WHENEVER. WHEREVER.
We'll be there.

June 22, 2023

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 2024 Capital Budget Application**

Enclosed are the original and 10 copies of Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") *2024 Capital Budget Application* (the "Application").

The Application seeks an order approving the Company's proposed 2024 capital budget and fixing and determining Newfoundland Power's average rate base for 2022.

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

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

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

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

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

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

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

Yours truly,

Dominic Foley

Dominic Foley
Legal Counsel

Enclosures

cc. Shirley Walsh
Newfoundland and Labrador Hydro

Dennis Browne, K.C.
Browne Fitzgerald Morgan & Avis

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

# Newfoundland Power Inc.
# 2024 Capital Budget Application

## Table of Contents

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

**IN THE MATTER OF** an application by Newfoundland Power Inc. for an order pursuant to sections 41 and 78 of the Act:
(a) approving its 2024 Capital Budget; and
(b) fixing and determining its 2022 rate base.

# 2024 Capital Budget Application

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

**IN THE MATTER OF** an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:
(a) approving its 2024 Capital Budget; and
(b) fixing and determining its 2022 rate base.

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

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

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

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

   (a) proposed single-year 2024 capital expenditures in the amount of $84,583,000 comprising projects and programs costing in excess of $750,000;

   (b) proposed single-year 2024 capital expenditures of $10,514,000 comprising projects and programs costing $750,000 and under;

   (c) proposed multi-year projects commencing in 2024 with capital expenditures of $5,234,000 in 2024, $19,414,000 in 2025 and $297,000 in 2026; and

   (d) ongoing multi-year projects previously approved in Order No. P.U. 36 (2021) and Order No. P.U. 38 (2022) with capital expenditures of $14,921,000 in 2024 (the "Previously Approved Multi-Year Projects").

3. The proposed 2024 Capital Budget includes contributions toward the cost of improvements or additions to property that Newfoundland Power intends to demand from its customers in 2024 including an estimated amount of $2,500,000 in contributions in aid of construction which shall be calculated in a manner approved by the Board.

4. There has been no change in the scope, nature, or magnitude of the Previously Approved Multi-Year Projects.

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

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

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

8. Schedule D to this Application shows Newfoundland Power's actual average rate base for 2022 of $1,230,434,000.

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

   (a) pursuant to section 41 of the Act, approving Newfoundland Power's proposed construction and purchase of improvements or additions to its property to be completed in 2024 in the amount of $115,252,000 as set out in Schedules A, B and C to this Application comprising:

      i. single-year project and program expenditures in excess of $750,000 in the amount of $84,583,000;
      ii. single-year project and program expenditures $750,000 and under in the amount of $10,514,000;
      iii. multi-year programs with 2024 expenditures of $5,234,000; and
      iv. previously approved multi-year projects with 2024 expenditures of $14,921,000.

   (b) pursuant to section 41 of the Act, approving Newfoundland Power's proposed multi-year construction and purchase of improvements or additions to its property for future years in the amount of $19,414,000 in 2025 and $297,000 in 2026 as set out in Schedules A and B to this Application; and

   (c) pursuant to section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2022 in the amount of $1,230,434,000 as set out in Schedule D to this Application.

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

**DATED** at St. John's, Newfoundland and Labrador, this 22nd day of June, 2023.

**NEWFOUNDLAND POWER INC.**

Dominic Foley

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

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

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

**IN THE MATTER OF** 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 its 2024 Capital Budget; and
(b) fixing and determining its 2022 rate base.

**AFFIDAVIT**

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

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

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

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 22nd day of June, 2023:

Dominic Foley

Barrister, NL

Byron Chubbs

## 2024 CAPITAL BUDGET SUMMARY

| Expenditure Type | Budget ($000s) |
|---|---|
| Single-Year Projects and Programs Over $750,000 | 84,583 |
| Single-Year Projects and Programs $750,000 and Under | 10,514 |
| Multi-Year Projects Commencing in 2024 | 5,234 |
| Multi-Year Projects Approved in Previous Years | 14,921 |
| **Total** | **$ 115,252** |

| Asset Class | Budget ($000s) |
|---|---|
| Distribution | 55,865 |
| Substations | 20,605 |
| Transmission | 15,064 |
| Generation - Hydro | 5,329 |
| Generation - Thermal | 311 |
| Information Systems | 6,180 |
| Telecommunications | 502 |
| General Property | 2,340 |
| Transportation | 3,806 |
| Unforeseen Allowance | 750 |
| General Expenses Capitalized | 4,500 |
| **Total** | **$ 115,252** |

