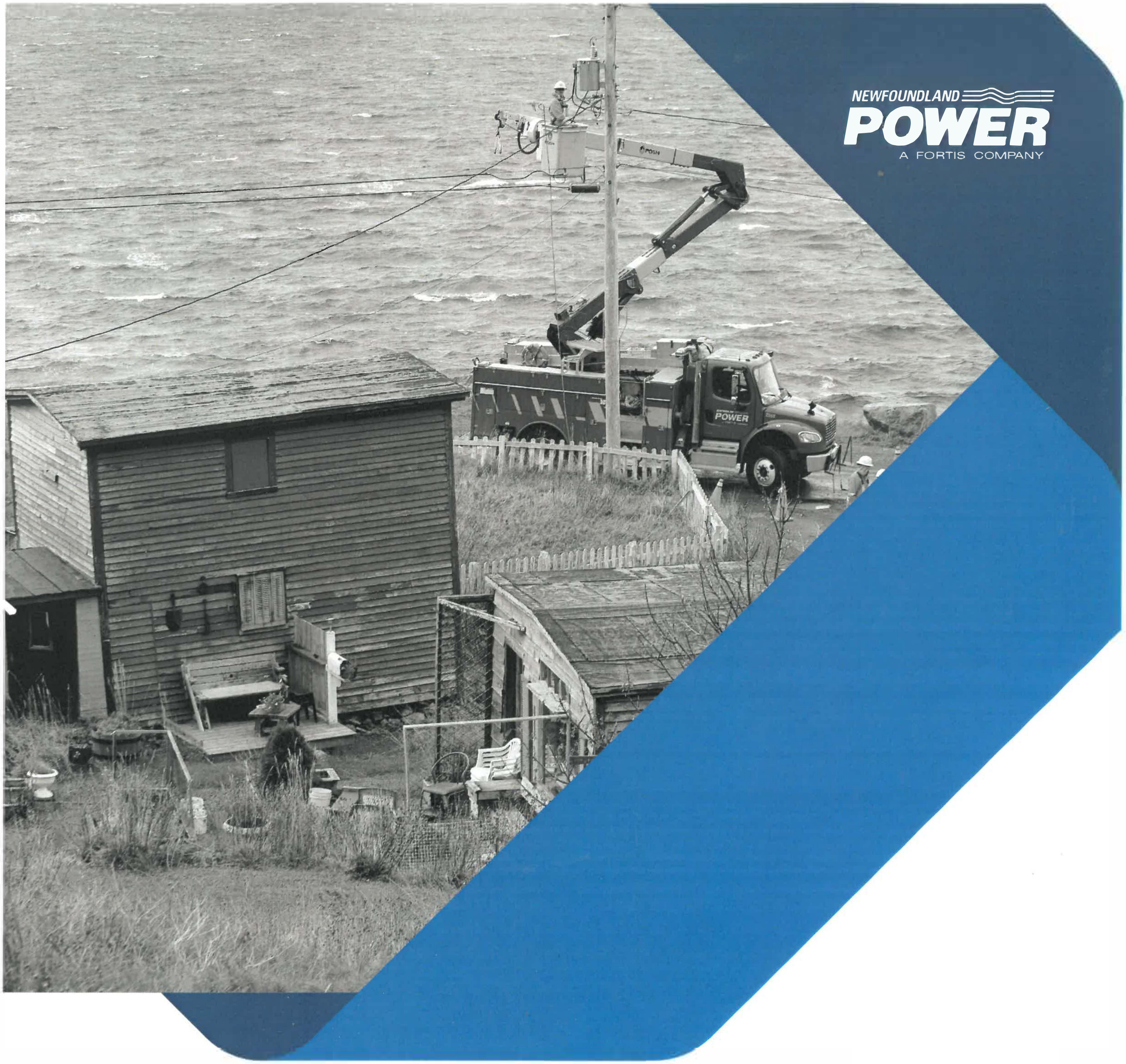
Budget: $10,333,000 Forecast: $11,879,000 Variance: $1,546,000

The forecast expenditure for *Extensions* is expected to be approximately 15% above the budgeted amount. The increase reflects a 15% increase in forecast new customer connections from 2,038 to 2,343.

3. *Services:*

Budget: $3,038,000 Forecast: $3,408,000 Variance: $370,000

The forecast expenditure for *Services* is expected to be approximately 12% above the budgeted amount. The increase reflects a forecast increase in new customer connections from 2,038 to 2,343.



1.1 Distribution Reliability Initiative

June 2022

REGISTERED PROFESSIONAL ENGINEER
RALPH W. MUGFORD
SIGNATURE
06/21/2022
DATE
NEWFOUNDLAND & LABRADOR

Prepared by: Ralph Mugford, P. Eng.

TABLE OF CONTENTS

1.0 INTRODUCTION

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") *Distribution Reliability Initiative* targets the Company's worst performing 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 acceptable 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, Responder, in September 2019. Responder is capable of providing outage data with greater granularity 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 2023, Newfoundland Power is proposing to refurbish Summerford ("SUM") Substation distribution feeder SUM-01. The project is proposed to be completed over two years at a cost of $656,000 in 2023 and $1,015,000 in 2024.

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.

Newfoundland Power has been implementing its *Distribution Reliability Initiative* for over two decades. The Company analyzed the project's overall effectiveness in improving the service reliability experienced by customers. The analysis shows the project has been effective in addressing the poor performance of specific feeders. On average, the project has improved the reliability performance of Newfoundland Power's worst performing feeders by approximately 68%.[1]

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[1] The analysis compared the reliability performance of distribution feeders refurbished under this project by examining the average duration of outages during the five years prior to capital upgrades and five years following capital upgrades. The average outage duration prior to capital upgrades was 8.23 hours. The average outage duration following capital upgrades was 2.64 hours. While the performance of specific feeders has been improved under the *Distribution Reliability Initiative*, the project has had a minimal impact on overall electrical system reliability.

Newfoundland Power's approach to assessing its worst performing feeders is consistent with good utility practice.[2] The Company uses five reliability indices to identify its worst performing feeders:

(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.

3.0 DISTRIBUTION FEEDER ASSESSMENT

3.1 General

The 2023 *Distribution Reliability Initiative* project targets SUM Substation distribution feeder SUM-01. Distribution feeder SUM-01 is one of two feeders leaving SUM Substation. It extends from the Summerford area, branching to Cottlesville and Virgin Arm/Moreton's Harbour, and running along Route 340 towards Twillingate. This feeder currently serves 1,812 customers on New World Island. The total length of the feeder, including all taps, is approximately 100 kilometres.

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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 the Canadian Electricity Association 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.

Figure 1 is a map illustrating the route of distribution feeder SUM-01 and its service area.[8]

Figure 1: Location of Feeder SUM-01

3.2 Reliability Performance

The reliability performance experienced by customers served by distribution feeder SUM-01 has been considerably worse than Newfoundland Power's corporate average over the last five years.

8 The location of SUM Substation and the downline reclosers currently installed on distribution feeder SUM-01 are shown in red.

Table 1 summarizes the feeder-level reliability data for SUM-01 from 2017 to 2021, 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, 2021

Feeder	Customer Minutes of Outage	SAIFI	SAIDI	CHIKM	CIKM
SUM-01	863,018	2.89	7.98	126	46
Corporate Average	92,664	1.37	1.82	49	40

Distribution feeder SUM-01 is experiencing below-average reliability performance across all five indicators used as part of the *Distribution Reliability Initiative.* The average duration of customer outages is 7.98, or approximately 4.4 times the corporate average for SAIDI. The average frequency of customer outages is 2.89, or approximately 2.1 times the corporate average for SAIFI.

The reliability performance of distribution feeder SUM-01 is consistent with what would generally be considered a worst performing feeder in the electric utility industry.[9]

3.3 Engineering Assessment

SUM-01 is a 25 kV distribution feeder originally constructed in the 1960s. The main three-phase trunk portion of SUM-01 is approximately 24 kilometres in length and extends from the Summerford area along Route 340 towards Twillingate. There is also a two-phase trunk section of feeder that extends approximately 15 kilometres from the three-phase trunk to the Virgin Arm/Moreton's Harbour area. The feeder has no tie points to other feeders, which eliminates the possibility for permanent or temporary load transfers to restore service to customers during planned or unplanned outages.

An engineering assessment of distribution feeder SUM-01 determined that equipment failure is the cause of most outages experienced by customers in this area. Inspections identified the factors contributing most to customer outages are: (i) corroded or broken conductor; (ii) preform ties on insulators; (iii) insulator failures; and (iv) deteriorated pole failures.

[9] 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 SUM-01 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.

Distribution feeder SUM-01 is constructed using 2/0 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. This is the case for distribution feeder SUM-01, which runs near the coastline on New World Island.

The feeder's conductor is in very poor condition, with deterioration and separation of the conductor strands. Repairs in response to conductor failure have resulted in a significant amount of splicing across the entirety of distribution feeder SUM-01.

Figure 2 shows the typical type of conductor deterioration present on the main trunk of distribution feeder SUM-01.

Figure 2: 2/0 ACSR Conductor Deterioration

As shown in Figure 2, the oxidation of the aluminum causes the conductor strands to break or deteriorate to the point that the electric current creates heat, resulting in conductor failure and customer outages.

In some instances, the aluminum conductor strands have completely separated from the inner steel core resulting in an unsafe condition that requires an unplanned outage to repair.

Figure 3 shows an example of the separation of conductor strands on distribution feeder SUM-01.

Figure 3: 2/0 ACSR Conductor Deterioration

Addressing the deteriorated condition of the 2/0 ACSR conductor typically requires the replacement of lengthy sections of conductor to facilitate the splicing of the replacement conductor to the existing conductor. There have been numerous splices resulting from previous conductor failures and deficiencies on distribution feeder SUM-01. Repeated repairs of conductor failures and excessive splicing can lower the overall strength of the conductor, making it more susceptible to failure.

Figure 4 shows a typical splice for a previous repair completed on distribution feeder SUM-01.

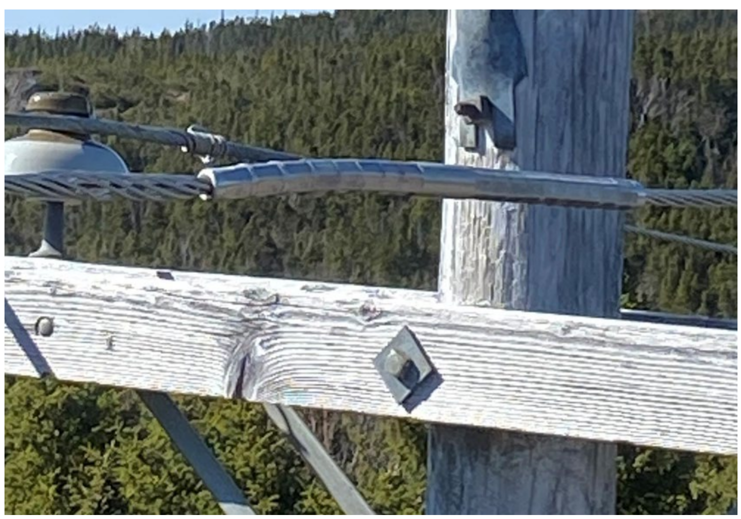

Figure 4: 2/0 ACSR Conductor Repair

Due to the deteriorated condition of the conductor, it cannot be safely repaired using hotline work methods.[10] All maintenance involving the conductor therefore requires the feeder to be

10 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.

removed from service, resulting in an outage to customers.[11] This can result in prolonged customer outages when a significant section of conductor must be replaced.

Additionally, due to the age and condition of the conductor, it is becoming more susceptible to failure when exposed to wind, ice and snow loading. Conductor failure during high winds has been an issue over the past number of years.[12] The geographic location of the feeder prolongs response times and therefore the duration of outages to customers.

In addition to conductor condition, inspections have identified 140 deficiencies on this section of feeder, including 79 deteriorated poles.

Appendix C provides photographs showing examples of the deterioration and deficiencies identified on this section of distribution feeder SUM-01.

An analysis of distribution feeder SUM-01 using data available from Responder was able to pinpoint specific sections of feeder with particularly high frequencies of customer outages. Responder data indicates that there have been 153 outage incidents on the feeder between September 2019 to the end of 2021. Of the 153 outage incidents, 124 events have been on the sections of feeder located northeast of SUM Substation along Route 340 towards Twillingate, including the two-phase tap to Virgin Arm/Moreton's Harbour. Further analysis identified that 70 of the events were caused by component and conductor failure.

4.0 ASSESSMENT OF ALTERNATIVES

4.1 General

Distribution feeder SUM-01 is experiencing significantly worse reliability compared to the average reliability experienced by Newfoundland Power's customers. An engineering assessment of distribution feeder SUM-01 identified significant deterioration on the section of feeder extending northeast from SUM Substation.

Two alternatives were identified and evaluated with respect to distribution feeder SUM-01. The two alternatives are: (i) a targeted refurbishment of a section of the distribution feeder and the installation of additional automated downline reclosers; and (ii) defer the refurbishment of the distribution feeder.

4.2 Alternative 1 – Targeted Refurbishment

Alternative 1 involves a targeted refurbishment of distribution feeder SUM-01.

[11] As examples, this could include the installation of replacement conductor or maintenance involving the transfer of existing conductor to new poles.

[12] Incidents of high winds are typical in this area. For example, since 2010, Twillingate has experienced an average of 10 days per year with sustained winds in excess of 100 kilometres/hour.

Under this alternative, a 6.5-kilometre section of three-phase line would be reconductored.[13] Deficiencies identified on poles, structures and other components would also be addressed through the replacement of those components.

This alternative also includes the installation of automated downline reclosers on distribution feeder SUM-01 to reduce the impact on customers of outages resulting from equipment failure.[14] Downline recloser SUM-01-R3 is not currently automated. Under this alternative, the downline recloser will be replaced with a fully automated recloser.[15] There is also an opportunity to install an additional downline recloser on the 15-kilometre, two-phase tap extending to Virgin Arm/Moreton's Harbour.

Combined, the targeted refurbishment and installation of downline reclosers would be expected to improve the poor service reliability experienced by customers on New World Island.

The total capital cost of Alternative 2 is $1,671,000.

4.3 Alternative 2 – Defer Refurbishment

Alternative 2 involves deferring the refurbishment of distribution feeder SUM-01.

Distribution feeder SUM-01 has been included in the list of the Company's worst performing feeders in each annual capital budget application since 2014. Since 2020, the feeder's performance has been monitored to determine whether capital upgrades are required.[16] Engineering assessments have determined that the deteriorated condition of distribution feeder SUM-01 contributes to the poor service reliability experienced by customers on New World Island.

A significant number of deficiencies and outage incidents have been identified on specific sections of distribution feeder SUM-01. The risk of equipment failure and outages to customers is therefore considered high, and would remain high if refurbishment of the distribution feeder is deferred.

Customers currently experience outages that are four times longer and two times more frequent than the Company average. Deferring the refurbishment of distribution feeder SUM-01

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13 This 6.5-kilometre section comprises less than 6% of the total length of distribution feeder SUM-01.

14 When the downline recloser opens it limits the outage to only those customers downstream of the recloser. For example, if a fault were to occur on the 15-kilometre, two-phase tap to the Virgin Arm/Moreton's Harbour area, the downline recloser would automatically isolate the faulted section and provide indication to the System Control Center. This would limit the number of customers experiencing an outage to the 535 customers downstream of the recloser, while maintaining service to the remaining 1,277 customers supplied upstream of the recloser.

15 There are three existing downline reclosers on distribution feeder SUM-01, as shown in Figure 1. Downline recloser SUM-01-R2 was replaced with a fully automated recloser in 2021 as part of the *Distribution Feeder Automation* project. In 2022, downline recloser SUM-01-R4 will be replaced with a fully automated recloser as part of the *Distribution Feeder Automation* project. Downline recloser SUM-01-R3 is an older hydraulic style recloser that is not automated.

16 From 2014 to 2019, the analysis of the worst performing feeders included with the *Distribution Reliability Initiative* reports indicated that the poor reliability performance was caused by specific events and no work was required.

would result in customers continuing to experience poor service reliability. This would be inconsistent with maintaining acceptable and equitable levels of service reliability for customers throughout Newfoundland Power's service territory.

5.0 PROJECT SCOPE

The assessment of alternatives identified that the poor service reliability experienced by customers on New World Island should be addressed in 2023 through a targeted refurbishment that includes the installation of downline reclosers.

The project scope for refurbishing distribution feeder SUM-01 includes:

(i) Replacing 6.5 kilometres of deteriorated 2/0 ACSR conductor with 4/0 Aluminum Alloy Stranded Conductor ("AASC");
(ii) Replacing poles, structures and other components identified during inspection as being in poor condition, including crossarms and insulators;
(iii) Installing an automated downline recloser on the two-phase tap supplying the Virgin Arm/Moreton's Harbour area; and
(iv) Replacing the existing hydraulic style downline recloser, SUM-01-R3, with a fully automated recloser.

This project is proposed to be completed over two years starting in 2023. Upon completion of the work, the Company will continue to assess data available from Responder to determine whether any further refurbishment is required.

6.0 PROJECT COST

Table 2 provides a detailed breakdown of the project to refurbish distribution feeder SUM-01 over two years in 2023 and 2024.

Table 2
Distribution Reliability Initiative
Project Cost
($000s)

Description	2023	2024	Total
Engineering	153	82	235
Labour - Contract	16	29	45
Labour - Internal	233	432	665
Material	103	191	294
Other	151	281	432
Total	$656	$1,015	$1,671

The total cost to refurbish distribution feeder SUM-01 is $1,671,000, including $656,000 in 2023 and $1,015,000 in 2024.

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 acceptable and equitable levels of service reliability for customers at the lowest possible cost.

The Company reviewed the performance indices and Responder data for distribution feeder SUM-01 to identify the cause of the poor service reliability experienced by customers on New World Island. An engineering assessment determined that capital upgrades to replace deteriorated conductor, address other deficiencies and install downline reclosers would address the poor service reliability experienced by these customers. A two-year project is proposed to address these deficiencies at a total cost of $1,671,000.

APPENDIX A:

Distribution Reliability Data: Worst Performing Feeders

Table A-1 Unscheduled Distribution-Related Outages 5-Year Average (2017-2021) Sorted by Customer Minutes of Interruption				
Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
SUM-01	5,204	863,018	2.89	7.98
DUN-01	6,692	681,184	6.39	10.83
DLK-03	4,502	583,821	3.20	6.92
GLV-02	6,566	532,703	4.33	5.86
BVS-04	5,899	487,414	3.72	5.13
DOY-01	5,685	479,947	3.27	4.60
SCR-01	2,624	435,405	2.74	7.59
BOT-01	3,588	435,139	2.09	4.23
WAV-01	3,450	417,086	2.65	5.34
GFS-06	5,344	397,429	2.80	3.47
WAL-02	4,324	393,404	3.06	4.64
BHD-01	2,590	375,461	2.74	6.63
CAB-01	3,267	351,771	2.69	4.83
BLK-01	3,876	341,125	2.38	3.49
NWB-02	1,853	315,096	1.71	4.84
Company Average	1,161	92,664	1.37	1.82

Table A-2
Unscheduled Distribution-Related Outages
5-Year Average
(2017-2021)
Sorted by Distribution SAIFI

Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
DUN-01	6,692	681,184	6.39	10.83
LEW-03	5,224	186,554	4.60	2.74
GLV-02	6,566	532,703	4.33	5.86
TWG-03	1,320	84,500	4.24	4.53
SCT-01	3,014	298,546	4.16	6.87
SUM-02	2,396	235,802	4.03	6.61
TWG-02	2,591	200,933	3.74	4.84
BUC-02	597	89,007	3.73	9.27
BVS-04	5,899	487,414	3.72	5.13
GBS-01	3,042	179,461	3.50	3.44
DOY-01	5,685	479,947	3.27	4.60
DLK-03	4,502	583,821	3.20	6.92
LEW-04	1,654	92,271	3.07	2.86
WAL-02	4,324	393,404	3.06	4.64
PAB-05	1,934	132,740	2.97	3.40
Company Average	1,161	92,664	1.37	1.82

Table A-3 Unscheduled Distribution-Related Outages 5-Year Average (2017-2021) Sorted by Distribution SAIDI				
Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
SBK-01[1]	6	2,541	1.92	14.12
DUN-01	6,692	681,184	6.39	10.83
BUC-02	597	89,007	3.73	9.27
TRP-01	1,623	301,784	2.73	8.47
SUM-01	5,204	863,018	2.89	7.98
SCR-01	2,624	435,405	2.74	7.59
SCT-02	561	110,700	2.25	7.41
DLK-03	4,502	583,821	3.20	6.92
SCT-01	3,014	298,546	4.16	6.87
BHD-01	2,590	375,461	2.74	6.63
SUM-02	2,396	235,802	4.03	6.61
WES-02	2,012	285,490	2.66	6.30
GLV-02	6,566	532,703	4.33	5.86
RVH-02	208	55,744	1.30	5.81
WAV-01	3,450	417,086	2.65	5.34
Company Average	1,161	92,664	1.37	1.82

[1] 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.

Table A-4 Unscheduled Distribution-Related Outages 5-Year Average (2017-2021) Sorted by Distribution CHIKM	
Feeder	Annual Distribution CHIKM
KBR-10	252
WAL-02	236
KBR-12	226
TWG-02	205
WAV-03	202
PAB-05	173
MOL-04	173
SLA-12	165
SLA-10	162
GOU-01	161
BCV-04	148
WAL-04	148
KBR-13	147
SJM-06	145
HWD-08	142
Company Average	49

Table A-5
Unscheduled Distribution-Related Outages
5-Year Average
(2017-2021)
Sorted by Distribution CIKM

Feeder	Annual Distribution CIKM
SLA-10	493
KBR-10	314
HWD-07	219
KBR-12	204
KBR-13	196
PAB-03	191
GOU-01	169
TWG-02	157
WAL-02	154
LEW-03	148
WAV-03	142
KEN-03	136
HWD-08	133
MSY-01	128
GBS-01	122
Company Average	40

APPENDIX B:

Worst Performing Feeders: Summary of Data Analysis

Worst Performing Feeders Summary of Data Analysis	
Feeder	Comments
BCV-04	Reliability during normal operation is above average in terms of SAIDI, SAIFI and CHIKM. Problems are significantly compounded during storms. Work is being carried out on this feeder in 2022 as part of the *Distribution Reliability Initiative.*
BHD-01	In 2017, there were two outages caused by broken poles. There were numerous insulator and conductor issues in 2020. 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.
BLK-01	Poor reliability was principally driven by three conductor breakages and an insulator failure in 2018. No work is required at this time.
BOT-01	In 2018, poor statistics were due to a vehicle hitting a pole. In 2019, poor reliability was due to a recloser issue. No work is required at this time.
BUC-02	Reliability is worsening principally due to conductor issues in 2017, 2018 and 2020. 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	Reliability is worsening principally 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.
CAB-01	Reliability statistics were driven by trees and two outages related to vehicle accidents damaging poles. No work is required at this time.
DLK-03	In 2018, a broken pole causing a major outage was the primary cause of poor reliability over the past five years. No 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. The poor reliability statistics are also driven by weather-related events in 2019. No work is required at this time.
DUN-01	Work was carried out on this feeder in 2019, 2020 and 2021 as part of the *Distribution Reliability Initiative* project. No additional work is required at this time.

Worst Performing Feeders Summary of Data Analysis	
Feeder	Comments
GBS-01	The poor reliability experienced on GBS-01 is principally due to weather related issues. No work is required at this time.
GFS-06	Poor reliability statistics were principally due to tree and conductor issues. Work was carried out in 2020 as part of the *Trunk Feeder* project to address identified issues.
GLV-02	Poor reliability statistics were driven by a wind-related event in 2017 and a broken pole in 2018. No work is required at this time.
GOU-01	Poor reliability statistics were driven by a wind-related event in 2021. No work is required at this time.
HWD-07	In 2020 there was an issue with a set of inline disconnects. No work is required at this time.
HWD-08	Poor reliability statistics were driven by conductor issues in 2019 and 2021. No work is required at this time.
KBR-10	There were several outages in 2020 due to adverse weather and trees. No work is required at this time.
KBR-12	There were several outages in 2020 due to adverse weather and trees. No work is required at this time.
KBR-13	Tree issues in 2017 and 2020 contributed to reduced reliability in those years. No work is required at this time.
KEN-03	Poor reliability statistics were driven by a broken insulator in each of 2018 and 2020. Work was carried out on this feeder in 2018 as part of the *Distribution Reliability Initiative*. No work is required at this time.
LEW-03	Reliability statistics were poor in 2019 and 2020. In 2019, issues were mainly due to wind and lightning. In 2020, outages were due to conductor issues and a vehicle accident. No work is required at this time.
LEW-04	Poor reliability statistics were driven by a broken pole in 2019 caused by a vehicle accident. No work is required at this time.
MOL-04	Poor reliability statistics were driven by a wind event in 2017 and a damaged riser in 2019. No work is required at this time.
MSY-01	Poor reliability statistics were due to a vehicle accident in 2019. No work is required at this time.

Worst Performing Feeders Summary of Data Analysis	
Feeder	Comments
NWB-02	Poor reliability statistics were due to a failed insulator in 2020 and broken pole caused by a vehicle accident in 2021. No work is required at this time.
PAB-03	Poor reliability statistics were due to wind issues in 2020. No work is required at this time.
PAB-05	Poor reliability statistics were due to an insulator failure and a broken conductor in 2020. No work is required at this time.
RVH-02	Poor reliability statistics were due to a wind-related event in 2017. Work was carried out on this feeder in 2017 as part of the *Distribution Reliability Initiative*. 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	The feeder had significant reliability issues in 2017 caused by broken insulators, birds, trees and vandalism. There was also a large outage in 2021 due to a bird. No work is required at this time.
SCT-01	Poor reliability statistics were driven by wind and tree-related events in 2017 and several broken insulators in 2018. In 2021 there were several outages due to trees and lightning. No work is proposed at this time but the feeder will continue to be monitored and will potentially require future capital investment to improve reliability performance.
SCT-02	Poor reliability statistics were driven by wind and vegetation-related events in 2017 and 2021. No work is required at this time.
SJM-06	Poor reliability statistics were driven by copper conductor corrosion and equipment failures in recent years. This feeder was included in the *2019 Distribution Reliability Initiative* project. No work is required at this time.
SLA-10	Poor reliability statistics were caused by conductor issues in 2021. No work is required at this time.
SLA-12	Poor reliability statistics were caused by lightning in 2021. No work is required at this time.

Worst Performing Feeders Summary of Data Analysis	
Feeder	Comments
SUM-01	Poor reliability statistics were caused by conductor and insulator issues in 2018, 2019 and 2020. In 2021 there were several large outages due to pole and conductor failure. Work is proposed on this feeder in 2023 as part of the *Distribution Reliability Initiative.*
SUM-02	Work was carried out in 2017 and 2018 as part of the *Distribution Reliability Initiative* project. No additional work is required at this time.
TRP-01	Work was carried out on this feeder in 2017 and 2018 as part of the *Distribution Reliability Initiative* project. No additional work is required at this time.
TWG-02	Poor reliability statistics were caused by several conductor issues in 2020. No work is required at this time.
TWG-03	Poor reliability statistics were caused by several insulator failures in 2017 and a broken conductor in 2020. No work is required at this time.
WAL-02	Poor reliability statistics were driven by wind and tree-related events in 2020. No work is required at this time.
WAL-04	Poor reliability statistics were driven by wind and conductor issues in 2020. No work is required at this time.
WAV-01	Poor reliability statistics were caused by wind-related issues in 2017. In addition, there was an outage caused by freezing rain in 2020. No work is required at this time.
WAV-03	Poor reliability statistics were caused by wind-related issues in 2017 and 2019. No work is required at this time.
WES-02	Poor reliability statistics were caused by conductor issues in 2020 and 2021. No work is required at this time.

APPENDIX C:

Photographs of Distribution Feeder SUM-01

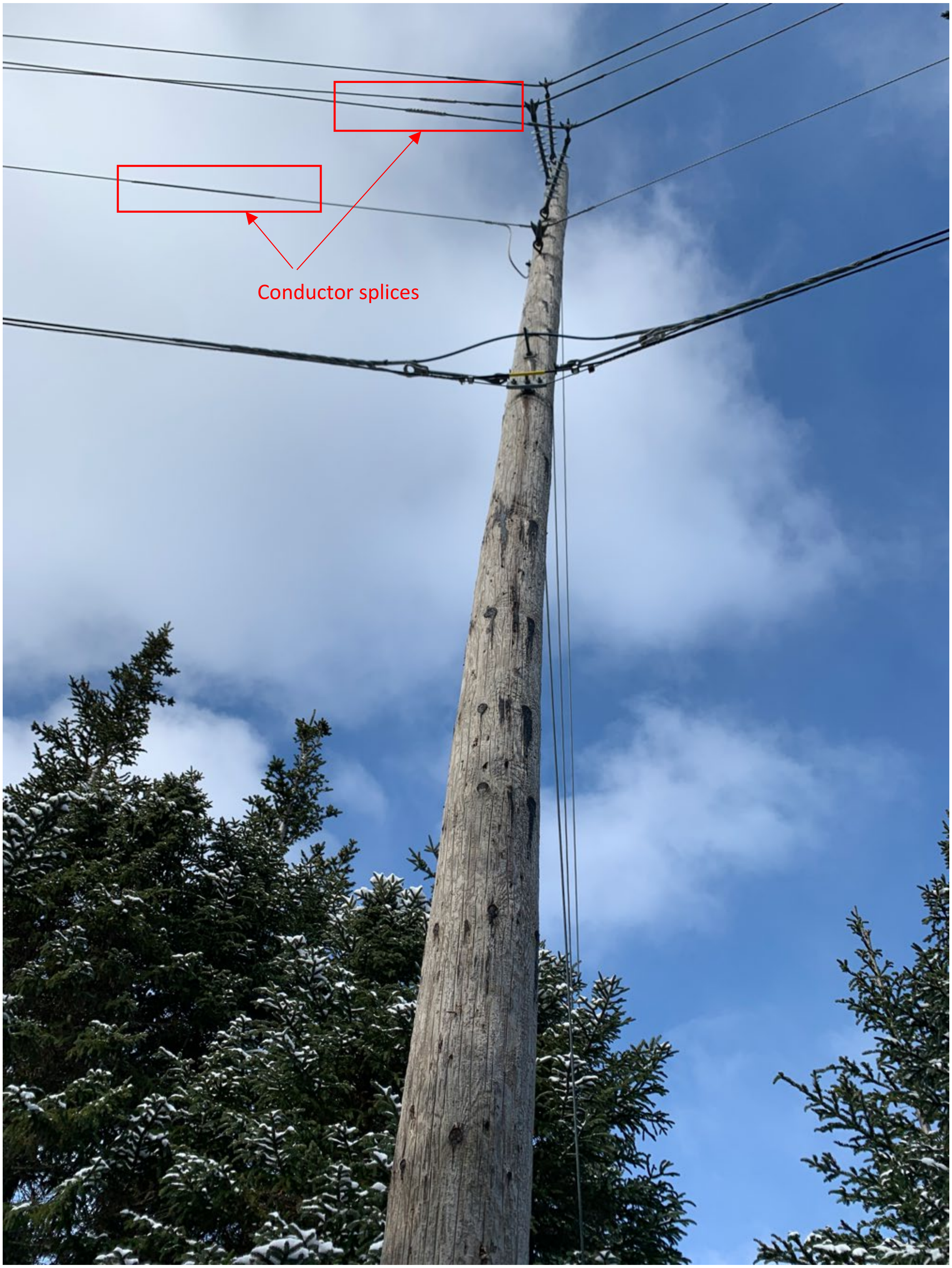


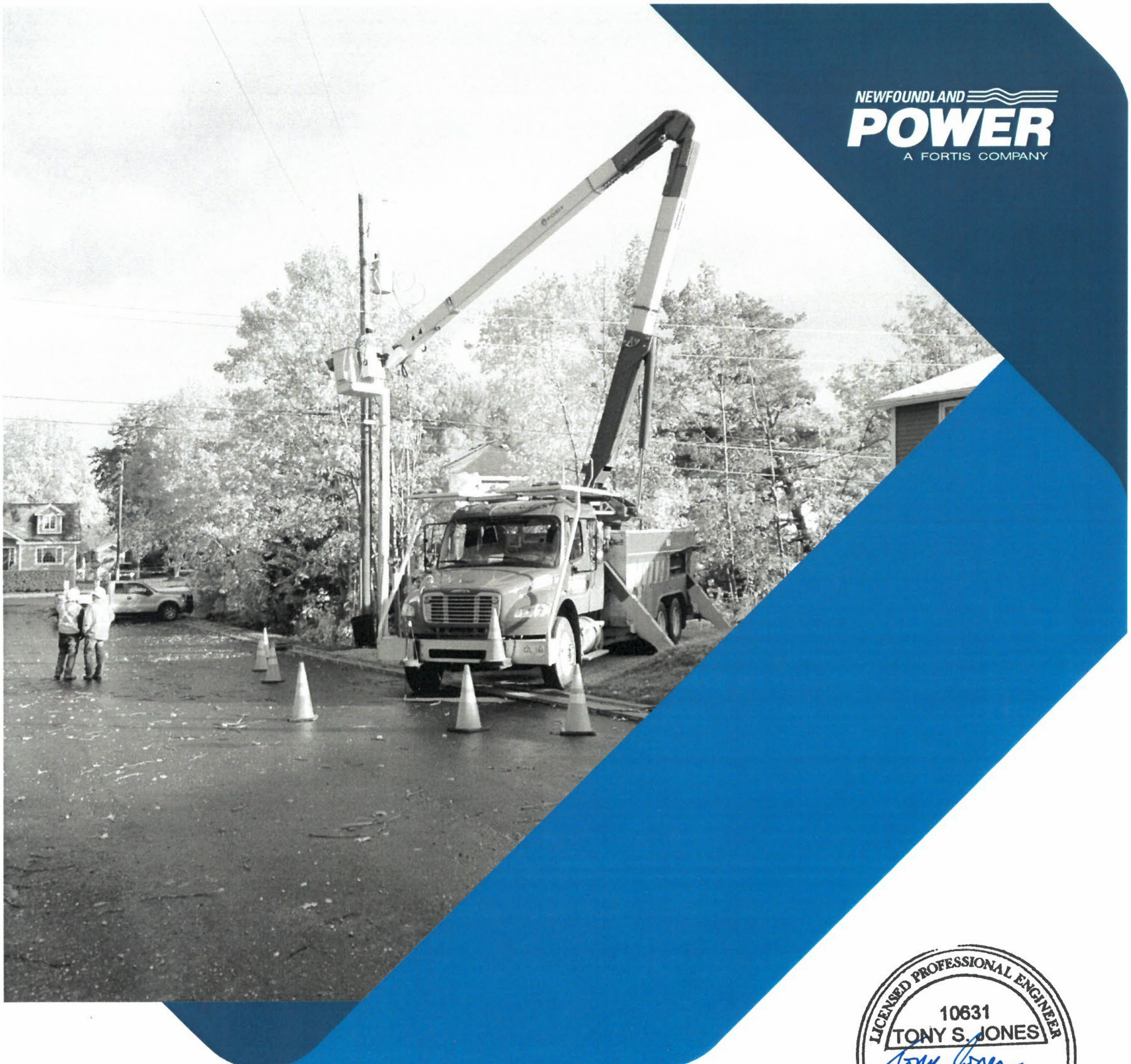
Figure C-1: Previous Conductor Failures

Figure C-2: Deteriorated Crossarm and Porcelain 2-Piece Insulators

Figure C-3: Deteriorated Pole

Figure C-4: Deteriorated Pole with Woodpecker Holes

Figure C-5: Bent Pole and Vintage Insulators



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1.2 Feeder Additions for Load Growth

June 2022

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1.0 INTRODUCTION

As load increases on an electrical system, the components of the system can become overloaded. These overload conditions can occur at the substation level, on equipment such as transformers, breakers and reclosers, or on specific sections of the distribution system.

When an overload condition has been identified, it can often be mitigated through operating practices such as feeder balancing or load transfers.[1] Such practices are low-cost solutions and are completed as normal operating procedures. However, in some cases it becomes necessary to complete upgrades to the distribution system to either increase capacity or alter system configuration in order to eliminate overload conditions. Eliminating overload conditions mitigates risks of in-service equipment failures, which can result in significant repair costs and extended customer outages.

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") has identified two overload conditions to be addressed in 2023 by upgrading existing distribution lines. The overload conditions described in this report can each be attributed to residential growth in the Company's service territory.

2.0 OVERLOADED CONDUCTORS

2.1 General

An overloaded section of conductor on a distribution line is at risk of failure. Failures are caused by overheating of the conductor as the load exceeds the conductor's capacity ratings. As a result, the conductor will have excessive sag, which may result in the conductor coming into contact with other conductors or the conductor breaking, causing a fault and subsequent customer outage and safety hazard. Overloaded conductor can also have a negative impact on restoration efforts following customer outages due to increased conductor loading associated with cold load pick-up.

Newfoundland Power undertakes analysis of distribution feeders using a distribution feeder computer modelling application to identify sections of feeders that may be overloaded. Overload conditions are identified using the computer modelling application. The results are followed up with field visits to ensure the accuracy of information.[2]

[1] Feeder balancing involves transferring load from one phase to another on a three-phase distribution feeder in order to balance the amount of load on each phase. Load transfers involve transferring load from one feeder to another adjacent feeder.

[2] Where necessary, load measurements are taken to verify the results of the computer modelling. The analysis uses conductor capacity ratings based on Newfoundland Power's *Distribution Planning Guidelines*. These ratings are shown in Appendix A.

2.2 Alternatives to Address Overloaded Conductor

There are generally five alternatives to address overloaded conductor. The applicability of each alternative 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 alternatives are:

(i) *Feeder Balancing -* In some cases, conductor may be overloaded on only one phase of a three-phase line. In this situation, it may be possible to remove the overload condition by balancing the downstream loads through load transfers from the highly loaded phase to one of the more lightly loaded phases. In some situations, overload conditions on individual phases can be alleviated by extending the three-phase trunk of the feeder. This is only applicable in situations where all three phases are not overloaded.

(ii) *Load Transfer -* On a looped system, if a tie point exists downstream of the overload condition, it may be possible to transfer a portion of load to an adjacent feeder. However, consideration must be given to the loading on the adjacent feeder to ensure a new overload condition is not created.

(iii) *Upgrade Conductor -* The overload condition can be eliminated by increasing the conductor size on the overloaded section or upgrading overloaded single-phase sections to three-phase.

(iv) *New Feeder -* In cases where the feeder conductor leaving a substation is overloaded, and none of the above alternatives can be used to resolve the overload condition, the addition of a new feeder from the substation may be required to transfer a portion of load from the overloaded conductor.

(v) *Non-Wires Alternatives -* Non-wires alternatives comprise a broad category that encompasses various innovative alternatives to standard "poles and wires" solutions. These include, but are not limited to, distributed energy resources, microgrids and battery storage.

3.0 PROJECT DESCRIPTION

3.1 Overloaded Single-Phase Lines

A heavily loaded single-phase tap can result in unbalanced loads on the three phases of a feeder and subsequent operation of feeder protection mechanisms at the substation. This results 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 taps mitigates reliability and safety risks in providing service to customers.

An analysis of Newfoundland Power's distribution feeders was completed using a distribution feeder computer modelling application to identify single-phase lines that may be overloaded.[3] Where necessary, load measurements were taken to verify the results of the computer simulation.

The analysis identified two locations where single-phase lines are overloaded and single-phase to three-phase upgrade is required, each of which is described below.

3.2 Distribution Feeder PUL-01 Upgrade ($312,000)

Pulpit Rock ("PUL") Substation is located along Whiteway's Pond Road in Torbay. Distribution feeder PUL-01 leaves PUL Substation and extends east along Country Drive and Torbay Road, serving approximately 1,300 residential and commercial customers in the Torbay area.

Figure 1 illustrates the routing for distribution feeder PUL-01.

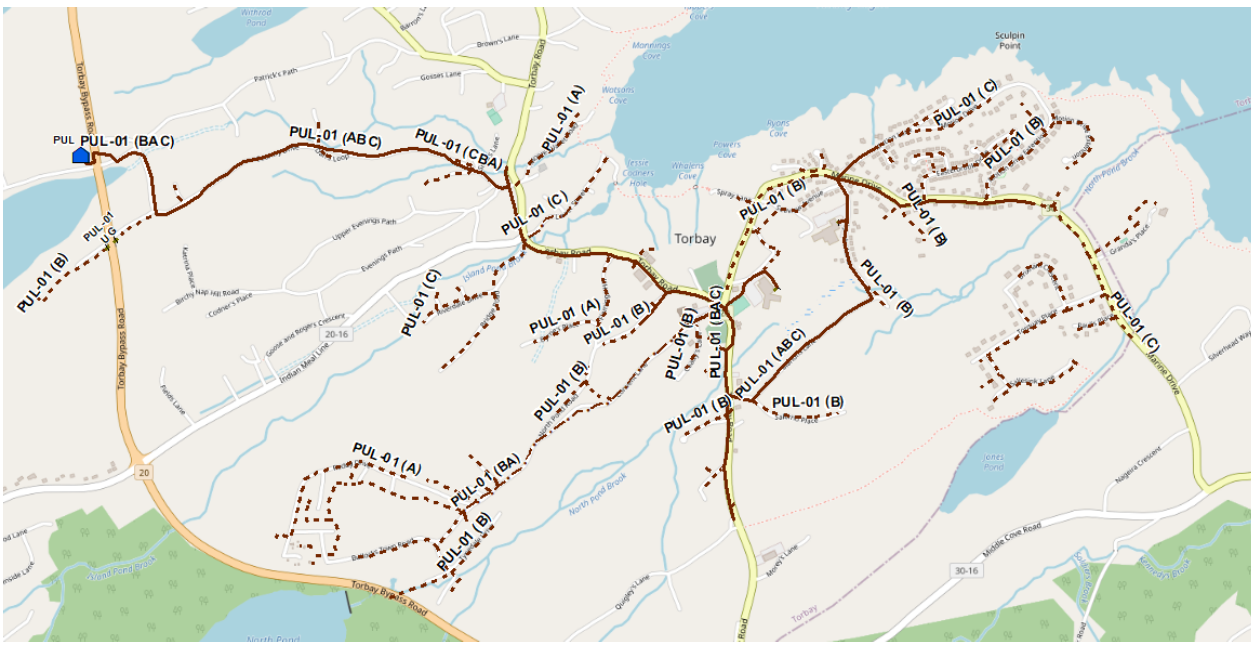

Figure 1: Distribution Feeder PUL-01

A 1.0 kilometre section of single-phase distribution line is overloaded. This section of distribution line extends south on Marine Drive and then west along Torquay Place in the Town of Torbay. Load growth on this single-phase line is mainly attributed to customer connection growth in Jones Pond Park Subdivision, as well as large home renovations and electrical service upgrades in the area of Marine Drive. The number of customers supplied by this line has increased by 76% over the last 15 years.[4]

---

3 Overloaded single-phase taps typically start out as only a few spans in length, but over time can grow into much larger feeder extensions. The growth most often occurs in new subdivisions where a large number of customers requiring single-phase service are added over time.

4 There were 46 customers supplied by this section of line in 2008 and 81 customers in 2022, an increase of 35 customers (35 / 46 = 0.76, or 76%).

An analysis of distribution feeder PUL-01 was completed using a distribution feeder modelling application and verified using actual load measurements. The analysis showed that the load on the identified single-phase section of the feeder is approximately 116 amps, which exceeds the Company's planning criteria for maximum current on a single-phase distribution line.[5]

Three technically viable alternatives were evaluated to mitigate the overloaded section of distribution feeder. These alternatives include a load transfer, upgrading from single-phase to three-phase, and a non-wires alternative. A new feeder build was excluded from consideration due to the relatively high cost associated with the work. Similarly, feeder balancing was excluded as the overloaded section of distribution feeder PUL-01 is single-phase.

Alternative 1: Load Transfer

This alternative would involve transferring load to an adjacent distribution feeder in the vicinity, PUL-05. Transferring load from distribution feeder PUL-01 to PUL-05 would require a feeder upgrade and re-conductoring 1.5 kilometres of single-phase to 3-phase distribution line along Middle Cove Road and Marine Drive. Costs associated with the work are estimated to be $364,000.

Figure 2 illustrates the work that would be required under this alternative.

Figure 2: Alternative 1 - PUL-05 Upgrades Along Middle Cove Road and Marine Drive

5 Newfoundland Power's planning criteria for maximum current on a single-phase distribution line is 85 amps.

Alternative 2: Upgrade Section to Three-Phase

This alternative would involve upgrading the 1.0 kilometre section of single-phase distribution line along Marine Drive and Torquay Place to three-phase 1/0 AASC conductor to resolve the overload condition. Costs associated with the work are estimated to be $312,000.

Figure 3 illustrates the work that would be required under this alternative.

Figure 3: Alternative 2 - PUL-01 Upgrades Along Marine Drive and Torquay Place

Alternative 3: Non-Wires Alternative

This alternative would utilize commercial-grade battery storage technology to provide four hours of on-peak capacity supply. Battery storage would address the overload condition and eliminate the requirement to upgrade distribution feeder PUL-01. Preliminary capital cost estimates associated with the procurement of a battery storage solution for this application are estimated to be approximately $482,000.[6] This does not include engineering, land

[6] The load on the single-phase section of distribution feeder PUL-01 is forecasted to reach 128 amps over the next 20 years. To offload this single-phase section to be within Newfoundland Power's planning limits of 85 amps, a 1.24 MWh battery storage system would be required to provide four hours of on-peak capacity. Based on current battery storage costs of $389/kWh obtained from *Cost Projections for Utility-Scale Battery Storage: 2021 Update,* June 2021, prepared for the National Renewable Energy Laboratory by Cole et al, the preliminary procurement cost of this solution is $482,000. This does not include operating and maintenance costs.

procurement, site preparation, battery system installation or interconnection to the distribution system.