**2024 CAPITAL BUDGET**

**SINGLE-YEAR PROJECTS AND PROGRAMS**

**OVER $750,000**

| Projects and Programs | Budget ($000s) |
|---|---|
| **Distribution** | |
| LED Street Lighting Replacement | 5,541 |
| Feeder Additions for Load Growth | 2,811 |
| Distribution Reliability Initiative | 900 |
| Distribution Feeder Automation | 888 |
| Distribution Feeder OXP-01 Refurbishment | 840 |
| Extensions | 12,140 |
| Reconstruction | 6,953 |
| Rebuild Distribution Lines | 4,974 |
| Relocate/Replace Distribution Lines for Third Parties | 4,066 |
| Replacement Transformers | 3,681 |
| New Transformers | 3,264 |
| New Services | 2,847 |
| New Street Lighting | 2,629 |
| Replacement Street Lighting | 863 |
| ***Total Distribution*** | **$52,397** |
| **Substations** | |
| Gambo Substation Refurbishment and Modernization | 5,267 |
| Memorial Substation Refurbishment and Modernization | 4,351 |
| Old Perlican Substation Refurbishment and Modernization | 3,356 |
| Substation Replacements Due to In-Service Failures | 4,797 |
| ***Total Substations*** | **$17,771** |
| **Transmission** | |
| Transmission Line Maintenance | 2,651 |
| ***Total Transmission*** | **$2,651** |

**2024 CAPITAL BUDGET**

**SINGLE-YEAR PROJECTS AND PROGRAMS**

**OVER $750,000**

| Projects and Programs | Budget ($000s) |
|---|---|
| **Generation - Hydro** | |
| Mobile Hydro Plant Surge Tank Refurbishment | 977 |
| Hydro Facility Rehabilitation | 794 |
| ***Total Generation - Hydro*** | **$1,771** |
| **Information Systems** | |
| Application Enhancements | 1,892 |
| Shared Server Infrastructure | 964 |
| System Upgrades | 957 |
| Cybersecurity Upgrades | 930 |
| ***Total Information Systems*** | **$4,743** |
| **General Expenses Capitalized** | |
| General Expenses Capitalized | 4,500 |
| ***Total General Expenses Capitalized*** | **$4,500** |
| **Unforeseen Allowance** | |
| Allowance for Unforeseen Items[1] | 750 |
| ***Total Unforeseen Allowance*** | **$750** |
| **Total** | **$84,583** |

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

## 2024 CAPITAL BUDGET

## SINGLE-YEAR PROJECTS AND PROGRAMS

## $750,000 AND UNDER

| Projects and Programs | Budget ($000s) |
|---|---|
| **Distribution** | |
| Distribution Feeder GDL-02 Refurbishment | 667 |
| Allowance for Funds Used During Construction | 260 |
| Distribution Feeder BIG-02 Relocation | 196 |
| Replacement Meters | 571 |
| Replacement Services | 457 |
| New Meters | 302 |
| ***Total Distribution*** | **$2,453** |
| **Substations** | |
| Substation Ground Grid Upgrades | 580 |
| PCB Removal | 544 |
| Oxen Pond Substation Bus Upgrade | 451 |
| Oxen Pond Substation Switch Replacements | 316 |
| Substation Protection and Control Replacements | 635 |
| ***Total Substations*** | **$2,526** |
| **Transmission** | |
| Transmission Line 24L Relocation | 701 |
| ***Total Transmission*** | **$701** |
| **Generation - Hydro** | |
| Hydro Plant Replacements Due to In-Service Failures | 716 |
| ***Total Generation - Hydro*** | **$716** |
| **Generation - Thermal** | |
| Thermal Plant Replacements Due to In-Service Failures | 311 |
| ***Total Generation - Thermal*** | **$311** |

## 2024 CAPITAL BUDGET

## SINGLE-YEAR PROJECTS AND PROGRAMS

## $750,000 AND UNDER

| Projects and Programs | Budget ($000s) |
|---|---|
| **Information Systems** | |
| Network Infrastructure | 420 |
| Personal Computer Infrastructure | 720 |
| ***Total Information Systems*** | **$1,140** |
| **Telecommunications** | |
| Fibre Optic Cable Build | 380 |
| Communications Equipment Upgrades | 122 |
| ***Total Telecommunications*** | **$502** |
| **General Property** | |
| Energized Conductor Support Tools | 539 |
| Additions to Real Property | 655 |
| Tools and Equipment | 570 |
| Physical Security Upgrades | 401 |
| ***Total General Property*** | **$2,165** |
| **Total** | **$10,514** |

## 2024 CAPITAL BUDGET

## MULTI-YEAR PROJECTS

### Multi-Year Projects Commencing in 2024

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

### Multi-Year Projects Approved in Previous Years

| Class | Project Description | 2022 | 2023 | 2024 | Total |
|---|---|---|---|---|---|
| Distribution | Distribution Reliability Initiative (SUM-01)[2] | - | 656 | 1,015 | 1,671 |
| Transmission | Transmission Line 94L Rebuild[3] | 4,473 | 4,346 | 4,276 | 13,095 |
| Transmission | Transmission Line 55L Rebuild[4] | - | 5,328 | 5,284 | 10,612 |
| Generation - Hydro | Mobile Hydro Plant Refurbishment[5] | - | 1,666 | 2,480 | 4,146 |
| Transportation | Replace Vehicles and Aerial Devices 2023-2024[6] | - | 2,833 | 1,866 | 4,699 |
| | **Total** | **$4,473** | **$14,829** | **$14,921** | **$34,223** |

2 Approved in Order No. P.U. 38 (2022). See the *2023 Capital Budget Application*, Schedule B, pages 8 to 11.
3 Approved in Order No. P.U. 36 (2021). See the *2022 Capital Budget Application*, Schedule B, pages 18 to 20.
4 Approved in Order No. P.U. 38 (2022). See the *2023 Capital Budget Application*, Schedule B, pages 105 to 107.
5 Approved in Order No. P.U. 38 (2022). See the *2023 Capital Budget Application*, Schedule B, pages 114 to 117.
6 Approved in Order No. P.U. 38 (2022). See the *2023 Capital Budget Application*, Schedule B, pages 182 to 186.

# 2024 CAPITAL PROJECTS AND PROGRAMS

# OVER $750,000

## 2024 CAPITAL PROJECTS AND PROGRAMS OVER $750,000

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

The Provisional Guidelines require capital expenditures to be organized by:

***(i) Investment Classification***

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

***(ii) Category***

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

***(iii) Materiality***

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

Schedule B to the Application details the capital expenditures proposed for 2024, including the investment classification, category and "all in" capital cost of each proposed expenditure. Expenditures are grouped by asset class. Within each asset class, projects are presented first followed by programs. Both projects and programs are ordered from the highest materiality segment to the lowest.

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

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

The following provides an overview of the information provided within Schedule B to the Application for each project and program proposed for 2024:

***(i) Project/Program Description***

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

***(ii) Project/Program Budget***

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

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

***(iii) Program Trend***

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

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

***(iv) Asset Background***

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

### *(v) Assessment of Alternatives*

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

### *(vi) Risk Assessment*

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

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

Figure 1 shows the risk matrix.

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

*Figure 1 - Risk Matrix*

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

A detailed description of the risk matrix methodology is provided in Appendix C to the *2024 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.

## 2024 CAPITAL BUDGET

## SCHEDULE B TABLE OF CONTENTS

| Projects and Programs | Page |
|---|---|

**DISTRIBUTION**

| | |
|---|---|
| **Title:** | **LED Street Lighting Replacement** |
| **Asset Class:** | **Distribution** |
| **Category:** | **Project** |
| **Investment Classification:** | **Service Enhancement** |
| **Budget:** | **$5,541,000** |

## 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 2024 represent the fourth year of this plan.[2] Approximately 10,000 street light fixtures are forecast to be replaced with LED fixtures in 2024. 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 2024 for the *LED Street Lighting Replacement* project.