Recommended Alternative

Of the technically viable alternatives considered, upgrading the overloaded section of distribution feeder PUL-01 from single-phase to three-phase is the least-cost alternative. This alternative is therefore recommended to address overload conditions in the area.

3.3 Distribution Feeder PUL-04 Upgrade ($358,000)

Distribution feeder PUL-04 leaves PUL Substation and extends south along Torbay Bypass Road and turns west onto Indian Meal Line. This distribution feeder serves 1,321 residential and commercial customers in the Torbay area.

Figure 4 illustrates the routing for distribution feeder PUL-04.

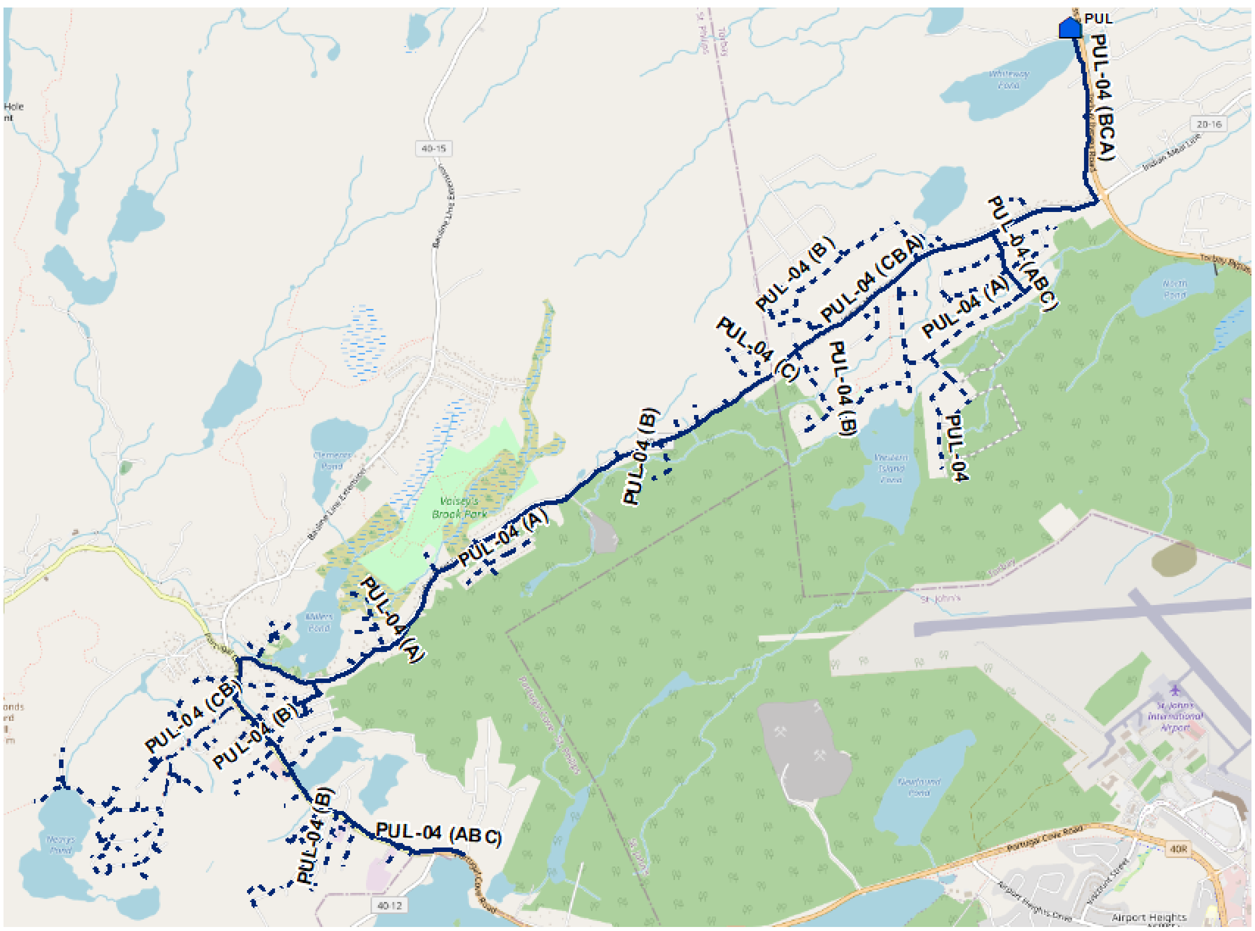

Figure 4: Distribution Feeder PUL-04

A 1.2 kilometre section of single-phase distribution line is overloaded. This section of line extends south on Western Island Pond Drive and then east on Forest River Road before turning on to Captain Matthew Davis Drive in the Town of Torbay. Load growth on this single-phase line can be attributed to customer connection growth in the Forest Landing Subdivision. The number of customers supplied by this line has increased considerably over the last 15 years.[7] Additional load growth in this area is expected to continue with an extension of the Forest Landing Subdivision scheduled to start in 2022. A total of 89 future lots are planned for this development.

An analysis of distribution feeder PUL-04 was completed using a distribution feeder modelling application and verified using actual load measurements. The analysis showed that the load on the identified single-phase section of the feeder is approximately 185 amps, which exceeds the Company's planning criteria for maximum current on a single-phase distribution line.[8]

Four technically viable alternatives were evaluated to mitigate the overloaded section of distribution feeder. These alternatives include two load transfer alternatives, upgrading from single-phase to 3-phase, and a non-wires alternative. A new feeder build was excluded from consideration due to the relatively high cost associated with the work. Similarly, a feeder balancing alternative was excluded as the overloaded section of distribution feeder PUL-04 is single-phase.

Alternative 1: Load Transfer from Rattling Brook Road

This alternative would involve reducing the load on Western Island Pond Drive by supplying Forest River Road through an existing feeder tie-point connected to Rattling Brook Road. However, to reduce the load on Western Island Pond Drive to fall within planning guidelines for a single-phase tap, an overload condition would be created on Forest River Road. To alleviate this, 1.2 kilometres of line would need to be upgraded from single-phase to 3-phase along Forest River Road. The cost of reconfiguring and upgrading the Forest Pond Road distribution line is estimated to be $358,000.

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7 There were six customers supplied by this section of line in 2008 and 46 customers in 2022, an increase of 40 customers (40 / 6 = 6.67, or 667%).

8 Newfoundland Power's planning criteria for maximum current on a single-phase distribution line is 85 amps.

Figure 5 illustrates the work that would be required under this alternative.

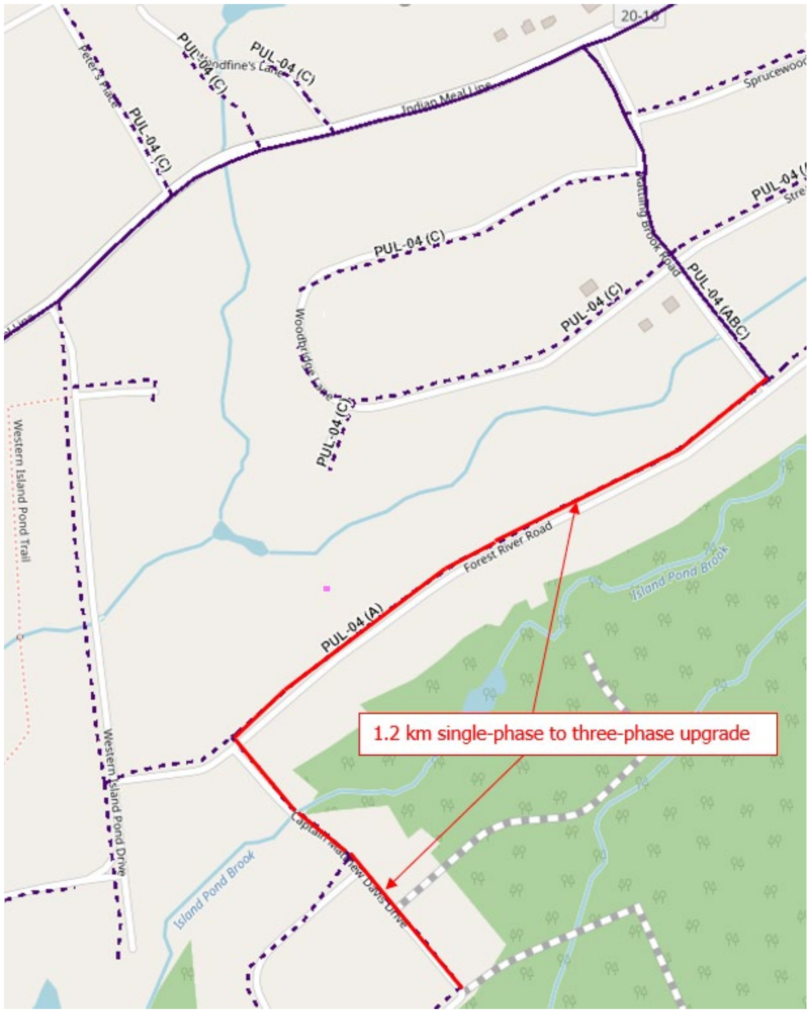

Figure 5: PUL-04 Upgrades Along Forest River Road

Alternative 2: Load Transfer from Skippers Landing

This alternative would involve reducing the load on Western Island Pond Drive through an existing feeder tie-point connected to Skippers Landing. However, to reduce the load on Western Island Pond Drive to fall within planning guidelines for a single-phase tap, an overload condition would be created on Skippers Landing. To resolve this, 1.9 kilometres of line would need to be upgraded from single-phase to three-phase along Skippers Landing. The cost of reconfiguring and upgrading the Skippers Landing distribution line is estimated to be $459,000.

Figure 6 illustrates the work that would be required under this alternative.

Figure 6: PUL-04 Upgrade Along Skippers Landing

Alternative 3: Upgrade Single-Phase Section to Three-Phase 1/0 AASC

This alternative would involve upgrading the overloaded 1.2 kilometre section of distribution feeder PUL-04 from single-phase to three-phase 1/0 AASC conductor. The cost associated with this work is estimated to be $358,000.

Figure 7 illustrates the work required for this alternative.

Figure 7: PUL-04 Upgrades Along Western Island Pond Drive, Forest River Road, and Captain Matthew Davis Drive

Alternative 4: Non-Wires Alternative

This alternative would utilize commercial-grade battery storage technology to provide four hours of on-peak capacity supply. This alternative would address the overload condition and eliminate the requirement to upgrade distribution feeder PUL-04. Preliminary costs associated with the procurement of a battery storage solution for this application are estimated to be approximately $1.4 million.[9] This does not include engineering, land procurement, site preparation, battery system installation or interconnection to the distribution system.

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[9] The load on the single-phase section of PUL-04 is forecasted to reach 211 amps over the next 20 years. To offload this single-phase section to be within Newfoundland Power's planning limits of 85 amps, a 3.64 MWh battery storage system would be required to provide four hours of on-peak capacity. Based on current battery storage costs of $389/kWh obtained from *Cost Projections for Utility-Scale Battery Storage: 2021 Update,* June 2021, prepared for the National Renewable Energy Laboratory by Cole et al, the estimated procurement cost of this solution is $1,416,000. This does not include operating and maintenance costs.

Recommended Alternative

The alternatives of transferring load from Skippers Landing or installing battery storage were eliminated from consideration due to their relatively higher capital costs. The two remaining alternatives of transferring load from Rattling Brook Pond and upgrading the overloaded section of distribution feeder PUL-04 from single-phase to three-phase have equivalent capital costs. However, the upgrading alternative would result in greater capacity to supply future load growth expected in the area. This alternative is therefore recommended to address overload conditions in the area.

4.0 PROJECT COST

Table 1 provides the cost of the *Feeder Additions for Load Growth* project to address overload conditions on distribution feeders PUL-01 and PUL-04 in 2023.

Table 1
Feeder Additions for Load Growth Project
2023 Project Cost
($000s)

Cost Category	PUL-01	PUL-04	Total
Material	66	114	180
Labour – Internal	92	127	219
Labour - Contract	149	107	256
Engineering	5	10	15
Other	0	0	0
Total	**312**	**358**	**670**

The total cost of the *Feeder Additions for Load Growth* project is $670,000 in 2023.

5.0 CONCLUSION

The *Feeder Additions for Load Growth* project for 2023 includes:

(i) Upgrading a 1.0 kilometre single-phase section of distribution feeder PUL-01 along Marine Drive and Torquay Place to three-phase 1/0 AASC; and

(ii) Upgrading a 1.2 kilometre single-phase section of distribution feeder PUL-04 along Western Island Pond Drive, Forest River Road and Captain Matthew Davis Drive to three-phase 1/0 AASC.

Completing these upgrades in 2023 will address overload conditions resulting from customer growth in the Town of Torbay and ensure the provision of safe and reliable service to customers in this area.

APPENDIX A:

Distribution Planning Guidelines
Conductor Ampacity Ratings

Table A-1 Aerial Conductor Ampacity Ratings						
Size and Type	Continuous Winter Rating[1]	Continuous Summer Rating[2]	Planning Ratings[3] CLPU Factor[4] = 2.0 Sectionalizing Factor[5] = 1.33			
	Amps	Amps	Amps	MVA		
				4.16 kV	12.5 kV	25.0 kV
1/0 AASC	303	249	228	1.6	4.9	9.8
4/0 AASC	474	390	356	2.6	7.7	15.4
477 ASC	785	646	590	4.2	12.7	25.5
#2 ACSR	224	184	168	1.2	3.6	7.3
2/0 ACSR	353	290	265	1.9	5.7	11.4
266 ACSR	551	454	414	3.0	8.9	17.9
397 ACSR	712	587	535	3.9	11.6	23.1
#6 Copper	175	125	132	0.95	2.9	5.7
#4 Copper	203	166	153	1.1	3.3	6.6
1/0 Copper	376	309	283	2.0	6.1	12.2
2/0 Copper	437	359	329	2.4	7.1	14.2

1 The winter rating is based on ambient conditions of 0ºC and 2 ft/s wind speed.
2 The summer rating is based on ambient conditions of 25ºC and 2 ft/s wind speed.
3 The planning rating is theoretically 75% of the winter conductor ampacity. In practice, the actual percentage will be something less due to: (i) the age and physical condition of the conductor; (ii) the number of customers on the feeder; (iii) the ability to transfer load to adjacent feeders; and (iv) operational considerations including the geographic layout and the distribution of customers on the feeder.
4 Cold load pick-up ("CLPU") occurs when power is restored after an extended outage. On feeders with electric heat, the load on the feeder can be 2.0 times as high as the normal winter peak load. This is the result of all electric heat coming on at once when power is restored. The duration of CLPU is typically between 20 minutes and one hour.
5 A two-stage sectionalizing factor is used during CLPU conditions to increase the Planning Rating of aerial conductors. Restoring power to one section of the feeder at a time reduces the overall effect of CLPU. The sectionalizing factor is the fraction of the load that is restored in the first stage multiplied by the CLPU factor. The optimal portion of the total load on a feeder that is restored in the first stage is 0.66, resulting in a sectionalizing factor of 0.66 x 2.0 = 1.33.

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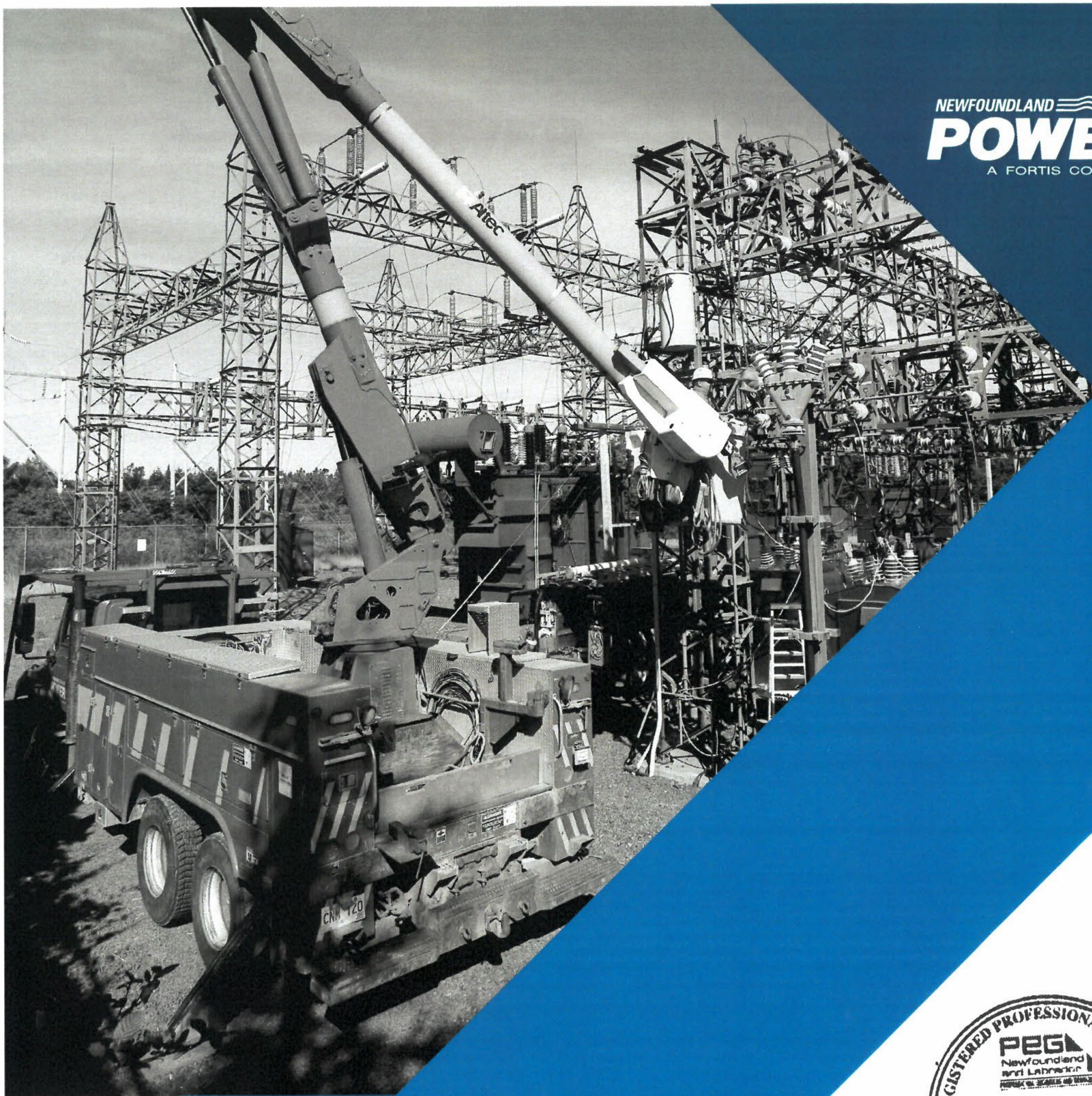

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2.1 2023 Substation Refurbishment and Modernization

June 2022

Prepared by: Michael Power, P. Eng.

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1.0 INTRODUCTION

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") operates 131 substations located throughout its service territory. These include: (i) generation substations that connect generating plants to the electrical system; (ii) transmission substations that connect transmission lines of different voltages; and (iii) distribution substations that connect the low-voltage distribution system to the high-voltage transmission system. 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.*[1] The plan focuses on the refurbishment and modernization of individual substations based on the condition of core infrastructure and equipment.

In 2023, the Company is proposing to refurbish and modernize: (i) Walbournes Substation in the City of Corner Brook at a cost of $4,955,000; and (ii) Molloy's Lane Substation in the City of St. John's at a cost of $4,827,000. Both substations serve large numbers of customers in urban areas and contain a considerable amount of deteriorated and obsolete equipment that pose a risk to their reliable operation.

This report provides an update on Newfoundland Power's *Substation Refurbishment and Modernization Plan* and the overall condition of substation assets, and details the two refurbishment and modernization projects proposed for 2023.

2.0 BACKGROUND

2.1 Substation Refurbishment and Modernization Plan

Good utility practice involves a structured and comprehensive approach to preventative and corrective maintenance for critical substation assets. Maintenance programs are intended to keep critical assets in good working order, prolong their life and protect against in-service failures with significant consequences.

Newfoundland Power's substations are inspected eight times annually. These inspections identify preventative and corrective maintenance necessary to ensure the reliable operation of critical substation assets.

Inspection results are incorporated into the Company's annual update of its *Substation Refurbishment and Modernization Plan*. Under this plan, individual refurbishment and modernization projects are coordinated with the maintenance cycle for major substation equipment. This coordination provides reliability and productivity benefits for customers.

[1] Newfoundland Power's *Substation Refurbishment and Modernization Plan* is an element of the *Substation Strategic Plan* filed with its *2007 Capital Budget Application*.

Table 1 provides the latest update of the *Substation Refurbishment and Modernization Plan*.

Table 1
Substation Refurbishment and Modernization Plan
2023-2027
($000s)

2023		2024		2025		2026		2027	
SUB	Cost	SUB	Cost	SUB	Cost	SUB	Cost	SUB	Cost
WAL	4,955	GAM	4,299	BLA	1,421	BLK	753	GOU	5,782
MOL	4,827	LOK	2,599	BCV	3,595	DLK	759	LAU	2,222
		MOP	2,356	BOT	1,124	GBY	5,819	PHR	2,476
		MUN	3,365	ISL	1,190	GFS	510	SMV	2,922
				LLK	2,739	HWD	1,438		
				OPL	2,552	MRP	300		
						PBD	1,927		
						SLA	984		
		MISC	2,123	MISC	2,348	MISC	2,617	MISC	2,940
$9,782		$14,742		$14,969		$15,107		$16,342	

Note: SUB: Substation (See the Electrical System Handbook included with the *2006 Capital Budget Application* for three-letter substation designations.)
MISC: Miscellaneous Substation Equipment Replacements

Newfoundland Power's current plan includes the refurbishment and modernization of 24 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, as described below. Refurbishment and modernization projects will continue to focus on addressing obsolete and deteriorated equipment in individual substations.

2.2 Substation Asset Assessment

Substations include a combination of electrical system equipment, such as power transformers and circuit breakers, and civil infrastructure, such as bus structures and buildings. The following section provides an update on the age and condition of major substation equipment and infrastructure, including the strategy for addressing these assets during refurbishment and modernization projects.

Overall, the assessment shows that substation asset management practices have improved the age and risk profile of certain assets, such as reclosers and circuit breakers. However, continued execution of the *Substation Refurbishment and Modernization Plan* is necessary to continue replacing obsolete and deteriorated substation equipment and infrastructure.

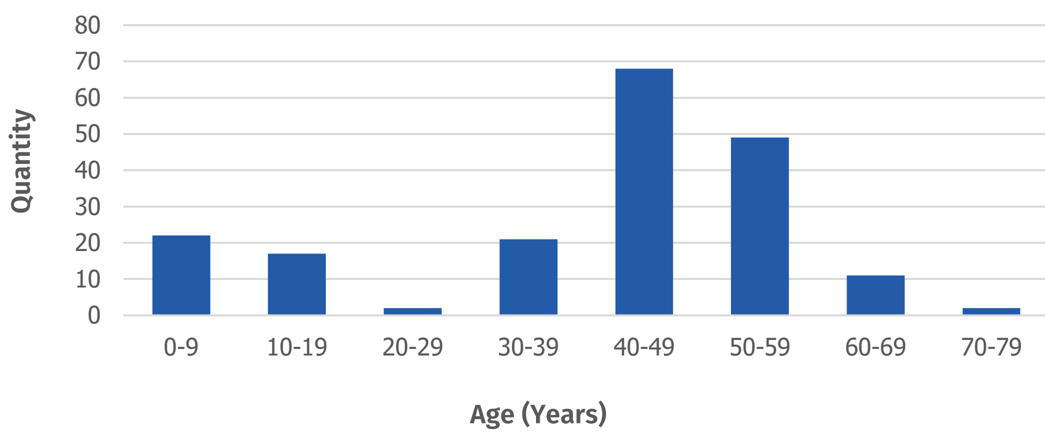
Power Transformers

Newfoundland Power has 192 substation power transformers in service. Power transformers are the most critical assets in a substation. 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,[2] with a sharp decline for in-service power transformers past 70 years of age.[3] The load profile in Newfoundland and Labrador is favorable for transformer life expectancy, as the highest loads are experienced in the winter when the ambient temperatures are the lowest.[4]

Figure 1 shows the age distribution of the Company's power transformers.

Figure 1
Power Transformer Age Distribution



Newfoundland Power's power transformers have historically exceeded what is typically seen in the industry, with 32% of the Company's transformer fleet at 50 years in service or older.

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2 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.

3 Based on 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.

4 The transformer temperature is influenced by the ambient temperature. The transformer temperature is one of the main factors affecting the winding insulation life of a transformer. Many transformer failures are a result of a breakdown of the winding insulation.

Given the age profile of the Company's transformer fleet, the probability of transformer failures will continue to increase as their condition degrades with age.

Newfoundland Power will continue conducting oil sampling and analysis to gauge the internal health of transformers and plan transformer replacements based upon this predictive style of maintenance.[5] Additionally, the Company has proposed to maintain a spare power transformer inventory to help manage risks associated with the increasing age of its transformer fleet and potential impacts on the provision of service to customers.[6]

Circuit Breakers

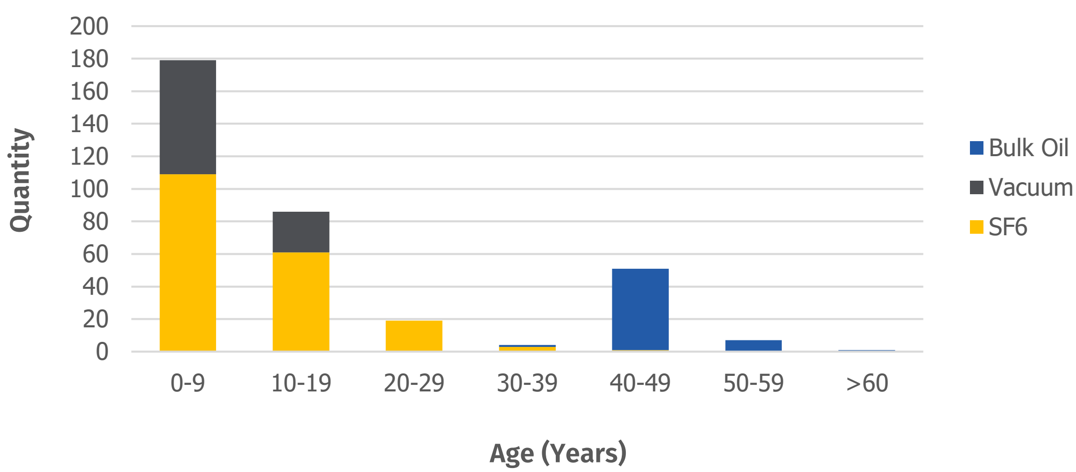
Newfoundland Power has 347 circuit breakers in service.[7] Circuit breakers are critical components of the transmission and distribution system. The failure of a circuit breaker to operate when required increases the risk of customer outages and damage to other assets.

The most common types of breakers currently in service are the SF6 and vacuum types.[8] A majority of the SF6 type breakers were installed to replace older bulk-oil type breakers. There remains a small number of older bulk-oil type breakers still in service.

Industry experience indicates the expected life of circuit breakers is between 30 and 50 years.

Figure 2 shows the age distribution of the Company's circuit breaker fleet.

Figure 2
Circuit Breaker Age Distribution



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5 Additional testing 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.

6 See the *2023 Capital Budget Application, report 2.2 Substation Spare Transformer Inventory.*

7 There are additional circuit breakers located in switchgear in the Company's substations and generation plants. This quantity of 347 breakers excludes switchgear circuit breakers.

8 Sulfur hexafluoride ("SF6") gas is used in high voltage circuit breaker design to extinguish the electrical arc created when opening energized breaker contacts.

The age profile of Newfoundland Power's circuit breakers has been much improved since 2007 as a result of the *Substation Refurbishment and Modernization*, *PCB Bushing Phase-out*, and *Replacements Due to In-Service Failures* projects.

There are 193 SF6 type breakers in service. The majority of these breakers are less than 20 years old, with an average age of 10 years.

While the age of the Company's SF6 circuit breakers is generally favourable, certain models are experiencing operational issues. Forty-four Hyosung SF6 circuit breakers were installed between 2008 and 2016.[9] These breakers have started to experience issues with excessive SF6 leaks, with nine of these units having gaskets replaced to address this issue. These breakers are being monitored closely for further leakage issues and will be repaired as required. Additionally, 30 Westinghouse/Siemens SF6 circuit breakers were installed between 1980 and 1990. These breakers are also susceptible to SF6 leaks and repairs are often not possible.[10] These breakers are replaced as problems occur and through *Substation Refurbishment and Modernization* projects.[11]

There are 59 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 46 years old.[12]

The small number of bulk-oil type breakers that remain in service are approaching the end of their useful service life. GE KSO and GE FKP oil-filled breakers comprise 90% of those in service. GE KSO breakers were manufactured from 1976 to 1991, have an average age of 43 years and can no longer be economically maintained.[13] The GE FKP breakers were manufactured from 1975 to 1982 and have an average age of 47 years. The age and condition of these breakers pose environmental risks as they can contain between 55 and 2,750 gallons of oil.

Currently, all new breakers being purchased are either SF6 or vacuum type, depending on the required voltage and fault interrupting capability.

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9 There are 18 66 kV breakers and 26 138 kV breakers.

10 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.

11 A majority of these breakers have been replaced, with only two remaining in service. These breakers are 33 and 41 years old and are at the end of their service life.

12 There are eight breaker replacements associated with the *PCB Bushing Phase-out* project that are scheduled to be completed in 2022. In 2023, there will be 51 bulk-oil type breakers remaining in service.

13 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.

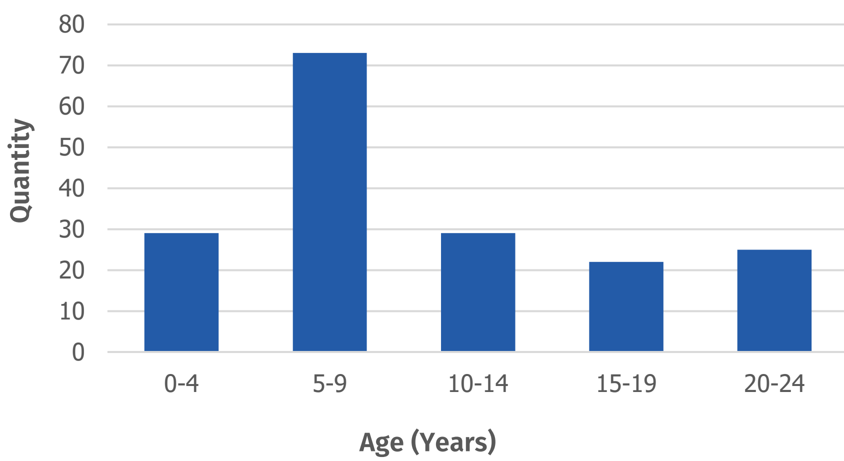
Reclosers

Newfoundland Power has 178 substation reclosers in service.[14] Following the completion of the feeder automation program in 2019, all in-service substation reclosers are either vacuum type or vacuum type insulated with SF6 gas.[15]

Industry experience indicates the expected life of reclosers is between 30 and 50 years.

Figure 3 shows the age distribution of the Company's substation reclosers.

Figure 3
Recloser Age Distribution



With the completion of the *Substation Feeder Automation* program in 2019, the age profile of the Company's substation reclosers is favourable.[16] All substation reclosers are currently less than 21 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 76 Nulec reclosers installed between 2001 to 2012 for

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14 There are additional reclosers located on the Company's distribution feeders. This quantity of 178 reclosers excludes the downline reclosers installed on distribution feeders.

15 In 2015, as part of the *Substation Refurbishment and Modernization* project, the Company initiated a five-year *Substation Feeder Automation* program to modernize its substation reclosers by replacing all of the other hydraulics reclosers.

16 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.

distribution feeder protection.[17] Over the past five years, eight of these reclosers have required replacement.[18] 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.

Switchgear

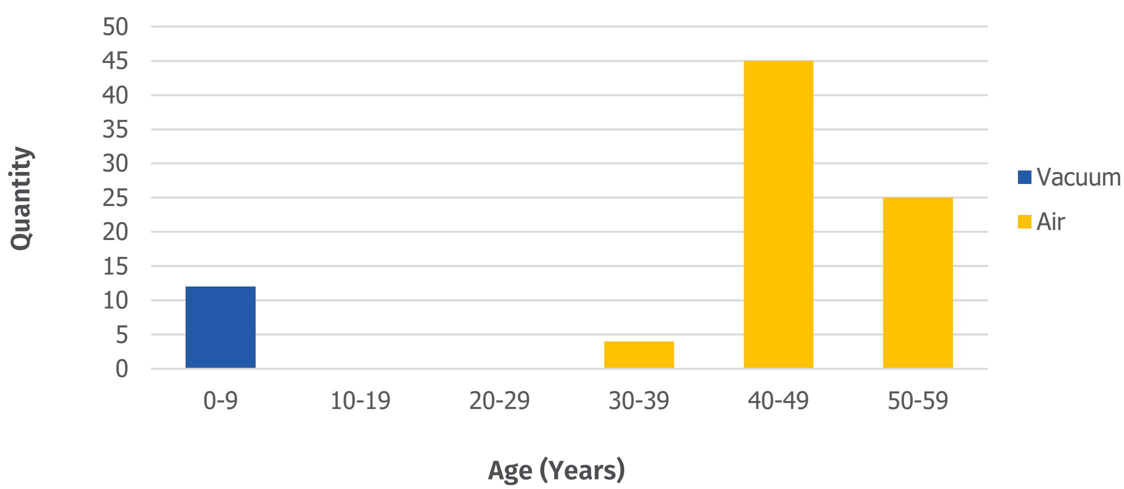
Newfoundland Power has eight substations with 11 distribution switchgear lineups.[19] The majority of this switchgear is operated at 12.5 kV distribution voltage; however, there are two locations with 4.16 kV switchgear.[20] The Company's substation switchgear consists of a total of 86 individual circuit breakers.[21]

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.

Figure 4 shows the age distribution of the Company's switchgear breakers.

Figure 4
Substation Switchgear Breaker Age Distribution



17 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.

18 Six of these failures have occurred in the last two years.

19 There are also 27 switchgear lineups associated with the Company's generation plants.

20 The only 4.16 kV distribution switchgear remaining in service are located at the Company's Grand Falls ("GFS") and Stamps Lane ("SLA") substations.

21 The most common type of switchgear breakers currently in-service are air-blast circuit breakers.

The majority of Newfoundland Power's substation switchgear breakers were purchased in the 1960s and 1970s. Approximately 29% of the Company's switchgear breakers have been in service for 50 years or more, which is the upper limit of typical industry experience. There is a high risk that in-service failures will occur as the switchgear breakers continue to age and deteriorate.

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 to mitigate arc flash hazards.[22] Arc flash technologies on newer switchgear mitigate this hazard to prevent injury to personnel and mitigate equipment damage.[23] Replacing end of life switchgear mitigates safety risks, equipment damage and supply interruptions impacting reliable service to customers.

Protection Relays

Protective relaying protects transmission lines, substation equipment and distribution feeder circuits. Newfoundland Power currently uses electromechanical relays, digital relays and controllers to protect its equipment. Failure of protective relaying can result in widespread outages, cause significant equipment damage, and jeopardize the safe operation of the electrical system.

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.[24] 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.[25]

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22 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.

23 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.

24 In its *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power,* December 17, 2014, The Liberty Consulting Group, examined Newfoundland Power's practice of replacing multiple obsolete electromechanical relays with a single modern microprocessor-controlled relay and concluded that the Company uses reasonable practices that conform to industry practice.

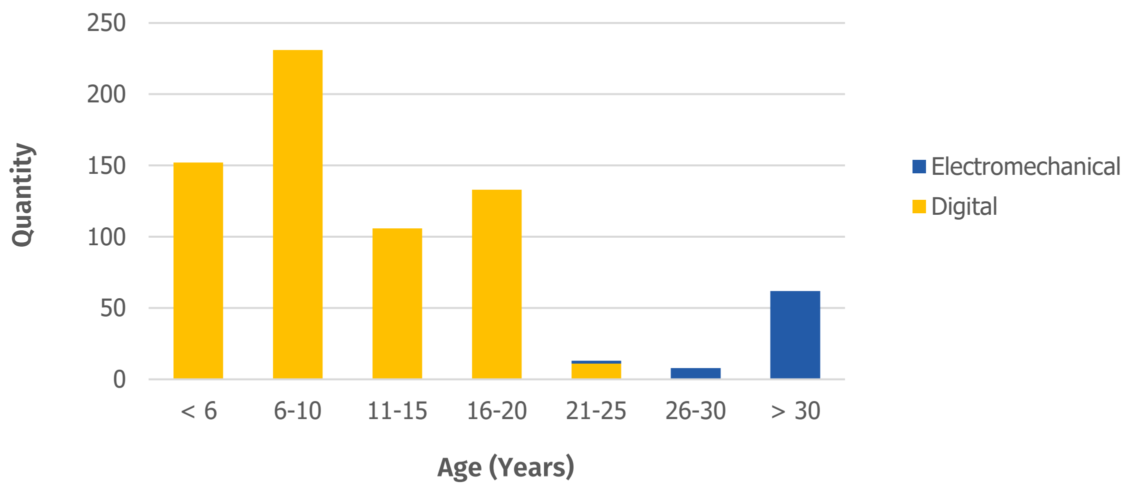
25 Remote administration of upgraded devices allows protection relays to be interrogated and reconfigured remotely. This allows engineers to interrogate protection relays remotely, providing quicker diagnosis of system problems. Without this capability, engineers would have to travel to the substation to interrogate the relay on site, thereby increasing the time necessary to diagnose fault data and restore service to customers.

Over the past 20 years, Newfoundland Power has upgraded most of the electromechanical protection devices. However, 10% of the protection devices currently in service are still electromechanical.

Industry experience indicates the expected useful service life for electromechanical relays is 20 to 30 years, and 10 to 25 years for digital relays.

Figure 5 provides the age distribution of Newfoundland Power's electromechanical and digital relays.

Figure 5
Electromechanical and Digital Relay Age Distribution



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.

Operating issues with the Company's older in-service digital relays have highlighted the need for asset replacement. This includes digital relays and controllers that are approaching 20 years in service. For example, since 2015, 11 Micom P142 relays have failed in-service and required replacement.[26] There are a number of other in-service relays that will soon reach the end of the expected life for digital relays.[27]

26 There are currently 118 Micom P142 relays in service. Micom P142 relays were installed from 2002 until 2017 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 65% of the in-service Micom P142 devices.

27 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.[28] Newfoundland Power has approximately 3,500 high voltage switches in service.

Switches that are operated infrequently tend to seize due to deterioration of bushings, corrosion in operating mechanisms or misalignment of blades. Substation switches such as transformer isolating and bus tie switches are operated infrequently. Consequently, they are susceptible to this form of failure.[29]

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.

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.[30] 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 more sensitive means of protection from internal faults.

Another method of providing transformer protection is to incorporate a high-speed ground switch for transformers up to 10 MVA.[31] The high-speed ground switch operates by providing a deliberate single-phase ground fault on the high voltage side of the power transformer.[32] 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.[33]

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28 This includes switches of all high voltage classes including 12.5 kV, 25 kV, 66 kV, and 138 kV.

29 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.

30 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.

31 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.

32 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.

33 The time for a high-speed ground switch to operate and the upstream circuit breaker to trip is slower than a standard circuit breaker operation.

Newfoundland Power has 18 fuses installed for transformer protection on transformers rated 10 MVA or higher, which is not industry standard. There are currently 12 high-speed ground switches in service being utilized for transformer protection.[34]

Proper transformer protection conforming with current standards is required to safely and reliably operate the electrical system. Replacing fuses and high-speed ground switches with circuit breakers provides a standard form of transformer protection that conforms to current standards.[35]

Bus Structures and Foundations

Bus structures are galvanized steel or wood pole structures that support the switches, insulators, and conductors in a substation.[36] Galvanized steel structures last longer than wood structures and are essentially maintenance-free. Steel structures are also more stable than wood structures as wood pole structures move and twist over time. This makes steel structures better suited to ensure that high voltage switches stay properly aligned, reducing maintenance, repair, and replacement of switches.

Many of the existing wooden bus structures in substations are between 60 and 70 years of age. Wooden structures over 50 years of age show signs of deterioration such as rotting, cracking, checking and splitting. This deterioration necessitates the replacement of some or all of the structure.

Newfoundland Power's existing steel structures are generally in good condition. However, 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 these as required.

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.[37] 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.[38] Newfoundland Power installs concrete containment foundations for power transformers to manage the environmental risk from oil spills.

3.0 ASSESSMENT OF ALTERNATIVES

The age and condition of Newfoundland Power's substations shows that certain critical substation equipment and infrastructure is reaching the end of its useful service life and is prone to deterioration or obsolescence. Preventative and corrective maintenance continues to

34 Nine of the 12 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.

35 Circuit breakers also provide the ability to remotely control the energization of the transformer through the Company's SCADA system.

36 Newfoundland Power has approximately 125 wooden and 135 steel bus structures.

37 See https://standards.ieee.org/ieee/980/7038/.

38 See https://standards.ieee.org/ieee/979/3665/.

be required to address substation equipment and infrastructure that is deteriorated, obsolete and at imminent risk of failure.

There are generally two alternative approaches to addressing maintenance in substations:

(i) Alternative 1 – Component Replacement

Alternative 1 focuses on the replacement of specific components at various substations throughout Newfoundland Power's service territory. This can include components that are identified as obsolete, failed or prone to failure based on operating experience. Under this alternative, work is prioritized based on the condition and criticality of a specific piece of equipment.

(ii) Alternative 2 – Refurbishment and Modernization

Alternative 2 involves undertaking refurbishment and modernization projects at individual substations. This approach focuses on addressing a large number of deficiencies at individual substations that are identified as being in poor condition. Under this alternative, projects are prioritized based on the condition of individual substations where a large volume of work is required.

Both the component replacement and refurbishment and modernization approaches are viable alternatives to address maintenance requirements in substations.

In Newfoundland Power's experience, implementing a combination of these alternatives allows the Company to maintain the overall condition of its 131 substations.

For 2023, the Company has proposed three programs and projects that address component replacements at various substations. The *Substation Replacements Due to In-Service Failures* program addresses equipment at various substations that has failed or is at imminent risk of failure. This program allows Newfoundland Power to respond to equipment failures that occur throughout normal operations, which are generally not predictable. The *Substation Protection and Control Replacements* project replaces obsolete electromechanical protection relays with industry standard digital relays. This project allows the Company to focus on replacing a specific piece of equipment that is obsolete and poses a risk to the safe and reliable operation of the electrical system. The *Substation Ground Grid Upgrades* project ensures substation ground grids are compliant with industry standards.

The *Substation Refurbishment and Modernization Plan* allows Newfoundland Power to focus on the condition of individual substations. Refurbishment and modernization projects are proposed when an individual substation contains a material amount of aged, deteriorated and obsolete equipment.

Implementation of the *Substation Refurbishment and Modernization Plan* provides both productivity and service benefits for customers. Focusing on a large volume of work required at a specific substation increases employee productivity and efficiency by reducing supervisory requirements, travel time, accommodation expenses and overhead expenses associated with job safety planning and environmental management planning. Since conducting work on critical equipment generally requires a substation to be removed from service, this approach also reduces requirements for customer outages and optimizes the deployment of portable substations required to maintain service to customers.

Newfoundland Power's substation asset management practices were reviewed by the Board of Commissioners of Public Utilities' (the "Board") consultant, The Liberty Consulting Group, in 2014 and were found to be consistent with good utility practice.[39]

4.0 PROJECT SCOPE AND COST

4.1 Walbournes Substation

Walbournes Substation was constructed in 1966 and serves approximately 6,900 customers in the Corner Brook area as a transmission and distribution substation.

A condition assessment has determined the substation contains a significant amount of deteriorated and obsolete equipment. The 12.5 kV switchgear is at end of life. The 66 kV switches are deteriorated and some components have experienced failures. The electromechanical protection relays at the substation are obsolete and the vintage digital protection relays are at end of life and have experienced failures. The least-cost alternative to refurbish and modernize this substation involves removing the existing building and 12.5 kV indoor switchgear and replacing it with outdoor distribution equipment and a new control building. The refurbishment and modernization of Walbournes Substation in 2023 will address these deficiencies.

Appendix A provides a detailed condition assessment and scope for the *Walbournes Substation Refurbishment and Modernization* project.

[39] Conclusion 3.6 of The Liberty Consulting Group's *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power,* December 17, 2014, stated that: *"Newfoundland Power's substation inspection, corrective maintenance, and preventive maintenance practices are consistent with good utility practices."*

Table 2 provides a detailed breakdown of the *Walbournes Substation Refurbishment and Modernization* project for 2023.

Table 2
Walbournes Substation
Refurbishment and Modernization Project
2023 Project Cost
($000s)

Cost Category	($000s)
Material	3,788
Labour – Internal	194
Labour – Contract	0
Engineering	818
Other	155
Total	$4,955

The project to refurbish and modernize Walbournes Substation is estimated to cost $4,955,000 in 2023.