Table 1
LED Street Lighting
Replacement Project
2024 Budget
($000s)

| Cost Category | 2024 |
|---|---|
| Material | $4,052 |
| Labour – Internal | 1,161 |
| Labour – Contract | 328 |
| Engineering | - |
| Other | - |
| Total | $5,541 |

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

2 Expenditures associated with the first three years of the *LED Street Lighting Replacement Plan* were approved by the Board in Order No. P.U. 37 (2020), Order No. P.U. 36 (2021), and Order No. P.U. 38 (2022).

Proposed expenditures for the *LED Street Lighting Replacement* project total $5,541,000 for 2024.

**ASSET BACKGROUND**

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

(i) *Lower overall costs for customers* – The capital cost of installing a LED fixture is approximately twice that of an HPS fixture. However, LED fixtures require 60% less energy to provide equivalent lighting output and require far less maintenance. Current customer rates for LED street lights are between 12% and 44% lower than rates for HPS street lights.[3]

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

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

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

The *LED Street Lighting Replacement Plan* is consistent with current Canadian utility practice and has also received the support of the largest municipal organization in the province, Municipalities Newfoundland and Labrador.[4] In addition to lower overall costs for customers, better lighting quality, and more reliable service, the *LED Street Lighting Replacement Plan* also reduces demand requirements on the provincial electricity system.[5]

**ASSESSMENT OF ALTERNATIVES**

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

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

3 Current rates are reflected in the *Schedule of Rates, Rules and Regulations* effective July 1, 2022.
4 See Newfoundland Power's *2021 Capital Budget Application, Volume 1, LED Street Lighting Replacement Plan*, Appendix A and Appendix D.
5 Ibid, Appendix B, Page B-1. The transition from HPS street lights to LED street lights reduces demand requirements on the Island Interconnected System by 4.0 MW.

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

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

An economic analysis provided as part of Newfoundland Power's *2021 Capital Budget Application* determined that the accelerated approach would reduce energy and maintenance costs to customers by approximately $52 million over 20 years, providing a positive net benefit to customers of approximately $4.9 million.[6]

An updated economic analysis was provided as part of Newfoundland Power's *2023 Capital Budget Application*. The updated analysis showed that the continued execution of the *LED Street Lighting Replacement Plan* continues to be in the best interest of customers.[7]

Without continuing to execute the Company's *LED Street Lighting Replacement Plan*, a maintenance program for HPS street lights would be required and customers would pay the higher rates associated with HPS street lights. Deferring the *LED Street Lighting Replacement* project would result in customers continuing to pay higher rates for street lighting, which would be inconsistent with the provincial power policy.[8]

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

**RISK ASSESSMENT**

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

By continuing to execute the *LED Street Lighting Replacement* project, customers will be provided with the lower rates of LED street lights immediately upon installation. It is estimated that customer rates for approximately 10,000 street lights will be reduced by between 12% and 44% in 2024 by executing this project.

---

6 Ibid., Appendix B.
7 See Order No. P.U. 38 (2022), Page 18, Lines 17-23.
8 See Order No. P.U. 38 (2022), Page 18, Lines 25-27.

Table 2 summarizes the risk assessment of the 2024 *LED Street Lighting Replacement* project.

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

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

**JUSTIFICATION**

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

**Title:** **Feeder Additions for Load Growth**
**Asset Class:** **Distribution**
**Category:** **Project**
**Investment Classification:** **System Growth**
**Budget:** **$2,811,000**

## PROJECT DESCRIPTION

The *Feeder Additions for Load Growth* project involves addressing overload conditions and providing additional capacity to address system load growth. For 2024, the *Feeder Additions for Load Growth* proposed project includes:

(i) A section of Bayview ("BVS") Substation distribution feeder BVS-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 and service upgrades in the areas of Pinchgut Lake, Georges Lake, Spruce Brook, and Gallants. The cost of completing the required upgrades is $1,736,000.

(ii) A section of Oxen Pond ("OXP") Substation distribution feeder OXP-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 and service upgrades in the area of Groves Road. The cost of completing the required upgrades is $470,000.

(iii) A section of Pulpit Rock ("PUL") Substation distribution feeder PUL-02 will be upgraded from single-phase to three-phase to address an overload condition that has developed as a result of customer connection growth and service upgrades in the area of Pouch Cove Line. The cost of completing the required upgrades is $605,000.