4.2 Molloy's Lane Substation

Molloy's Lane Substation was constructed in 1960 and serves approximately 8,900 customers in the west end area of St. John's.

A condition assessment of the substation shows that it contains a significant amount of deteriorated and obsolete equipment. The 66 kV wood pole structure at the substation is deteriorated. Many 66 kV and 12.5 kV switches are deteriorated and some have experienced failure. The electromechanical protection relays are obsolete and the vintage digital protection relays are at end of life and have experienced failures. The substation also lacks standard transformer spill containment to protect against environmental hazards. The refurbishment and modernization of Molloy's Lane Substation in 2023 will address these deficiencies.

Appendix B provides a detailed condition assessment and scope for the *Molloy's Lane Substation Refurbishment and Modernization* project.

Table 3 provides a detailed breakdown of the *Molloy's Lane Substation Refurbishment and Modernization* project for 2023.

Table 3
Molloy's Lane Substation
Refurbishment and Modernization Project
2023 Project Cost
($000s)

Cost Category	($000s)
Material	3,731
Labour – Internal	182
Labour – Contract	0
Engineering	833
Other	81
Total	$4,827

The project to refurbish and modernize Molloy's Lane Substation is estimated to cost $4,827,000 in 2023.

5.0 CONCLUSION

The implementation of Newfoundland Power's *Substation Refurbishment and Modernization Plan* continues to be appropriate given the age and condition of the Company's substation assets. Implementing this plan allows the Company to maintain the overall condition of its substation assets in a manner that provides efficiency and service benefits for customers.

For 2023, Newfoundland Power is proposing to refurbish and modernize its Walbournes and Molloy's Lane substations. Both substations contain a significant amount of deteriorated and obsolete equipment. Refurbishing and modernizing these substations will ensure the continued provision of safe and reliable service to approximately 6,900 customers in the City of Corner Brook and surrounding area, and 8,900 customers in the City of St. John's.

APPENDIX A:

Walbournes Substation Refurbishment and Modernization

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1.0 WALBOURNES SUBSTATION

Walbournes ("WAL") Substation was built in 1966 as a transmission and distribution substation. The substation is supplied by Newfoundland Power 66 kV transmission lines 351L and 352L from Massey Drive Terminal Station. WAL Substation feeds Frenchman's Cove ("FRN") Substation through radial transmission line 353L. The WAL Substation 12.5 kV distribution switchgear is energized by two transformers, 66 kV to 12.5 kV (20 MVA) WAL-T1 and 66 kV to 12.5 kV (25 MVA) WAL-T2. There are six 12.5 kV distribution feeders, serving approximately 6,900 customers on the west side of Corner Brook and the communities of Curling and Mount Moriah.

Figure A-1 shows WAL Substation.

Figure A-1: WAL Substation

2.0 CONDITION ASSESSMENT

2.1 66 kV Infrastructure

The majority of the switches on the 66 kV bus structures are in excess of 46 years in service and are in a deteriorated condition primarily as a result of corrosion.[1] This includes five side break switches and four air break switches. One of the side break switches is seized closed and can no longer be operated. The deteriorated switches require replacement.

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[1] The Company's strategy for switches is to operate and maintain switches whenever opportunities and substation work permit, and to replace switches when they are more than 30 years old. 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 existing transformer air break switches require replacement with two new 66 kV circuit breakers. These breakers can be controlled by the new bus and transformer protection relay to better protect the transformer from high voltage faults.[2] This would improve automation and eliminate substation and transmission outages for customers at WAL Substation and FRN Substation due to problems on either of the WAL transformers.

The 66 kV steel structures, foundations, buses, and insulators are all in good condition. The three 66 kV SF6 transmission line circuit breakers are in good condition and will remain in service.[3]

2.2 12.5 kV Infrastructure

The 12.5 kV distribution feeders are supplied by six 12.5 kV metal clad distribution switchgear breakers. This switchgear was manufactured by ITE Imperial Corporation in 1965. The WAL Substation switchgear is one of the two oldest switchgear lineups in the Company's substations.[4]

Figures A-2 and A-3 show the 12.5 kV switchgear cubicles.

Figure A-2: WAL Substation 12.5 kV Switchgear Front Layout and Protection and Controls

Figure A-3: WAL Substation 12.5 kV Switchgear Rear Layout

2 The high-voltage breaker, in conjunction with the upgraded protection relays, will improve equipment protection and reliability.

3 One breaker was replaced early in 2022 as the result of an in-service failure. The other two breakers are 20 and 22 years old with considerable life remaining.

4 The Company maintains 11 switchgear lineups in eight substations.

Due to the vintage of this 57-year-old switchgear, support from the manufacturer has been discontinued and replacement parts are no longer available. The switchgear is not built to current standards to mitigate arc flash hazards.[5] The existing switchgear building height is not sufficient for arc resistant switchgear with an arc plenum. An arc plenum is critical to the protection of personnel from an arc flash event.[6]

The fault levels on this switchgear exceed the breaker's interrupting capacity when the two WAL transformers are paralleled. This prevents the two transformers from being paralleled, and reduces the operational benefits of shared capacity and redundancy of supply.

The feeder protection and controls are installed on the front panels of the existing switchgear cubicles. The Company's standard is to install the protection and controls remote from the switchgear in a separate control room. This removes the requirement to operate the breakers locally in close proximity to the switchgear which enhances safety for personnel in the event of a catastrophic failure.

The switchgear only has a main bus. The Company's standard for feeder distribution incorporates a main bus and a transfer bus.[7] The absence of a transfer bus does not allow a feeder to remain energized from the switchgear when a breaker is required to be removed for maintenance or repair.

The WAL Substation switchgear breakers also have arc chutes that contain asbestos.

This switchgear is at the end of its service life. It has been determined that the least-cost option is to replace the existing switchgear with standard outdoor distribution equipment.[8] This would include a new 12.5 kV steel bus structure, eight circuit breakers, 16 sets of hook-stick operated switches, seven air break switches, and one set of 12.5 kV potential transformers.

All low-voltage equipment require standard varmint protection to be installed.[9]

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5 Arc flash technologies on newer switchgear mitigate the hazards of arc flash events to prevent injury to personnel and mitigate equipment damage. 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 breaker(s).

6 Arc resistant switchgear incorporates an arc plenum to contain and remove the hot gases, burning particles and other arc byproducts created during an arcing fault and channels them away from the equipment to the outside environment. This provides an increased level of protection for personnel that may be near the switchgear when an internal arcing fault occurs.

7 A main and transfer bus configuration consists of two independent buses. Under normal operating conditions, the distribution feeders are fed from the main bus. When it becomes necessary to remove a circuit breaker from service for maintenance or repairs, the associated feeder can remain energized through the transfer bus.

8 Cost estimates to replace the existing switchgear building with a new switchgear building are greater than replacing the existing switchgear building with standard outdoor breakers and switches.

9 Report *2.1 Substation Strategic Plan,* included with the *2007 Capital Budget Application*, verified that these barriers can be effective in preventing damage to equipment and customer outages caused by small animals and birds. Conclusion 2.10 of The Liberty Consulting Group's *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power,* December 17, 2014, states that, *"The use of insulated coverings, guards and insulated leads have been effective in preventing animal-caused damage and outages."*

2.3 Power Transformers

WAL-T1 power transformer was manufactured by Westinghouse in 1976. WAL-T1 is a 66 kV to 12.5 kV, 20 MVA power transformer. WAL-T2 power transformer was manufactured by Virginia Transformer in 2004. WAL-T2 is a 66 kV to 12.5 kV, 25 MVA power transformer.

Both power transformers are in good condition. WAL-T1 lacks standard spill containment. Both WAL-T1 and WAL-T2 must be moved farther away from the 66 kV structure to allow installation of the new circuit breaker. New spill containment foundations are therefore required for both transformers to protect against environmental damage in the event of an oil spill from the units.[10]

Figures A-4 and A-5 show WAL-T1 and WAL-T2.

Figure A-4: WAL-T1

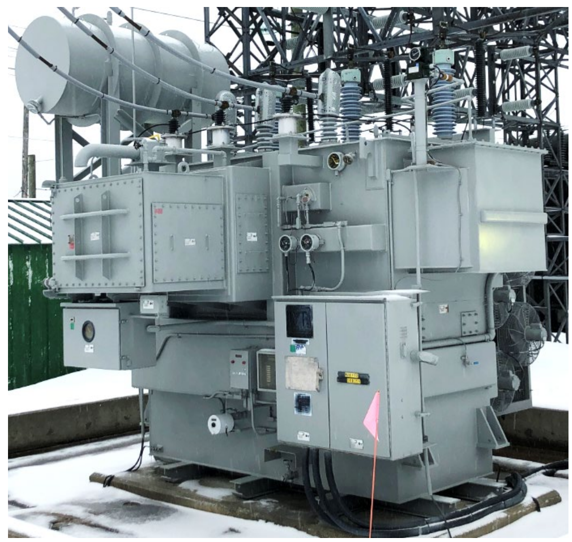

Figure A-5: WAL-T2

2.4 Protection and Control

The WAL-T2 and feeder protection is provided by microprocessor-based digital relays. The WAL-T2 relay is 18 years old and is in good condition. The feeder protection for the six feeders are Micom P142 relays and are 19 years old. A number of these early vintage Micom P142 relays have failed in recent years with 11 of these relays in various Company substations requiring replacement since 2015.[11] Parts to repair this version of relay are no longer available

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10 *IEEE Standard 980-2013 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. These impacts can range from the clean-up costs associated with a spill to the contamination of a water supply. See https://standards.ieee.org/ieee/980/7038/. Additionally, *IEEE Standard 979-2012 Guide for Substation Fire Protection* recommends spill containment to minimize the surface area of a spill. This provides fire protection benefits. See https://standards.ieee.org/ieee/979/3665/.

11 Three of these Micom P142 relay replacements have occurred in WAL Substation – WAL-04 in 2018, WAL-02 in 2021, and WAL-04 again in 2021. The Company has over 80 of these early vintage Micom P142 relays currently in service.

from the manufacturer. These relays are at the end of their service life.

The protection relays for the three transmission lines, the 66 kV bus, WAL-T1, and the spare feeder are vintage electromechanical type and are 47 years old.

Figure A-6 shows the vintage electromechanical relays.

Figure A-6: Electromechanical Relays

The protection and control of the substation assets require modernization by replacing the obsolete electromechanical relays with microprocessor-based digital relays, reducing the protection relay device count of these 27 electromechanical relays to four digital 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.[12]

12 Report *2.1 Substation Strategic Plan* included with the *2007 Capital Budget Application* identified that electromechanical relays contain moving parts that can fail as they age, wear and accumulate dirt and dust. In its *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power,* December 17, 2014, the Board's consultants, The Liberty Consulting Group, examined Newfoundland Power's practice of replacing multiple obsolete electromechanical relays with a single modern microprocessor controlled relay and concluded that the Company uses reasonable practices that conform to industry practice.

Along with the digital relays, the associated communications equipment requires upgrading. A communications gateway would provide remote control and monitoring of the power system protection equipment from the SCADA system.[13] The communications gateway would integrate the SCADA system with all the substation devices that provide monitoring, protection and control of the transmission lines, distribution feeders and substation transformers. The enhancement would also allow for remote administration of upgraded devices.[14]

2.5 Building

The existing substation building houses protection and control equipment and the 12.5 kV switchgear. The existing building was built in 1966 as part of the original construction of the substation. An extension was completed in 1969, and a second extension was completed in 1976 to add the control room.

Figures A-7 and A-8 show the WAL Substation control building.

Figure A-7: WAL Substation Building

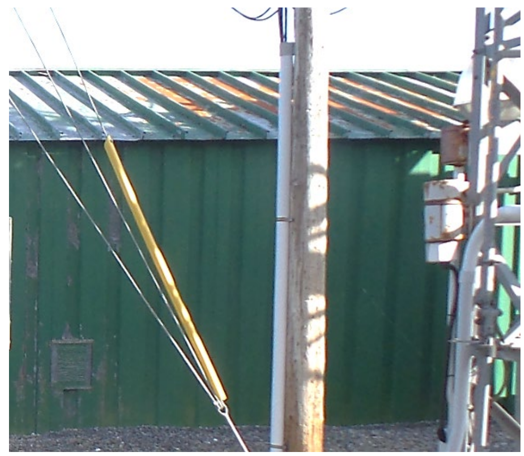

Figure A-8: WAL Substation Building Roof Showing Signs of Deterioration

The building is constructed with timber framing and has a metal roof and siding. No upgrades have been completed on the roof or siding. As shown in Figure A-8, the metal cladding on the roof is showing deterioration. There is also asbestos used in some of the interior construction materials.

13 The enhanced capabilities provided by the microprocessor-based digital relays provide greater options for remote control and monitoring through the Company's SCADA system.

14 Remote administration of upgraded devices allows protection relays to be interrogated and reconfigured remotely. This allows engineers to interrogate protection relays from their office, providing quicker diagnosis of system problems and improved outage response times. Without this capability, engineers would have to travel to the substation to interrogate the relay on site, thereby greatly increasing the time necessary to diagnose fault data.

In order to construct the new spill containment foundation for both transformers and to erect the new 12.5 kV distribution structure, the existing building would require removal. A new control building would permit installation of the new protection and communications panels. This would also improve clearances between energized equipment and the building.

2.6 Site Condition

WAL Substation is located on a sloped piece of land. Poor site drainage has caused multiple flooding events at the substation and within the switchgear building. The yard would require extension to accommodate the increased footprint required for the spill containment foundations for the transformers and the new 12.5 kV distribution structure.

A grounding study is necessary and the ground grid for the substation would require upgrading to align with current standards and to cover the expanded substation yard and new equipment.[15]

3.0 ASSESSMENT OF ALTERNATIVES

In the case of WAL Substation, the number of components requiring preventative and corrective maintenance at this time justifies the requirement to refurbish and modernize the substation in 2023.

The refurbishment and modernization of WAL Substation was originally planned to be completed in 2022, but was deferred to allow further engineering assessment of the components in the substation.[16] The WAL Substation refurbishment and modernization project can no longer be deferred. The 66 kV switches are deteriorated and have started to experience failure. The obsolete electromechanical protection relays have not been industry standard for many years and must be replaced. The vintage digital protection relays are experiencing failures and have reached end of life. The manufacturer no longer supports the 12.5 kV switchgear, and this switchgear does not meet current safety standards or provide the operational benefits of modern distribution equipment.

Continued deferral of the WAL Substation refurbishment and modernization project would increase the risk that some components will be ran to failure. Run to failure is not a viable alternative as it would increase risks to the delivery of safe and reliable service to approximately 6,900 customers in the Corner Brook area.

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15 Newfoundland Power designs substation ground grids using the *ANSI/IEEE Standard 80-2013 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practice for designing substation ground grids.

16 The five-year capital plan filed with the 2018 Capital Budget Application included the refurbishment and modernization of Walbournes Substation in 2022.

4.0 PROJECT SCOPE

The 2023 scope of work at WAL Substation includes the following:

(i) Dismantle the existing 12.5 kV switchgear;
(ii) Dismantle the existing switchgear building;
(iii) Construct a new control building;
(iv) Replace all deteriorated 66 kV switches;
(v) Install two new 66 kV circuit breakers;
(vi) Install new 12.5 kV distribution equipment including a steel bus structure, circuit breakers, switches, and potential transformers;
(vii) Construct new spill containment foundations for WAL-T1 and WAL-T2;
(viii) Install new digital relays and the associated communications equipment;
(ix) Extend the ground grid to cover substation equipment extension; and
(x) Install standard varmint protection on all 12.5 kV equipment.

Table A-1 summarizes the planned equipment replacements, including the age and condition of components.

Table A-1
2023 Planned Equipment Replacements
Walbournes Substation

Equipment	Age (Years)	Condition
66 kV Air Break Switches	36-53	Deteriorated/End of Life
66 kV Side Break Switches	46-53	Deteriorated/End of Life
12.5 kV Switchgear	57	End of Life
Electromechanical Protection Relays	47	Obsolete
Digital Protection Relays	19	End of Life

5.0 PROJECT COST

Table A-2 provides the cost breakdown for the the *Walbournes Substation Refurbishment and Modernization* project.

Table A-2
Walbournes Substation
Refurbishment and Modernization Project
2023 Project Cost
($000s)

Cost Category	Total
Material	3,788
Labour - Internal	194
Labour - Contract	0
Engineering	818
Other	155
Total	**$4,955**

The total project cost for the *Walbournes Substation Refurbishment and Modernization* project is $4,955,000 in 2023.

APPENDIX B:

Molloy's Lane Substation Refurbishment and Modernization

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Page

1.0 MOLLOY'S LANE SUBSTATION

Molloy's Lane ("MOL") Substation is located on Topsail Road in St. John's and was built in 1960 as a distribution and transmission substation. The substation is supplied by 66 kV transmission lines 15L from Stamps Lane ("SLA") Substation and 19L from Hardwoods ("HWD") Substation. Two 25 MVA power transformers supply eight 12.5 kV distribution feeders, serving approximately 8,900 customers in the west end area of St. John's.

Figure B-1 shows MOL Substation.

Figure B-1: MOL Substation

2.0 CONDITION ASSESSMENT

2.1 Power Transformers

MOL-T1 power transformer was manufactured by Maloney Electric in 1980. MOL-T1 is a 66 kV to 12.5 kV, 25 MVA power transformer. MOL-T2 power transformer was manufactured by Federal Pioneer in 1976. MOL-T2 is a 66 kV to 12.5/25 kV, 25 MVA power transformer.

Both transformers are in good condition, but do not have spill containment foundations. New spill containment foundations are required for transformers MOL-T1 and MOL-T2 to protect against environmental damage in the event of an oil spill from the units.[1]

[1] *IEEE Standard 980-2013 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. These impacts can range from the clean-up costs associated with a spill to the contamination of a water supply. Additionally, *IEEE Standard 979-2012 Guide for Substation Fire Protection* recommends spill containment to minimize the surface area of a spill. This provides fire protection benefits.

Figure B-2 shows the MOL-T1 and MOL-T2 transformers.

Figure B-2: MOL-T1 and MOL-T2 Transformers

2.2 66 kV Infrastructure

Engineering assessments have determined that the 62-year-old 66 kV wood pole structures comprising the 66 kV bus are deteriorated. Thirteen of the 14 wood poles require replacement and 14 of the 16 wooden crossarms require replacement. Multiple poles and crossarms are splitting. The wood pole structures require replacement with a new steel bus structure. A yard extension will be necessary to accommodate the new structure. New concrete foundations will be required for the steel structure and associated equipment.

Figures B-3 and B-4 show the deteriorated wood structures.

Figure B-3: Deteriorated Wood Poles

Figure B-4: Deteriorated Wood Crossarms

A new 66 kV steel structure equipped with 66 kV rated equipment is required. This includes one additional set of 66 kV potential transformers, four transmission line side break switches, and two transformer air break switches. The transformer air break switches would be motorized and would include ground switches.[2]

A new 66 kV circuit breaker with two side break switches is required as a tie-breaker between the two transmission line buses. This tie-breaker would be controlled by the new bus and transformer protection relays. This would improve automation and reduce substation and transmission outages for customers served by MOL Substation.[3]

The 15L transmission line circuit breaker is a 66 kV SF6 breaker and is in good condition.[4] The 19L transmission line circuit breaker is an oil filled breaker. This breaker is currently 46 years old and is the same model as the breaker that previously failed on 15L.[5] This breaker is at the end of its service life.[6]

2.3 12.5 kV Infrastructure

Engineering assessments have determined that the 12.5 kV steel structure and insulators are in good condition. The concrete foundations generally are in good condition, with the exception of five concrete pier foundations that require refurbishment.

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2 The motorized air break switches in conjunction with the upgraded protection relays will improve equipment protection.

3 The installation of the tie-breaker allows customers to remain fed from one of the MOL transformers in the event of a fault on the other MOL transformer.

4 This breaker was installed in 2020 to replace a failed oil filled breaker that was 48 years old.

5 The average service life prior to replacement for a General Electric FKP oil filled 66 kV breaker within the Company's fleet is 44 years.

6 The 66 kV General Electric FKP breakers are also an environmental concern as they hold 295 gallons of oil. Replacing this breaker will reduce the risk of the release of oil into the environment. The breaker will be replaced with a SF6 breaker which is the Company's standard for 66 kV breakers.

Figure B-5 shows the deteriorated 12.5 kV concrete pier foundation.

Figure B-5: Deteriorated 12.5 kV Concrete Pier Foundation

The switches on the 12.5 kV bus structure are in excess of 30 years in service and require replacement due to their mechanical condition.[7] This includes six feeder air break switches, four feeder side break switches, and five sets of feeder hook stick operated switches. One set of 12.5 kV potential transformers is also required for transformer protection.

There are 10 circuit breakers installed as part of the MOL Substation 12.5 kV distribution bus. Three of these breakers are less than 10 years old, and six breakers are scheduled to be replaced in 2022 as part of the *PCB Bushing Phase-out* project. The remaining breaker is a 45-year-old Allis-Chalmers SDO oil filled breaker.[8] The breaker requires replacement with a vacuum breaker, which is the Company's standard for 12.5 kV breakers.

[7] The Company's strategy for switches is to operate and maintain switches whenever opportunities and substation work permit, and to replace switches when they are more than 30 years old. 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.

[8] The Company purchased 11 of these Allis-Chalmers SDO oil filled breakers in the late 1970s. Six of these units have already been removed from service. This breaker is at the end of its service life and will be replaced. These breakers are also an environmental concern as they hold upwards of 60 gallons of oil. Replacing this breaker will reduce the risk of the release of oil into the environment.

All low-voltage equipment requires standard varmint protection to be installed.[9]

2.4 Protection and Control

The protection relays for the 66 kV bus and transformers MOL-T1 and MOL-T2 are vintage electromechanical type relays that were installed in 1980. At present, there are 19 electromechanical relays installed in three individual protection panels inside the substation control building. [10]

Figure B-6 shows the protection equipment for transformers MOL-T1 and MOL-T2.

Figure B-6: MOL-T1 and MOL-T2 Protection Equipment

[9] Report *2.1 Substation Strategic Plan*, included with the *2007 Capital Budget Application*, verified that these barriers can be effective in preventing damage to equipment and customer outages caused by small animals and birds. Conclusion 2.10 of The Liberty Consulting Group's *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power,* December 17, 2014, states that, *"The use of insulated coverings, guards and insulated leads have been effective in preventing animal-caused damage and outages."*

[10] Report *2.1 Substation Strategic Plan*, included with the *2007 Capital Budget Application* identified that electromechanical relays contain moving parts that can fail as they age, wear and accumulate dirt and dust. In its *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power,* December 17, 2014, the Board's consultants, The Liberty Consulting Group, examined Newfoundland Power's practice of replacing multiple obsolete electromechanical relays with a single modern microprocessor-controlled relay and concluded that the Company uses reasonable practices that conform to industry practice.

The protection and control of the substation assets require modernization by replacing the obsolete electromechanical relays with microprocessor-based digital relays, reducing the total protection relay device count of these 19 electromechanical relays to two digital relays.[11]

The transmission protection for one of the 66 kV transmission lines and the feeder protection for eight of the 12.5 kV feeders are early vintage microprocessor-based digital relays. The feeder protection for the eight feeders are Micom P142 relays and are 19 years old. A number of these early vintage Micom P142 relays have failed in recent years with 11 of these relays in various Company substations requiring replacement since 2015.[12] Parts to repair this version of the relay are no longer available from the manufacturer. These relays are at the end of their service life.

2.5 Control Building

The existing control building was built in 1960. The building currently houses the protection and communications equipment. The building was originally constructed to house 12.5 kV switchgear.[13] There is insufficient clearance between the building and the 12.5 kV distribution equipment to meet current safety clearance standards.

A new control building must be constructed in a different location in order to meet clearance standards to the energized 12.5 kV distribution equipment. The new building would permit the installation of the new protection and communication panels while allowing minimum disruption to the existing protection scheme and the integrity of the electrical system during construction.

[11] This protection upgrade will also involve replacing all of these existing protection panels. 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.

[12] The Company has over 80 of these early vintage Micom P142 relays currently in service.

[13] In the early 1970s, there was a catastrophic failure of the switchgear. The building foundation, walls, and roof were damaged and required repair. The switchgear was removed and replaced with outdoor distribution equipment. The 12.5 kV steel structure and breakers were installed in the small space remaining between the power transformers and the building.

Figures B-7 and B-8 shows the MOL Substation control building.

Figure B-7: MOL Substation Control Building

Figure B-8: MOL Substation Control Building with Insufficient Clearances to 12.5 kV Structure

2.6 Site Condition

The MOL Substation site is in good condition, with minor upgrades required at this time. The yard would require extension to accommodate the increased footprint required for the spill containment foundations for the transformers and the new 66 kV steel structure.

A grounding study would be required and the ground grid for the substation would be extended to cover the expanded substation yard and new equipment.[14]

3.0 ASSESSMENT OF ALTERNATIVES

In the case of MOL Substation, the number of components requiring preventative and corrective maintenance at this time justifies the requirement to refurbish and modernize the substation in 2023.

The refurbishment and modernization of MOL Substation was originally planned to be completed in 2021, but was deferred to allow further engineering assessment of the components in the substation.[15] The MOL Substation refurbishment and modernization project can no longer be deferred. The 66 kV wood pole structure is deteriorated and requires replacement. The obsolete electromechanical protection relays have not been industry standard for many years and must be replaced. The vintage digital protection relays are experiencing failures and have reached end of life. A 66 kV oil filled breaker requires replacement as it has reached the end of its service life.[16]

Continued deferral of the MOL Substation refurbishment and modernization project would increase the risk that some components will be ran to failure. Running to failure is not a viable alternative as it would increase risks to the delivery of safe and reliable service to approximately 8,900 customers in the City of St. John's.

4.0 PROJECT SCOPE

The 2023 scope of work at MOL Substation involves the following:

(i) Complete a yard extension;
(ii) Construct new 66 kV steel bus structure;
(iii) Install new concrete spill containments foundation for MOL-T1 and MOL-T2;
(iv) Dismantle the existing building;
(v) Construct a new control building;
(vi) Install two new 66 kV breakers;
(vii) Install one new 12.5 kV breaker;
(viii) Install new 66 kV switches;
(ix) Replace deteriorated 12.5 kV switches;
(x) Install 66 kV and 12.5 kV potential transformers;
(xi) Install new digital relays;
(xii) Extend the ground grid to cover substation equipment extension; and
(xiii) Install standard varmint protection on all 12.5 kV equipment.

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14 Newfoundland Power designs substation ground grids using the *ANSI/IEEE Standard 80-2013 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practice for designing substation ground grids.

15 The five-year capital plan filed with the 2019 Capital Budget Application included the refurbishment and modernization of Molloy's Lane Substation in 2021.

16 A similar breaker in the substation experienced an in-service failure in 2020 and was replaced under the *Substation Replacements Due to In-Service Failures* project.

Table B-1 summarizes the planned equipment replacements, including the age and condition of components.

Table B-1 2023 Planned Equipment Replacements Molloy's Lane Substation		
Equipment	Age (Years)	Condition
66 kV Wood Pole Structure	62	Deteriorated
66 kV Circuit Breaker	46	End of Life
12.5 kV Circuit Breaker	45	End of Life
66 kV Air Break Switches	32-51	Deteriorated/End of Life
66 kV Side Break Switches	51	Deteriorated/End of Life
12.5 kV Air Break Switches	30-35	Deteriorated/End of Life
12.5 kV Side Break Switches	32-34	Deteriorated/End of Life
12.5 kV Hook-Stick Operated Switches	49	Deteriorated/End of Life
Electromechanical Protection Relays	44	Obsolete
Digital Protection Relays	19	End of Life

5.0 PROJECT COST

Table B-2 provides the cost breakdown of the *Molloy's Lane Substation Refurbishment and Modernization* project.

Table B-2
Molloy's Lane Substation
Refurbishment and Modernization Project
2023 Project Cost
($000s)

Cost Category	Total
Material	3,731
Labour - Internal	182
Labour - Contract	0
Engineering	833
Other	81
Total	$4,827

The total project cost for the *Molloy's Lane Substation Refurbishment and Modernization* project is $4,827,000 in 2023.

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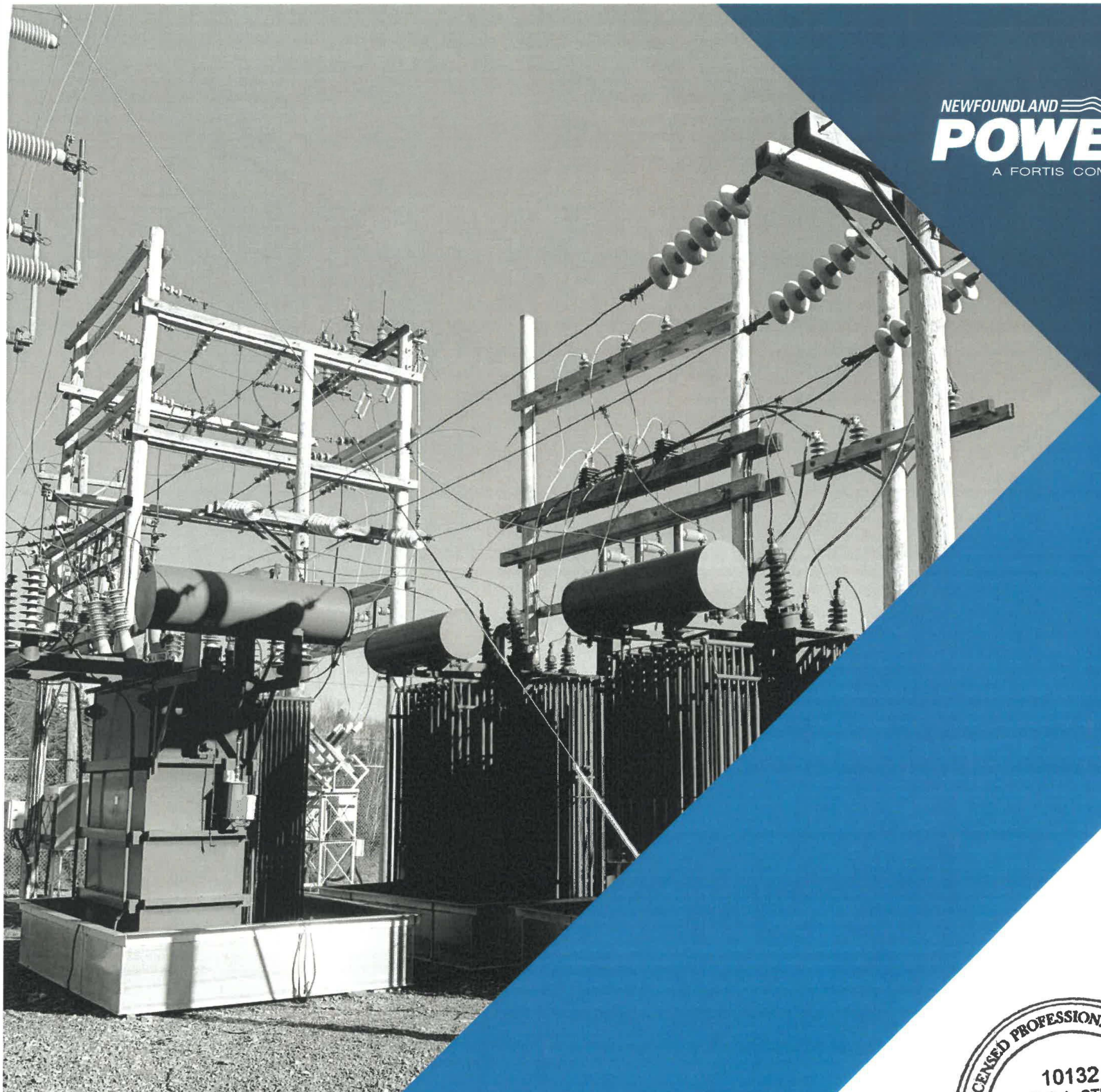

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2.2 Substation Spare Transformer Inventory

June 2022

Prepared by: Tyler Stevens, P. Eng.

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1.0 INTRODUCTION

Newfoundland Power Inc. ("Newfoundland Power" or the "The Company") operates 131 substations located throughout its service territory. The most critical pieces of equipment in substations are power transformers. The in-service failure of a power transformer can result in extended outages to thousands of customers.

The majority of Newfoundland Power's substation power transformers have aged beyond the service life typically observed in the industry. The Company maintains an inventory of spare power transformers to respond to failures and ensure the delivery of reliable service to customers. The Company's inventory of spare power transformers has historically relied on units that were removed from service due to load growth. The inventory is therefore limited and is expected to diminish going forward due to the current low-growth environment.

In response to this risk, Newfoundland Power plans to maintain adequate inventory levels by purchasing power transformers to serve as spares. This includes the proposed purchase of a 15/20/25 MVA, 66-25/12.5 kV power transformer in 2023 to serve as an emergency spare. The cost of this project is $1,500,000.

This report provides a risk assessment of Newfoundland Power's substation power transformers, a description of how other utilities are managing similar risks, and the Company's specifications for the spare power transformer proposed to be purchased in 2023.

2.0 BACKGROUND

2.1 Newfoundland Power's Power Transformer Fleet

Newfoundland Power has 192 power transformers in service. The Company's power transformers step voltages up or down depending on the application. The most common applications include: (i) changes from transmission to distribution voltages, such as 66 kV to 12.5 kV; and (ii) changes between transmission voltages, such as 138 kV to 66 kV. A small number of power transformers also support the Company's hydro plants, which generate low-cost energy for customers.[1]

[1] Power transformers in hydro plants change from generation voltages to either distribution or transmission voltages.

Newfoundland Power conducts regular condition monitoring and maintenance of its power transformers. Oil sampling and analysis is completed annually to gauge the internal health of transformers. More frequent analysis is completed if condition warrants.[2] Other testing and checks are also completed to monitor transformer condition.[3] This analysis and testing determines any requirements for transformer maintenance or replacement.

Completing maintenance on a power transformer often requires the unit 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.[4] Portable substations are also installed to maintain service to customers during capital projects and equipment failures in substations. Capital projects at substations typically require the deployment of a portable substation for between two and seven months. Portable substation deployment in response to equipment failures can last substantially longer, ranging as high as six to 18 months when off-site repairs or replacement are required.

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.[5] The Company also has access to one portable substation from Newfoundland and Labrador Hydro ("Hydro"), P2, through an equipment sharing agreement.[6]

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[2] Oil sampling includes standard oil tests and dissolved gas in oil analysis. Standard oil tests check for contaminants and moisture, which at unacceptable levels can lower the dielectric strength of oil and cause a fault. Dissolved gas analysis is used to monitor and diagnose internal transformer electrical problems, such as the presence of arcing or poor electrical connections. Certain gases naturally increase as a transformer ages, but can be a sign of excessive temperatures and overloading in newer transformers.

[3] Additional testing 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.

[4] 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.

[5] Portable substations each include an air break switch used for isolation on the high-voltage side, a multiple-winding power transformer, and a breaker on the low-voltage side. The flexibility provided by the multiple-winding transformer allows the portable substations to connect to transmission, generation and distribution systems of different voltages and capacities. However, each portable substation is technically limited to only serve locations corresponding to its capacity and voltage specifications.

[6] 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 93 of Newfoundland Power's 192 power transformers. However, all but one of these power transformers is covered by a Newfoundland Power portable substation.

Table 1 provides an overview of the five portable substations.

Table 1
Portable Substation Summary

Portable Substation	Size (MVA)	Primary Voltages (kV)	Secondary Voltages (LV)	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	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 8 and 56 years. Combined, these units are capable of providing emergency backup for the majority of power transformers in Newfoundland Power's system.

2.2 Risk Assessment

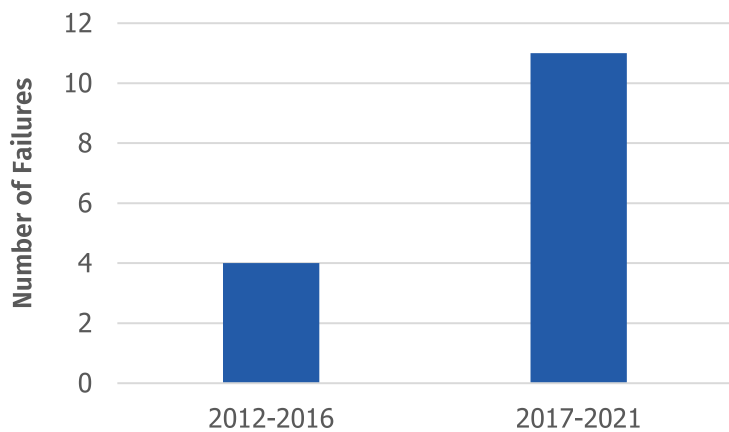
2.2.1 Probability of Power Transformer Failure

Newfoundland Power conducted a risk assessment of its substation power transformers to assess the current probability and consequences of equipment failures. The assessment included trends in power transformer failures, the age profile of its transformer fleet, and market trends in transformer delivery times.

The quantity of power transformers failures has increased over the last decade.

Figure 1 shows the number of power transformer failures experienced from 2012 to 2021.[7]

Figure 1
Power Transformer Failures
(2012-2021)



Newfoundland Power has experienced 11 power transformer failures over the last five years. This compares to four power transformer failures over the previous five-year period.

Of the 11 failures experienced over the last five years, four power transformers failed in service and the remaining seven were identified as being at imminent risk of failure through condition monitoring. Five of the 11 power transformers required replacement, while the remaining six were repaired and returned to service.

The service life of the Company's power transformers has typically exceeded what is observed in the industry. This performance may be explained by a number of factors, including transformer loading, the Company's maintenance program and a winter peaking system coupled with low ambient temperatures.[8]

Industry experience suggests the service life of a power transformer is typically between 30 and 50 years under ideal conditions.[9] Industry experience also suggests that power transformer failure rates tend to vary based on age, with units aged 60 years and older failing at nearly double the rate of those aged 40 to 60.[10]

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7 See Appendix A for the list of substation power transformer failures experienced from 2012 to 2021.

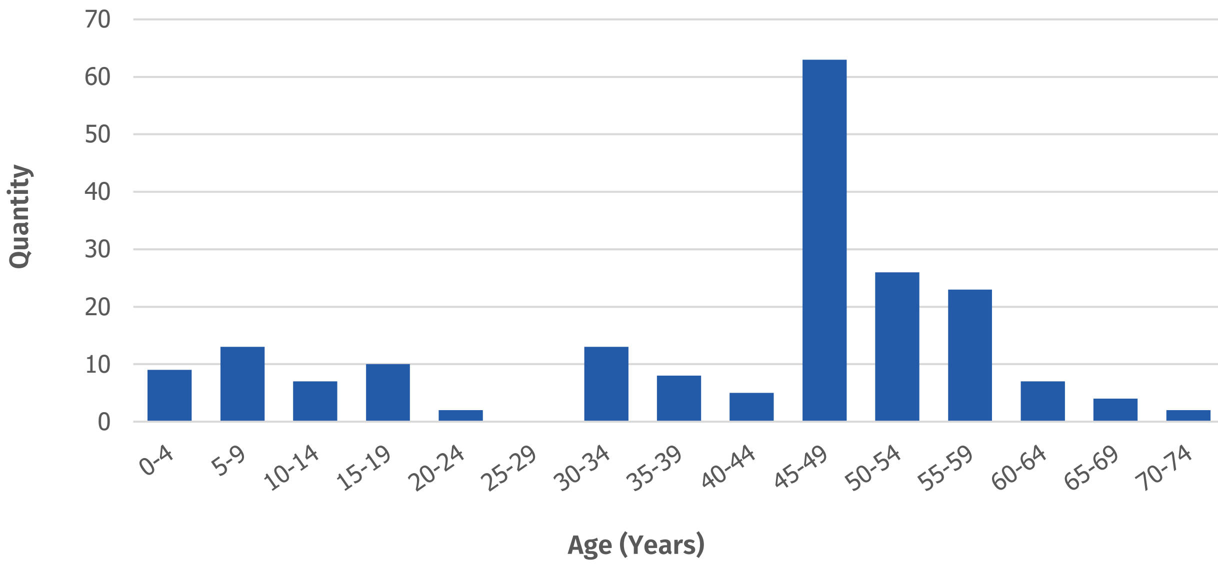
8 Practical conditions, such as ambient temperature, high loading and fault exposure, can reduce the expected service life of power transformers. High temperatures have an adverse effect on the insulating properties inside the transformer and causes the premature aging of power transformers. Insulation 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.

9 See International Council on Large Electric Systems ("CIGRE"), *Asset Management Decision Making Using Different Risk Assessment Methodologies*, 2013, page 94.

10 See Centre for Energy Advancement through Technological Innovation ("CEATI"), *Station Equipment: Failure Rates,* 2016, page 3-3.

Figure 2 shows the age distribution of Newfoundland Power's power transformers.

Figure 2
Power Transformer Age Distribution



A total of 62 power transformers in the Company's fleet, or approximately 32%, are aged 50 years or older, which is the upper limit of typical industry experience. The percentage of power transformers aged 50 years or older is expected to increase materially over the next five years, with an additional 33% of transformers between the age of 45 and 49 years.[11] While the service life of Newfoundland Power's power transformers typically exceeds industry experience, the probability of failure is expected to increase as the equipment degrades with age.

2.2.2 Consequence of Power Transformer Failure

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

Examining whether it is possible to transfer load is the first step in Newfoundland Power's emergency response following transformer failure. A load transfer can typically restore service to customers within a few hours. The ability to transfer load depends on whether there is transformer capacity available at the substation or an adjacent substation, and the presence of sufficient distribution tie points. In the Newfoundland Power system, this option is generally limited to highly networked urban areas, such as St. John's, during non-peak periods.[12]

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11 A total of 63 of the Company's 192 power transformers have been in service for 45 to 49 years.

12 During periods of high customer demand during the winter, there is limited ability to transfer load between power transformers within the Company's urban areas. Additionally, substations supplied by radial transmission and distribution systems are not capable of transferring load to other substations as they have a single connection point to the electrical system.

In many instances, a portable substation must be deployed to restore service to customers following a transformer failure. The deployment of a portable substation was required to restore service to customers following 11 of the 15 power transformer failures that occurred over the last decade.[13] If a portable substation is readily available, service can typically be restored to customers within 24 to 36 hours. Newfoundland Power aims to ensure a portable substation is available at all times for emergency backup purposes.

The length of time a portable substation must remain in service varies depending on whether the power transformer requires repair or replacement, and whether a suitable spare is available. In some cases, transformers can be repaired on site within days or weeks. In other cases, transformers must be shipped out of province to a third-party repair facility, which can require six to 12 months. When replacement of a transformer is required, it can require between 12 and 18 months to design, procure, deliver, install and commission the transformer.

Newfoundland Power has typically had a small quantity of spare power transformers available to respond to a transformer failure.[14] A spare power transformer can typically be installed within a month of a transformer failure. A spare unit can be installed on a permanent basis, or as a temporary solution to cease reliance on a portable unit while equipment repairs are completed or an appropriately sized replacement can be procured.[15] Two-thirds of the Company's inventory of spare power transformers is currently older than 45 years.

Historically, the spares available to Newfoundland Power have been limited to power transformers that were removed from service due to system load growth and the requirement to replace transformers with larger capacity units. The backup coverage provided by the Company's supply of spares is limited and is expected to diminish due to the current low-growth environment. There are currently no transformer replacements due to load growth included in the Company's five-year capital plan.[16]

Newfoundland Power uses a competitive tendering process to procure transformers. The Company analyzed market trends in vendors' proposed delivery times for power transformers as part of assessing the consequences of power transformer failures.[17] The analysis showed the average proposed delivery time for power transformers from the time of order has increased in each of the last three years, from an average of 34 weeks in 2019 to an average of 43 weeks in 2022. An increase in delivery times for replacement transformers represents a risk that additional time could be required to respond to transformer failures.

13 See Appendix A.

14 A spare transformer is assessed to determine its suitability for installation based on various factors, including transformer capacity, voltages, winding configuration, physical size and any space constraints in the substation. Further information on the spare power transformers currently available is provided in section 3.4 of this report.

15 Depending on the capacity of the spare transformer and the load requirements of the substation, the permanent, least-cost solution may involve the purchase and installation of a smaller sized power transformer and removal from service of the installed spare transformer.

16 See the *2023 Capital Budget Application, 2023-2027 Capital Plan.*

17 The analysis was based on delivery times proposed by vendors through Newfoundland Power's competitive tendering process for power transformers over the last 10 years.

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

The impact on customers of power transformer failure can be observed in the failure of Bonavista Substation transformer BVA-T1 in November 2018. BVA-T1 failed in service, resulting in an outage to approximately 2,600 customers in the Bonavista area. It required approximately 24 hours to deploy a portable substation and fully restore service to customers.[18] A portable substation was required to be installed at Bonavista Substation for 11 months while the transformer was repaired.

2.3 Current Utility Practice

The risks posed by aging power transformers is not unique to Newfoundland Power. According to the Electric Power Research Institute ("EPRI"), large customer load growth in the 1970s and 1980s has caused an *asset wall* of transformers in the 35 to 45 year age range that are approaching the end of their nominal design lives.[19]

A 2021 survey conducted through CEATI indicates that utilities currently manage power transformer failures through a combination of portable substations and spare transformers. A total of 15 transmission and distribution utilities responded to the survey. The average age of the transformer fleets of the surveyed utilities was 35 years, compared to 41 years for Newfoundland Power.

[18] At the time BVA-T1 failed, a portable substation was located nearby in Clarenville and was ready for transport, which enabled a rapid deployment of the unit to Bonavista Substation.

[19] See EPRI, *Utilizing Industry-Wide Data to Better Understand Power Transformer Fleet Performance,* page 1-3.

Table 2 summarizes the results of the CEATI survey on utility practices for managing power transformer failure.

Table 2
2021 CEATI Survey
Utility Power Transformer Failure Management[20]

Utility	Average Age of Transformer Fleet	Portable Substations	Spare Transformer Inventory
Utility 1	30	No	Yes
Utility 2	43	Yes	Yes
Utility 3	35	Yes	Yes
Utility 4	29	No	Yes
Utility 5	40	Yes	Yes
Utility 6	35	Yes	Yes
Utility 7	34	Yes	Yes
Utility 8	42	Yes	Yes
Utility 9	35	No	Yes
Utility 10	42	Yes	Yes
Utility 11	25	Yes	Yes
Utility 12	40	Yes	Yes
Utility 13	40	Yes	Yes
Utility 14	23	No	Yes
Utility 15	38	Yes	Yes

The survey showed that all 15 surveyed utilities maintain an inventory of spare transformers. Spare transformers commonly account for between 2% and 5% of a utility's total fleet, ranging as high as 15% to 17%. Similar to Newfoundland Power, 11 of the surveyed utilities have both an inventory of spare transformers and portable substations.

[20] A portion of the surveyed utilities have systems that are constructed to meet N-1 criteria and therefore have redundant installed transformer capacity. These include Utility 11 and Utility 14. Utility 10 meets N-1 criteria on its transmission power transformers. Utility 15 meets N-1 criteria for transmission power transformers above 161 kV.

3.0 ASSESSMENT OF ALTERNATIVES

3.1 General

Newfoundland Power's customers are exposed to increasing risk of extended outages due to the age and condition of the Company's power transformers. The Company completed an assessment of alternatives to manage the increasing risk of power transformer failure over the near term. The Company identified and assessed three alternatives to respond to the increased risk of power transformer failure: (i) manage risk through existing emergency response capabilities; (ii) increase emergency response capabilities; and (iii) increase inventory of spare power transformers.

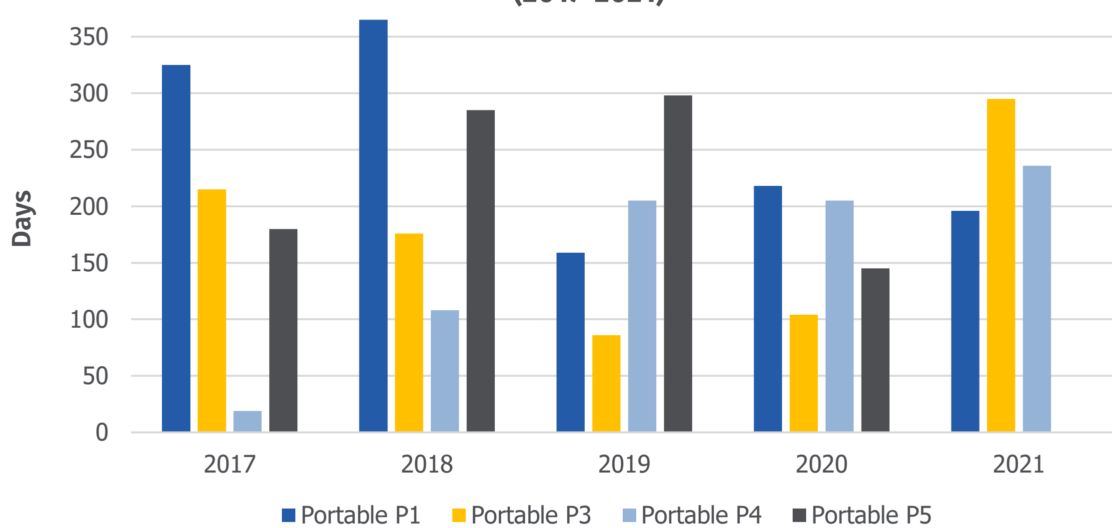
The alternatives were assessed from the perspective of what risk mitigation would be provided in each case and potential impacts on the reliability and cost of service provided to customers.

3.2 Alternative 1 – Manage Through Existing Emergency Response Capability

Alternative 1 involves managing the increased risk of power transformer failure through Newfoundland Power's existing emergency response capabilities. Emergency response capabilities are focused on restoring service to customers promptly and safely following equipment failure. Options to restore service to customers during an emergency include load transfers, opportunities for which are limited, or the deployment of a portable substation.

Figure 3 shows the utilization of Newfoundland Power's portable substations from 2017 to 2021.[21]

Figure 3
Portable Substation Utilization
(2017-2021)



21 Figure 3 includes periods during which a portable substation was removed from service for refurbishment or repairs. For example, P1 was removed from service for refurbishment throughout 2018. Figure 3 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.

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.

Newfoundland Power aims to have one portable substation available at all times for emergency backup purposes. Historically, the Company has generally been able to achieve this objective using its existing fleet of portable substations. Maintaining an inventory of spare power transformers has supported the availability of portable units.

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 be required to remain in service for up to six to 18 months. Given the age and condition of the Company's transformer fleet, it is reasonable to expect multiple power transformer failures could occur over the same period. This alone could reduce the availability of Newfoundland Power's portable substations by half for an extended period of time if a suitable spare is not available.

Reduced availability of portable substations would pose a risk to the delivery of reliable service to customers from two perspectives.

First, it would expose customers to a risk of even longer duration outages. A readily available portable substation can be deployed to restore service to customers within 24 to 36 hours. However, redeploying a portable substation that is already in service may not be possible or may require four or more days to uninstall, redeploy and restore service to customers. An outage of this duration would not be viewed as acceptable by customers.

Second, it would present risks to the execution of the Company's annual capital and maintenance programs for substations. Portable substations are critical to the effective implementation of annual maintenance and capital programs at substations. While capital expenditures related to the removal of polychlorinated biphenyls ("PCBs") will conclude by 2025,[22] substation refurbishment and modernization requirements are forecast to increase.[23] Newfoundland Power prioritizes the restoration of service to customers over maintenance activities. A reduced availability of portable substations could therefore result in the deferral of substation maintenance, which would pose additional risks of equipment failure and customer outages.

Based on these characteristics, existing emergency response capabilities are not expected to be sufficient to alleviate the increased risk of power transformer failure.

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[22] Federal regulations require the phase-out of PCBs by the end of 2025. See the *2023 Capital Budget Application, 2023-2027 Capital Plan,* Appendix A, Table A-3 for forecast capital expenditures in the substation asset class, including the *PCB Bushing Phase-out* project.

[23] See the *2023 Capital Budget Application, report 2.1 2023 Substation Refurbishment and Modernization* for an assessment of the age and condition of Newfoundland Power's substation assets and expected refurbishment and modernization requirements.

3.3 Alternative 2 – Increase Emergency Response Capability

Alternative 2 involves responding to the increased risk of power transformer failure by purchasing an additional portable substation to increase the Company's emergency response capability. The cost of purchasing a portable substation is approximately two to four times that of a similarly sized power transformer. For example, Newfoundland Power purchased 50 MVA portable substation P5 in 2012 at a cost of approximately $3.7 million.

Historically, Newfoundland Power's fleet of portable substations has been appropriately sized to support substation maintenance activities, capital projects and short-term emergency response. The existing fleet of portable units is not expected to remain sufficient if it is required to respond to the increased risk of power transformer failure going forward. This is due to a combination of increased power transformer failures resulting in more frequent, long-duration deployments of portable units and a diminished number of spare units available to reduce deployment times.

The purchase of an additional portable substation would provide a degree of risk mitigation by partially relieving expected pressures on the availability of portable substations going forward. However, portable substations are designed to provide operational flexibility and are best suited for applications that require deployment for shorter periods of time, such as during substation maintenance, capital work, or on-site equipment repairs. Without an adequate inventory of spare transformers, portable substations would continue to be exposed to longer duration deployments. Newfoundland Power's limited and diminishing availability of spare power transformers would therefore reduce the degree of risk mitigation provided by this alternative.

3.4 Alternative 3 – Maintain Spare Transformer Inventory

Alternative 3 involves maintaining an adequate inventory of spare power transformers by purchasing units specifically for use as spares, including the purchase of one conventional spare in 2023.

As described above, the availability of a suitable spare following the failure of a power transformer can significantly reduce the duration that a portable substation is required to be in service. This is because 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 replacement is being procured.

Maintaining an adequate inventory of spare power transformers is consistent with current utility practice. Newfoundland Power has historically relied on power transformers removed from service in response to system load growth for use as spares. The Company has not typically procured power transformers specifically to serve as spares.

Table 3 provides details on Newfoundland Power's current inventory of spare power transformers.[24]

Table 3
Spare Transformer Availability

Equipment ID	Age	Capacity (MVA)	Primary Voltage (kV)	Secondary Voltage (kV)
200299	46 Years	15/20	138	25
200219	52 Years	10	66	12.5
200185	54 Years	1.68/2.24	66/33	12.5/4.16
200113	54 Years	1.68/2.24	66	25/12.5
200358	13 Years	0.5	66	7.2/14.4
200220	52 Years	10/13.3	66	12.5/4.16
200352	19 Years	25/33.3/41.6	138	66
200328	39 Year	5/6.7/8.3	66	25
200258	48 Years	10/13.3	66	12.5

Newfoundland Power currently has five spare power transformers that were previously removed from service and are immediately available for deployment. Power transformer 200299 is a 15/20 MVA unit that is 46 years old. Power transformer 200219 is a 10 MVA unit that is 52 years old. The remaining three transformers that are immediately available have limited capacity and provide minimal backup coverage for the Company's existing fleet. These are transformers 200185, 200113 and 200358.

Two additional power transformers can be removed from service in the event of an emergency. Power transformer 200220 is currently serving as Stamp's Lane Substation transformer SLA-T1, but is not needed for capacity. This power transformer is 52 years old with additional life remaining. Power transformer 200352 is 19 years old and is currently serving as Salt Pond Substation transformer SPO-T5. This unit could be considered for temporary relocation to address a failure, but must be reinstalled on the Burin Peninsula once it is no longer needed for emergency use.[25]

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24 Hydro also maintains seven 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.

25 SPO-T5 works in tandem with power transformer SPO-T4 serving approximately 8,500 customers on the Burin Peninsula. These two power transformers provide N-1 redundancy for supplying the 66 kV transmission system.

Two additional units are expected to become available in the near future. Power transformer 200328 is currently serving as Dunville Substation transformer DUN-T1. This unit is 39 years old and is expected to become available for use as a spare following conclusion of an ongoing capital project. Power transformer 200258 is currently serving as Humber Substation transformer HUM-T3. This unit is 48 years old and is also expected to become available following conclusion of an ongoing capital project. HUM-T3 is showing signs of poor condition and is considered suitable for temporary use only.

Combined, these nine spare power transformers provide coverage for approximately 55% of Newfoundland Power's fleet.[26] Two-thirds of existing spare units are in excess of 45 years old. The coverage provided by the Company's inventory of spare power transformers is expected to diminish over time as existing spares are placed in service or approach end of life. Contributing to this diminished coverage is the fact that system growth is not expected to result in any additional spares becoming available over the next five years.

Maintaining a reasonable inventory of spare transformers going forward would require capital expenditures to stock conventional spares. Newfoundland Power implements a standard transformer design where possible to promote greater interchangeability of units. The Company's standard transformer design is a 15/20/25 MVA, 66-25/12.5 kV unit. This power transformer specification covers a majority of the existing power transformers in service. It would therefore provide the widest possible coverage, making it an ideal spare.

If the Company were to purchase this ideal spare, the number of power transformers covered by an available spare unit would increase from 55% to 75% as of 2023. The ideal spare would be the only unit providing backup coverage for 39 power transformers. Of the 48 power transformers not covered by the ideal or existing spares, 37 would be generating plant transformers. The remaining nine distribution and two transmission power transformers either have large capacities or unique specifications not covered by the ideal or existing spares.[27]

Purchasing this ideal spare would significantly improve the probability that a power transformer would be available to either permanently or temporarily return a substation to service. Whether installation of the spare is permanent or temporary would depend on which option is least-cost for customers, such as whether a failed unit can eventually be repaired, or replaced with a unit of a smaller capacity that is less costly to replace than the spare.

In both cases, the availability of a spare would reduce potential pressures on the availability of portable substations by reducing the duration that portable units must be installed in response to failure of a power transformer. This, in turn, would reduce the risk of exposing customers to extended outages should a portable substation not be readily available.

[26] See Appendix B to this report for the coverage provided by each of the power transformers included in Table 3.

[27] As examples, HWD-T3 (66-25 kV, 50 MVA), HOW-T3 (25-4.16 kV, 1 MVA), SCT-T2 (25-12.5 kV, 4 MVA), and GAN-T3 (66 kV, 3.5 MVA) are all units with uncommon specifications. If one of these transformers were to fail, a portable substation would be used to return service to customers while longer-term alternatives are assessed.

4.0 PROJECT SCOPE AND COST

Newfoundland Power has determined that procuring power transformers specifically to serve as spares is necessary to mitigate increasing risks of power transformer failure over the near term. The Company plans to maintain an adequate inventory of spare transformers going forward through the procurement of conventional spares that will be placed in service upon the failure of an in-service unit. This includes the proposed procurement of a 15/20/25 MVA, 66-25/12.5 kV power transformer in 2023.

Table 4 below summarizes the cost of purchasing the spare power transformer in 2023.

Table 4
Substation Spare Transformer Inventory Project
2023 Project Cost
($000s)

Cost Category	Total
Material	1,475
Labour – Internal	0
Labour – Contract	0
Engineering	25
Other	0
Total	$1,500

The total cost to purchase the spare power transformer is $1,500,000 in 2023.

Newfoundland Power will assess the condition of its spare transformers and its inventory requirements annually to determine the need for any additional spares. The Company will seek Board approval of any additional spare units through future capital applications.

5.0 CONCLUSION

Newfoundland Power's customers are exposed to increasing risk of extended outages due to the failure of aging and deteriorated power transformers. An assessment of alternatives determined that procurement of spare power transformers has become necessary to maintain an adequate inventory of units that can be readily deployed in response to equipment failures. Maintaining a reasonable inventory of spare units is consistent with current utility practice, will help mitigate risks of extended customer outages and is necessary to continue delivering reliable service to customers at the lowest possible cost.

APPENDIX A:

Power Transformer Failures: 2012 to 2021

Table A-1 lists Newfoundland Power's actual experience with respect to substation power transformer failures from 2012 to 2021.

Table A-1
Power Transformer Failures
(2012-2021)

Transformer	Voltage	Capacity (MVA)	Year Purchased	Year Failed	Action	Portable Required	Type of Failure
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	66 - 4.16	7.46	1968	2020	Repair	Yes	Imminent
HUM-T3	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
BVA-T1	138 - 12.5	25	1990	2019	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
PUL-T1	66 - 12.5	25	1991	2014	Repair	Yes	In-Service
TRP-T1	66 - 12.5	14.95	1973	2014	Repair	Yes	In-Service
VIR-T2	66 - 12.5	25	1988	2014	Repair	Yes	In-Service
ROP-T1	66 - 6.9	4	1942	2014	Replacement	Yes	Imminent

APPENDIX B:

Power Transformer Listing – Portable/Spare Capability

		Operating Voltage				NP Portables				Newfoundland Power Spares									
Location	Type	High (kV)	Low (kV)	Size MVA	2022 Forecast MVA	P1	P3	P4	P5	200-299	200-113	200-185	200-358	200-219	200-352	200-220	200-258	200-328	Ideal Spare
ABC-T1	Dist.	66.0	12.5	13.33	5.78	X	X	X	X					X		X	X		X
AIR-T1	Dist.	66.0	25.0	25.00	12.00		X	X	X										X
BCV-T1	Dist.	66.0	25.0	25.00	25.77		X	X	X										X
BFS-T1	Dist.	138.0	25.0	20.00	8.47		X	X	X	X									
BHD-T1	Dist.	66.0	25.0	7.46	3.64	X	X	X	X									X	X
BIG-T1	Dist.	66.0	12.5	11.11	9.82	X	X	X	X					X		X	X		X
BLA-T1	Dist.	138.0	25.0	6.67	6.00		X	X	X	X									
BLK-T2	Dist.	138.0	25.0	20.00	13.22		X	X	X	X									
BOT-T1	Dist.	138.0	25.0	20.00	12.87		X	X	X	X									
BOY-T1	Dist.	66.0	2.4	0.30	N/A	X													
BRB-T1	Dist.	138.0	25.0	20.00	11.37		X	X	X	X									
BRB-T4	Dist.	138.0	25.0	25.00	13.52		X	X	X	X									
BVA-T1	Dist.	138.0	25.0	25.00	10.99		X	X	X	X									
BVJ-T1	Dist.	138.0	25.0	2.67	0.21		X	X	X	X									
BVS-T1	Dist.	66.0	12.5	20.00	15.24		X	X	X										X
BVS-T2	Dist.	66.0	12.5	15.00	9.58	X	X	X	X					X		X	X		X
CAB-T2	Dist.	66.0	25.0	6.67	4.09	X	X	X	X									X	X
CAR-T1	Dist.	66.0	25.0	25.00	19.06		X	X	X										X
CAT-T2	Dist.	138.0	25.0	20.00	5.45		X	X	X	X									
CHA-T1	Dist.	66.0	25.0	50.00	38.91			X	X										
CHA-T2	Dist.	66.0	25.0	25.00	18.56		X	X	X										X
CLK-T1	Dist.	66.0	12.5	10.00	4.85	X	X	X	X					X		X	X		X
CLK-T2	Dist.	66.0	12.5	10.00	5.15	X	X	X	X					X		X	X		X
CLV-T2	Dist.	138.0	25.0	20.00	11.60		X	X	X	X									
CLV-T3	Dist.	138.0	25.0	25.00	11.66		X	X	X	X									
COB-T1	Dist.	138.0	25.0	20.00	12.29		X	X	X	X									
COB-T3	Dist.	138.0	25.0	25.00	16.29		X	X	X	X									
COL-T1	Dist.	138.0	25.0	16.67	6.61		X	X	X	X									
DLK-T1	Dist.	66.0	25.0	25.00	21.90		X	X	X										X
DOY-T2	Dist.	66.0	25.0	6.67	4.52	X	X	X	X									X	X
DUN-T1	Dist.	66.0	25.0	6.70	7.66	X	X	X	X									X	X
FER-T1	Dist.	66.0	12.5	4.00	2.61	X	X	X	X					X		X	X		X
FRN-T1	Dist.	66.0	25.0	6.67	5.33	X	X	X	X									X	X
GAL-T1	Dist.	66.0	12.5	13.33	9.47	X	X	X	X					X		X	X		X
GAL-T2	Dist.	66.0	12.5	13.33	9.42	X	X	X	X					X		X	X		X
GAM-T1	Dist.	138.0	25.0	6.67	5.06		X	X	X	X									

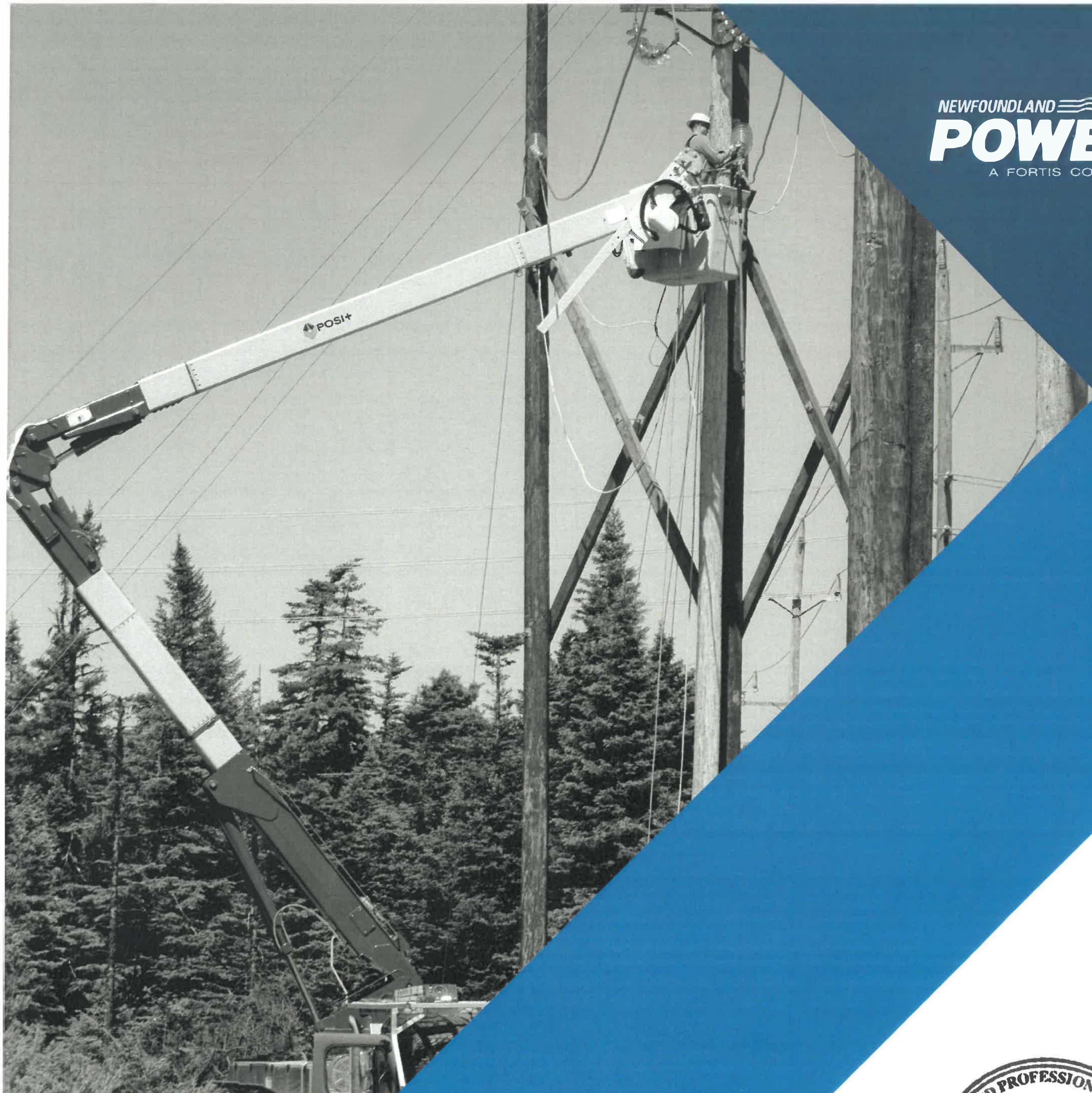
Location	Type	Operating Voltage		Size MVA	2022 Forecast MVA	NP Portables				Newfoundland Power Spares									
		High (kV)	Low (kV)			P1	P3	P4	P5	200-299	200-113	200-185	200-358	200-219	200-352	200-220	200-258	200-328	Ideal Spare
GAN-T1	Dist.	138.0	25.0	20.00	15.80		X	X	X	X									
GAR-T1	Dist.	66.0	12.5	3.72	1.99	X	X	X	X		X	X		X		X	X		X
GBE-T1	Dist.	66.0	7.2	0.33	0.23	X	X	X	X				X						
GBS-T1	Dist.	66.0	25.0	25.00	10.25		X	X	X										X
GBY-T1	Dist.	66.0	25.0	13.33	7.40	X	X	X	X									X	X
GDL-T1	Dist.	66.0	25.0	25.00	21.40		X	X	X										X
GDL-T2	Dist.	66.0	25.0	25.00	19.42		X	X	X										X
GDL-T3	Dist.	66.0	25.0	25.00	22.06		X	X	X										X
GFS-T2	Dist.	138.0	25.0	20.00	12.83		X	X	X	X									
GFS-T3	Dist.	138.0	25.0	50.00	29.12			X	X										
GFS-T5	Dist.	66.0	4.2	11.17	6.32	X										X			
GIL-T1	Dist.	66.0	25.0	6.67	6.17	X	X	X	X									X	X
GLN-T1	Dist.	138.0	25.0	8.34	3.07		X	X	X	X									
GLV-T1	Dist.	138.0	25.0	20.00	10.91		X	X	X	X									
GOU-T2	Dist.	66.0	12.5	20.00	14.88		X	X	X										X
GOU-T3	Dist.	66.0	12.5	13.33	10.49		X	X	X							X	X		X
GPD-T1	Dist.	66.0	12.5	2.80	0.86	X	X	X	X		X	X		X		X	X		X
GRH-T2	Dist.	138.0	25.0	20.00	14.71		X	X	X	X									
HAR-T1	Dist.	66.0	12.5	14.90	14.29		X	X	X										X
HBS-T1	Dist.	66.0	25.0	6.67	3.32	X	X	X	X									X	X
HCT-T3	Dist.	66.0	12.5	2.24	1.42	X	X	X	X		X	X		X		X	X		X
HGR-T1	Dist.	66.0	25.0	8.33	9.19	X	X	X	X										X
HOL-T1	Dist.	138.0	25.0	20.00	13.78		X	X	X	X									
HOW-T3	Dist.	25.0	4.2	1.00	0.83	X													
HUM-T2	Dist.	66.0	4.2	7.46	6.44	X										X			
HUM-T3	Dist.	66.0	12.5	13.33	10.91		X	X	X							X	X		X
HWD-T1	Dist.	66.0	12.5	20.00	20.71		X	X	X										X
HWD-T2	Dist.	66.0	12.5	20.00	20.61		X	X	X										X
HWD-T3	Dist.	66.0	25.0	50.00	50.99			X	X										
ILC-T1	Dist.	66.0	12.5	13.33	9.72		X	X	X					X		X	X		X
ISL-T1	Dist.	66.0	12.5	4.00	3.85	X	X	X	X					X		X	X		X
JON-T1	Dist.	66.0	12.5	0.33	0.00	X	X	X	X				X						
KBR-T3	Dist.	66.0	25.0	25.00	20.49		X	X	X										X
KBR-T4	Dist.	66.0	25.0	25.00	21.21		X	X	X										X
KEL-T1	Dist.	66.0	25.0	25.00	25.70		X	X	X										X
KEN-T1	Dist.	66.0	25.0	25.00	19.27		X	X	X										X
KEN-T2	Dist.	66.0	25.0	50.00	40.72			X	X										

Location	Type	Operating Voltage		Size MVA	2022 Forecast MVA	NP Portables				Newfoundland Power Spares									
		High (kV)	Low (kV)			P1	P3	P4	P5	200-299	200-113	200-185	200-358	200-219	200-352	200-220	200-258	200-328	Ideal Spare
LAU-T1	Dist.	66.0	12.5	13.30	10.75		X	X	X							X	X		X
LET-T1	Dist.	66.0	25.0	16.67	9.29	X	X	X	X										X
LEW-T1	Dist.	138.0	25.0	25.00	18.97		X	X	X	X									
LGL-T1	Dist.	66.0	25.0	14.90	6.74	X	X	X	X									X	X
LLK-T1	Dist.	138.0	25.0	20.00	6.92		X	X	X	X									
LOK-T3	Dist.	66.0	12.5	4.00	3.25	X	X	X	X					X		X	X		X
LPD-T1	Dist.	66.0	12.5	25.00	9.27	X	X	X	X					X		X	X		X
MIL-T1	Dist.	66.0	25.0	16.67	7.89	X	X	X	X									X	X
MKS-T1	Dist.	138.0	25.0	14.90	8.00		X	X	X	X									
MMT-T1	Dist.	66.0	12.5	6.67	4.53	X	X	X	X					X		X	X		X
MOB-T2	Dist.	66.0	12.5	16.67	12.70		X	X	X							X	X		X
MOL-T1	Dist.	66.0	12.5	25.00	25.98		X	X	X										X
MOL-T2	Dist.	66.0	25.0	25.00	24.55		X	X	X										X
MSY-T1	Dist.	138.0	25.0	20.00	17.05		X	X	X	X									
MUN-T1	Dist.	66.0	12.5	14.96	6.79	X	X	X	X					X		X	X		X
MUN-T2	Dist.	66.0	12.5	20.00	10.84		X	X	X							X	X		X
NCH-T1	Dist.	66.0	12.5	6.67	2.89	X	X	X	X					X		X	X		X
NHR-T1	Dist.	66.0	12.5	13.33	7.13	X	X	X	X					X		X	X		X
NWB-T1	Dist.	138.0	25.0	11.20	5.85		X	X	X	X									
OPL-T1	Dist.	66.0	12.5	15.00	7.45	X	X	X	X					X		X	X		X
OXP-T1	Dist.	66.0	12.5	13.33	11.65		X	X	X							X	X		X
PAB-T5	Dist.	66.0	12.5	13.33	8.28	X	X	X	X					X		X	X		X
PAS-T1	Dist.	66.0	12.5	13.30	12.13		X	X	X							X	X		X
PBD-T1	Dist.	138.0	25.0	16.67	2.81		X	X	X	X									
PEP-T1	Dist.	66.0	25.0	25.00	13.18		X	X	X										X
PEP-T2	Dist.	66.0	25.0	25.00	13.99		X	X	X										X
PHR-T3	Dist.	33.0	4.2	4.00	3.12	X													
PJN-T1	Dist.	66.0	7.2	0.33	0.31	X	X	X	X				X						
PUL-T1	Dist.	66.0	25.0	25.00	20.28		X	X	X										X
PUL-T2	Dist.	66.0	25.0	25.00	20.70		X	X	X										X
QTZ-T1	Dist.	66.0	4.2	0.75	0.11	X						X				X			
RBK-T2	Dist.	66.0	25.0	6.67	3.01	X	X	X	X									X	X
ROB-T1	Dist.	66.0	25.0	6.67	4.14	X	X	X	X									X	X
RRD-T2	Dist.	66.0	12.5	20.00	17.68		X	X	X										X
RRD-T3	Dist.	66.0	12.5	20.00	20.04		X	X	X										X
RVH-T1	Dist.	66.0	25.0	8.33	2.89	X	X	X	X									X	X
SCR-T1	Dist.	138.0	25.0	8.30	5.96		X	X	X	X									

Location	Type	Operating Voltage		Size MVA	2022 Forecast MVA	NP Portables				Newfoundland Power Spares									
		High (kV)	Low (kV)			P1	P3	P4	P5	200-299	200-113	200-185	200-358	200-219	200-352	200-220	200-258	200-328	Ideal Spare
SCT-T1	Dist.	66.0	25.0	6.67	2.66	X	X	X	X									X	X
SCT-T2	Dist.	25.0	12.5	4.00	0.89	X													
SCV-T2	Dist.	66.0	25.0	11.20	12.69		X	X	X										X
SJM-T1	Dist.	66.0	25.0	25.00	17.44		X	X	X										X
SJM-T2	Dist.	66.0	12.5	25.00	18.86		X	X	X										X
SJM-T3	Dist.	66.0	25.0	25.00	12.64		X	X	X										X
SLA-T1	Dist.	66.0	4.2	13.30	9.07	X										X			
SLA-T2	Dist.	66.0	4.2	10.40	0.00	X						X				X			
SLA-T3	Dist.	66.0	12.5	25.00	14.93		X	X	X										X
SLA-T4	Dist.	66.0	12.5	25.00	19.32		X	X	X										X
SMV-T1	Dist.	66.0	25.0	4.00	2.74	X	X	X	X									X	X
SPF-T1	Dist.	138.0	25.0	20.00	12.73		X	X	X	X									
SPO-T1	Dist.	66.0	12.5	15.00	11.11		X	X	X							X	X		X
SPR-T1	Dist.	138.0	25.0	16.67	11.92		X	X	X	X									
STG-T1	Dist.	66.0	25.0	6.67	3.41	X	X	X	X									X	X
STX-T1	Dist.	66.0	12.5	6.67	4.53	X	X	X	X					X		X	X		X
SUM-T1	Dist.	66.0	25.0	13.33	7.63	X	X	X	X									X	X
SUN-T5	Dist.	138.0	25.0	25.00	16.00		X	X	X	X									
TNS-T1	Dist.	138.0	14.4	1.00	0.87		X		X										
TRN-T1	Dist.	66.0	25.0	6.67	3.55	X	X	X	X									X	X
TRP-T1	Dist.	66.0	12.5	15.00	2.55	X	X	X	X					X		X	X		X
TWG-T1	Dist.	66.0	12.5	13.33	8.49	X	X	X	X					X		X	X		X
VIC-T1	Dist.	66.0	12.5	13.33	8.53	X	X	X	X					X		X	X		X
VIR-T1	Dist.	66.0	12.5	20.00	23.15		X	X	X										X
VIR-T2	Dist.	66.0	25.0	25.00	25.67		X	X	X										X
VIR-T3	Dist.	66.0	25.0	25.00	12.73		X	X	X										X
WAL-T1	Dist.	66.0	12.5	20.00	17.68		X	X	X										X
WAL-T2	Dist.	66.0	12.5	25.00	26.45		X	X	X										X
WAV-T6	Dist.	66.0	12.5	13.30	6.09	X	X	X	X					X		X	X		X
WBC-T1	Dist.	66.0	25.0	8.33	3.92	X	X	X	X									X	X
WES-T1	Dist.	66.0	12.5	13.33	9.95	X	X	X	X					X		X	X		X
CAB-T1	Gen.	66.0	7.2	11.25	6.44	X	X		X										
FPD-T1-A	Gen.	12.5	4.2	0.25	0.25														
FPD-T1-B	Gen.	12.5	4.2	0.25	0.25														
FPD-T1-C	Gen.	12.5	4.2	0.25	0.25														
GRH-T1	Gen.	66.0	13.8	30.00	20.51		X		X										

Location	Type	Operating Voltage		Size MVA	2022 Forecast MVA	NP Portables				Newfoundland Power Spares									
		High (kV)	Low (kV)			P1	P3	P4	P5	200-299	200-113	200-185	200-358	200-219	200-352	200-220	200-258	200-328	Ideal Spare
HCP-T1	Gen.	66.0	6.9	12.00	8.10	X	X		X										
HCT-T1	Gen.	66.0	4.2	3.00	2.77	X													
LBK-T1	Gen.	66.0	2.4	10.00	5.74	X													
LOK-T1	Gen.	46.0	6.9	2.50	1.54	X	X		X										
LOK-T2	Gen.	66.0	46.0	7.46	3.08	X	X		X										
LOK-T4	Gen.	46.0	6.9	2.50	1.54	X	X		X										
MOP-T1	Gen.	66.0	6.9	13.33	10.77		X		X										
MRP-T1	Gen.	66.0	2.4	1.50	1.20	X													
NCH-T2	Gen.	66.0	6.9	5.33	4.41	X	X		X										
PAB-T3	Gen.	66.0	4.2	4.00	2.56	X													
PBK-T1	Gen.	66.0	6.9	6.67	4.21	X	X		X										
PHR-T1	Gen.	66.0	2.4	6.70	4.82	X													
PIT-T1-A	Gen.	12.5	4.2	0.33	0.19														
PIT-T1-B	Gen.	12.5	4.2	0.33	0.19														
PIT-T1-C	Gen.	12.5	4.2	0.33	0.19														
PUN-T1-A	Gen.	66.0	2.4	0.33	0.17	X													
PUN-T1-B	Gen.	66.0	2.4	0.33	0.17	X													
PUN-T1-C	Gen.	66.0	2.4	0.33	0.17	X													
RBH-T1	Gen.	25.0	6.9	9.30	5.74														
RBK-T1	Gen.	66.0	6.9	23.75	15.18		X		X										
ROP-T1	Gen.	66.0	6.9	5.33	3.33	X	X		X										
SBK-T1	Gen.	66.0	6.9	7.00	6.47	X	X		X										
SCV-T1	Gen.	66.0	4.2	3.33	3.08	X													
TCV-T1	Gen.	66.0	6.9	7.50	6.46	X	X		X										
TOP-T1	Gen.	25.0	2.4	0.75	0.75														
TOP-T1	Gen.	25.0	2.4	0.75	0.75														
TOP-T1	Gen.	25.0	2.4	0.75	0.75														
VIC-T2	Gen.	12.5	2.4	0.60	0.50														
WBK-T1	Gen.	12.5	4.2	0.33	0.43														
WBK-T1	Gen.	12.5	4.2	0.33	0.43														
WBK-T1	Gen.	12.5	4.2	0.33	0.43														
WES-T2	Gen.	66.0	13.8	16.00	8.21	X	X		X										
BLK-T3	Tran.	138.0	66.0	41.60	N/A			X							X				
BRB-T2	Tran.	138.0	66.0	41.60	N/A			X							X				
BRB-T3	Tran.	138.0	66.0	41.60	N/A			X							X				
CAT-T1	Tran.	138.0	66.0	16.70	N/A		X	X							X				

Location	Type	Operating Voltage		Size MVA	2022 Forecast MVA	NP Portables				Newfoundland Power Spares									
		High (kV)	Low (kV)			P1	P3	P4	P5	200-299	200-113	200-185	200-358	200-219	200-352	200-220	200-258	200-328	Ideal Spare
CLV-T1	Tran.	138.0	66.0	25.00	N/A		X	X							X				
COB-T2	Tran.	138.0	66.0	41.60	N/A			X							X				
GAM-T2	Tran.	138.0	66.0	41.60	N/A			X							X				
GAN-T2	Tran.	138.0	66.0	21.30	N/A		X	X							X				
GAN-T3	Tran.	66.0	N/A	3.50	N/A		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		X	X											
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							X				



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3.1 2023 Transmission Line Rebuild

June 2022

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TABLE OF CONTENTS

1.0 INTRODUCTION

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") transmission lines are the backbone of the electricity system providing service to customers. The Company maintains approximately 2,100 kilometres of transmission line that operate at 66 kV or 138 kV. Most of these transmission lines are located across country, away from road right of ways.

Transmission line failures typically result in outages to a significant number of customers at once. Maintaining transmission lines is therefore critical to the delivery of reliable service to customers.

The 2023 *Transmission Line Rebuild* project includes a new multi-year project to rebuild Transmission Line 55L in 2023 and 2024.

2.0 BACKGROUND

Newfoundland Power filed a *Transmission Line Rebuild Strategy* as part of its *2006 Capital Budget Application*. The strategy outlines a long-term plan to rebuild the Company's aging transmission lines. Rebuild projects are prioritized based on physical condition, risk of failure, and the potential impact on customers in the event of a failure.

This strategy is updated annually to ensure it reflects the latest condition assessments, inspection information, and operating experience. Appendix A provides the most recent update to the strategy.

A total of 26 transmission lines have been rebuilt under the strategy since 2006. By year-end 2022, approximately 79% of the strategy will have been executed.[1] Newfoundland Power plans to continue implementation of the *Transmission Line Rebuild Strategy* in 2023 by rebuilding Transmission Line 55L.

3.0 ASSESSMENT OF TRANSMISSION LINE 55L

Transmission Line 55L is a 66 kV radial line running between Blaketown ("BLK") Substation on the Trans-Canada Highway, and Clarkes Pond ("CLK") Substation in Placentia. The transmission line provides the sole source of supply for approximately 3,400 customers served by Placentia Junction, Dunville, Clarkes Pond and Quartz substations.

Transmission Line 55L was originally constructed in 1971, except for a small 1.0-kilometre section constructed in 1968. The tap to Quartz ("QTZ") Substation was constructed in 1981. The line includes approximately 43.3 kilometres of original construction, consisting of

[1] Three transmission lines have been removed from the strategy since 2006: 101L and 102L, which have been addressed as part of the *Central Newfoundland System Planning Study*, and 53L, which is no longer in service. This brings the total number of transmission lines encompassed by the strategy to 34. The rebuild of one transmission line included in the strategy (124L) will be completed in 2022, changing the total rebuilt by year end to 27 (27 / 34 = 0.79, or 79%). Five of the seven remaining transmission lines rebuilds are included in the schedule provided in Appendix A. The final two transmission line rebuilds, 105L and 35L, are currently scheduled for rebuild in 2028.

372 single-pole structures and 54 H-frame structures. The line was constructed using 4/0 AASC, 266.8 ACSR, and 397.5 ACSR conductor.[2]

Transmission Line 55L is not constructed to meet current standards. The Canadian Standards Association ("CSA") establishes standards for the construction of overhead systems based on local climatic conditions. At the time of construction in 1971, the area in which Transmission Line 55L operates was classified "CSA Heavy". This classification required the line be built to withstand 12.5 millimetres of ice and 400 N/m^2 of wind. Standards have changed since 1971.[3] The area is now classified as "CSA Severe", which requires the line be built to withstand 19 millimetres of ice and 400 N/m^2 of wind. The sub-standard design of this line increases risk of equipment failures.

Customers supplied by Transmission Line 55L have been subjected to outages due to equipment failures during significant weather systems. For example, in 2017 customers experienced an outage of approximately 4.5 hours due to a severe wind storm, which resulted in approximately 891,000 customer minutes of outage. Customers experienced a similar outage due to a wind storm in 2020, resulting in a total of approximately 817,000 customer minutes of outage. Over the last two decades, customers served by Transmission Line 55L have experienced over 10 million minutes of outage.

Due to its radial configuration, maintenance work to address deficiencies on Transmission Line 55L requires either lengthy customer outages, the installation of mobile generation, or the use of hotline work methods using specialized resources. Significant time can also be required to undertake repairs, as a large portion of the line is located across country away from road right of ways. Due to its configuration and location, there are significant costs incurred when performing maintenance on this line in order to maintain service to customers in the area.

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[2] ACSR is a bare overhead conductor constructed with aluminum outer strands and a steel core to support the weight of the cable. 266.8 ACSR has been noted to have poor operating characteristics in a salt spray environment. 266.8 ACSR is no longer a standard conductor for the Company's transmission lines.

[3] *CSA 22.3 No. 1-01 Overhead Systems* was updated in 2001 to include the severe weather loading area.

Table 1 summarizes the maintenance performed on Transmission Line 55L and associated costs over the most recent 5-year period.

Table 1
Maintenance Expenditures for 55L
(2017-2021)

Component Replaced	2017	2018	2019	2020	2021
Poles	3	-	-	1	2
Insulators	87	-	4	-	6
Anchors	1	-	-	-	-
Framings	3	-	2	-	2
Cribs	1	-	-	-	1
Ball link eye bolts	3	-	-	3	-
Total Cost	$163,000	$0	$38,000	$30,000	$51,000

Annual maintenance costs for Transmission Line 55L have averaged approximately $56,000 annually since 2017. Due to its configuration and location, replacing even a small number of line components can result in a high cost. For example, approximately $30,000 was incurred in 2020 to replace one pole and three ball link eye bolts.

Transmission Line 55L was inspected in 2022 to assess its current condition. The inspections determined that 253 of 490 poles on the line are deteriorated to the point where replacement is required. In addition, 61 structures were identified as either having deteriorated insulators, deteriorated crossarms or hardware deficiencies.

Many of the poles on Transmission Line 55L are showing signs of significant shell separation.[4] Shell separation creates a safety risk for employees climbing the poles to perform maintenance as the deteriorated shell is unable to support the weight of the climber and the climber's spikes can tear out of the pole. Without the ability to climb the poles, performing maintenance on crossarms and insulators requires off-road aerial equipment to access the structures.

Overall, the sub-standard design and deteriorated condition of Transmission Line 55L makes it susceptible to equipment failure due to severe wind, ice or snow loading.

Appendix B provides pictures of examples of the deterioration noted on Transmission Line 55L.

[4] This phenomenon causes the outer shell of the poles to separate longitudinally, resulting in deep checks extending from the bottom of the pole to the top. These checks extend deep enough to allow moisture and fungus to enter the pole past the treated outer layer and into the untreated centre of the pole. Repeated freeze and thaw cycles exacerbate this problem by widening the checks, and the result is failure of the poles.

4.0 ASSESSMENT OF ALTERNATIVES

4.1 General

Transmission Line 55L is critical to the delivery of service to customers in the Placentia area. Due to its radial configuration and location across country, equipment failures have resulted in lengthy customer outages. The line's sub-standard design and its deteriorated condition continue to pose a risk to the delivery of reliable service to customers.

Transmission Line 55L was originally planned to be rebuilt in 2007, but was deferred through routine maintenance. Completing minor maintenance on the line can carry a high cost. Based on its condition, criticality in serving customers and operating experience, a capital project to address the deteriorated condition of Transmission Line 55L can no longer be deferred.

Three alternatives were evaluated to address the deteriorated condition of Transmission Line 55L: (i) address the existing deficiencies in 2023 and defer the replacement of other components; (ii) rebuild the line in its existing right of way; and (iii) rebuild the line in a new right of way. The assessment of these alternatives is provided below.

4.2 Alternative 1 - Address Existing Deficiencies

Alternative 1 involves completing a project in 2023 to address the deficiencies identified during inspection in 2022. A total of 217 deteriorated structures would be replaced in 2023 under this alternative. The project would require approximately 17 weeks to execute. The installation and operation of two portable generators would be required throughout the duration of the project in order to maintain supply to customers in the area.[5]

Alternative 1 assumes that replacement of the remainder of the line components could be deferred by over a decade to 2036. At this point, the remaining line components would be in service for 65 years and would be beyond their expected useful service life, indicating an increased risk of equipment failure.[6] Under this alternative, the remaining 209 structures and 43.3 kilometres of overhead conductor would be replaced in 2036. The project would require approximately 24 weeks to execute. The installation and operation of two portable generators would be required throughout the duration of the project.

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[5] Completing the work using hot line methods was considered, but deemed to be unfeasible due to the large number of resources required. Completing the work under a number of outages was considered, but deemed to be unfeasible as it would significantly affect the quality of service provided to customers in the area.

[6] For example, the industry average expected useful service life of transmission line overhead conductor is 63 years.

Table 2 provides the capital costs associated with Alternative 1.[7]

Table 2 Alternative 1 Capital Costs ($000)		
Year	Item	Cost
2023	Replace 217 structures	$6,735
2023	Portable Generation	$775
2036	Replace 209 structures	$6,521
2036	String 43.3 km of new conductor	$1,476
2036	Portable Generation	$1,083
	Total	$16,590

The total capital cost of Alternative 1 is $16,590,000. This does not include operating costs associated with fuel required to deploy portable generation.[8]

4.3 Alternative 2 - Rebuild in Existing Right of Way

Alternative 2 involves rebuilding Transmission Line 55L in its existing right of way. Approximately 22.1 kilometres of transmission line would be rebuilt in 2023 and 21.2 kilometres would be rebuilt in 2023, including stringing new conductor. Execution of this alternative would require approximately 12 weeks in 2023 and 14 weeks in 2024. The deployment of two portable generators would be required throughout execution of the project in order to maintain service to customers.

7 In addition to capital costs, there would also be additional operating costs associated with fuel for the operation of portable generation.

8 Fuel costs to deploy portable generation are estimated to be $782,000 in 2023 and $897,000 in 2036.

Table 3 provides the capital costs associated with Alternative 2.

Table 3
Alternative 2 Capital Costs
($000)

Year	Item	Cost
2023	Rebuild 22.1 km of transmission line	$4,968
2023	Portable Generation	$647
2024	Rebuild 21.2 km of transmission line	$5,078
2024	Portable Generation	$700
	Total	$11,393

The total capital cost of Alternative 2 is $11,393,000. This does not include operating costs associated with fuel required to deploy portable generation.[9]

4.4 Alternative 3 - Rebuild in New Right of Way

Alternative 3 involves rebuilding Transmission Line 55L in a new right of way. The existing line would remain energized and continue to supply customers while the project is ongoing. A portion of the line would also be relocated along the Argentia Access Road, making the structures more easily accessible for inspection, maintenance and response to customer outages.[10] Under this alternative, 24.1 kilometres of transmission would be rebuilt in 2023 and 21.2 kilometres would be rebuilt in 2024, including stringing new conductor.

9 Fuel costs to deploy portable generation are estimated to be $1,068,000 in 2023 and $1,143,000 in 2024.

10 Approximately 30 kilometres of the entire line will be moved roadside. Two kilometres will be added to the overall length of the line under this alternative.

Table 4 provides the capital costs associated with Alternative 3.[11]

Table 4 Alternative 3 Capital Costs ($000)		
Year	Item	Cost
2023	Rebuild 24.14 km of transmission line	$5,328
2024	Rebuild 21.19 km of transmission line	$5,284
	Total	$10,612

The total capital cost of Alternative 3 is $10,612,000.

4.5 Net Present Value Analysis of Alternatives

A net present value ("NPV") calculation of customer revenue requirement was completed for each alternative. Capital costs from 2023 were converted to the customer revenue requirement and the resulting customer revenue requirement was reduced to an NPV using the Company's weighted average incremental cost of capital.

Table 5 provides the results of the NPV analysis for the three alternatives, including capital costs and fuel costs associated with portable generation.

Table 5 Net Present Value Analysis ($000)	
Alternative	NPV
1 – Address Existing Deficiencies	$16,497
2 – Rebuild in Existing Right of Way	$15,091
3 – Rebuild in New Right of Way	$12,044

The NPV analysis determined that Alternative 3, which involves rebuilding Transmission Line 55L in a new right of way, is the lowest cost of the viable alternatives.

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11 The rebuild cost of transmission line per kilometre is higher under this alternative because the new right of way would require a larger amount of brush clearing, a more extensive survey, a new crown land application and additional engineering.

A sensitivity analysis was completed of Alternative 1, which involves addressing existing deficiencies in 2023 and deferring the replacement of the other structures and conductor. The analysis evaluated the impact of advancing or deferring the future replacements by five years.

Table 6 provides the sensitivity analysis of Alternative 1 based on the NPV of customer revenue requirement.

Table 6
Sensitivity Analysis of Alternative 1
($000s)

Base Case NPV	Advanced Replacement NPV	Deferred Replacement NPV
$16,497	$18,007	$15,242

The sensitivity analysis of Alternative 1 determined that advancing the future replacements by five years increases the cost to approximately $18 million. Deferral by five years decreases the cost to approximately $15.2 million. In both cases, Alternative 3 remains the least-cost alternative to address the deterioration identified on Transmission Line 55L.

5.0 PROJECT SCOPE AND COST

Transmission Line 55L is proposed to be rebuilt as a multi-year project. A 24.1-kilometre section will be rebuilt in 2023 and the remaining 21.2-kilometre section will be rebuilt in 2024.

Appendix C shows the routing of Transmission Line 55L and identifies the sections to be rebuilt in 2023 and 2024.

Detailed engineering design will be completed in order to build the line to current CSA standards to ensure it can withstand local climatic conditions. The line will be constructed in a new right of way with approximately 30 kilometres of the line moved roadside. In addition to being the least-cost alternative, moving the line roadside will provide operational benefits, including easier access for completing inspections, maintenance and responding to customer outages.

Table 7 provides a detailed breakdown of the cost to rebuild Transmission Line 55L.

Table 7
Transmission Line 55L Rebuild Project
2023 Project Cost
($000s)

Description	2023	2024	Total
Engineering	479	391	870
Labour - Contract	2,747	2,709	5,456
Labour - Internal	315	300	615
Material	934	1,042	1,976
Other	853	842	1,695
Total	$5,328	$5,284	$10,612

The cost of rebuilding Transmission Line 55L is approximately $5,328,000 in 2023 and $5,284,000 in 2024.

6.0 CONCLUSION

Transmission Line 55L is a radial line that is critical to the delivery of reliable service to approximately 3,400 customers in the Placentia area. The line was constructed in 1971, is not built to current design standards, and is experiencing significant levels of deterioration. The line's sub-standard design and deteriorated condition have caused equipment failures, which have resulted in customer outages and significant maintenance costs.

The rebuilding of Transmission Line 55L was deferred by over 15 years. However, based on its age, condition and criticality, continued maintenance is no longer feasible.

An analysis determined that rebuilding Transmission Line 55L in a new right of way is the least-cost alternative to address its deteriorated condition. The rebuild project will address deficiencies identified during inspection, ensure the line is constructed to current standards, and provide operational benefits by moving a portion of the line roadside. Overall, execution of this project is necessary to deliver reliable service to customers in the Placentia area at the lowest possible cost.

APPENDIX A:

Transmission Line Rebuild Schedule: 2023-2027

Table A-1
Transmission Line Rebuild Schedule
2023-2027
($000s)

Line	Year Built	2023	2024	2025	2026	2027
55L BLK-CLK	1971	5,328	5,284			
94L BLK-RVH	1969	4,346	4,276			
146L GAN-GAM	1964		4,702	4,840		
48L BRB-BLK[1]	1967			3,162	3,342	
95L RVH-TRP	1969			5,284	5,586	
108L GAN-GBY[2]	1965				3,236	9,289
100L SUN-CLV	1964					5,994
105L GFS-SBK	1963					
35L OXP-KEN	1965					
TOTAL		9,674	14,262	13,286	12,164	15,283

[1] Transmission Line 48L was not in the *2006 Transmission Line Rebuild Strategy*. Recent inspections indicate that Transmission Line 48L is deteriorating and in need of replacement.

[2] Transmission Line 108L was not in the *2006 Transmission Line Rebuild Strategy*. Recent inspections indicate that Transmission Line 108L is deteriorating and in need of replacement.

APPENDIX B:

Photographs of Transmission Line 55L

Figure B-1: Deep Splits in Pole

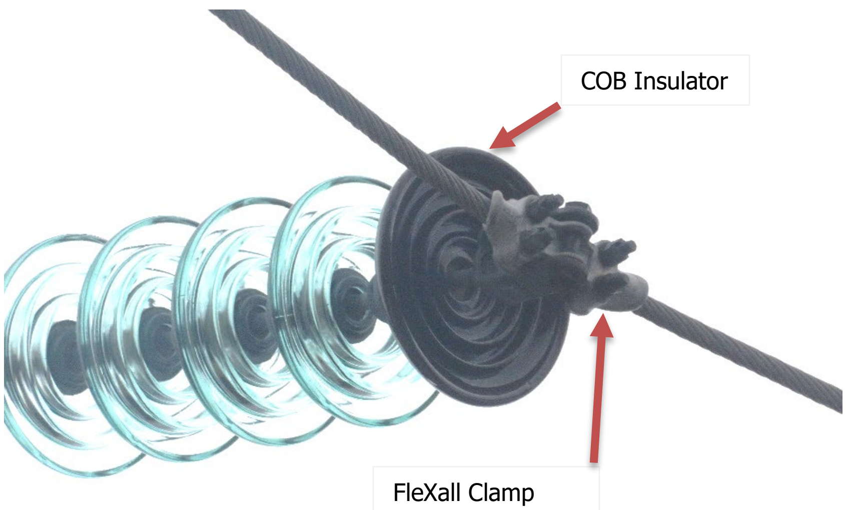

Figure B-2: COB Insulator and FleXall Clamp

Figure B-3: Cracked Porcelain Insulator

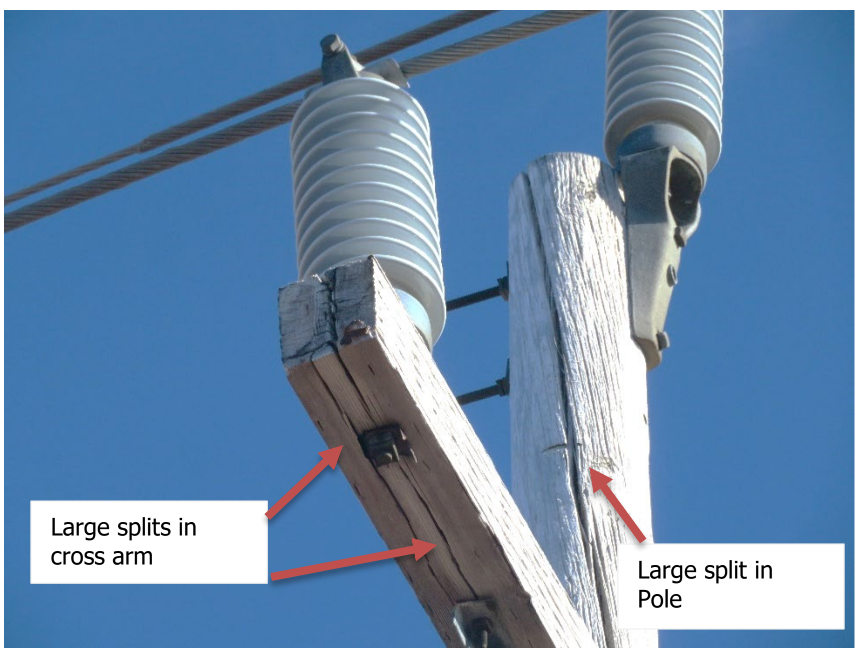

Figure B-4: Split Cross Arm and Split Pole Top

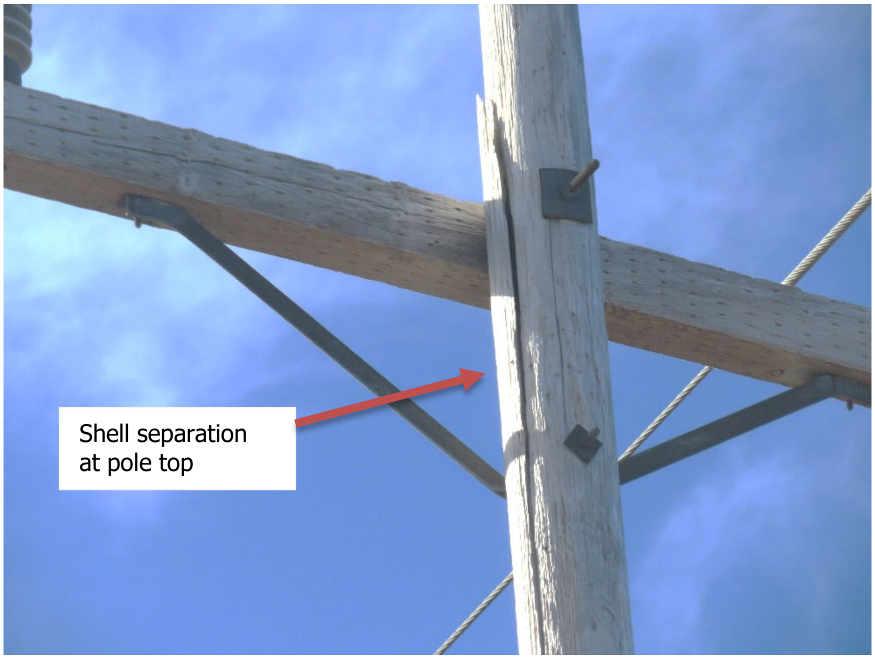

Figure B-5: Shell Separation

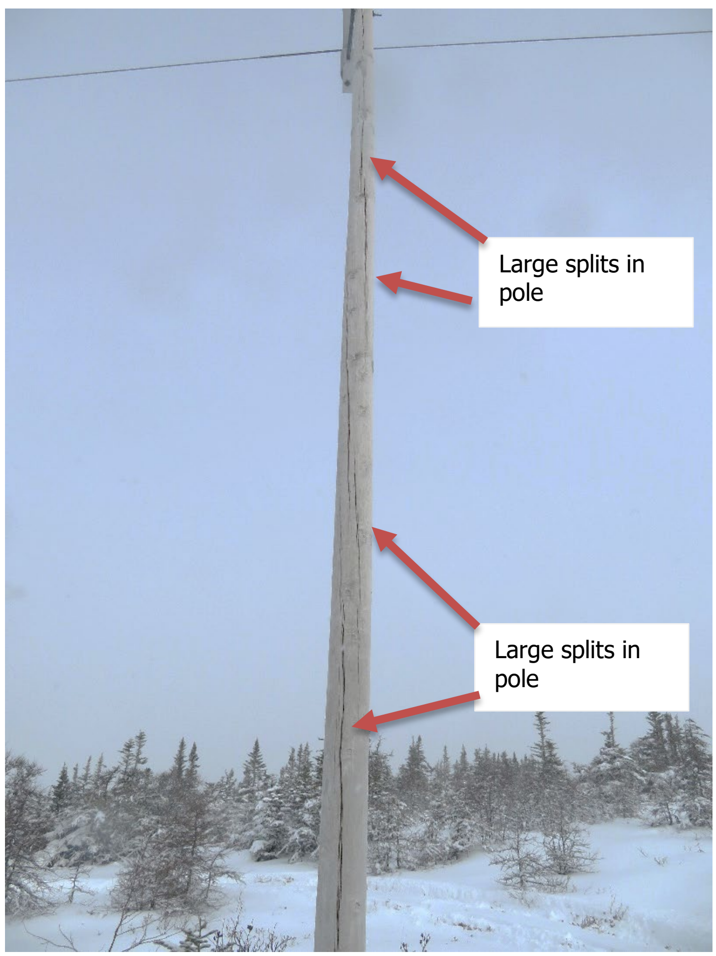

Figure B-6: Deep Splits in Pole

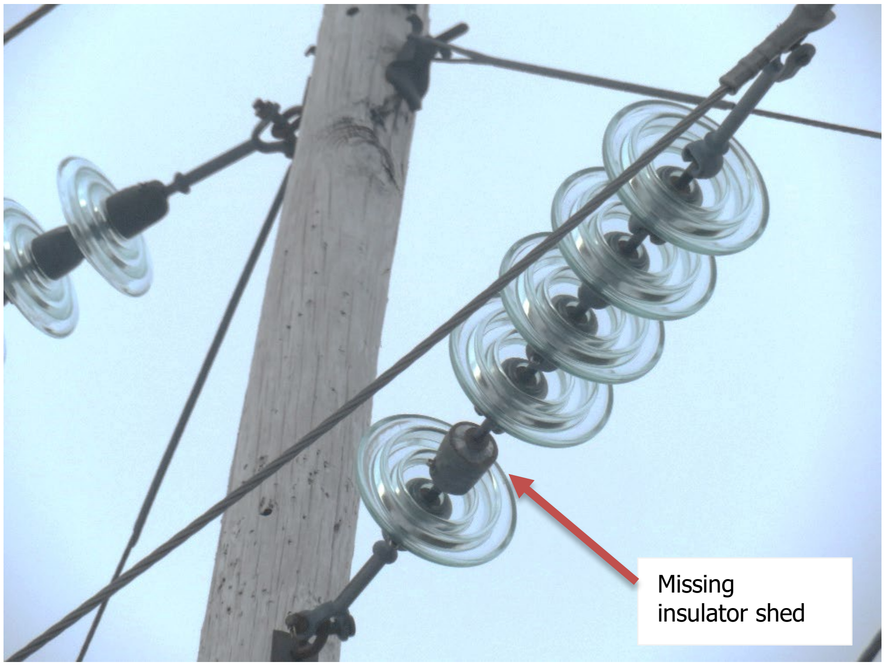

Figure B-7: Broken Insulator Shed

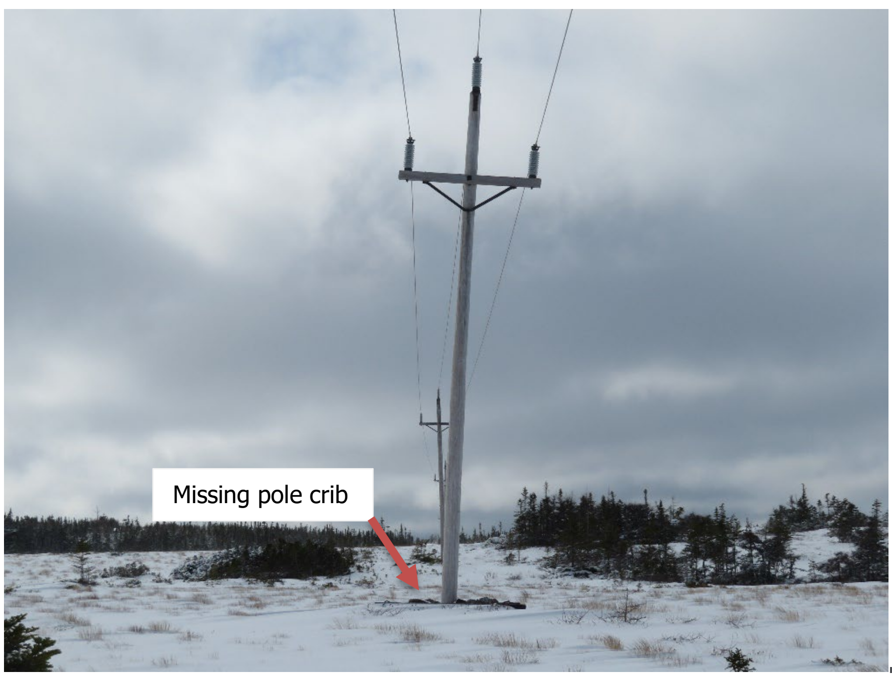

Figure B-8: Pole Crib Deteriorated/Pole Leaning

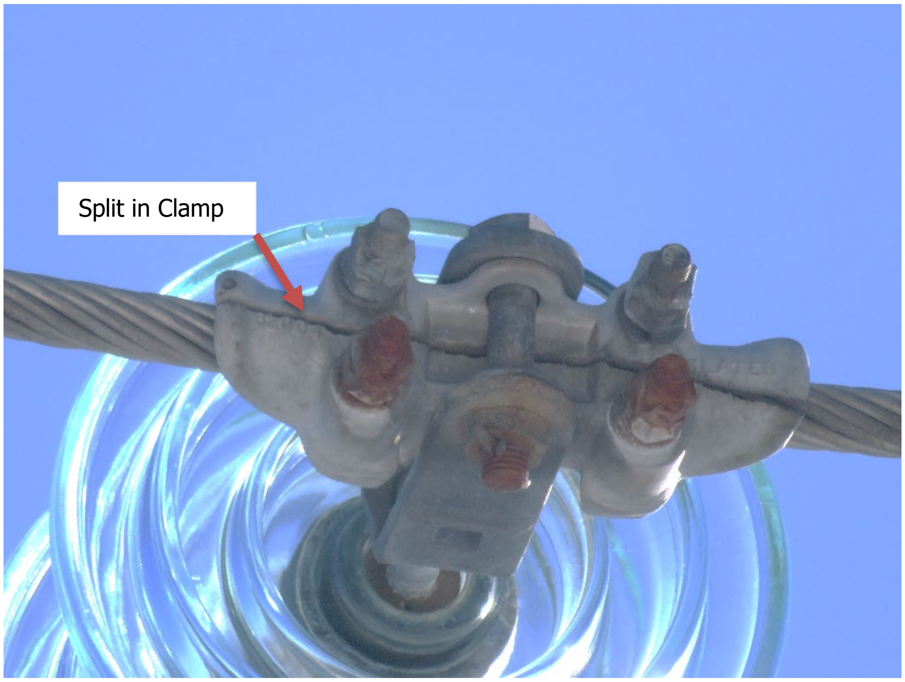

Figure B-9: Split FleXall Clamp

Figure B-10: Woodpecker Holes

Figure B-11: Deteriorated Pole Top

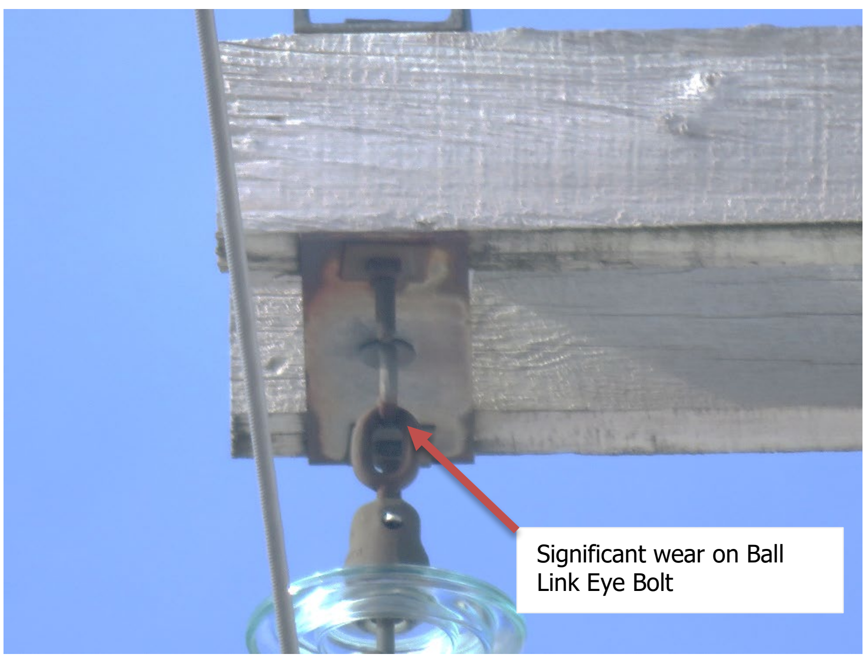

Figure B-12: Worn Ball Link Eye Bolt

Figure B-13: Split Pole Top

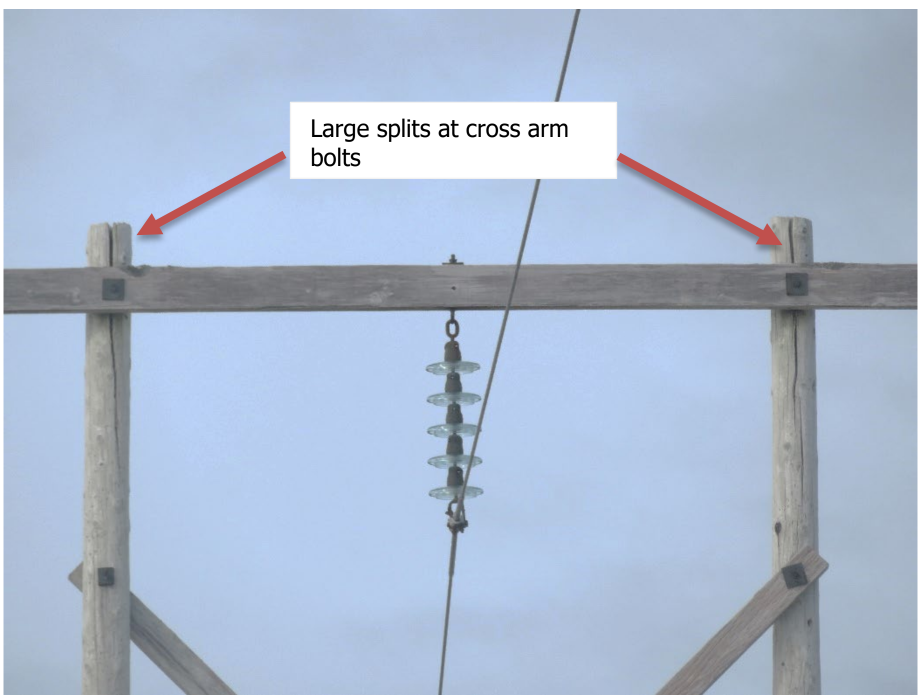

Figure B-14: Split Pole Tops

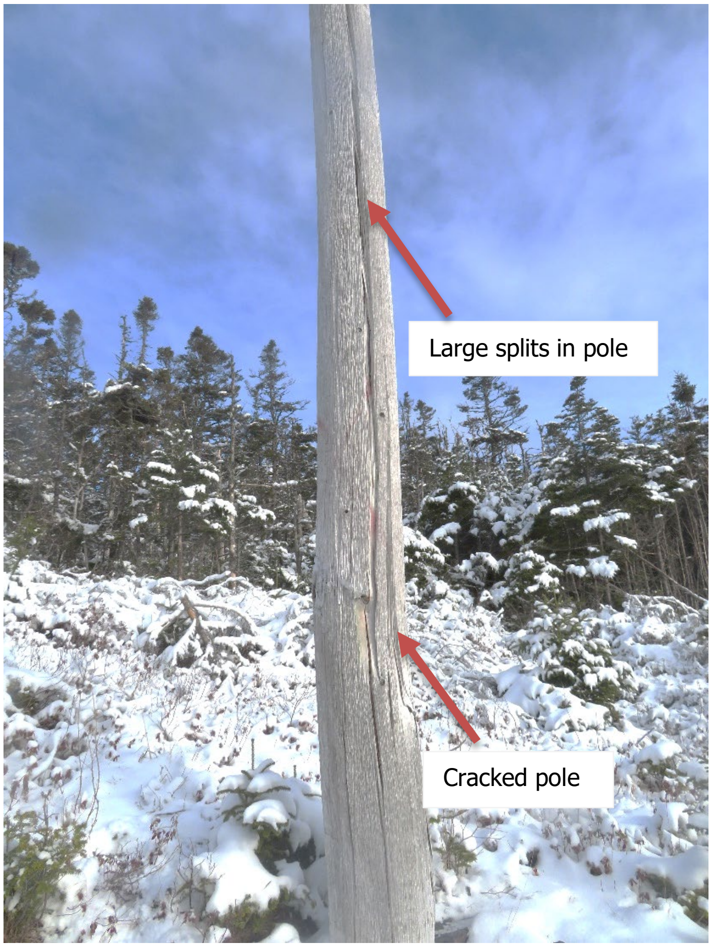

Figure B-15: Cracked Pole

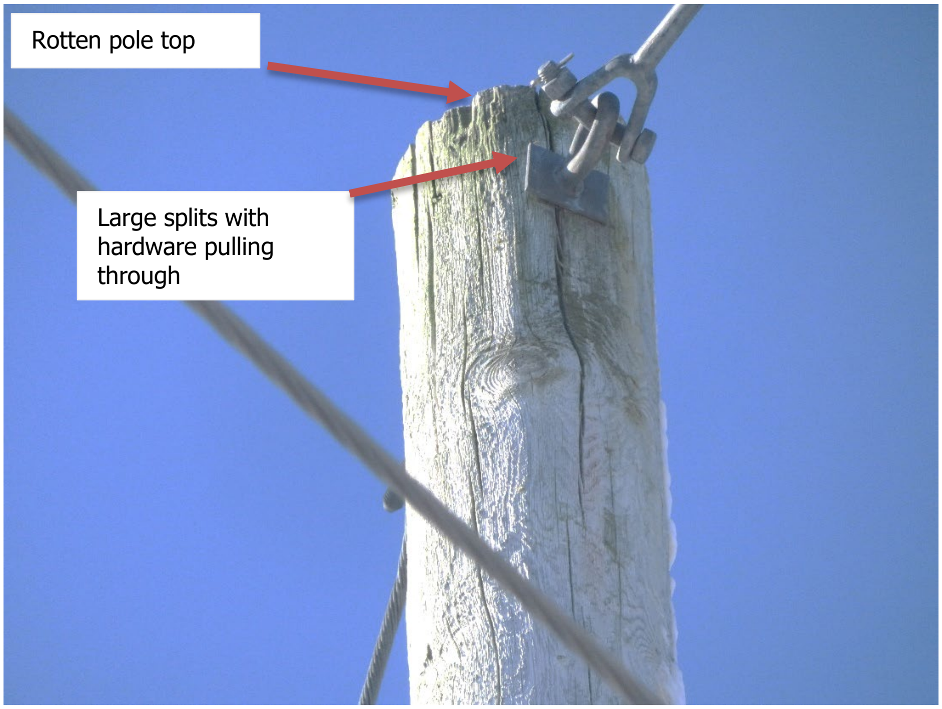

Figure B-16: Cracked/Rotten Pole Top

Figure B-17: Deep Splits in Pole

Figure B-18: Shell Separation

APPENDIX C:

Maps of Transmission Line 55L

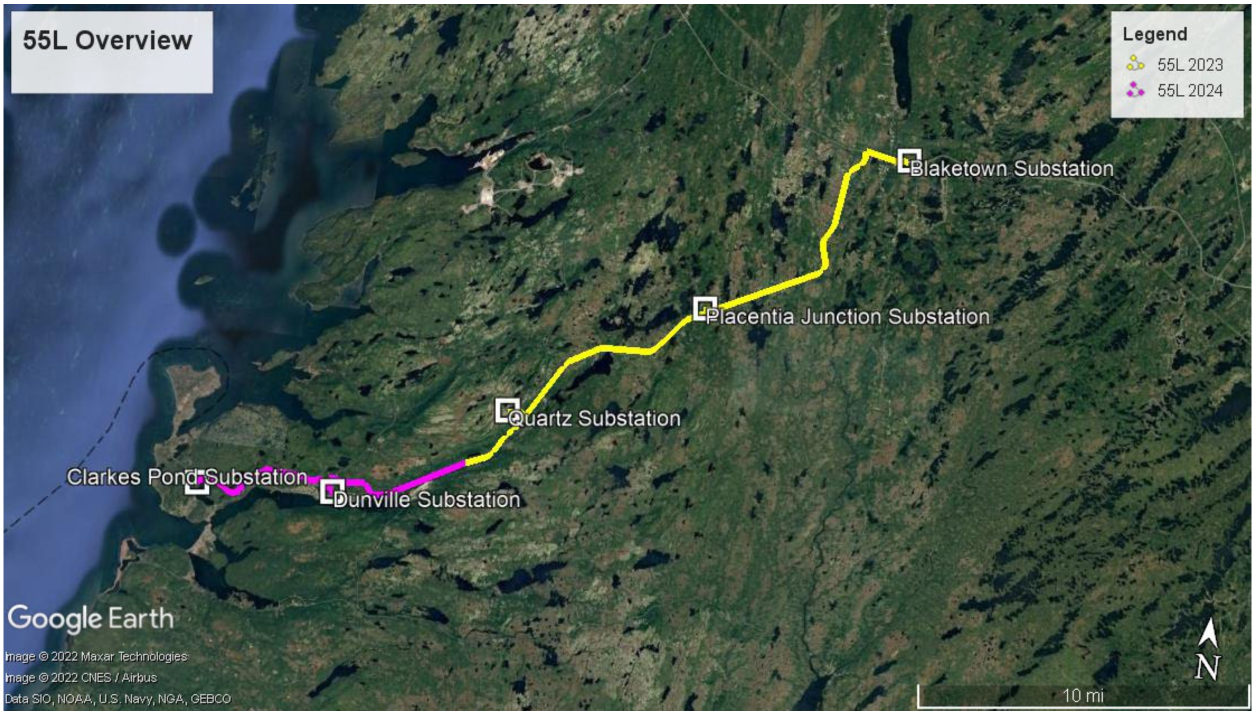

Figure C-1: Map of Transmission Line 55L

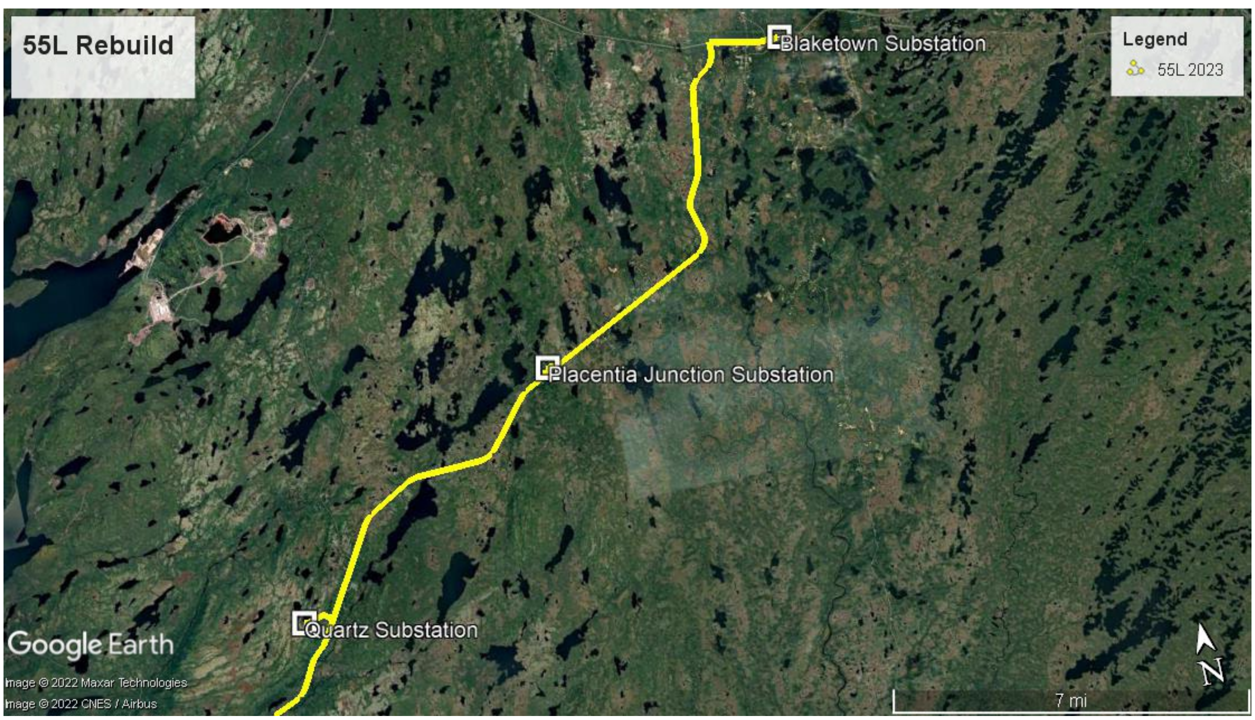

Figure C-2: Map of 55L Route (2023)

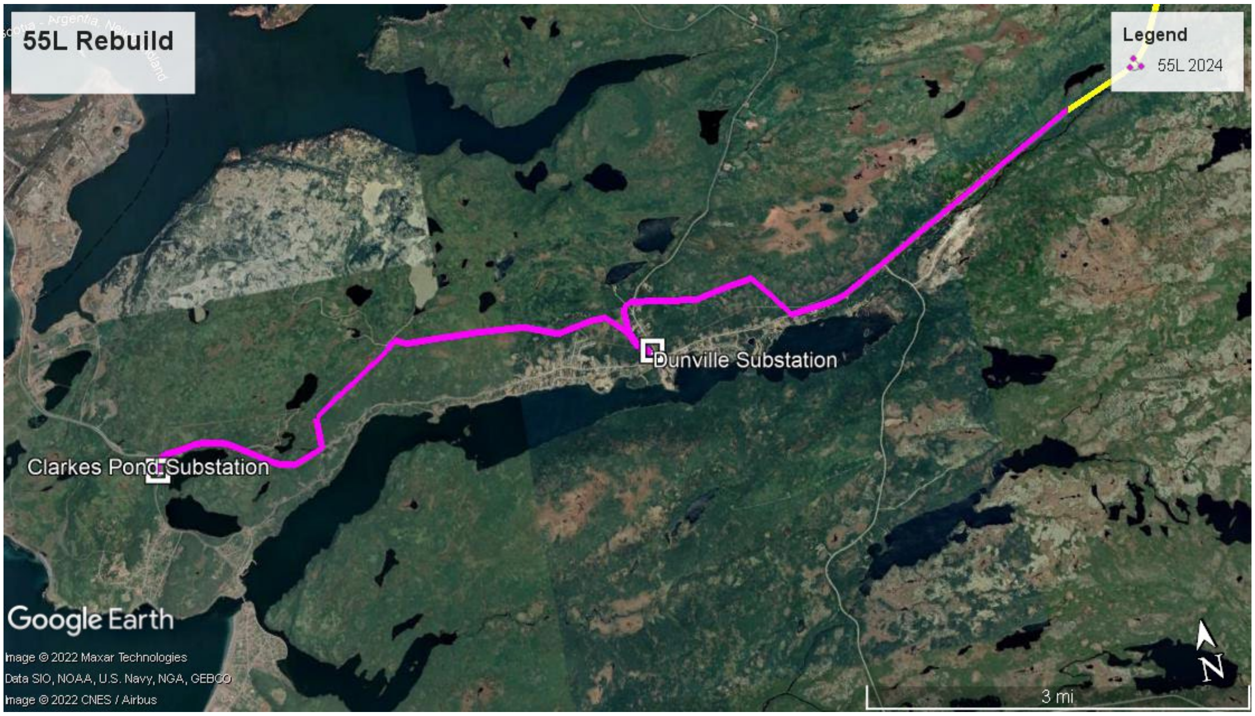

Figure C-3: Map of 55L Route (2024)

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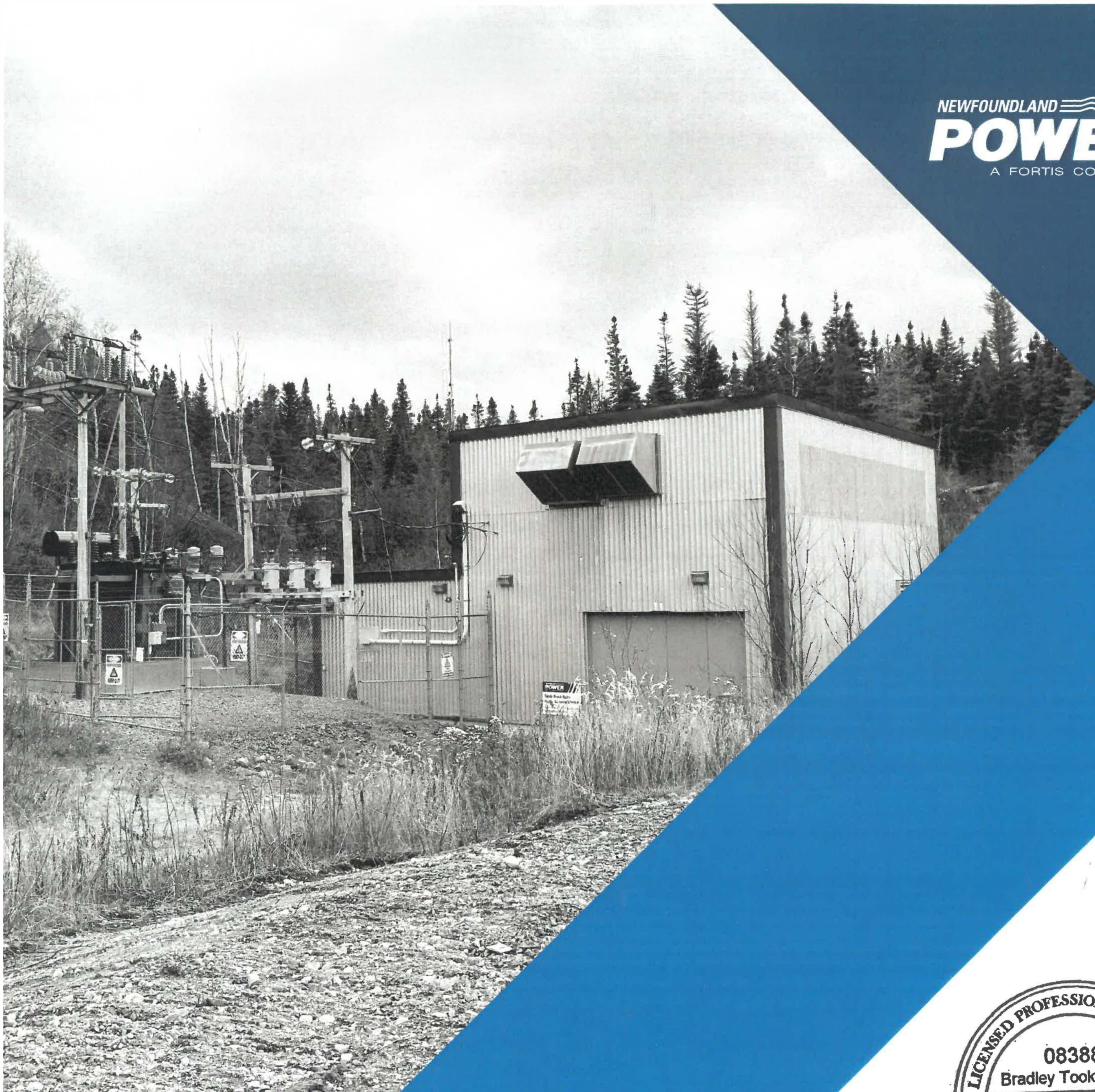

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4.1 Sandy Brook Hydro Plant Generator Refurbishment

June 2022

Prepared by: Bradley Tooktoshina, P. Eng.

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1.0 INTRODUCTION

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") Sandy Brook hydroelectric development (the "Sandy Brook Plant" or the "Plant") is located on a tributary of the Exploits River, approximately 13 kilometres southwest of the Town of Grand Falls - Windsor. The Plant has provided 59 years of reliable energy production.

The Board approved the replacement of the Plant's woodstave penstock in Order No. P.U. 36 (2021). Replacement of the penstock is being completed over two years. The engineering is being completed in 2022 and installation of the replacement penstock will be completed in 2023.

The Plant's generator also requires refurbishment due to its age and condition. Newfoundland Power is proposing to rewind the Plant's generator stator and reinsulate the generator rotor in 2023.[1] Pooling capital work in this manner will allow work on the generator to be completed while the Plant is out of service for penstock replacement, thereby minimizing plant downtime.

The capital cost to rewind the generator stator and reinsulate the generator rotor is approximately $1,577,000 in 2023.

2.0 BACKGROUND

The Sandy Brook Plant was placed into service in 1963 and contains one vertical hydro generating unit with a capacity of 6.31 MW at a rated net head of 33.5 metres. The Plant's production supports customers supplied by the Island Interconnected System with normal annual production of approximately 29.41 GWh. This is approximately 6.7% of the total normal hydroelectric production of Newfoundland Power.[2] In a typical year, the Plant is operated during all 12 months.

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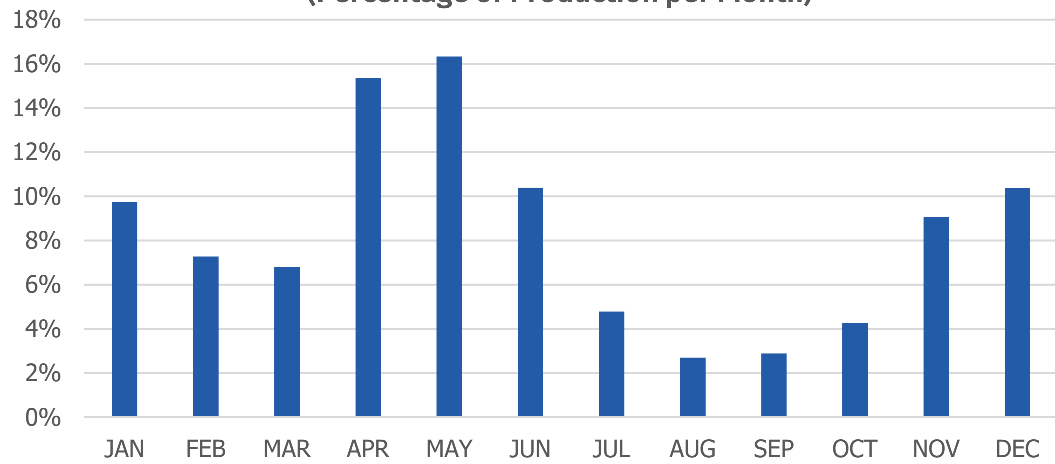
1 The refurbishment of the Plant's generator is a single-year project that can be started and completed in the 2023 capital budget year. As a result, the Company did not seek approval of the generator refurbishment project in its *2022 Capital Budget Application*. However, capital costs associated with the generator refurbishment were included in the Sandy Brook Plant Economic Evaluation filed in Newfoundland Power's *2022 Capital Budget Application*.

2 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 29.41 GWh.

Figure 1 shows the average production of the Sandy Book Plant by month from 2017 to 2021.

Figure 1
Sandy Brook Plant Production
(Percentage of Production per Month)



The Sandy Book Plant is operated throughout the year as a source of low-cost energy for Newfoundland Power's customers. The Plant is operated to maximize energy production in an efficient manner and is also routinely placed into service at the request of Newfoundland and Labrador Hydro ("Hydro").[3] These requests are most often received during the winter peak periods, although non-peak operation is also requested. The Plant's operation is also coordinated with Hydro to assist in the management of water levels and ice cover on the Exploits River.

There have been a number of upgrades to the Plant's infrastructure and equipment over time.

[3] From 2017 through 2021, Hydro requested generation 352 times.

Table 1 summarizes the upgrades completed at the Sandy Brook Plant over the last 25 years.

Table 1
Sandy Brook Plant Upgrades

Year	Upgrade
1997	Brush Temperature and Vibration Sensors Installed
1999	Cooling Water System Upgraded
2000	Station Service Transfer Switch Installed
2001	Instrumentation and Programmable Logic Controller Installed
2001	Turbine Runner and Wicket Gates Replaced
2004	Bearing Oil Level Sensors Added
2007	Battery Bank and Charger Replaced
2009	ION Revenue Meter Installed
2010	Powerhouse Roof Replaced
2010	Powerhouse Heating, Ventilation and Lighting Upgraded
2011	Switchgear and Plant Control Replaced
2022/2023	Penstock Replacement (Ongoing)

This report provides an assessment of the current condition of the generator, a risk assessment of the Plant including the results of an updated economic analysis, as well as the proposed project scope and cost breakdown.

3.0 CONDITION ASSESSMENT

The Sandy Brook Plant's generator, SBK-G1, was manufactured in 1963 by Canadian Westinghouse and is original to the Plant.

Figure 2 shows the Sandy Brook Plant generator.

Figure 2: Sandy Brook Plant Generator

Table 2 lists the electrical parameters of the Plant's generator.

Table 2 Generator SBK-G1 Electrical Parameters			
Rating:	7,000 KVA	Speed:	300 RPM
Voltage:	6,900 VAC	Exciter Voltage:	125 VDC
Current:	585 Amperes	Exciter Current:	363 Amperes
Power Factor:	0.85 %	Temp. Rise Rotor:	60° C
Phases:	3	Temp. Rise Stator:	60° C
Frequency:	60 Hz	Serial No.:	IS-IS0981

The Plant's generator is comprised of three major electrical components: the stator, rotor and exciter.

The stator is a stationary component containing a series of insulated copper coils or windings fixed into a laminated steel core. The copper coils are electrically isolated from the steel core via insulation that contains inorganic materials such as mica, glass fibers and/or asbestos, along with a high-temperature synthetic resin binder. This insulation is rated as NEMA Class B, which is rated for a maximum temperature rise of 80° C over a reference ambient temperature of 40° C with a maximum allowable hot spot temperature of 130° C.[4]

The rotor is made up of a series of laminated steel poles with insulated copper coils wound around their perimeters. When direct current electricity is passed through the coils, the poles become electromagnets. The poles produce magnetic fields, which induce alternating current electrical power in the stator coils. The copper coils of the rotor are electrically isolated from the steel poles via a Class B insulation system similar to that described for the stator coils.

The exciter, in conjunction with the voltage regulator, automatically maintains the generator field current under varying electrical loads. The exciter was originally supplied with the Westinghouse generator in 1963 with infrared brush temperature sensors added in 1997.

The Sandy Brook Plant stator and rotor windings are original to the 59-year-old unit. Generator insulation has a design life of 40 years, with the actual in-service life dependent upon several factors including quality control during manufacturing, installation practice and operating conditions such as the generator loading, operating temperature, humidity, contamination and exposure to electrical system faults.[5]

The generator was last dismantled in 2001 when the turbine runner and wicket gates were replaced. The stator windings and rotor were found to be contaminated with oil mist from the bearings and carbon residue from the brushes used to provide power to the rotor poles. The rotor poles were also found to be contaminated with oil and carbon residue. The stator and rotor were both cleaned at the time and the insulation resistance was verified. The stator coil wedges were also reset and both the stator coils and rotor poles were painted with a protective coating. In 2001, both the stator and rotor were deemed to be in satisfactory condition.

Coils in stators are subjected to thermal and mechanical stresses during normal operation. These stresses result in movement of the coils in the stator slots. This movement, as well as the normal electrical stress placed on the insulation during operation, leads to degradation of the insulating material on the coils. Failure of the insulating material will result in an in-service failure of the generator. A particularly serious fault may damage the steel laminations that make up the generator core.[6] If that were to occur, the core may have to be replaced along with the windings, thereby significantly increasing the cost of the replacement.

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[4] NEMA insulation classes are defined by the National Electrical Manufacturers Association. The NEMA Motors and Generators standard is one of the standards used by generator manufacturers to classify the insulation material. The insulation systems are primarily classified by NEMA into one of four base categories: A, B, F or H. Each classification is defined by the insulation systems ability to endure a specified temperature under continuous operation.

[5] See *Operation and Maintenance Strategies for Hydropower, 2020 International Bank for Reconstruction and Development,* available online at https://openknowledge.worldbank.org/handle/10986/33313/.

[6] The stator core is laminated and insulated in order to reduce induced circulating currents and associated heat due to the magnetic field of the rotor.

Insulation on the copper coils that make up the rotor poles experience thermal and mechanical stresses due to the centrifugal forces present during normal operation. During a forced shutdown, the speed of the rotor increases dramatically, increasing the magnitude of the forces exerted on the rotor poles.[7] Over time, the thermal cycling and centrifugal forces causes the insulation on the poles to deteriorate. The exciter's commutator and the slip rings are scored through normal use and require resurfacing. The exciter requires rewinding in conjunction with reinsulating the rotor poles.

A review of the operating experience of the generator during the period from 2017 to 2021 shows that there have been a total 1,178 on/off loading cycles for an average of 235 per year. The frequent on/off cycling of the generator has led to thermal cycling and vibration, which contributes to the deterioration of the insulating components of the stator and rotor.

4.0 RISK ASSESSMENT

Newfoundland Power has typically achieved longer service lives for generators beyond the typically accepted 40-year lifespan for stator windings and rotor poles. This can be attributed to proactive preventative maintenance and regular monitoring. Stator rewinding and rotor reinsulating have historically been done proactively based on age, as condition warranted or whether there had been a failure during operation. Eight generators in the Company's fleet have been rewound/reinsulated in recent years. These generators were rewound or reinsulated at an average age of 57 years in service, ranging from a low of 43 years to a high of 79 years.

The Sandy Book Plant's generator stator windings and rotor pole insulation are original and will be 60 years old in 2023. The generator stator windings and rotor poles are amongst the oldest remaining in service in Newfoundland Power's fleet of generating plants.

A statistical analysis of the lifetime of stator windings published by the Institute of Electrical and Electronics Engineers indicates that the probability of failure increases with age. The analysis shows the average age of generators with resin-based windings is approximately 27 years. The leading causes of failure are aging and contamination of the windings.[8]

7 The centrifugal force exerted on the rotor poles as they rotate is expressed as $F = mv^2/r$. As the speed increases, the magnitude of the force increases as the square of the speed.

8 See C. Sumereder, *Statistical Lifetime of Hydro Generators and Failure Analysis*, *IEEE Transactions on Dielectrics and Electrical Insulation*, Vol. 15, No. 3, June 2008.

Figure 3 shows the probability of failure over the lifetime of stator windings.[9]

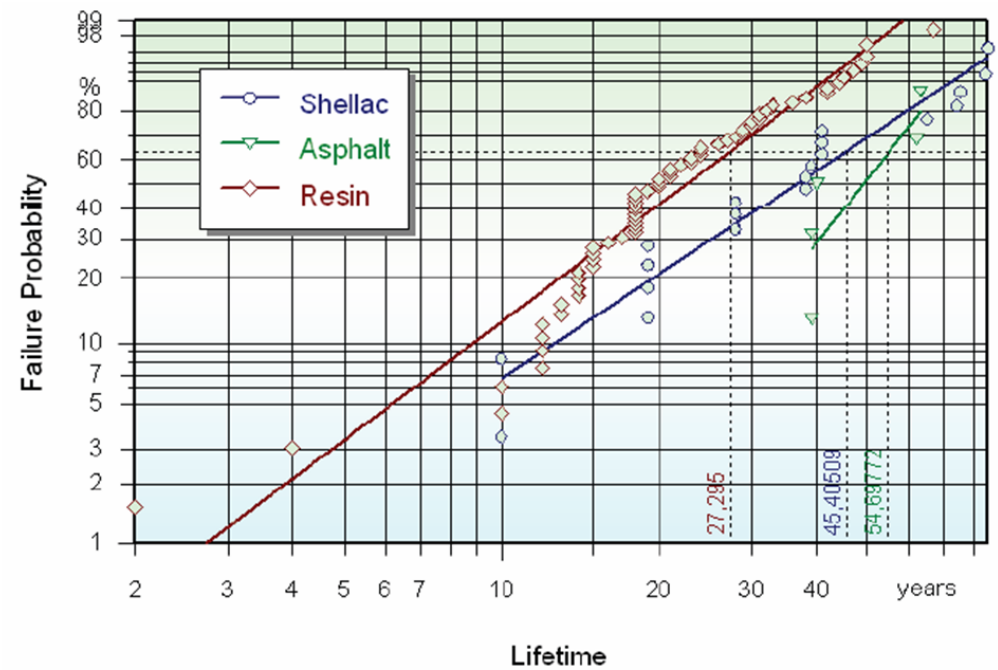

Figure 3: Statistical Lifetime of Hydro Generators by Insulation System

According to industry experience, hydro generators with resin-based windings in excess of 60 years have a very high probability of failure.

Given its age and operating experience, the probability of failure of the Sandy Brook generator is considered high. An in-service failure of the generator may lead to equipment damage and loss of production over an extended period of time while the engineering, manufacturing and installation work is completed. This would likely result in added cost due to the unplanned nature of emergency work.

The Sandy Brook Plant's generator is the second oldest single generator plant and the second largest energy producing generator in Newfoundland Power's fleet that has not yet been rewound or reinsulated.[10] Based on the increasing probability of an in-service failure and associated risk of additional damage, the generator requires refurbishment to fully rewind the stator and reinsulate the rotor poles.

9 See C. Sumereder, *Statistical Lifetime of Hydro Generators and Failure Analysis*, *IEEE Transactions on Dielectrics and Electrical Insulation*, Vol. 15, No. 3, June 2008.

10 The Mobile hydro plant has the oldest generator in service that has not been rewound or reinsulated. A stator rewind and rotor pole reinsulation of the Mobile hydro plant generator is currently planned for 2024.

There is a very low risk of the Sandy Brook Plant becoming stranded before its useful life has concluded. Newfoundland Power completed an economic analysis of the Plant as part of its *2022 Capital Budget Application*, as well as various sensitivity analyses.[11] The economic analysis accounted for capital costs required to rewind the stator and reinsulate the rotor poles. The analysis confirmed the Plant will continue to provide low-cost energy to customers over the longer term.

Table 3 provides the results of an updated economic analysis of the Sandy Brook Plant based on current capital cost estimates for the generator refurbishment and the latest marginal cost estimates from Hydro.[12]

Table 3
Sandy Brook Plant
Updated Economic Evaluation

	50 Year Levelized Value	Net benefit
Cost of Plant Production	3.27 ¢/kWh	
Benefits of Production (Run of River)		
Value of Energy	2.28 ¢/kWh	
Value of Capacity	3.57 ¢/kWh	
Total	5.85 ¢/kWh	2.58 ¢/kWh
Benefits of Production (Fully Dispatchable)		
Value of Energy	2.28 ¢/kWh	
Value of Capacity	5.60 ¢/kWh	
Total	7.88 ¢/kWh	4.61 ¢/kWh

The updated economic analysis for the Sandy Brook Plant confirms that the Plant will continue to provide an economic benefit for Newfoundland Power's customers. The net benefit of Plant production is between 2.58 ¢/kWh and 4.61 ¢/kWh.

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11 See *report 1.2 Sandy Brook Plant Penstock Replacement* included with Newfoundland Power's *2022 Capital Budget Application* and responses to Requests for Information CA-NP-078, NLH-NP-015, NLH-NP-019 and NLH-NP-022.

12 The revised capital cost estimate for the generator refurbishment is $1,577,000 in 2023, compared to $1,446,000 at the time of the original analysis. For Hydro's latest update on marginal costs, see *Marginal Cost Update - 2021 Summary Report, March 7, 2022, Appendix A*, filed in response to Request for Information TC-IC-NLH-001, Attachment 1, as part of the utilities' applications regarding the *Electrification, Conservation and Demand Management Plan: 2021-2025*.

5.0 ASSESSMENT OF ALTERNATIVES

5.1 General

The continued operation of Newfoundland Power's Sandy Brook Plant would provide an economic benefit to the Company's customers. Considering the age and operating experience of the Sandy Brook Plant's generator, the probability of failure is considered high. Rewinding the stator and reinsulating the rotor poles is required to ensure the Plant's reliable operation going forward.

Newfoundland Power identified and assessed two alternatives for refurbishing the Plant's generator: (i) complete the refurbishment in 2023 during penstock replacement; and (ii) defer refurbishment to a future year. A description of each alternative is detailed below.

5.2 Alternative 1 - Refurbish Generator During Penstock Replacement

Alternative 1 involves completing the generator refurbishment in 2023 while the Sandy Brook Plant is out of service for penstock replacement.

The refurbishment of a hydro plant generally requires the plant to be removed from service, which results in lost production and the need to purchase more expensive replacement energy from Hydro. The previously approved penstock replacement project requires approximately 24 weeks of construction time to complete. The generator refurbishment project can also be completed within the same 24-week window.

Completing both projects simultaneously would require no additional Plant downtime. This alternative therefore avoids customers incurring additional costs to replace lost production from the Plant with more expensive sources of generation.

5.3 Alternative 2 - Defer Refurbishment to a Future Year

Alternative 2 involves deferring the generator refurbishment to a future year.

Deferring the generator refurbishment to a future year could result in the work being completed in either a planned or unplanned manner.

Completing the generator refurbishment in a planned manner during a future year would require the Sandy Brook Plant to be removed from service for 24 weeks during that year. This would result in spill from the Plant of 12.8 GWh. Replacing this lost production would carry a cost of approximately $200,000.[13] The planned refurbishment of the generator would need to

[13] The 24-week plant outage results in a production loss of approximately 12.8 GWh or $214,000, based on current marginal cost of $16,690 per GWH for 2023. The 12.8 GWh is calculated based on the anticipated water spilled during the construction period.

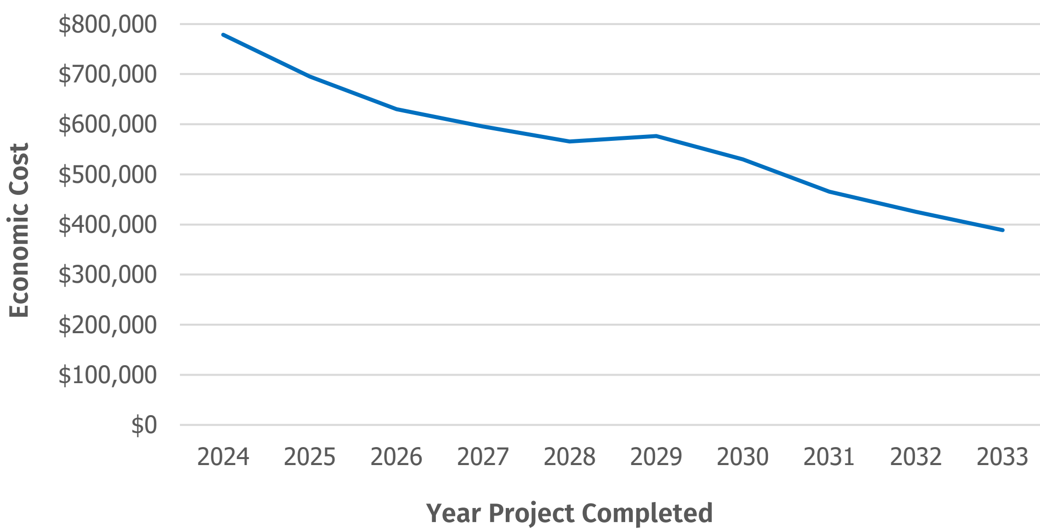
be deferred to at least 2026 for the economic benefit of deferral to outweigh the cost of replacing lost production.[14] Following 2026, the economic benefit of deferral is minimal, with incremental savings of approximately $50,000 per year.

However, based on the age of the generator, the probability of equipment failure increases each year that the generator remains in service without refurbishment. An unplanned refurbishment of the generator in response to equipment failure carries substantially higher costs.

First, it is estimated that an unplanned refurbishment would result in the Plant being out of service for at least a year. This is because the design, procurement and installation of the necessary components would all take place while the Plant is out of service. The cost of replacing lost production is therefore higher under this scenario.

Figure 4 shows the cost of replacing lost production during an unplanned refurbishment of the Sandy Brook Plant generator.[15]

Figure 4
Sandy Brook Plant - Unplanned Refurbishment
Economic Cost of Replacement Production



The economic cost of replacing lost production during an unplanned refurbishment would be over $700,000 in 2024. This cost would decline over time, but remain above $400,000 per year until at least 2032.

---

14 The analysis determined that 2026 represents the year during which the economic benefits associated with deferring the capital costs are equal to or greater than the economic cost of replacing lost production.

15 The costs shown in Figure 4 are provided on a present value basis and are based on Hydro's *Marginal Cost Update - 2021 Summary Report, March 7, 2022.*

In addition to the increased cost of replacing lost production, the capital cost of an unplanned refurbishment could be substantially higher. This is because an in-service failure of the generator could result in damage to other Plant components that are currently in good condition. As a result, the incremental cost of an unplanned refurbishment could exceed $1 million if the project is deferred and an in-service failure occurs.

5.4 Discussion of Alternatives

Refurbishing the Sandy Brook Plant generator is necessary to ensure the Plant's reliable operation going forward and the continued provision of low-cost energy to customers.

Completing the generator refurbishment in 2023 while the Plant is out of service for penstock replacement would avoid the need for additional Plant downtime and the costs associated with purchasing more expensive generation to replace the lost production.

Deferring the generator refurbishment would provide minimal economic benefit, while exposing customers to potentially much higher costs. The refurbishment would need to be deferred to at least 2026 to provide any economic benefit to customers and would provide a benefit of approximately $50,000 per year thereafter. Over this period, customers would be exposed to a high probability of an in-service equipment failure. The cost of replacing lost production alone could exceed $700,000 depending on when the unplanned refurbishment is required. The incremental capital cost could be as high as $1 million if an in-service failure resulted in damage to other Plant components.

Overall, based on the age of the generator, the minimal benefit of project deferral is more than offset by risks of increased costs due to the high probability of in-service equipment failure. Refurbishing the generator in 2023 is therefore the least-cost alternative to ensure continued operation of the Sandy Brook Plant and the provision of low-cost energy to customers.

6.0 PROJECT SCOPE

The generator stator windings will be designed and ordered early in 2023. Disassembly of the generator will commence when the unit is taken out of service to start the penstock replacement in June 2023. Following testing for asbestos content, the existing stator windings will be removed from the core while all necessary hazardous material precautions are taken.

In June 2023, the rotor and exciter will be removed from the generator and shipped to a contractor for removal of the poles, asbestos testing, removal of the pole winding insulation, reinsulation and reinstallation on the rotor poles. After delivery in late summer, the new stator coils will be installed in the laminated steel core. The rotor will be returned to the Plant once the stator winding is completed. Reassembly will consist of installing the rotor and exciter, coupling to the turbine, realignment, connection of required wiring and instrumentation, commissioning and testing.

The work will take approximately 24 weeks to complete and will be coordinated with the penstock replacement.

7.0 PROJECT COST

Table 4 provides the cost breakdown for the *Sandy Book Hydro Plant Generator Refurbishment* project.

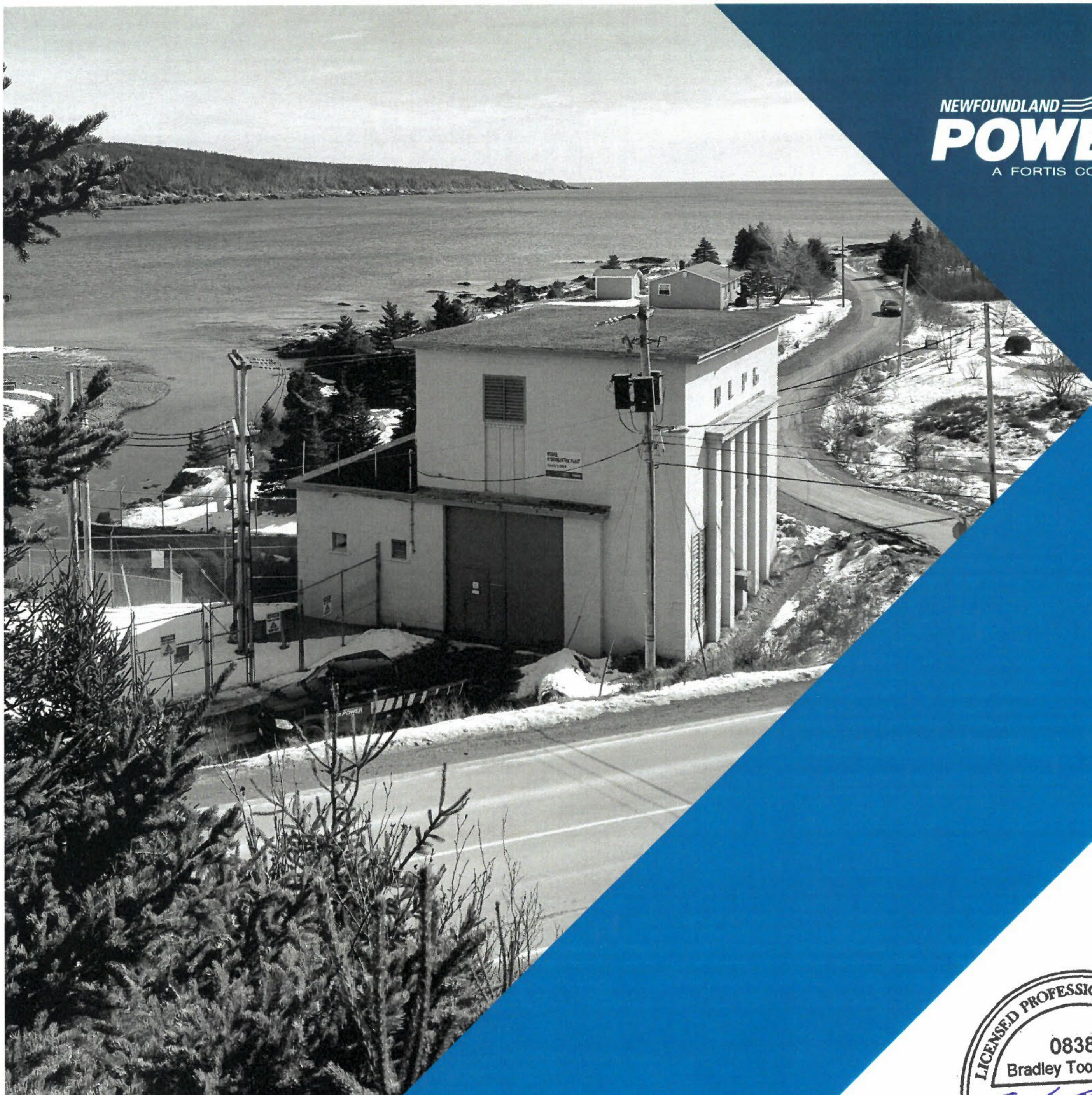
Table 4
Sandy Brook Hydro Plant
Generator Refurbishment
2023 Project Cost
($000s)

Cost Category	Total
Material	1,241
Labour - Internal	147
Labour - Contract	-
Engineering	87
Other	102
Total	1,577

The cost of the *Sandy Book Hydro Plant Generator Refurbishment* project is $1,577,000 in 2023.

8.0 CONCLUSION

The Sandy Brook Plant provides low-cost energy to Newfoundland Power's customers. The Plant's generator is original to the Plant and has been in service for nearly 60 years. The unit is at an age where the probability of failure is high. Rewinding the generator stator and reinsulating the generator rotor poles is required to ensure the Plant's reliable operation and the continued provision of low-cost energy to customers. As assessment determined that refurbishing the generator in 2023 while penstock replacement is ongoing is the least-cost alternative to complete this work.



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A FORTIS COMPANY

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NEWFOUNDLAND & LABRADOR

4.2 Mobile Hydro Plant Refurbishment

June 2022

Prepared by: Bradley Tooktoshina, P. Eng
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TABLE OF CONTENTS

1.0 INTRODUCTION

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") Mobile hydroelectric generating plant ("Mobile Plant" or "the Plant") is located on the Avalon Peninsula in the town of Mobile.[1] The Mobile Plant was commissioned in 1951 with a capacity of 11.0 MVA under a net head of approximately 114.6 metres. The Plant contains a single vertical 13,000 hp Francis turbine manufactured by Voith Hydro coupled to a Canadian Westinghouse generator. The Plant is connected to the Island Interconnected System at Mobile Substation and has provided 71 years of reliable energy production.

The Mobile Plant is the second largest of Newfoundland Power's 23 hydro plants in terms of its capacity and annual energy production.[2] Capital upgrades to the Plant have been limited over the last decade due to termination of the original lease of the rights to the Mobile River watershed by the City of St. John's (the "City") and the resultant arbitration process, which concluded in 2020.

The Company is proposing a multi-year project for 2023 and 2024 to refurbish and upgrade obsolete, deteriorated and non-standard equipment at the Mobile Plant. The project includes: (i) replacing and upgrading building systems; (ii) upgrading protection and control systems, including switchgear; and (iii) refurbishing the turbine and generator.

The project is estimated to cost $1,666,000 in 2023 and $2,480,000 in 2024.[3]

2.0 BACKGROUND

The City leased to Newfoundland Power the rights to the Mobile River watershed supplying the Mobile Plant in 1946.[4] The City gave notice to Newfoundland Power in 2006 of its intention to terminate the lease effective March 1, 2009. The parties subsequently entered into an arbitration proceeding regarding the rights to the Mobile River watershed and ownership of the Mobile Plant. The proceeding concluded in 2020 when the parties agreed to a new 50-year lease for the rights to the Mobile River watershed.[5] The current lease ensures the Company's customers continue to be supplied with low-cost power from Mobile Plant until at least January 1, 2070.

1 The Mobile Plant operates in series with the Morris hydroelectric generating plant (the "Morris Plant"), with water first being used at the Morris Plant and then being used at the Mobile Plant.

2 Only Newfoundland Power's Rattling Brook hydro plant, with two generators at 7.5 MVA and 8.25 MVA, is larger in capacity and annual energy production than the Mobile Plant.

3 Newfoundland Power's five-year capital plan also includes additional capital expenditures in 2024 associated with the Mobile Plant's penstock, surge tank, canal and substation. Capital expenditures associated with these upgrades are incorporated into the lifecycle cost analysis included in Appendix A. Approval of these expenditures is expected to be proposed as part of the Company's *2024 Capital Budget Application.*

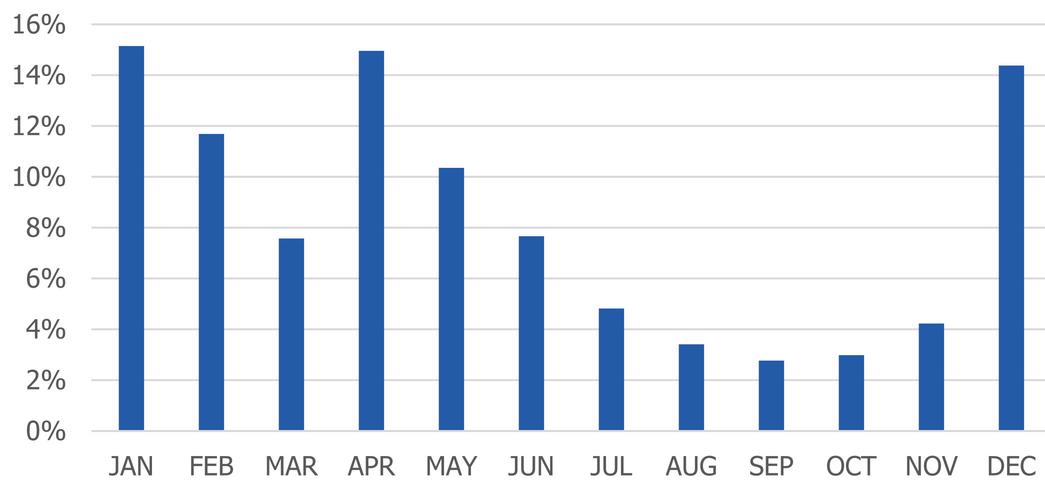
4 The lands and waters of the Mobile River watershed are vested with the City of St. John's by virtue of the *City of St. John's Act.*

5 The current lease establishes that Newfoundland Power will pay a water rental fee to the City of St. John's that is equivalent to the water rental fee paid to the Provincial Government for the Company's other hydro plants. The water rental fee paid to the Provincial Government is based on plant production in accordance with the *Water Power Rental Regulations, 2003*. The rate was $2.70/MWh in 2021 and increases annually according to the Consumer Price Index.

The normal annual production of the Mobile Plant is approximately 40.32 GWh, or 9.2% of the total normal hydroelectric production of Newfoundland Power.[6] The Plant is typically operated during all 12 months of the year.

Figure 1 shows the average production of the Mobile Plant by month based on the most recent five-year average.

Figure 1
Mobile Plant Production
(Percentage by Month)



The Mobile 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").[7] These requests are most often received during the winter peak period, although non-peak operation is also requested.

Production from the Mobile Plant has typically been the highest from the months of December through April. This corresponds to when customer load and capacity constraints are greatest on the Island Interconnected System.

In addition to energy and capacity benefits, the Mobile Plant provides reliability benefits for customers on the Southern Shore of the Avalon Peninsula. There are approximately 4,500 customers in this area that are served by three substations supplied by radial Transmission Line 24L. When maintenance is required and the transmission line is deenergized, the Mobile Plant

[6] 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 Mobile Plant at 40.32 GWh.
[7] From 2017 through 2021, Hydro requested generation 352 times.

is one of seven hydro plants on the Southern Shore that operates as an isolated system to supply customers in the area.[8]

Table 1 lists the upgrades that have been completed at the Mobile Plant over the last 25 years.

Table 1
Mobile Plant Upgrades

Year	Upgrade
1997	Battery Bank Replacement
1997	AC Distribution Panels Replacement
1999	Surge Tank Replacement
1999	Programmable Logic Controller Installation
1999	AC Distribution Cable Replacement
1999	Cooling Water System Upgrade
2000	Transfer Switch for Essential Service Panel Installation
2001	Power Cable Switchgear to Generator Replacement
2001	Plant Heating Upgrade
2004	Brush Gear Replacement
2005	Main Inlet and Bypass Valves Replacement
2006	Battery Bank and Charger Replacement
2008	Powerhouse Exhaust Fan Replacement
2009	ION Revenue Meter Installation
2013	Battery Bank and Charger Replacement
2014	Plant Metering Upgrade
2015	Pressure Reducing Valve Replacement
2018	Cooling Water Manifold Replacement
2021	Service Water System Replacement

Upgrades completed to the Mobile Plant have been limited over the last decade due to uncertainty regarding the future ownership and operation of the Plant. The upgrades completed have largely focused on the replacement of systems that failed or were at imminent risk of failure.

[8] There were five occasions in the past three years when the hydro plants on the Southern Shore have been operated as an isolated system to supply customers in the area. The Mobile Plant has the largest capacity of the seven plants and, when the Southern Shore is operated as an isolated system, the Plant operates in isochronous mode as the swing generator to regulate frequency for the other isolated generators.

3.0 CONDITION ASSESSMENT

3.1 General

Newfoundland Power conducted a detailed condition assessment of the Mobile Plant to identify deteriorated, obsolete and non-standard equipment. This included assessments of: (i) building systems; (ii) protection and control systems, including switchgear; and (iii) the turbine and generator.

3.2 Building Systems

Powerhouse

The powerhouse building is of original 1951 construction. The building houses equipment critical to the operation of the Mobile Plant, including the generator, turbine, governor, protection and controls, and switchgear.

Figure 2 shows the powerhouse building.

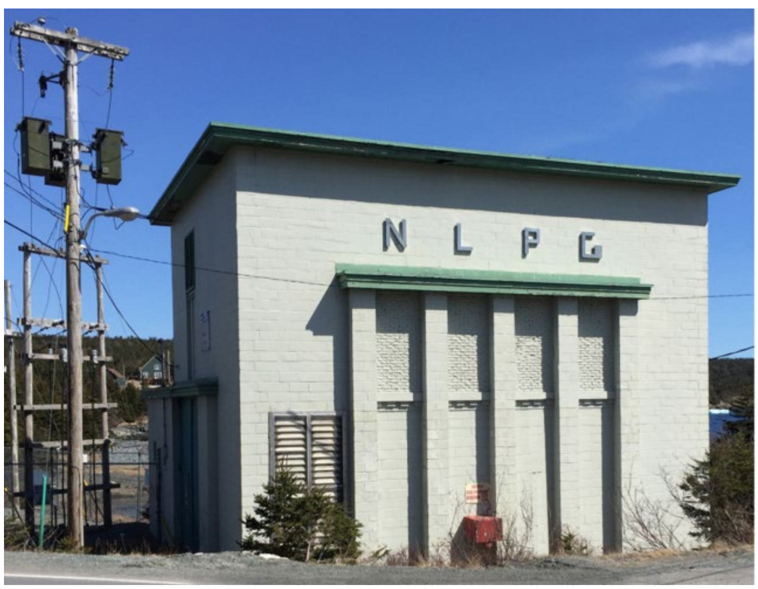


Figure 2: Powerhouse Building

The building envelope is currently 71 years old. The roofing system has failed and requires replacement. Water is currently penetrating the roofing structure and entering the building interior. Left unmitigated, this will lead to mold growth and potentially damage the equipment located inside the Plant.

The building has inadequate heating and lighting systems. Inadequate heating in the turbine pit has contributed to condensation on the stator windings when the unit is shut down.

Condensation on the stator windings can result in failure of the generator upon start up. Inadequate lighting poses a safety hazard to employees completing maintenance at the Plant.[9]

The building's size would be inadequate to accommodate the installation of modern switchgear.[10]

Crane

The crane is original to the Plant's 1951 construction and no upgrades have been completed other than regular maintenance. The crane is periodically used for routine maintenance activities, but has not been required for a heavy lift approaching its maximum capacity since the turbine runner was replaced in 1990.

Figures 3 and 4 show the crane, including its electrical bus.

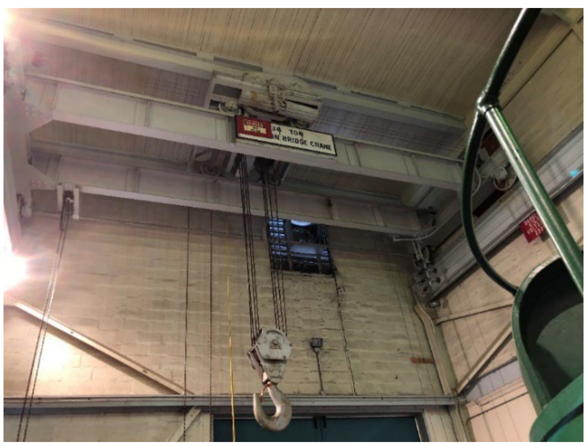


Figure 3: Powerhouse Crane

Figure 4: Electrical Bus

Use of the crane to lift major Plant components would require an overhaul to ensure its safe operation.[11] This would include refurbishing and upgrading its electrical bus, control pendant, trolley and hoist. A certified load test would also be required.

AC and DC Distribution Systems

The normal station service transformer bank is mounted on a pole in front of the Plant and is supplied from Mobile Substation. A service drop extends from the transformer bank to the rear of the powerhouse. The transformers have rusted and require replacement.

---

9 Section 36 of the *Occupational Health and Safety Regulations, 2012* requires adequate illumination.

10 The existing switchgear at the Mobile Plant is physically smaller in size compared to arc flash switchgear for similarly sized breaker interrupting capability.

11 For example, refurbishing the generator rotor would require its removal from the generator assembly. This would approach the 36 ton capacity of the crane. The rotor is large at approximately 8.5 feet in diameter, with only half an inch of clearance all the way around. Failure of the crane during a lift of the rotor would risk catastrophic damage to the stator windings and core, and pose an extreme safety hazard to employees working in the powerhouse.

The two existing AC panels were installed in 1997 and are both 225 Amp, 42-circuit panels.[12] The non-essential services panel has 13 spare circuits and the essential services panel has nine spare circuits. The DC distribution panel is a 42-circuit panel that is 1985 vintage.

The existing GNB Exide Absolyte IIP gel-cell battery bank and the battery charger installed in 2006 have life remaining and do not require replacement at this time.

3.3 Protection and Control Systems

Plant Control

Newfoundland Power has upgraded the majority of its hydro plants to be operated by modern programmable logic controller ("PLC") technology with digital protection.[13] This technology interfaces digitally with the Company's Supervisory Control and Data Acquisition ("SCADA") system and provides modern remote control and water management capabilities. These capabilities are essential to the safe and efficient operation of hydro plants.[14] The Mobile Plant is the Company's largest-producing plant without a modern control system.

Generator control is provided by antiquated electromechanical relay logic and governor controls. This technology poses challenges when operating the Mobile Plant as part of an isolated system on the Southern Shore.[15]

An Allen-Bradley SLC5/04 PLC and PanelView 550 Human Machine Interface ("HMI") were installed at Mobile Plant in 1999 to replace the previous alarm monitoring annunciator panel. The PLC monitors vibration, bearing temperatures, control cooling water and annunciates trips and alarms. The PLC also displays telemetry information such as forebay elevation and generator output to the onsite Plant Operator using the PanelView HMI. The existing PLC technology was discontinued by the manufacturer in 2018 and has become obsolete.[16]

The existing PLC has limited functionality. The PLC does not provide information needed to ensure efficient Plant production, such as the position of the wicket gates controlling the flow of water to the turbine runner or the maximum allowed output based on Plant conditions. Due to the Plant's obsolete technology, existing water management capabilities are limited to an alarm that shuts down the Plant when water levels in the forebay become too low. This impedes achieving the most efficient production of energy at the Plant.[17]

---

[12] New circuit breakers for these 25 year old panels are no longer manufactured.

[13] Modern PLC technology with digital protection has been installed in 17 of Newfoundland Power's 23 hydro plants.

[14] For example, a modern water management system includes control modes to automatically achieve the most efficient production of energy based on the availability of water in the forebay.

[15] The controls require a Plant Operator to be on site to adjust the frequency and voltage of the generator. The existing flyball governor controlling the turbine does not operate smoothly due to its age and condition. Continuous manual adjustment of the voltage and frequency by the Plant Operator is therefore required.

[16] SLC5/04 PLC units do not have the processing power, memory or access to the necessary input/output modules to provide modern protection and control functionality. Newfoundland Power is gradually replacing in-service SLC5/04 PLC units and salvaging the modules as spare equipment for other installations.

[17] Additionally, the existing PLC cannot be configured to allow remote access by operations employees. Field visits are therefore required to diagnose issues at the Plant, which creates further inefficiencies in Plant operations.

The 27-year-old copper communications cables that provide communication from the forebay to the PLC are prone to faults. Damage to the communications cables is evident at the Plant with faulted cable pairs and signs of burning on the cable pair protectors at both ends.

Addressing the deficiencies identified with plant control, including water management, would require the installation of a modern PLC system with all standard control, protection and automation functionality. The existing communications cables also require replacement due to their condition.

The instrumentation on the generator and turbine systems has been upgraded over the past number of years with speed, bearing oil temperature and cooling water flow measurement added in 1980 and vibration monitoring in 2007. The existing instrumentation is in good condition and can be maintained.

Excitation System

The exciter is the original unit supplied with the Westinghouse generator in 1951. The exciter is heavily contaminated with carbon from the brushes and the commutator is showing signs of wear. The exciter's commutator and the slip rings are scored through normal use over time and require resurfacing, and the exciter's age and condition indicates that it should be rewound.

Infrared brush temperature sensors are also required. Information on temperature is essential as excessive heat or arcing can cause equipment to overheat or catch fire due to the carbon dust and oil residue that typically forms during normal operations.

The voltage regulator is the original Brown Boveri Model AB2/1 with mechanical operating mechanisms. These units have been discontinued by their manufacturer and cannot be integrated into a modern PLC system. The voltage regulator requires replacement with a digital unit that could be integrated into a modern PLC system and provide improved voltage regulation under varying system conditions.

The field breaker, which is located in the switchgear, was replaced in 1993 and is in good condition.

Governor

The governor is the main speed controller of the turbine generator as it varies the water flow through the turbine to control its output. The Plant governor is the original Woodward Type HR, 16,800 ft. lb. unit.

The governor speed and gate limit are motorized and are currently operated using electromechanical relay logic to control the load on the unit. As described above, the existing PLC provides no information on wicket gate position or gate limit for unit control or remote indication.

A typical hydraulic governor is composed of two sections: the power piston and the control head. The power piston provides the mechanical force necessary to operate the turbine wicket gates under load. The control head adjusts the position of the power piston to maintain system frequency through varying load conditions.

Figures 5 and 6 show the governor power piston and control head.

Figure 5: Governor Power Piston

Figure 6: Governor Control Head

The original equipment manufacturer discontinued supplying replacement parts for the power piston and control head units in 2008.

Due to its robust design with no parts exposed to excessive wear, hydraulic power pistons typically remain serviceable for many years.[18] The existing hydraulic power piston assembly, hand wheel and gate operating linkages can be retained. All seals, bushings and other components require inspection and refurbishment to further extend the life of the power piston assembly. The relay valve, which initiates the movement of the power piston, requires inspection and overhaul. The control head would require replacement to be compatible with a modern PLC system.[19]

18 Other plant refurbishment projects have replaced the control head portion of these governors with digital systems that provide enhanced control and feedback capabilities. When found to be in good condition, the power pistons were refurbished and remained in service.

19 The flyball governor head, pilot valve assembly and mechanical restoring linkages would no longer be required upon implementing a modern PLC system and would require removal.

Protective Relaying

The generator electrical protection is provided by the original Westinghouse electromechanical relays and an electronic negative sequence relay added in 1986. Electromechanical relays are no longer industry standard for providing protection.[20]

Figure 7 shows the existing electromechanical protective relaying located in the switchgear cubicles.

Figure 7: Electromechanical Protective Relaying

The following protective elements are currently in service:

40	Loss of Field
46	Stator Unbalance Current (Negative Sequence)
49	Thermal Protection
51N	Neutral Overcurrent
51V	Backup Protection – Voltage Controlled Overcurrent
59	Overvoltage
87/87S	Differential, Split Phase Differential

[20] Additionally, the technical skills necessary to maintain the obsolete electromechanical relays are diminishing within the Company.

The existing protective relaying at the Mobile Plant lacks three elements of the minimum protection set.[21] This increases the risk of having the unit operating with a fault and subsequent damage to the generator's windings.

Switchgear

The switchgear is the original equipment manufactured by Westinghouse and was installed in 1951. The generator breaker was replaced in 1990, the field breaker was replaced in 1993 and the bus insulators were replaced in 1995. The potential transformers and current transformers, which are integral to the switchgear, are original to the Plant. The emergency station service transformers, the protective relays, control switches and meters are also the original equipment. The original equipment manufacturer no longer provides spare parts for the 71-year-old switchgear. Additionally, the generator breaker is a SACE Type DR7.2-40 air breaker, does not operate dependably and is at the end of its service life.

The existing switchgear does not meet current arc flash ratings for this type of equipment. An arc flash hazard study was completed in 2020. As a result of the high fault level energy at this location, there is a high arc flash hazard associated with this switchgear requiring an arc flash boundary of 0.9 metres. Anyone operating near the switchgear is required to wear Class 3 personal protective equipment ("PPE") with a rating of 25 cal/cm^2.[22] The control switches are incorporated into the switchgear doors, which greatly increase arc flash hazards for personnel operating these switches.

The switchgear requires replacement to mitigate operating issues and current safety hazards. The installation of the new switchgear would necessitate reconfiguration of the power cables to the generator and to the power transformer.[23]

3.4 Turbine Generator

Turbine

The original 13,000 horsepower turbine was supplied by Dominion Engineering Works in 1951. In 1990, after 39 years in service, the runner and wicket gates were replaced with new stainless-steel components supplied by Voith Hydro. The wicket gate facing plates were also replaced. Other worn components, such as the wicket gate stem, wicket gate linkage and operating ring bushings were replaced with grease lubricated brass bushings.

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[21] The existing generator protection does not include Rotor Ground 64F, Frequency 81 and Sensitive Ground Fault 87GN protection elements, which are recommended by the Institute of Electrical and Electronics Engineers ("IEEE") for generators of this size.

[22] This PPE is comprised of an arc flash rated jacket and pants, face and head protection and arc flash rated gloves.

[23] The concrete floor under the existing switchgear would require removal and the conduits to the power transformer and generator would require extension to the corresponding cubicles in the new switchgear. The installation of new power cables would be required as the existing power cables would be too short.

Figure 8 shows the turbine headcover.

Figure 8: Turbine Headcover

A detailed inspection was completed in 2020, which found that the runner and wicket gate components installed in 1990 remain in good condition. The wicket gate facing plates were also found to be in good condition other than minor surface abrasion between the wicket gates due to gate movement.

Other wicket gate components, such as the stems, linkages and operating ring bushings, cannot be inspected without disassembly. These components have been in place since the runner replacement and turbine overhaul in 1990. Due to the continuous movement of the wicket gates and the requirement for lubrication, these parts wear over time and are typically replaced when a turbine is overhauled.

The wicket gate facing plates require refurbishment to ensure smooth operation of the wicket gates and tight sealing upon shutdown. The turbine shaft/head cover seal requires inspection for wear on the turbine shaft. A replacement shaft sleeve may be required depending on the results of the inspection. The turbine bearing also requires inspection and refurbishment.

Generator

The Mobile Plant generator, MOP-G1, was manufactured in 1951 by Canadian Westinghouse and is original to the Plant. It is the oldest single generator and the largest energy producing generator in the Company’s fleet still with its original stator windings and rotor.

Figure 9 shows the generator.

Figure 9: Generator

Table 2 details the electrical parameters of generator MOP-G1.

Table 2 Generator MOP-G1 Electrical Parameters			
Rating:	11,000 KVA	Speed:	514 RPM
Voltage:	6,900 VAC	Exciter Voltage:	125 VDC
Current:	920 Amperes	Exciter Current:	350 Amperes
Power Factor:	0.85 %	Phases:	3
Frequency:	60 Hz	Serial No.:	42532

The generator is comprised of three major components: the stator, rotor and exciter.[24] The Mobile Plant's stator windings, rotor and exciter are original to the 71-year-old generator.[25]

[24] For information on the exciter, see section 3.3 Protection and Control Systems.

[25] Generator insulation has a typical design life of 40 years, with the actual life dependent upon several factors including quality control during manufacture, installation practice and operating conditions such as the generator loading, operating temperature, humidity, contamination and exposure to electrical system faults.

The stator is a stationary component containing a series of insulated copper coils or windings fixed into a laminated steel core. The insulation is rated as NEMA Class B, which is rated for a maximum temperature rise of 80˚C over a reference ambient temperature of 40˚C with a maximum allowable hot spot temperature of 130˚C.[26]

Stator coils are subjected to thermal and mechanical stresses during normal operation. These stresses result in movement of the coils in the stator slots. This movement, as well as the normal electrical stress placed on the insulation during operation, leads to degradation of the insulating material on the coils. Failure of the insulating material would result in an in-service failure of the generator. A particularly serious fault may damage the special steel laminations that make up the generator core.[27] In that instance, the core may have to be replaced along with the windings.

The rotor is made up of a series of laminated steel poles with insulated copper coils wound around their perimeters. When direct current electrical power is passed through the coils, the poles become electromagnets. The poles therefore produce magnetic fields, which induce alternating current electrical power into the stator coils. The rotor's copper coils are electrically isolated from the steel poles via a Class B insulation system.

Insulation on the copper coils that make up the rotor poles also experiences thermal and mechanical stresses due to the centrifugal forces present during normal operation. During a unit trip under load, the speed of the rotor increases, thereby increasing the magnitude of the force exerted on the rotor poles.[28] Over time the insulation on the poles deteriorates.

A review of the on/off loading cycle of the Plant during the period 2017 to 2021 shows that there have been a total 725 cycles for an average of 145 per year. The Plant operates based on water levels and in response to Hydro's requests to maximize generation. The cycling nature of the operation leads to thermal cycling and vibration which can lead to deterioration of the insulating components of the generator.

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26 NEMA insulation classes are defined by the National Electrical Manufacturers Association. The NEMA Motors and Generators standard is one of the standards used by generator manufactures to classify the insulation material. The insulation systems are primarily classified by NEMA into one of four base categories; A, B, F or H. Each classification is defined by the insulation systems ability to endure a specified temperature under continuous operation.

27 The stator core is laminated and insulated in order to reduce induced circulating currents and associated heat due to the magnetic field of the rotor.

28 The centrifugal force exerted on the rotor poles as they rotate is expressed as $F = mv^2/r$. As the speed increases, the magnitude of the force increases as the square of the speed.

A visual inspection of the stator, rotor and exciter show contamination with oil mist from the bearings impregnated with carbon dust from the brakes and slip ring brushes. This mixture of oil and carbon dust imbeds in the rotor insulation, causing deterioration. The unit has not been disassembled for cleaning and inspection since the turbine replacement in 1990.

In 2024, the generator will be in service for 34 years since the last time it was disassembled. The rotor pole must be reinsulated and the stator must be rewound. The following items must also be addressed as part of the generator work:

(i) Resistance temperature detectors in the new stator windings are required to monitor winding temperature from the new control system.

(ii) The generator neutral is solidly connected to ground. This method of grounding does not provide adequate protection of the generator windings as it permits high ground fault currents to flow through the windings. To minimize the magnitude of fault currents, high impedance grounding is the preferred method of generator neutral connection. A neutral grounding transformer with secondary resistor is required to provide this protection.

(iii) Generators are shut down when there is insufficient water available for production. This usually occurs during the summer and early fall when humidity is high. As a result, moisture accumulation on the stator windings compromises the winding insulation. Energizing the generator with moisture present could result in an electrical flashover and permanent winding damage. A new MegAlert® stator insulation testing system is required to prevent the generator from re-energizing should the insulation fall below a safe value.[29]

(iv) The surge protection, which consists of surge capacitors and surge arrestors, is located in the generator termination cubicle. The existing surge capacitors would require replacement with two-bushing units to facilitate the operation of a stator insulation testing system. To ensure the surge protection system can adequately protect the generator windings from electric system surges, the original surge arrestor would require replacement with intermediate class metal oxide varistor type surge arrestors.

(v) The six generator protection neutral current transformers and three split-phase current transformers located in the generator termination cubicle are the original units. The neutral current transformers, which provide the critical sensing for all the generator protection elements, require replacement with three new units. The split-phase current transformers also require replacement.

[29] MegAlert® stator insulation testing systems are integrated with modern PLC systems to provide a warning and prompt corrective action when the stator winding's insulation value is reduced.

4.0 RISK ASSESSMENT

The condition assessment of the Mobile Plant identified numerous instances of deteriorated, obsolete and non-standard equipment.

The powerhouse roof is deteriorated, resulting in water entering the building. The turbine pit heating system is inadequate and results in moisture buildup on the stator windings, which increases the risk of equipment failure upon start-up of the Plant.

The Mobile Plant is the largest capacity hydro plant in the Company's system without modern protection and control systems. Obsolete control systems contribute to inefficiencies in Plant operations, which increases costs to customers.

The Plant contains obsolete electromechanical relays. Electromechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust. The Company's experience has been that, as these older type relays approach 40 years of age, they may fail to clear faults reliably. Failure of protective relaying can result in Plant outages and significant equipment damage. The age and deterioration of the Plant's electromechanical relays indicates that the risk of failure is high.

The existing switchgear is antiquated and does not meet current arc flash ratings for this type of equipment. The antiquated switchgear poses a significant safety risk to employees working in the Plant and requires the use of specialized PPE to ensure their protection.

The Mobile Plant generator stator windings and rotor pole insulation are original and will be 73 years old in 2024. The generator is the oldest original single generator plant remaining in service in the Company's fleet of generating plants. The generator was last dismantled in 1990 and is due for an overhaul.

Generator rewinding and rotor reinsulating have historically been done proactively based on age, if condition warranted, or if there was a failure during operation. Ten units have been rewound/reinsulated by the Company at an average age of 51 years.[30] This experience demonstrates that proactive maintenance activities successfully extend the service lives of generators beyond the generally accepted lifespan of 40 years.

A statistical analysis of the lifetime of stator windings published by the IEEE indicates that the probability of failure increases with age. The analysis shows the average service life of generators with shellac-based windings is 45 years. The leading causes of failures are aging and contamination of the windings.[31]

[30] The rewind ages vary from a low of 32 years to a high of 68 years.

[31] See C. Sumereder, *Statistical Lifetime of Hydro Generators and Failure Analysis*, *IEEE Transactions on Dielectrics and Electrical Insulation*, Vol. 15, No. 3, June 2008.

Figure 10 shows the probability of failure over the lifetime of stator windings.[32]

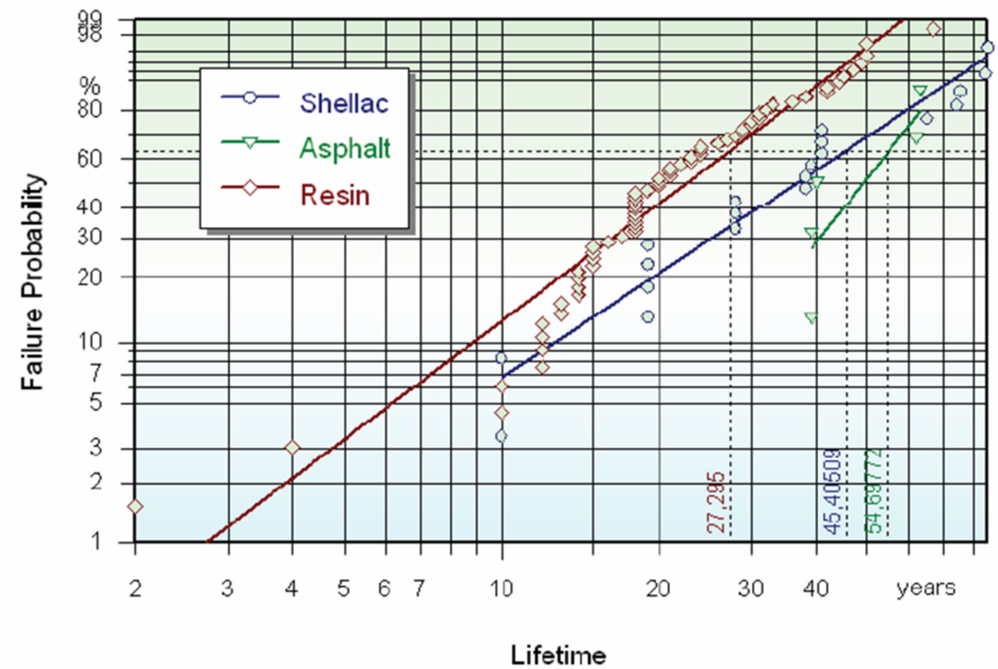

Figure 10: Statistical Lifetime of Hydro Generators by Insulation System

According to industry experience, hydro generators with shellac-based windings in excess of 60 years have a high probability of failure.

An in-service failure of the generator may lead to additional generator damage, loss of generator load capability and loss of production. An in-service failure will leave the unit out of service for an extended period while the engineering, manufacture and installation activities are completed. This would increase the cost of replacing the lost production and result in added cost to customers due to the emergency nature of the work.

In addition to cost impacts, the increased risk of equipment failure also poses risks to the delivery of reliable service to customers on the Southern Shore on the Avalon Peninsula, who rely on supply from the Plant when Transmission Line 24L is out of service.

A lifecycle cost analysis has determined that continued operation of the Mobile 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.

32 See C. Sumereder, *Statistical Lifetime of Hydro Generators and Failure Analysis*, *IEEE Transactions on Dielectrics and Electrical Insulation*, Vol. 15, No. 3, June 2008.

Table 3 summarizes the results of the lifecycle cost analysis of the Mobile Plant.

Table 3
Mobile Plant Lifecycle Cost Analysis Results

	50 Year Levelized Value	Net benefit
Lifecycle Cost of the Plant	2.70 ¢/kWh	-
Cost of Replacement Production (Run of River)	7.84 ¢/kWh	5.14 ¢/kWh
Cost of Replacement Production (Fully Dispatchable)	9.49 ¢/kWh	6.79 ¢/kWh

The analysis shows the Plant's production provides a net benefit for customers of between 5.14 ¢/kWh and 6.79 ¢/kWh. The cost of replacement production would need to be reduced by between 66% and 72% to be less than the cost of operating the Plant. The large differences between costs and benefits suggest any reasonable variance in the estimates will support the continued operation of the Plant. Various sensitivity analyses have confirmed the economic benefit of the Plant's production.

The present value of the cost of continued operation of the Plant is $17.6 million. This compares to the cost of replacing the Plant's production of between $51.2 and $62.0 million.

Appendix A to this report provides the detailed lifecycle cost analysis, including the sensitivity analyses.

5.0 ASSESSMENT OF ALTERNATIVES

5.1 General

A condition assessment and corresponding risk assessment determined that the Mobile Plant contains deteriorated, obsolete and non-standard equipment that must be refurbished or upgraded 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. Retirement of the Plant is therefore not a viable alternative to address its condition.

Newfoundland Power identified and assessed two alternatives to address the deteriorated condition of the Mobile Plant: (i) refurbish the Plant in 2023 and 2024; and (ii) defer refurbishment of the Plant. The assessment of each alternative is detailed below.

5.2 Alternative 1: Refurbish Plant in 2023/2024

Alternative 1 involves refurbishing the Mobile Plant in 2023 and 2024. Refurbishment would include the building systems, protection and control systems, switchgear, and turbine and generator.

The work required for 2023 could be completed without a Plant outage. A Plant outage of approximately 26 weeks would be necessary in 2024 to complete the building modifications, protection and control systems upgrade, switchgear replacement, and the turbine and generator refurbishment. A 26-week Plant outage would result in a production loss of approximately 14 GWh, which in 2024 equates to approximately $220,000.[33] The value of lost production is calculated based on the anticipated amount of water spilled during the construction period.

5.3 Alternative 2: Defer Refurbishment to a Future Year

Alternative 2 involves deferring refurbishment to a future year. The present value of the savings from deferring the planned refurbishment is approximately $200,000 per year.[34] There are no other potential benefits associated with deferring the refurbishment.

Based on the age and condition of the Plant, the risk of failure is high. Deferring the proposed refurbishment to a future year would increase the risk of failure of a major Plant component. Deferring upgrades to the control system increases the risk that the components will no longer be serviceable upon failure.

Failure of components, such as the switchgear and parts of the turbine generator system, could result in loss of production for a year or more. A year's worth of lost production from the Mobile Plant is estimated to cost approximately $1.2 million.[35]

Addressing failures under emergency conditions in response to an unplanned failure would add additional costs. For example, the cost of responding to switchgear or turbine generator failure will require increased engineering and administration effort in comparison to the planned refurbishment.[36] The cost could be much greater if damage from the failure is extensive. For example, if the in-service failure results in a fire, many components that are currently in good condition could be damaged and require replacement.

Overall, the minimal benefit of deferring the Mobile Plant refurbishment is outweighed by the potential costs associated with responding to an in-service failure of the Plant if the project were to be deferred.

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33 Based on a 2024 marginal energy cost estimate during the non-winter period of $15,700 per GWh.

34 Difference between the net present value of completing the work in 2024 and completing the work in a future year. For example, deferring the project execution by one year to 2025 will provide a potential savings of $197,000.

35 The loss of 40.32 GWh of production at the current marginal energy cost estimates of $32.74 per GWh in 2025 and $25.56 in 2034 ranges from approximately $1,320,000 and $1,030,000 respectively.

36 There will be a certain amount of additional engineering and administration necessary to address the in-service failure to ensure the site remains safe and that there is no additional damage to the environment. Also, additional cost will be incurred when removing the damaged equipment from the site and effectively disposing of it.

In addition to these cost dynamics, deferring the refurbishment would not address current safety risks associated with arc flash hazards resulting from the switchgear. It would also not realize the operational efficiencies that can be achieved by modernizing the Plant.

6.0 PROJECT SCOPE

The assessment of alternatives determined that refurbishing the Mobile Plant in 2023 and 2024 is necessary to address the deteriorated condition of the Plant and ensure its continued safe and reliable operation at the lowest possible cost.

The *Mobile Hydro Plant Refurbishment* project includes upgrades or refurbishment of eight components within the Plant, which are:

(i) Powerhouse Building Upgrade

The powerhouse roof will be replaced and new heating and lighting systems will be installed.[37] A building extension will be constructed adjacent to the current structure to facilitate the installation of new switchgear and controls. A wall will be constructed to separate the switchgear from the control room to mitigate arc flash hazards. A new door will be installed to access the new control room without having to pass through the switchgear zone.

(ii) Crane Rehabilitation

The crane in the powerhouse will be refurbished in advance of the required turbine generator disassembly and reassembly. This will require replacing the live electrical bus on the crane bridge and building rails with a retractable cable reel or festoon system to improve safety by reducing exposure to electrical hazards. It will also include replacing the old wired control pendant with wireless type to improve line of sight and safety, completing an overhaul of the trolley and hoist unit, and completing a certified load test.

(iii) AC/DC Distribution System Upgrade

The deteriorated station service transformers will be replaced with a new 6,900-120/208 VAC wye connected transformer bank. Additional circuit capacity will be installed by replacing the existing AC panels with two 60-circuit 120/208 VAC non-essential services panels and one 60-circuit 120/208 VAC essential services panel. A new 60-circuit DC distribution panel will also be installed for additional capacity required for the new governor, digital protection and control equipment.

[37] The heat and ventilation control cabinet will be replaced and the new controls integrated with the unit control PLC system. A thermostat/humidistat will be installed on the generator pit and will be used by the unit control PLC to control all heat and ventilation equipment. The exhaust fan and air intake louvers on the building will be disassembled, inspected for damaged and refurbished as required. The exhaust fan was replaced in 2008 and is anticipated to remain in service following inspection.

(iv) Protection and Control Upgrade

A modern unit control PLC system will be installed to provide all standard control, protection and automation functionality, including a modern water management system.[38] The new unit control panel will contain the processor, associated monitoring and control equipment and control switches.[39]

The forebay water level system, which is critical to the implementation of the water management system in the PLC, will be replaced. A new fibre optic communications cable will be installed to transfer water level information from the forebay to the Plant.

A new network communications panel with a data concentrator and network switch will be installed to replace the existing remote terminal unit, improving communications to the SCADA system. The improved communications infrastructure will permit remote administration of the PLC and digital relays by engineering and operations staff.[40]

Infrared brush temperature sensors will be added to the exciter's commutator and slip rings. The voltage regulator will be replaced with a digital unit that will be integrated into the unit control PLC system and will provide improved voltage regulation under varying system conditions.

The existing electromechanical relays will be replaced with digital relays providing the minimum protection set.

The exciter will be shipped to a contractor to be rewound. Infrared brush temperature sensors will be added, a digital voltage regulator will be installed, and the power cables will be replaced.

(v) Governor Upgrade

The governor's control head will be replaced with a PLC-based, digital control system.[41] The generator speed and frequency will be matched to the power system by the new governor control system.[42] The speed switch will be removed and the

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[38] This includes remote control of the generator, stop/start and loading function, water management system, and monitoring generating unit alarms and protection trips.

[39] The following equipment will be located in the new unit control panel: PLC; industrial HMI; ethernet switch; automatic voltage regulator; MegAlert® remote LED display and switch board meter; synchroscope; emergency stop pushbutton; start pushbutton; stop pushbutton; alarm reset pushbutton; generator breaker control switch (ANSI device No. 52CS); field breaker control switch (ANSI device No. 41CS); speed raise/lower control switch (ANSI device No. 15CS); gate limit control switch (ANSI device No. 65CS); voltage raise/lower control switch (ANSI device No. 70CS); automatic/manual synchronizing control switch (ANSI device No. 25CS); generator lock out relay (ANSI device No. 86G); and three position local/remote control switch (ANSI device No. 43CS).

[40] Remote administration creates efficiency as the protection and control engineer or technologist can access the relays and PLC from their office without being dispatched to the Plant.

[41] The new governor control system will interface with the generator control PLC.

[42] The bearing oil temperature, cooling water monitoring, generator stator temperature monitoring, and vibration sensors will be integrated into the new unit control PLC. Governor oil level and pressure, bearing oil levels, compressed air pressure will be added and integrated into the unit control PLC. A scroll case pressure sensor will be added and integrated into the unit control PLC.

governor PLC will perform the speed processing functions previously performed by the speed switch.

The relay valve, which initiates the movement of the power piston, will be inspected and overhauled. All seals, bushings and other components will be inspected and refurbished as required to extend the life of the power piston.

(vi) Switchgear Replacement

The existing switchgear will be replaced with an arc flash rated assembly.[43] The control switches and associated wiring will be relocated to a new unit control panel remote from the switchgear and outside the arc flash zone of influence, ensuring enhanced employee safety.[44] The installation of the new switchgear will necessitate reconfiguration of the power cables to the generator and to the power transformer and the installation of new power cables.

(vii) Turbine Overhaul

The turbine will be overhauled following disassembly of the generator. Wear components of the turbine, such as wicket gate and operating ring bushings, will be replaced with self-lubricating bushings, which require no maintenance and have less environmental risk. The turbine's wicket gate facing plates will be refurbished to ensure smooth operation of the wicket gates and tight sealing upon shutdown. The turbine shaft/head cover seal will be inspected for wear on the turbine shaft and a replacement shaft sleeve and seal will be installed if required. The turbine bearing will be inspected and refurbished as necessary. Inspections will be completed on other minor components and repairs or replacements carried out, as required.

(viii) Generator Refurbishment

The generator will be disassembled to facilitate rewinding the stator and reinsulating the rotor poles. As part of disassembly: (i) new resistance temperature detectors will be installed in the stator windings; (ii) a neutral grounding transformer with secondary resistor will be installed to provide protection; (iii) a MegAlert® stator insulation testing system will be integrated with the unit control PLC system to provide a warning and prompt corrective action when the insulation value is reduced; (iv) the original surge arrestor will be replaced with intermediate class metal oxide varistor type surge arrestors; and (v) current potential transformers will be replaced.

The design and procurement of replacement components will be completed in 2023. The Plant will be taken out of service in June 2024, at which point components to be replaced or refurbished will be removed. The Plant will be out of service for approximately 26 weeks while the new components are installed and commissioned.

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43 The new switchgear will be equipped with an arc-flash protection system containing an externally vented vacuum breaker with closed-door racking capability. Higher accuracy instrument transformers for improved protection and metering will be supplied with the switchgear.

44 A 120/208 VAC three-phase emergency station service transformer will be incorporated into the new switchgear to enable the Plant to continue to be black started and carry isolated load in the event of a system power interruption.

7.0 PROJECT COST

Table 4 provides a breakdown by category of the cost of the *Mobile Hydro Plant Refurbishment* project.[45]

Table 4
Mobile Hydro Plant Refurbishment Project
Project Cost
($000s)

Cost Category	2023	2024	Total Cost
Material	1,331	1,714	3,045
Labour - Internal	115	448	563
Labour - Contract	-	-	-
Engineering	170	181	351
Other	50	137	187
Total	1,666	2,480	4,146

The *Mobile Hydro Plant Refurbishment* project is estimated to cost $1,666,000 in 2023 and $2,480,000 in 2024, for a total cost of $4,146,000.

8.0 CONCLUSION

Many of the critical components in the Mobile Plant are original and have been in service approaching 72 years. The Plant is at the age where the probability of failure of critical components is high. A lifecycle cost analysis confirmed that continued operation of the Plant, including the cost of refurbishment, will provide an economic benefit for customers over the longer term.

The *Mobile Hydro Plant Refurbishment* project includes refurbishing the building systems, replacing the switchgear, upgrading protection and control systems, and refurbishing the turbine generator. An assessment of alternatives determined that completing this work in 2023 and 2024 is necessary to ensure the safe and reliable operation of the Plant at the lowest possible cost.

[45] In Newfoundland Power's *2023-2027 Capital Plan,* there is a substation-related project associated with the Mobile Plant's operation estimated at $2,356,000. This cost has been included in the lifecycle analysis provided in Appendix A.

APPENDIX A:

Lifecycle Cost Analysis of the Mobile Plant

TABLE OF CONTENTS

1.0 INTRODUCTION

This lifecycle evaluation examines the future viability of generation at Newfoundland Power's Mobile Plant. The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2023 and 2024 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, the term of the watershed lease with the City of St. John's, and expresses the results in terms of the levelized cost of energy. It also provides sensitivity analyses that examine the sensitivity of the results to changes in assumptions.

2.0 LIFECYCLE COSTS

2.1 Capital Costs

Table A-1 provides all significant capital expenditures for the Mobile Plant over the next 25 years.

Table A-1
Mobile Hydroelectric Plant
Capital Expenditures
($000s)

Year	Expenditure
2023	1,666
2024[1]	6,653
2037	281
2039	155
2042	1,535
Total	$10,290

The estimated capital expenditure for the Plant is $10,290,000 over the next 25 years.[2] These capital expenditures include the multi-year expenditures planned for 2023 and 2024, additional single-year expenditures in 2024, and future capital expenditures commencing in 2037.

[1] Additional capital expenditures included in 2024 are related to substation, penstock, and surge tank refurbishments which are not included in the 2023/2024 capital budget project.

[2] Capital expenditures beyond the initial 25 years are included in the analysis and are broadly indicative of the expenditures anticipated.

Attachment A provides a comprehensive breakdown of capital costs.

2.2 Operating Costs

Annual operating costs for the Plant, including water rental fees, are estimated to be approximately $282,000 per year.[3] 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 $114,000 for 2023.[4] This fee will be paid annually to the City of St. John's 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 2024, it is expected that approximately 14 GWh of reduced production will occur, which will result in additional energy costs of $220,000.

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 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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[3] Reflects 2023 dollars.

[4] The water rental rate has been set to be equivalent to the Provincial Government legislated water power rental charge. The charge in 2021 was $2.70/MWh and is increased annually by the Consumer Price Index. 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 Mobile Hydro Plant

Marginal Cost Period	Normal Production (GWh)	Production (%)	Average Normal Production (MW)
Non-Winter Period (All hours)	20.57	51	3.52
Winter Period			
On-Peak	9.27	23	7.12
Off-Peak	10.48	26	6.49
Annual Production	40.32	100	4.60

The average normal production during the on-peak winter period is 7.12 MW. This is 68% of the maximum winter capacity of 10.5 MW.[5]

When Newfoundland Power receives a request from Hydro to maximize hydro plant production, the Mobile Plant produces on average 8.4 MW.[6] It is during the on-peak winter period in which the benefits of electricity production are highest.[7]

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. Once the Muskrat Falls Project is fully commissioned, there will be excess power available to export to other jurisdictions on the North American Grid.

An updated marginal cost study completed by Hydro in 2022 provides estimates of the opportunity cost of selling energy to other jurisdictions (the "Marginal Cost Update").[8] The marginal energy cost estimates vary by time of day and by season. To recognize these

[5] The maximum winter capacity is based on the typical production from the Plant during the Company's annual generation capacity test. The generation capacity test is required by Hydro's Utility Rate.

[6] The average production calculation is based on requests during the winter season when capacity shortfalls are highest. The production during requests is impacted by Plant availability and the availability of water in the reservoir. On occasion, the Plant may require maintenance and be unavailable when requested. The availability of water for production will limit the production available during requests through reduced forebay levels, and reduced inflows from upstream rivers and storage. Reduced storage can occur due to lack of rainfall and previous operation of the Plant including requests to maximize generation from Hydro.

[7] See Attachment C.

[8] The most recent marginal cost study results are found in the report *Marginal Cost Study Update - 2021 Summary Report*, March 7, 2022, Appendix A, filed in response to Request for Information TC-IC-NLH-001, Attachment 1, *Electrification, Conservation and Demand Management Plan: 2021-2025*.

time-varying characteristics, the costs are summarized by winter on-peak, winter off-peak and non-winter periods.

Attachment C to this report provides the forecast marginal energy costs for the period 2023 to 2040.

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 of Newfoundland and Labrador.[9] Removing the Plant from service would reduce the capacity available to supply customers and increase the need for new generation sources.

The Marginal Cost Update provides estimates of the marginal cost of generation capacity in terms of cost per MWh and cost per kW of peak demand.

The Plant can provide 10.5 MW of capacity during the winter. The cost of replacement capacity is dependent on the extent to which this capacity is available to meet peak load conditions. This is impacted by the amount of storage, the timing of rainfall, how the Plant is dispatched, the volume of requests to maximize generation and the potential that the Plant is out of service when required to meet customer demand.

To assess the cost of replacement capacity, Newfoundland Power completed an evaluation under two assumptions: (i) assuming the Plant's production reflects a *run-of-river* hydro plant; and (ii) evaluating the Plant as a *fully dispatchable* plant.

A *run-of-river* plant has little storage and provides minimum flexibility for the Company to schedule production for periods of greatest value.[10] 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 Mobile Plant has total available storage of 15.8 GWh. This level of storage represents about 63 days of production at a production rate of 10.5 MW. However, storage levels are often not full, and there are practical limitations to managing the

9 The Board's ongoing review of Hydro's Reliability and Resource Adequacy Study may impact the need for capacity additions on the Island Interconnected System.

10 As examples, periods of greatest value for production include during generation shortages and peak demand periods.

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.[11]

4.0 LIFECYCLE ANALYSIS RESULTS

4.1 Base Case Analysis

An analysis has been completed comparing the lifecycle costs of the Plant to the cost of replacement production. The costs are presented on a levelized cost of energy approach. The levelized cost of energy expresses the costs and benefits in terms of a ¢/kWh of production.

Table A-3 compares the estimated levelized costs of the Plant's production and the cost of replacement production.

Table A-3
Lifecycle Analysis Results

	50 Year Levelized Value[12]	Net benefit
Lifecycle Cost of the Plant	**2.70 ¢/kWh**	
Cost of Replacement Production (Run-of-River)		
Energy Costs	2.75 ¢/kWh	
Capacity Costs	5.09 ¢/kWh	
Total	7.84 ¢/kWh	5.14¢/kWh
Cost of Replacement Production (Fully Dispatchable)		
Energy Cost	2.75 ¢/kWh	
Capacity Cost	6.74 ¢/kWh	
Total	9.49 ¢/kWh	6.79 ¢/kWh

The cost to replace the Plant's production will exceed the Plant's cost by between 5.14 ¢/kWh and 6.79 ¢/kWh. In order for the replacement production costs to be less than the Plant costs, the production replacement costs would need to be reduced by between 66% and 72% based on the run-of-river and fully dispatchable assumptions, respectively. The large differences

11 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.

12 See Attachment D.

between costs and benefits suggest any reasonable variance in the estimates of the costs and benefits will support the continued operation of the Plant.

Attachment D provides the detailed results of the calculated levelized costs and benefits.[13]

4.2 Sensitivity Analysis

To illustrate the robustness of the conclusion that continued operation is less expensive than replacement production, the following scenarios were included in a sensitivity analysis:

Scenario 1: Uncertainty with marginal costs beyond 2041
Assumes excess energy and capacity resulting from the termination of the Churchill Falls ("CFLCo") contract in 2041 will result in there being no cost of electricity to replace the Plant's production beyond 2041.[14]

Scenario 2: Uncertain accuracy of Hydro's marginal capacity cost
Assumes Hydro's marginal capacity costs decrease by 25%.

Scenario 3: Uncertain accuracy of Hydro's marginal energy cost
Assumes Hydro's marginal energy costs decrease by 25%.

Table A-4 shows comparison of the present value of the Plant operations to the present value of replacement production for the base case and each scenario.

Table A-4
Sensitivity Analysis Results
(Present Value in $2024)

Scenario	Cost of Continued Operation ($M)	Cost of Replacement Production		Net Savings ($M)
		Run-of-River ($M)	Fully Dispatchable ($M)	
Base Case[15]	17.6	51.2	62.0	33.6 – 44.4
Scenario 1	13.7	31.0	37.1	17.3 – 23.4
Scenario 2	17.6	42.9	51.0	25.3 – 33.4
Scenario 3	17.5	46.7	57.5	29.2 – 40.0

13 The financial assumptions used in the economic evaluation are provided in Attachment E.
14 This scenario is to simulate a situation whereby once the CFLCo contract ends in 2041, future production from CFLCo will be in excess of available internal and export markets and can fully address capacity constraints on the Island of Newfoundland.
15 The base case provides the results of the levelized costs provided in Table A-3 expressed as present value of costs as opposed to the levelized cost per kWh.

The sensitivity analysis shows that the cost of continuing to operate the Plant will provide an economic benefit under all scenarios.

5.0 CONCLUSION

The results indicate that continued operation of the Mobile Plant is economically justified under current forecast capital, operating, marginal energy and capacity costs. Continued operation is also justified within reasonable variations in costs, including uncertainty of marginal costs.

Attachment A:

Summary of Capital Costs

Mobile Hydro Plant Economic Analysis
Summary of Capital Costs (2023-2069)
($000s)

Description	2023	2024	2037	2039	2042	2049	2054	2067	2069
Civil									
Dam, Spillways and Gates	-	592	281	-	1,535	-	-	300	-
Penstock	-	698	-	-	-	-	-	-	-
Surge Tank	-	483	-	-	-	300	-	-	-
Powerhouse	928	-	-	-	-	200	-	-	-
Mechanical									
Turbine	-	346	-	-	-	-	-	-	-
Governor	45	125	-	-	-	-	-	-	50
Powerhouse Systems	-	-	-	-	-	50	-	-	-
Electrical									
Generator Refurbishment	260	1,136	-	-	-	-	-	-	-
Control Systems	138	362	-	120	-	-	120	-	120
Switchgear	175	511	-	-	-	-	-	-	-
AC/DC Systems	120	-	-	-	-	25	-	-	-
Battery/Charger	-	-	-	35	-	-	35	-	35
Other									
Substation Refurbishment	-	2,356	-	-	-	-	-	-	-
Transmission Line Refurbishment	-	44	-	-	-	-	-	-	-
Total ($2023)	1,666	6,653	281	155	1,535	575	155	300	205

Attachment B:

Summary of Operating Costs

Mobile Hydro Plant Economic Evaluation Summary of Operating Costs ($2023)	
	Amount
2017	$158,634
2018	$156,404
2019	$158,815
2020	$77,701
2021	$290,367
Average[1]	**$168,384**
Water Power Rental[2]	$114,106
Total Average Operating Cost	**$282,490**

1 Cost excludes the water power rental rate.
2 Calculated using the City of St. John's current water rental rate ($2.70/MWh in 2021 plus CPI Inflator) multiplied by the normal annual output of the plant.

Attachment C:

Marginal Costs Estimates

Marginal Cost Projections 2023-2040
Island Interconnected System
At Hydro's Delivery Point to Newfoundland Power

	Energy Supply Costs			Generation and Transmission Capacity Costs			
	Winter		Non-Winter	Winter		Non-Winter	
Year	**On-Peak**	**Off-Peak**	**All hours**	**On-Peak**	**Off-Peak**	**All hours**	**Annual**
	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/kW·yr
2023	62.65	49.37	16.69	167.76	64.70	2.76	338.53
2024	60.96	49.30	15.75	184.20	71.13	3.05	371.96
2025	55.59	46.74	15.29	126.94	48.61	2.01	255.14
2026	51.62	43.91	15.28	113.04	43.11	1.75	226.71
2027	50.99	43.13	15.58	120.97	46.20	1.89	242.79
2028	49.83	43.06	16.06	129.51	49.53	2.04	260.14
2029	52.06	44.84	18.04	138.73	53.12	2.20	278.85
2030	51.55	45.13	17.02	148.34	56.87	2.36	298.35
2031	47.05	40.47	16.33	162.32	62.33	2.61	326.75
2032	45.05	39.51	15.80	177.76	68.36	2.88	358.14
2033	45.60	39.01	14.64	113.60	43.12	1.71	227.22
2034	40.51	36.38	13.30	119.30	45.32	1.81	238.75
2035	41.40	35.70	13.77	125.31	47.65	1.91	250.91
2036	35.58	32.16	12.21	131.65	50.11	2.02	263.74
2037	36.25	31.30	10.99	138.35	52.70	2.13	277.28
2038	36.38	33.77	11.51	144.34	55.02	2.23	289.40
2039	34.41	30.62	10.34	150.61	57.45	2.33	302.07
2040	33.27	32.07	9.81	157.17	59.99	2.44	315.34

Notes:

1. 2023-2040 based on the marginal cost projections provided by Hydro in the summary report Marginal Cost Study Update – 2021 dated March 7, 2022.
2. Beyond 2041, marginal cost projections are escalated based on Conference Board of Canada GDP deflator, long term projection dated January 22, 2022.

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	17,600	1,087	40.32	2.70
Cost of Replacement Production (Run-of-River)				
Energy Cost	17,972	1,110	40.32	2.75
Capacity Cost	33,242	2,053	40.32	5.09
Total	**51,214**	**3,163**		**7.84**
Cost of Replacement Production (Fully Dispatchable)				
Energy Cost	17,972	1,110	40.32	2.75
Capacity Cost	43,993	2,717	40.32	6.74
Total	**61,965**	**3,827**		**9.49**

[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

	Year	Generation ($)	Transmission ($)	Substation ($)	Capital Revenue Requirement ($)	Operating Costs ($)	Spillage Cost ($)	Total Cost ($)	Present Value ($)	Cumulative Present Value ($)	Present Value of Sunk Costs ($)	Total Cumulative Present Value ($)
-1	2023	928,000	0	0	76,780	0	0	76,780	81,241	81,241	1,039,515	1,120,756
0	2024	4,991,000	44,000	2,356,000	703,993	0	220,483	924,475	924,475	1,005,717	8,849,213	9,854,929
1	2025	0	0	0	761,623	292,011	0	1,053,634	995,779	2,001,496	8,129,410	10,130,906
2	2026	0	0	0	739,488	297,221	0	1,036,709	925,984	2,927,479	7,468,903	10,396,382
3	2027	0	0	0	718,390	302,558	0	1,020,948	861,834	3,789,313	6,862,474	10,651,787
4	2028	0	0	0	698,246	308,065	0	1,006,311	802,833	4,592,146	6,305,414	10,897,560
5	2029	0	0	0	678,979	313,712	0	992,691	748,481	5,340,627	5,793,470	11,134,097
6	2030	0	0	0	660,520	319,366	0	979,886	698,257	6,038,884	5,322,790	11,361,674
7	2031	0	0	0	642,804	325,119	0	967,923	651,859	6,690,743	4,889,886	11,580,629
8	2032	0	0	0	625,771	330,893	0	956,664	608,899	7,299,642	4,491,594	11,791,237
9	2033	0	0	0	609,366	336,711	0	946,078	569,097	7,868,739	4,125,040	11,993,780
10	2034	0	0	0	593,540	342,580	0	936,120	532,187	8,400,926	3,787,611	12,188,537
11	2035	0	0	0	578,246	348,498	0	926,744	497,927	8,898,853	3,476,927	12,375,780
12	2036	0	0	0	563,442	354,531	0	917,973	466,132	9,364,986	3,190,820	12,555,806
13	2037	358,688	0	0	579,086	360,590	0	939,676	450,952	9,815,938	3,111,683	12,927,622
14	2038	0	0	0	567,931	366,733	0	934,664	423,918	10,239,856	2,854,098	13,093,954
15	2039	204,604	0	0	570,525	372,894	0	943,419	404,393	10,644,249	2,710,678	13,354,927
16	2040	0	0	0	557,994	379,194	0	937,188	379,664	11,023,913	2,484,629	13,508,543
17	2041	0	0	0	543,694	385,550	0	929,244	355,775	11,379,688	2,276,468	13,656,156
18	2042	2,129,955	0	0	707,888	391,981	0	1,099,869	397,979	11,777,668	2,908,578	14,686,246
19	2043	0	0	0	710,825	398,483	0	1,109,308	379,354	12,157,021	2,665,495	14,822,516
20	2044	0	0	0	691,836	405,067	0	1,096,903	354,514	12,511,536	2,441,896	14,953,432
21	2045	0	0	0	673,411	411,714	0	1,085,125	331,451	12,842,986	2,236,204	15,079,190
22	2046	0	0	0	655,504	418,546	0	1,074,050	310,054	13,153,040	2,046,975	15,200,015
23	2047	0	0	0	638,076	425,490	0	1,063,566	290,168	13,443,208	1,872,891	15,316,099
24	2048	0	0	0	621,086	432,550	0	1,053,636	271,675	13,714,883	1,712,747	15,427,630
25	2049	895,052	0	0	679,355	439,727	0	1,119,083	272,706	13,987,589	1,797,837	15,785,426
26	2050	0	0	0	670,091	447,023	0	1,117,115	257,278	14,244,868	1,643,511	15,888,378
27	2051	0	0	0	651,826	454,441	0	1,106,267	240,790	14,485,658	1,501,634	15,987,292
28	2052	0	0	0	633,994	461,981	0	1,095,975	225,451	14,711,109	1,371,216	16,082,325
29	2053	0	0	0	616,560	469,646	0	1,086,206	211,173	14,922,282	1,251,349	16,173,630
30	2054	261,967	0	0	621,401	477,439	0	1,098,839	201,898	15,124,180	1,192,244	16,316,424
31	2055	0	0	0	606,704	485,361	0	1,092,064	189,636	15,313,816	1,086,890	16,400,706
32	2056	0	0	0	589,582	493,414	0	1,082,996	177,735	15,491,550	990,132	16,481,682
33	2057	0	0	0	572,780	501,601	0	1,074,381	166,639	15,658,189	901,292	16,559,482
34	2058	0	0	0	556,272	509,924	0	1,066,196	156,289	15,814,478	819,751	16,634,229
35	2059	0	0	0	540,035	518,385	0	1,058,419	146,630	15,961,108	744,936	16,706,044
36	2060	0	0	0	524,046	526,986	0	1,051,032	137,611	16,098,719	676,323	16,775,042
37	2061	0	0	0	508,287	535,730	0	1,044,017	129,187	16,227,907	613,427	16,841,334
38	2062	0	0	0	492,738	544,619	0	1,037,357	121,315	16,349,221	555,804	16,905,025
39	2063	0	0	0	477,383	553,655	0	1,031,039	113,955	16,463,176	503,041	16,966,217
40	2064	0	0	0	462,207	562,842	0	1,025,049	107,072	16,570,248	454,761	17,025,009
41	2065	0	0	0	447,195	572,181	0	1,019,375	100,633	16,670,881	410,614	17,081,495
42	2066	0	0	0	432,333	581,674	0	1,014,008	94,606	16,765,487	370,278	17,135,765
43	2067	627,979	0	0	470,129	591,326	0	1,061,455	93,595	16,859,082	390,281	17,249,363
44	2068	0	0	0	460,411	601,137	0	1,061,548	88,464	16,947,545	351,913	17,299,458
45	2069	443,477	0	0	481,343	611,112	0	1,092,454	86,040	17,033,586	352,425	17,386,010
46	2070	0	0	0	468,821	621,251	0	1,090,072	81,138	17,114,724	317,529	17,432,253
47	2071	0	0	0	451,845	631,560	0	1,083,405	76,214	17,190,938	285,743	17,476,681
48	2072	0	0	0	525,652	642,039	0	1,167,691	77,633	17,268,571	250,795	17,519,366
49	2073	0	0	0	385,485	652,692	0	1,038,177	65,232	17,333,803	226,574	17,560,377
50	2074	0	0	0	372,226	663,521	0	1,035,747	61,506	17,395,309	204,470	17,599,779

Present Value of the Cost of Replacement Energy (Reduced Exports)

	Year	Marginal Energy Costs	Present Value	Cumulative Present Value
			$	$
-1	2023	-	-	-
0	2024	-	-	-
1	2025	1,319,919	1,247,443	1,247,443
2	2026	1,253,200	1,119,353	2,366,795
3	2027	1,245,415	1,051,317	3,418,113
4	2028	1,243,612	992,152	4,410,264
5	2029	1,323,701	998,060	5,408,324
6	2030	1,301,084	927,140	6,335,463
7	2031	1,196,446	805,761	7,141,224
8	2032	1,156,881	736,334	7,877,558
9	2033	1,132,872	681,460	8,559,018
10	2034	1,030,604	585,902	9,144,920
11	2035	1,041,240	559,444	9,704,364
12	2036	918,161	466,228	10,170,592
13	2037	890,319	427,266	10,597,858
14	2038	928,152	420,964	11,018,822
15	2039	852,595	365,462	11,384,284
16	2040	846,543	342,943	11,727,227
17	2041	860,733	329,545	12,056,772
18	2042	875,089	316,644	12,373,416
19	2043	889,604	304,221	12,677,636
20	2044	904,304	292,267	12,969,904
21	2045	919,143	280,752	13,250,655
22	2046	934,394	269,738	13,520,393
23	2047	949,898	259,157	13,779,550
24	2048	965,659	248,990	14,028,540
25	2049	981,682	239,223	14,267,763
26	2050	997,970	229,839	14,497,602
27	2051	1,014,529	220,822	14,718,424
28	2052	1,031,362	212,160	14,930,584
29	2053	1,048,475	203,837	15,134,421
30	2054	1,065,872	195,841	15,330,262
31	2055	1,083,557	188,158	15,518,421
32	2056	1,101,536	180,777	15,699,198
33	2057	1,119,813	173,686	15,872,884
34	2058	1,138,393	166,872	16,039,756
35	2059	1,157,282	160,326	16,200,082
36	2060	1,176,484	154,037	16,354,119
37	2061	1,196,005	147,994	16,502,113
38	2062	1,215,849	142,189	16,644,301
39	2063	1,236,023	136,611	16,780,912
40	2064	1,256,532	131,252	16,912,164
41	2065	1,277,381	126,103	17,038,267
42	2066	1,298,576	121,156	17,159,423
43	2067	1,320,122	116,403	17,275,826
44	2068	1,342,026	111,837	17,387,663
45	2069	1,364,293	107,450	17,495,113
46	2070	1,386,930	103,235	17,598,348
47	2071	1,409,943	99,185	17,697,533
48	2072	1,433,337	95,294	17,792,827
49	2073	1,457,120	91,556	17,884,383
50	2074	1,481,297	87,964	17,972,347

Present Value of the Cost of Replacement Capacity (Run-of-River Assumption)

	Year	Marginal Capacity Cost	Present Value	Cumulative Present Value
		$	$	$
-1	2023	-	-	-
0	2024	-	-	-
1	2025	1,536,243	1,372,166	1,372,166
2	2026	1,644,935	1,388,573	2,760,739
3	2027	1,762,153	1,405,843	4,166,582
4	2028	1,888,588	1,423,979	5,590,561
5	2029	2,020,420	1,439,731	7,030,292
6	2030	2,212,267	1,489,877	8,520,169
7	2031	2,424,284	1,543,013	10,063,182
8	2032	1,540,698	926,781	10,989,964
9	2033	1,618,640	920,202	11,910,166
10	2034	1,700,879	913,860	12,824,026
11	2035	1,787,662	907,747	13,731,773
12	2036	1,879,250	901,856	14,633,629
13	2037	1,961,193	889,501	15,523,130
14	2038	2,046,932	877,410	16,400,540
15	2039	2,136,649	865,577	17,266,117
16	2040	2,172,463	831,760	18,097,877
17	2041	2,208,698	799,200	18,897,077
18	2042	2,245,333	767,844	19,664,921
19	2043	2,282,435	737,673	20,402,595
20	2044	2,319,890	708,609	21,111,203
21	2045	2,358,383	680,811	21,792,014
22	2046	2,397,514	654,104	22,446,118
23	2047	2,437,294	628,444	23,074,563
24	2048	2,477,735	603,791	23,678,354
25	2049	2,518,846	580,106	24,258,460
26	2050	2,560,640	557,349	24,815,809
27	2051	2,603,127	535,485	25,351,294
28	2052	2,646,319	514,479	25,865,773
29	2053	2,690,228	494,297	26,360,070
30	2054	2,734,866	474,906	26,834,976
31	2055	2,780,243	456,276	27,291,252
32	2056	2,826,374	438,377	27,729,629
33	2057	2,873,271	421,181	28,150,810
34	2058	2,920,945	404,658	28,555,468
35	2059	2,969,411	388,784	28,944,252
36	2060	3,018,680	373,533	29,317,785
37	2061	3,068,767	358,880	29,676,665
38	2062	3,119,686	344,801	30,021,466
39	2063	3,171,449	331,275	30,352,741
40	2064	3,224,071	318,280	30,671,021
41	2065	3,277,566	305,794	30,976,816
42	2066	3,331,948	293,798	31,270,614
43	2067	3,387,233	282,273	31,552,887
44	2068	3,443,436	271,200	31,824,087
45	2069	3,500,571	260,561	32,084,649
46	2070	3,558,653	250,340	32,334,989
47	2071	3,617,700	240,519	32,575,508
48	2072	3,677,726	231,084	32,806,592
49	2073	3,738,749	222,019	33,028,612
50	2074	3,800,783	213,310	33,241,921

Present Value of the Cost of Replacement Capacity (Fully Dispatchable Assumption)

	Year	Effective Capacity[1] MW	Marginal Capacity Cost $	Present Value $	Cumulative Present Value $
-1	2023	-	-	-	-
0	2024	-	-	-	-
1	2025	8.60	2,194,010	2,073,538	2,073,538
2	2026	8.60	1,949,490	1,741,276	3,814,814
3	2027	8.60	2,087,785	1,762,405	5,577,219
4	2028	8.60	2,236,938	1,784,626	7,361,844
5	2029	8.60	2,397,828	1,807,942	9,169,786
6	2030	8.60	2,565,589	1,828,213	10,997,999
7	2031	8.60	2,809,799	1,892,293	12,890,292
8	2032	8.60	3,079,699	1,960,174	14,850,465
9	2033	8.60	1,953,924	1,175,350	16,025,815
10	2034	8.60	2,053,019	1,167,148	17,192,963
11	2035	8.60	2,157,584	1,159,242	18,352,205
12	2036	8.60	2,267,934	1,151,621	19,503,826
13	2037	8.60	2,384,399	1,144,278	20,648,104
14	2038	8.60	2,488,573	1,128,694	21,776,799
15	2039	8.60	2,597,578	1,113,443	22,890,241
16	2040	8.60	2,711,646	1,098,514	23,988,755
17	2041	8.60	2,757,098	1,055,597	25,044,352
18	2042	8.60	2,803,085	1,014,274	26,058,626
19	2043	8.60	2,849,578	974,480	27,033,106
20	2044	8.60	2,896,665	936,190	27,969,296
21	2045	8.60	2,944,200	899,303	28,868,599
22	2046	8.60	2,993,051	864,025	29,732,625
23	2047	8.60	3,042,713	830,131	30,562,755
24	2048	8.60	3,093,199	797,566	31,360,321
25	2049	8.60	3,144,522	766,279	32,126,600
26	2050	8.60	3,196,697	736,219	32,862,819
27	2051	8.60	3,249,738	707,338	33,570,157
28	2052	8.60	3,303,659	679,590	34,249,748
29	2053	8.60	3,358,475	652,931	34,902,679
30	2054	8.60	3,414,200	627,318	35,529,996
31	2055	8.60	3,470,850	602,709	36,132,705
32	2056	8.60	3,528,439	579,066	36,711,771
33	2057	8.60	3,586,985	556,350	37,268,121
34	2058	8.60	3,646,501	534,525	37,802,646
35	2059	8.60	3,707,006	513,556	38,316,202
36	2060	8.60	3,768,514	493,410	38,809,613
37	2061	8.60	3,831,042	474,055	39,283,668
38	2062	8.60	3,894,608	455,458	39,739,126
39	2063	8.60	3,959,229	437,591	40,176,717
40	2064	8.60	4,024,922	420,425	40,597,143
41	2065	8.60	4,091,706	403,933	41,001,076
42	2066	8.60	4,159,597	388,087	41,389,163
43	2067	8.60	4,228,614	372,863	41,762,026
44	2068	8.60	4,298,777	358,236	42,120,262
45	2069	8.60	4,370,104	344,183	42,464,445
46	2070	8.60	4,442,615	330,681	42,795,127
47	2071	8.60	4,516,328	317,709	43,112,836
48	2072	8.60	4,591,265	305,246	43,418,082
49	2073	8.60	4,667,445	293,272	43,711,354
50	2074	8.60	4,744,889	281,767	43,993,121

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 2023 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:		Capital Structure	Return	Weighted Cost
	Debt	55.00%	3.608%	1.98%
	Common Equity	45.00%	8.500%	3.83%
	Total	100.00%		5.81%

CCA Rates:	Class	Rate	Details
	17.1 & 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: Conference Board of Canada GDP deflator, long term forecast dated January 22, 2022.

Supporting Documents: Newfoundland and Labrador Hydro's Marginal Cost Study Update - 2021 Summary Report, March 7, 2022, Appendix A, filed in response to Request for Information TC-IC-NLH-001, Attachment 1, Electrification, Conservation and Demand Management Plan 2021-2025.

NEWFOUNDLAND POWER
A FORTIS COMPANY

5.1 2023 Application Enhancements

June 2022

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1.0 INTRODUCTION

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") operates approximately 190 software applications in providing service to customers. These applications include third-party software products that support various business functions, as well as internally developed software designed to provide niche functionality.

Each year, the Company reviews opportunities to enhance its software applications to improve its operating efficiency and effectiveness in serving customers. This can include enhancements to applications to reduce operating costs through the elimination of manual processes or other requirements. It can also include enhancements that provide an improved customer service experience and other customer benefits.

The 2023 *Application Enhancements* project includes the enhancement or replacement of five software applications to reduce costs to customers or improve customer service delivery, as well as various other minor enhancements identified through normal operations. Execution of the 2023 *Application Enhancements* project will better enable Newfoundland Power to meet customers' service expectations at the lowest possible cost, as described below.

2.0 PROJECT DESCRIPTION

2.1 Digital Forms Portfolio Enhancements

Description

Newfoundland Power routinely seeks to digitize paper-based forms through its Digital Forms Portfolio.[1] The digitization of paper-based forms typically provides multiple operational benefits, including a reduction in manual data-entry requirements, improved data quality and enhanced record keeping. For 2023, the Company is proposing to digitize two paper-based processes: (i) underground wire location services; and (ii) meter record keeping.

The Company provides underground wire location services to ensure customers and contractors are working safely when performing excavation activities near underground wires.[2] As part of the service, a Newfoundland Power employee completes a site visit with a requesting customer and provides the customer with a paper-based clearance form that identifies where the underground lines are located and any constraints affecting work in the area. In 2021, approximately 2,000 underground wire location services were completed.

Digitizing the clearance form associated with underground wire location services will reduce manual processes for form completion. It will also provide easier access to forms for record keeping and enhanced document retrieval through the creation of a centralized database.

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[1] The Company's Digital Forms Portfolio Enhancements item was included the *2021 Capital Budget Application* and approved by the Board in Order No. P.U. 37 (2020). Further enhancements to the system were included the *2022 Capital Budget Application* and approved by the Board in Order No. P.U. 36 (2021).

[2] Underground wire location services are required under Occupational Health and Safety Regulations. See, for example, section 406 of NLR 5/12, *Occupational Health and Safety Regulations, 2012*.

Enhanced record keeping will streamline existing processes, avoid duplication in work and support safety compliance requirements.[3]

The second manual process that Newfoundland Power intends to digitally enhance is meter record keeping and lifecycle tracking. The Company tracks the lifecycle of a customer meter from meter purchase to meter retirement. When a meter is issued from inventory to a line truck, the meter is manually tracked on a paper form that identifies the meter identification information, when and where the meter was installed, and details of an associated meter retirement, if applicable. Information from the paper form is later manually keyed into the Company's Meter Equipment System. Each month, the general foreperson completes a reconciliation process that requires retracing a sample of meter installations to ensure the process was completed correctly and that the meters are accounted for appropriately.[4] In 2021, over 3,000 customer meter installations were completed.

Digitizing the meter tracking process will allow meter movements to be tracked in a centralized database rather than on paper forms that reside in multiple line trucks spread throughout the Company's service territory. Digital meter tracking will allow for more efficient record keeping of this high-volume work task. The centralized database will simplify the meter tracking process and reduce time spent manually keying data and completing meter reconciliation processes. It will also provide improved record keeping for auditing purposes.

Table 1 provides the cost breakdown of the Digital Forms Portfolio Enhancements.

Table 1
Digital Forms Portfolio Enhancements
2023 Project Cost
($000s)

Cost Category	2023
Material	-
Labour – Internal	103
Labour – Contract	-
Engineering	-
Other	60
Total	**163**

3 Approximately 100 follow-up site visits are typically required annually. A centralized database would allow an employee tasked with completing a wire locate to more easily determine if a locate has already been completed in a particular area, reducing the effort required on the follow-up visit or eliminating the requirement to complete the follow-up visit altogether.

4 For example, the reconciliation process confirms that the meter issued to the line truck has been installed and any meter removed has been returned to the warehouse to be retired appropriately.

The estimated cost of the Digital Forms Portfolio Enhancements is $163,000 in 2023.

Justification

This enhancement is justified on the basis of improved operating efficiencies and reduced operating costs. The implementation of digital forms for completing underground wire locates and tracking meter lifecycles will reduce manual processes and improve record keeping and document retrieval processes going forward. A cost-benefit analysis determined that implementing this solution will provide a positive net present value for customers.

Appendix A provides a detailed breakdown of the net present value analysis for this item.

2.2 Geographic Information System Enhancement

Description

Newfoundland Power implemented its Geographic Information System ("GIS") in 2013 to manage information on the location of Company assets and customer premises. The GIS provides location information to various other software applications to enable their operation, including the Outage Management System. Operation of these systems is essential to ensuring an effective and efficient response to customer outages, customers' service requests, and other work in the field.

Since 2019, operations and engineering employees have accessed real-time location information through an online portal provided by the GIS vendor. The cost of using the online portal is based on subscription fees from the vendor, which are set based on the number of licenses required. Current operations require approximately 200 licences, resulting in subscription fees of approximately $35,000 per year.

Newfoundland Power's current service agreement with its vendor enables this functionality to be delivered through an add-on to existing software, known as GIS Enterprise. By implementing GIS Enterprise, employees would continue to have access to essential location information and subscription fees for the online portal would no longer be required. Implementing this functionality would not increase the cost of the current service agreement, but would require internal labour and third-party support to migrate existing GIS data to new hardware and restructure current software architecture.

The software vendor has indicated that all clients will be required to upgrade to GIS Enterprise prior to their next system upgrade. The next upgrade of Newfoundland Power's GIS is currently scheduled for 2026. The Company has determined that implementing GIS Enterprise is necessary to facilitate its next system upgrade and that undertaking the upgrade in 2023 would eliminate subscription fees and result in annual operating cost savings of approximately $35,000. Deferring the upgrade to 2026 would defer these cost savings.

Table 2 provides the cost breakdown for the GIS Enhancement.

Table 2 GIS Enhancement 2023 Project Cost ($000s)	
Cost Category	2023
Material	-
Labour – Internal	285
Labour – Contract	-
Engineering	-
Other	50
Total	335

The estimated cost of the GIS Enhancement is $335,000 in 2023. This includes costs associated with migrating information to different hardware and restructuring current software architecture.

Justification

The GIS Enhancement is justified based on operating cost savings for customers from 2023 to 2025. The implementation of GIS Enterprise is a prerequisite for the next system upgrade required for Newfoundland Power's GIS, which is scheduled for 2026. Completing the move to GIS Enterprise in 2023 will eliminate current subscription costs from 2023 to 2025.

2.3 Virtual Meeting System Replacement

Description

This item involves replacing the software solution used to manage virtual meetings. Newfoundland Power has been using WebEx as its virtual meeting solution since 2018. WebEx is currently used for video conferencing and virtual meetings for employees, vendors and with other outside parties. Annual user fees for WebEx are currently $75,000.

Microsoft Teams is a virtual meeting solution with capabilities similar to WebEx. Newfoundland Power can access Microsoft Teams as part of its existing Microsoft Enterprise Agreement with no added annual cost. However, internal labour and third-party support would be required up front to configure, secure and integrate the solution to other existing software.

The Company's WebEx contract expires in July 2023. A net present value analysis was completed to determine whether continuing to use WebEx or transitioning to Microsoft Teams would be least-cost for customers. The analysis determined that implementing Microsoft Teams and eliminating annual user fees associated with WebEx would be least cost.

Table 3 provides the cost breakdown for the Virtual Meeting System Replacement.

Table 3
Virtual Meeting System Replacement
2023 Project Cost
($000s)

Cost Category	2023
Material	-
Labour – Internal	114
Labour – Contract	-
Engineering	-
Other	100
Total	214

The estimated cost of the Virtual Meeting System Replacement is $214,000 in 2023. This includes internal labour and third-party support required to configure, secure and integrate the solution to other existing software.

Justification

The Virtual Meeting System Replacement is justified on the basis of a reduction in operating costs to customers. Microsoft Teams is currently available to Newfoundland Power at no additional cost under the current Microsoft Enterprise Agreement. Implementing Microsoft Teams for virtual meetings will reduce operating costs through the termination of WebEx services, resulting in a positive net present value for customers.

Appendix B provides a detailed breakdown of the net present value analysis for this item.

2.4 Environment, Health and Safety System Replacement

Description

This item involves replacing the software solution used to manage Newfoundland Power's environment, health and safety processes. Newfoundland Power implemented its current Environment, Health and Safety System in 2014. The system is used to document environment and safety incidents and training, contractor inspections and work observations. The effective management of these processes is necessary to maintain the safety of employees and contractors, as well as to comply with Occupational Health and Safety Regulations.

The cost to operate and maintain the existing Environment, Health and Safety System is expected to increase by approximately 25% in 2023.[5] Given the age of the system and increasing costs, the Company completed a market survey to determine whether continued use of the existing system is the least-cost alternative. The results determined that alternative solutions exist that provide comparable functionality with substantially lower annual costs.[6] A net present value analysis determined that replacing the existing system would reduce overall costs to customers.

Table 4 provides the cost breakdown for the Environment, Health and Safety System Replacement.

Table 4
Environment, Health and Safety System Replacement
2023 Project Cost
($000s)

Cost Category	2023
Material	-
Labour – Internal	228
Labour – Contract	-
Engineering	-
Other	75
Total	**303**

The estimated cost of the Environment, Health and Safety System Replacement is $303,000 in 2023. This includes the procurement of new software and internal labour costs associated with system design, configuration and testing.

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5 Newfoundland Power currently incurs costs of approximately $65,200 per year to use, support and maintain Intelex. The vendor indicated in 2022 that costs for the system will increase to approximately $81,700 in 2023. This includes the purchase of 2 additional licenses for users. This is an overall increase of approximately 25% (($81,700 - $65,200) / ($65,200) = 25.3%).

6 Results of the survey showed that the range of costs for alternative solutions was between $10,000 and $26,000 annually.

Justification

The Environment, Health and Safety System Replacement is justified on the basis of reducing costs for customers. Newfoundland Power's existing system has been in operation for nearly 10 years and annual costs to operate and maintain the system have increased. A market survey showed that alternative solutions exist that have lower annual costs. A net present value analysis determined that replacing the system with a lower-cost alternative would result in a positive net present value for customers.

Appendix C provides a detailed breakdown of the net present value analysis for this item.

2.5 takeCHARGE Website Enhancements

Description

This item involves enhancing the website that supports customer energy conservation and electrification initiatives under the takeCHARGE partnership. 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 and electrification education and awareness resources. There were over 290,000 visits to the takeCHARGE website in 2021. This is consistent with promotion of the takeCHARGE website as the primary resource for customer information and customers' increasing preference for digital communication.

In 2023, takeCHARGE website enhancements are required to ensure customers continue to have access to up-to-date information on customer energy conservation and electrification initiatives. Specific enhancements include: (i) modifying the website to include updated information on customer programs; and (ii) expanding educational content for residential and commercial customers related to energy conservation and electrification.

Table 5 provides the cost breakdown for the takeCHARGE Website Enhancements.

Table 5 takeCHARGE Website Enhancements 2023 Expenditures ($000s)	
Cost Category	2023
Material	-
Labour – Internal	46
Labour – Contract	-
Engineering	-
Other	22
Total	68

The estimated cost of the takeCHARGE Website Enhancements is $68,000 in 2023.

Justification

Enhancements to the takeCHARGE website are justified on the basis of improvements in customer service delivery and the continued promotion of energy conservation and electrification initiatives to customers. Updates to the takeCHARGE website will ensure customers continue to have access to accurate, up-to-date information on energy conservation and electrification.

2.6 Various Minor Enhancements

Description

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.

Table 6 provides the cost breakdown for Various Minor Enhancements.

Table 6 Various Minor Enhancements 2023 Expenditures ($000s)	
Cost Category	2023
Material	-
Labour – Internal	365
Labour – Contract	-
Engineering	-
Other	90
Total	455

The estimated cost of Various Minor Enhancements is $455,000 in 2023. The budget for this item is based on the most recent three-year average for Various Minor Enhancements.

Justification

Work completed as part of Various Minor Enhancements is justified on the basis of improved customer service, increased operating efficiencies, and compliance with regulatory and legislative requirements.

3.0 PROJECT COST

Table 7 summarizes the cost breakdown for the 2023 *Application Enhancements* project.

Table 7
Application Enhancements Project
2023 Project Cost
($000s)

Cost Category	2023
Material	-
Labour – Internal	1,141
Labour – Contract	-
Engineering	-
Other	397
Total	1,538

The total cost of the 2023 *Application Enhancements* project is approximately $1,538,000.

4.0 CONCLUSION

The 2023 *Application Enhancements* project will allow Newfoundland Power to reduce manual processes and annual costs associated with the operation of existing software applications, while also leveraging opportunities to provide improved customer service. This will result in a more efficient and effective service being provided to customers.

APPENDIX A:

Net Present Value Analysis - Digital Forms Portfolio Enhancements

NET PRESENT VALUE ANALYSIS

Digital Forms Portfolio Enhancements

		Capital Impacts						Operating Cost Impacts						
		Capital Additions		CCA Tax Deductions				Cost Increases		Cost Benefits				
	YEAR	New Software A	New System Software B	Software	System Hardware	Residual CCA	Total C	Labour	Non-Lab D	Labour	Non-Lab E	Net Operating Savings F	Income Tax G	After-Tax Cash Flow H
0	2023	($163,000)	$0	$163,000	$0	$0	$163,000	$0	$0	$55,168	$0	$55,168	$32,350	($75,482)
1	2024	$0	$0	$0	$0	$0	$0	$0	($30,494)	$56,740	$0	$26,246	($7,874)	$18,372
2	2025	$0	$0	$0	$0	$0	$0	$0	($31,011)	$58,357	$0	$27,346	($8,204)	$19,142
3	2026	$0	$0	$0	$0	$0	$0	$0	($31,564)	$60,020	$0	$28,456	($8,537)	$19,919
4	2027	$0	$0	$0	$0	$0	$0	$0	($32,131)	$61,731	$0	$29,600	($8,880)	$20,720
5	2028	$0	$0	$0	$0	$0	$0	$0	($32,716)	$63,490	$0	$30,774	($9,232)	$21,542
6	2029	$0	$0	$0	$0	$0	$0	$0	($33,316)	$65,300	$0	$31,984	($9,595)	$22,389
7	2030	$0	$0	$0	$0	$0	$0	$0	($33,916)	$67,161	$0	$33,245	($9,974)	$23,271
7Yr	Present Value (See Note I)	@		5.21%										$42,798

NOTES:

- A is the sum of the software additions by year.
- B is the sum of the computer network hardware additions by year.
- C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.
- D is any software maintenance fees and internal support costs associated with the project. The non-labour costs are escalated to current year using the GDP Deflator Index. The labour cost estimates are escalated to current year using Newfoundland Power's Labour Escalation Rates.
- E is the reduced operating costs. The non-labour cost estimates are escalated to current year using the GDP Deflator Index. The labour costs are escalated to current year using Newfoundland Power's Labour Escalation Rates.
- F is the sum of columns D and E.
- G is the impact on taxes from the CCA and operating cost deductions. It is equal to column C (total) less column F times the tax rate.
- H is the after tax cash flow which is the sum of the capital expenditure (columns A + B) plus operating expenditures (column F) plus income tax (column G).
- I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

APPENDIX B:

Net Present Value Analysis - Virtual Meeting System Replacement

NET PRESENT VALUE ANALYSIS

Virtual Meeting System Replacement

		Capital Impacts							Operating Cost Impacts						
		Capital Additions		CCA Tax Deductions				Cost Increases		Cost Benefits					
	YEAR	New Software A	New System Software B	Software	System Hardware	Residual CCA	Total C	Labour	Non-Lab D	Labour	Non-Lab E	Net Operating Savings F	Income Tax G	After-Tax Cash Flow H
0	2023	($214,000)	$0	$214,000	$0	$0	$214,000	$0	$0	$0	$31,250	$31,250	$54,825	($127,925)
1	2024	$0	$0	$0	$0	$0	$0	$0	$0	$0	$76,234	$76,234	($22,870)	$53,364
2	2025	$0	$0	$0	$0	$0	$0	$0	$0	$0	$77,528	$77,528	($23,258)	$54,270
3	2026	$0	$0	$0	$0	$0	$0	$0	$0	$0	$78,911	$78,911	($23,673)	$55,238
4	2027	$0	$0	$0	$0	$0	$0	$0	$0	$0	$80,328	$80,328	($24,098)	$56,230
5	2028	$0	$0	$0	$0	$0	$0	$0	$0	$0	$81,790	$81,790	($24,537)	$57,253
6	2029	$0	$0	$0	$0	$0	$0	$0	$0	$0	$83,289	$83,289	($24,987)	$58,302
7	2030	$0	$0	$0	$0	$0	$0	$0	$0	$0	$84,790	$84,790	($25,437)	$59,353
7Yr	Present Value (See Note I)	@		5.21%										$194,096

NOTES:

A is the sum of the software additions by year.
B is the sum of the computer network hardware additions by year.
C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.
D is any software maintenance fees and internal support costs associated with the project. The non-labour costs are escalated to current year using the GDP Deflator Index. The labour cost estimates are escalated to current year using Newfoundland Power's Labour Escalation Rates.
E is the reduced operating costs. The non-labour cost estimates are escalated to current year using the GDP Deflator Index. The labour costs are escalated to current year using Newfoundland Power's Labour Escalation Rates.
F is the sum of columns D and E.
G is the impact on taxes from the CCA and operating cost deductions. It is equal to column C (total) less column F times the tax rate.
H is the after tax cash flow which is the sum of the capital expenditure (columns A + B) plus operating expenditures (column F) plus income tax (column G).
I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

APPENDIX C:

Net Present Value Analysis - Environment, Health and Safety System Replacement

NET PRESENT VALUE ANALYSIS

Environment, Health and Safety System Replacement

		Capital Impacts							Operating Cost Impacts						
		Capital Additions		CCA Tax Deductions				Cost Increases		Cost Benefits					
	YEAR	New Software	New System Software	Software	System Hardware	Residual CCA	Total	Labour	Non-Lab	Labour	Non-Lab	Net Operating Savings	Income Tax	After-Tax Cash Flow
		A	B		C			D		E		F	G	H
0	2023	($303,000)	$0	$303,000	$0	$0	$303,000	$0	$0	$0	$20,437	$20,437	$84,769	($197,794)
1	2024	$0	$0	$0	$0	$0	$0	$0	($25,411)	$0	$83,092	$57,681	($17,304)	$40,377
2	2025	$0	$0	$0	$0	$0	$0	$0	($25,843)	$0	$84,502	$58,659	($17,598)	$41,061
3	2026	$0	$0	$0	$0	$0	$0	$0	($26,304)	$0	$86,010	$59,706	($17,912)	$41,794
4	2027	$0	$0	$0	$0	$0	$0	$0	($26,776)	$0	$87,554	$60,778	($18,233)	$42,545
5	2028	$0	$0	$0	$0	$0	$0	$0	($27,263)	$0	$89,148	$61,885	($18,566)	$43,319
6	2029	$0	$0	$0	$0	$0	$0	$0	($27,763)	$0	$90,782	$63,019	($18,906)	$44,113
7	2030	$0	$0	$0	$0	$0	$0	$0	($28,263)	$0	$92,418	$64,155	($19,247)	$44,908
7Yr	Present Value (See Note I)	@		5.21%										$45,853

NOTES:

A is the sum of the software additions by year.
B is the sum of the computer network hardware additions by year.
C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.
D is any software maintenance fees and internal support costs associated with the project. The non-labour costs are escalated to current year using the GDP Deflator Index. The labour cost estimates are escalated to current year using Newfoundland Power's Labour Escalation Rates.
E is the reduced operating costs. The non-labour cost estimates are escalated to current year using the GDP Deflator Index. The labour costs are escalated to current year using Newfoundland Power's Labour Escalation Rates.
F is the sum of columns D and E.
G is the impact on taxes from the CCA and operating cost deductions. It is equal to column C (total) less column F times the tax rate.
H is the after tax cash flow which is the sum of the capital expenditure (columns A + B) plus operating expenditures (column F) plus income tax (column G).
I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

NEWFOUNDLAND POWER
A FORTIS COMPANY

6.1 Rate Base: Additions, Deductions and Allowances

June 2022

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1.0 INTRODUCTION

1.1 General

In the *2023 Capital Budget Application* (the "Application"), Newfoundland Power Inc. ("Newfoundland Power" or the "Company") seeks final approval of its 2021 average rate base. This is consistent with current regulatory practice before the Board.

Newfoundland Power's 2021 average rate base of $1,202,946,000 is set out in Schedule C to the Application.

To meet the cost of service standard, rate base, as calculated in accordance with the Asset Rate Base Method, should reflect what the utility must finance. For investment in utility plant, it is the depreciated value of the plant that must be effectively financed. However, for rate base to fully reflect the financing requirements associated with the provision of regulated service, it must also be adjusted to reflect other costs required to provide service.

Conceptually, additions to rate base are costs that have been incurred to provide service, but have not yet been recovered through customer rates. Deductions from rate base represent amounts that have been recovered through customer rates in advance of the required utility payment for those costs. Rate base allowances simply reflect the cost associated with maintaining the required working capital and inventories necessary to provide service. Each of these items affects what the utility must finance.

In Order No. P.U. 32 (2007), the Board approved Newfoundland Power's calculation of rate base in accordance with the Asset Rate Base Method. That calculation included the additions to, deductions from, and allowances in rate base, which are more fully described in this report.

1.2 Compliance and Related Matters

In Order No. P.U. 19 (2003), the Board, in effect, ordered Newfoundland Power to file with its capital budget applications: (i) evidence related to changes in deferred charges, including pension costs; and (ii) a reconciliation of average rate base and average invested capital.

Commencing in 2008, Newfoundland Power's rate base is calculated in accordance with the Asset Rate Base Method. This includes provision for allowances calculated in accordance with accepted regulatory practice. The use of allowances versus average year-end balances results in permanent differences between Newfoundland Power's average rate base and average invested capital. Accordingly, they are, in effect, the principal reconciling items between the Company's average rate base and average invested capital.

This report provides evidence relating to: (i) changes in deferred charges, including pension costs; and (ii) the cash working capital allowance and materials and supplies allowance included in rate base. This complies with the requirements of Order No. P.U. 19 (2003).

To provide the Board with a comprehensive overview of those items in Newfoundland Power's rate base other than plant investment, this report reviews *all* additions, deductions and allowances included in rate base.

Four years of data are provided in this report. This includes 2 historical years, the current year and the subsequent year. The 2022 and 2023 forecast rate base additions and deductions reflect the Company's most recent forecasts and estimates. The data presented is year-end data. This is consistent with past evidence submitted in compliance with Order No. P.U. 19 (2003).

2.0 ADDITIONS TO RATE BASE

2.1 Summary

Table 1 summarizes Newfoundland Power's additions to rate base for 2020 and 2021, and the forecast additions for 2022 and 2023.

Table 1
Additions to Rate Base
2020-2023F
($000s)

	2020	2021	2022F	2023F
Deferred Pension Costs	89,900	88,888	95,109	102,130
Credit Facility Costs	46	96	51	37
Cost Recovery Deferral – Hearing Costs	247	-	-	-
Cost Recovery Deferral – Conservation	17,049	16,421	20,407	22,294
Cost Recovery Deferral - Pension Capitalization	-	-	-	799
Cost Recovery Deferral – 2022 Revenue Shortfall	-	-	460	230
Customer Finance Programs	2,098	1,755	1,789	1,801
Demand Management Incentive Account	1,002	1,342	-	-
Total Additions	110,342	108,502	117,816	127,291

Additions to rate base were approximately $108.5 million in 2021. This is approximately $1.8 million lower than 2020. The lower additions to rate base in 2021 reflect: (i) decreases in deferred pension costs which reflects a lower discount rate and its impact on interest costs; (ii) decreases in deferred recovery of annual customer energy conservation program costs; and

(iii) the conclusion of a regulatory amortization for hearing costs associated with the *2019/2020 General Rate Application*.

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).[1]

Table 2 provides details of changes in Newfoundland Power's deferred pension costs from 2020 through 2023F.

Table 2
Deferred Pension Costs
2020-2023F
($000s)

	2020	2021	2022F	2023F
Deferred Pension Costs, January 1st	91,824	89,900	88,888	95,109
Pension Plan Funding	2,838	2,764	2,730	2,609
Pension Plan Expense	(4,762)	(3,776)	3,491	4,412
Deferred Pension Costs, December 31st	89,900	88,888	95,109	102,130

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.

There were no amendments to the credit facility in 2020. The balance as of December 31, 2021, includes the unamortized credit facility issue costs related to the 2018 and 2019 amendments as these costs had not been reflected in the Company's revenue requirements for 2020 or 2021.[2]

1 Deferred pension costs were approved for inclusion in average rate base in Order No. P.U. 19 (2003).

2 In August 2018, the maturity date of the committed credit facility was extended to August 2023 at a cost of $40,000 to be amortized over the five-year life of the agreement, beginning in 2018. In August 2019, the maturity date of the committed credit facility was extended to August 2024 at a cost of $35,000 to be amortized over the five-year life of the agreement, beginning in 2019.

In August 2021, the committed credit facility was renegotiated to extend its maturity date to August 2026. Costs related to this amendment totalled $71,000 and are being amortized over the five-year life of the agreement, beginning in 2021.

In the *2022/2023 General Rate Application*, the unamortized credit facility issue costs of $31,000 for the 2018 and 2019 amendments were included as a component of the Company's cost of capital for revenue requirement purposes in 2022 and 2023. As these costs are now reflected in customer rates, they are not included in rate base for those years.

The unamortized credit facility issue costs associated with the 2021 credit facility amendments are included in rate base for 2021, 2022 and 2023 as these costs have not yet been reflected in the Company's revenue requirements.

Table 3 provides details of Newfoundland Power's amortization of deferred credit facility issue costs from 2020 through 2023F.

Table 3
Credit Facility Costs
2020-2023F
($000s)

	2020	2021	2022F	2023F
Balance, January 1st	61	46	96	51
Cost – Reduction	-	-	(31)	-
Cost – Addition	-	71	-	-
Amortization	(15)	(21)	(14)	(14)
Balance, December 31st	46	96	51	37

2.4 Cost Recovery Deferral – Hearing Costs

In Order No. P.U. 2 (2019), the Board approved hearing costs of up to $1.0 million related to the Company's *2019/2020 General Rate Application* to be recovered in customer rates over the period March 1, 2019 to December 31, 2021.[3]

[3] In Order No. P.U. 3 (2022), the Board approved the recovery of actual hearing costs related to the Company's *2022/2023 General Rate Application* directly through the Rate Stabilization Account ("RSA").

Table 4 provides details of the changes in Newfoundland Power's deferred hearing costs from 2020 through 2023F.[4]

Table 4
Cost Recovery Deferral - Hearing Costs
2020-2023F
($000s)

	2020	2021	2022F	2023F
Balance, January 1st	494	247	-	-
Amortization	(247)	(247)	-	-
Balance, December 31st	247	-	-	-

2.5 Cost Recovery Deferral – Conservation

In Order No. P.U. 13 (2013), the Board approved the deferral of annual customer energy conservation program costs and the amortization of annual costs over seven years, with recovery through the 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.

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 5 provides details of the forecast amortizations of the deferred cost recovery related to conservation from 2020 through 2023F.

Table 5
Cost Recovery Deferral – Conservation
2020-2023F
($000s)

	2020	2021	2022F	2023F
Balance, January 1st	17,371	17,049	16,421	20,407
Implementation True-Up[5]	-	-	1,875	-
Cost	3,583	3,494	4,708	4,955
Amortization	(3,905)	(4,122)	(2,597)	(3,068)
Balance, December 31st	17,049	16,421	20,407	22,294

2.6 Cost Recovery Deferral – Pension Capitalization

In Order No. P.U. 3 (2022), the Board approved: (i) revisions to the Company's calculation of its General Expenses Capitalized ("GEC"); (ii) the establishment of a Pension Capitalization Cost Deferral Account; and (iii) the deferral of $1.427 million ($0.999 million after-tax) with recovery through the RSA over a five-year period commencing January 1, 2023.

[5] Implementation of Order No. P.U. 3 (2022) resulted in revised balances for annual deferred customer energy conservation program costs incurred up to December 31, 2021.

Table 6 provides details of the forecast amortizations of the deferred cost recovery related to Pension Capitalization from 2020 through 2023F.

Table 6
Cost Recovery Deferral – Pension Capitalization
2020-2023F
($000s)

	2020	2021	2022F	2023F
Balance, January 1st	-	-	-	-
Cost	-	-	-	999
Amortization	-	-	-	(200)
Balance, December 31st	-	-	-	799

2.7 Cost Recovery Deferral – 2022 Revenue Shortfall

The Board's disposition of Newfoundland Power's *2022/2023 General Rate Application* in Order No. P.U. 3 (2022) resulted in a $0.93 million ($0.65 million after-tax) shortfall in the recovery of the revenue requirements for 2022 (the "2022 Revenue Shortfall"). The Order approved the recovery of this shortfall through a regulatory amortization beginning on March 1, 2022 and ending December 31, 2024.

Table 7 provides details of the forecast amortizations of the deferred cost recovery related to the 2022 Revenue Shortfall from 2020 through 2023F.

Table 7
Cost Recovery Deferral – 2022 Revenue Shortfall
2020-2023F
($000s)

	2020	2021	2022F	2023F
Balance, January 1st	-	-	-	460
Cost	-	-	651	-
Amortization	-	-	(191)	(230)
Balance, December 31st	-	-	460	230

2.8 Customer Finance Programs

Customer finance programs are loans provided to customers for the purchase and installation of products and services related to conservation programs and contributions in aid of construction ("CIAC").

Table 8 provides details of changes to balances related to customer finance programs from 2020 through 2023F.

Table 8
Customer Finance Programs
2020-2023F
($000s)

	2020	2021	2022F	2023F
Balance, January 1st	2,494	2,098	1,755	1,789
Change	(396)	(343)	34	12
Balance, December 31st	2,098	1,755	1,789	1,801

2.9 Demand Management Incentive Account

In Order No. P.U. 32 (2007), the Board approved the Demand Management Incentive Account (the "DMI Account") to replace the Purchase Power Unit Cost Variance Reserve.

Table 9 provides details of the DMI Account from 2020 through 2023F.

Table 9
DMI Account
2020-2023F
($000s)

	2020	2021	2022F	2023F
Balance, January 1st	1,881	1,002	1,342	-
Transfers to the RSA	(1,881)	(1,002)	(1,342)	-
Operation of DMI	1,002	1,342	-	-
Balance, December 31st	1,002	1,342	-	-

The disposition of the December 31, 2021 balance in the DMI Account to the RSA as of March 31, 2022 was approved in Order No. P.U. 10 (2022).

3.0 DEDUCTIONS FROM RATE BASE

3.1 Summary

Table 10 summarizes Newfoundland Power's deductions from rate base for 2020 and 2021, and the Company's forecasts for 2022 and 2023.

Table 10
Deductions from Rate Base
2020-2023F
($000s)

	2020	2021	2022F	2023F
Other Post Employment Benefits ("OPEBs")	66,739	73,566	78,930	84,183
Customer Security Deposits	1,212	1,401	1,401	1,401
Accrued Pension Obligation	5,258	5,168	5,289	5,468
Accumulated Deferred Income Taxes	12,683	15,976	18,767	32,054
Weather Normalization Reserve	3,734	2,020	6,904	-
2019 Revenue Surplus	613	-	-	-
Total Deductions	90,239	98,131	111,291	123,106

Deductions from rate base were approximately $98.1 million in 2021. Newfoundland Power's total deductions from rate base in 2021 were approximately $7.9 million higher than 2020.

The increased deductions from rate base were primarily due to: (i) the increase in the OPEBs liability which reflects the amortization of the OPEBs regulatory asset,[6] and (ii) an increase in accumulated deferred income taxes which reflects continued investment in the electricity system and the impact of actuarial results on the Company's employee future benefits. Increases are partially offset by a lower weather normalization reserve and the conclusion of a regulatory amortization for the 2019 Revenue Surplus related to the *2019/2020 General Rate Application*.

This section outlines the deductions from rate base in further detail.

[6] In Order No. P.U. 31 (2010), the Board approved, beginning in 2011, the adoption of the accrual method of accounting for OPEBs and related income tax. In addition, the Board approved a 15-year straight line amortization of a transitional balance starting in 2011.

3.2 Other Post Employment Benefits

Newfoundland Power's OPEBs are comprised of retirement allowances for retiring employees, as well as health, medical and life insurance for retirees and their dependents.

Table 11 provides details of the changes related to the net OPEBs liability from 2020 through 2023F.

Table 11
Other Post Employment Benefits
2020-2023F
($000s)

	2020	2021	2022F	2023F
Regulatory Asset	17,520	14,016	10,512	7,008
OPEBs Liability	84,259	87,582	89,442	91,191
Net OPEBs Liability	66,739	73,566	78,930	84,183

3.3 Customer Security Deposits

Customer security deposits are provided by customers in accordance with the *Schedule of Rates, Rules and Regulations*.

Table 12 provides details on the changes in customer security deposits from 2020 through 2023F.

Table 12
Customer Security Deposits
2020-2023F
($000s)

	2020	2021	2022F	2023F
Balance, January 1st	1,420	1,212	1,401	1,401
Change	(208)	189	-	-
Balance, December 31st	1,212	1,401	1,401	1,401

3.4 Accrued Pension Obligation

Accrued pension obligation is the cumulative costs of Newfoundland Power's unfunded pension plans net of associated benefit payments.

Table 13 provides details of changes related to accrued pension obligation from 2020 through 2023F.

Table 13
Accrued Pension Obligation
2020-2023F
($000s)

	2020	2021	2022F	2023F
Balance, January 1st	5,104	5,258	5,168	5,289
Change	154	(90)	121	179
Balance, December 31st	5,258	5,168	5,289	5,468

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.[7,8,9]

7 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.

8 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.

9 In Order No. P.U. 31 (2010), the Board approved the use of Tax Accrual Accounting to recognize deferred income taxes related to timing differences between other employee future benefits recognized for tax purposes (cash payments) and other employee future benefit expense recognized for accounting purposes (accrual basis).

Table 14 provides details of changes in the accumulated deferred income taxes from 2020 through 2023F.

Table 14
Accumulated Deferred Income Taxes
2020-2023F
($000s)

	2020	2021	2022F	2023F
Balance, January 1st	10,088	12,683	15,976	18,767
Change	2,595	3,293	2,791	13,287
Balance, December 31st	12,683	15,976	18,767	32,054

3.6 Weather Normalization Reserve

In Order No. P.U. 1 (1974), the Board ordered that rate base be adjusted for the balance in the Weather Normalization Reserve.

Table 15 provides details of changes in the balance of the Weather Normalization Reserve from 2020 through 2023F.

Table 15
Weather Normalization Reserve
2020-2023F
($000s)

	2020	2021	2022F	2023F
Balance, January 1st	(5,654)	3,734	2,020	6,904
Operation of the reserve	3,734	2,020	6,904	-
Transfers to the RSA	5,654	(3,734)	(2,020)	(6,904)
Balance, December 31st	3,734	2,020	6,904	-

The disposition of the December 31, 2021 balance in the Weather Normalization Reserve account to the RSA as of March 31, 2022 was approved by the Board in Order No. P.U. 11 (2022).

3.7 2019 Revenue Surplus

The Board's disposition of Newfoundland Power's *2019/2020 General Rate Application* in Order No. P.U. 2 (2019) resulted in a $2.5 million ($1.7 million after-tax) surplus in the recovery of the revenue requirements for 2019 (the "2019 Revenue Surplus"). The Order provided for credit of the 2019 Revenue Surplus through a regulatory amortization beginning on March 1, 2019 and ending December 31, 2021.

Table 16 provides details on the 2019 revenue surplus amortization from 2020 through 2023F.

Table 16
2019 Revenue Surplus
2020-2023F
($000s)

	2020	2021	2022F	2023F
Balance, January 1st	1,226	613	-	-
Credit	-	-	-	-
Amortization	(613)	(613)	-	-
Balance, December 31st	613	-	-	-

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 17 provides details on changes in the cash working capital allowance from 2020 through 2023F.

Table 17
Rate Base Allowances
Cash Working Capital Allowance[10]
2020-2023F
($000s)

	2020	2021	2022F	2023F
Gross Operating Costs	541,367	534,377	547,173	546,371
Income Taxes	17,004	10,714	12,670	(1,694)
Municipal Taxes Paid	18,092	18,332	18,427	18,328
Non-Regulated Expenses	(2,892)	(2,521)	(2,283)	(2,242)
Total Operating Expenses	573,571	560,902	575,987	560,763
Cash Working Capital Factor	1.789%	1.789%	1.138%	1.199%
	10,261	10,035	6,557	6,725
HST Adjustment	242	242	41	20
Cash Working Capital Allowance	10,503	10,277	6,598	6,745

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.[11]

[10] The cash working capital allowance for 2020 through 2021 is calculated based on the method used to calculate the 2019/2020 Test Year average rate base approved by the Board in Order No. P.U. 2 (2019). The cash working capital allowance for 2022F through 2023F is calculated based on the method used to calculate the 2022/2023 Test Year average rate base approved by the Board in Order No. P.U. 3 (2022).

[11] 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 18 provides details on changes in the materials and supplies allowance from 2020 through 2023F.

Table 18
Rate Base Allowances
Materials and Supplies Allowance
2020-2023F
($000s)

	2020	2021	2022F	2023F
Average Materials and Supplies	9,572	10,979	12,170	11,239
Expansion Factor[12]	24.05%	24.05%	19.08%	19.08%
Expansion	2,302	2,640	2,322	2,144
Materials and Supplies Allowance	7,270	8,339	9,848	9,095

12 The expansion factor is based on a review of actual inventories used for expansion projects. The calculation of the 2020 through 2021 rate base, including a materials and supplies allowance based upon an expansion factor of 24.05%, was approved by the Board in Order No. P.U. 2 (2019). The calculation of the 2022F through 2023F rate base, including a materials and supplies allowance based upon an expansion factor of 19.08%, was approved by the Board in Order No. P.U. 3 (2022).