Design work for the *Feeder Additions for Load Growth* project will be completed in the first quarter of 2024. Construction will begin in the second quarter and will be completed by the end of the fourth quarter of 2024.

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 2024 for the *Feeder Additions for Load Growth* project.

Table 1
Feeder Additions for Load Growth Project
2024 Budget
($000s)

| Cost Category | 2024 |
|---|---|
| Material | 540 |
| Labour – Internal | 753 |
| Labour – Contract | 725 |
| Engineering | 277 |
| Other | 516 |
| Total | $2,811 |

Proposed expenditures for the *Feeder Additions for Load Growth* project total $2,811,000 for 2024.

**ASSET BACKGROUND**

Distribution feeder BVS-04 serves approximately 1,660 customers west of the Corner Brook city limits. A 11.0-kilometre section of distribution feeder extending along Pinchgut Lake, Georges Lake, Spruce Brook, and Gallants is overloaded. Load growth on this single-phase line can be attributed to customer connection growth and electrical service upgrades in the area. The number of customers supplied by this single-phase line has increased by 49% over the last 15 years.

Distribution feeder OXP-01 serves approximately 1,290 customers in the St. John's area. A 1.5-kilometre section of distribution feeder on Groves Road is overloaded. Load growth on this single-phase line can be attributed to customer connection growth along Groves Road and electrical service upgrades in the area. The number of customers supplied by this single-phase line has increased by 64% over the last 15 years.

Distribution feeder PUL-02 serves approximately 1,900 customers in the Flatrock and Pouch Cove area. A 2.5-kilometre section of distribution feeder along Pouch Cove Line is overloaded. Load growth on this single-phase line can be attributed to customer connection growth, as well as electrical service upgrades in the area. The number of customers supplied by this single-phase line has increased by 112% over the last 15 years.

**ASSESSMENT OF ALTERNATIVES**

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

*BVS-04*

An 11.0-kilometre section of distribution feeder BVS-04 is overloaded. Three categories of alternatives that are generally available to address overloaded conductor are not applicable to BVS-04. Feeder balancing is not applicable as the identified section of BVS-04 is single phase. A load transfer is not applicable as there is no adjacent feeder. A new feeder build is not feasible due to the magnitude of the associated costs. As a result, the alternatives evaluated to mitigate the overloaded section of distribution feeder BVS-04 include: (i) upgrading the overloaded section of feeder from single-phase to three-phase; and (ii) a non-wires alternative.

The capital cost of the alternative to upgrade the 11.0-kilometre section of BVS-04 from single-phase to three-phase to resolve the overload condition is estimated to be $1,736,000. The non-wires alternative would utilize commercial-grade battery storage technology to provide capacity to alleviate the overload condition during peak load conditions. A preliminary capital cost estimate for the procurement of a battery storage solution for this application is approximately $2,092,000.[9] This does not include engineering, land procurement, site preparation, battery system installation or interconnection to the distribution system.

Of the technically viable alternatives considered, upgrading the overloaded section of distribution feeder BVS-04 from single-phase to three-phase is least cost. This is therefore the recommended alternative to address the identified overload condition.

*OXP-01*

A 1.5-kilometre section of distribution feeder on Groves Road is overloaded. Three categories of alternatives that are generally available to address overloaded conductor are not applicable to OXP-01. Feeder balancing is not applicable as the identified section of OXP-01 is single phase. A load transfer is not feasible as there is no adjacent feeder. A new feeder build is not appicable due to the magnitude of the associated costs. As a result, the alternatives evaluated to mitigate the overloaded section of distribution feeder OXP-01 include: (i) upgrading the overloaded section of feeder from single-phase to three-phase; (ii) upgrading the feeder by building a new three-phase section; and (iii) a non-wires alternative.

The capital cost of the alternative to upgrade the 1.5-kilometre section of OXP-01 from single-phase to three-phase to resolve the overload condition is estimated to be $470,000. This would

[9] Based on current battery storage costs of $427/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 $2,092,000.

include replacing substandard #4 Copper conductor and 23 deteriorated poles that require replacement.

The alternative of constructing a new three-phase section of distribution feeder was also assessed. This alternative would involve reducing the load on the overloaded single-phase section of distibution feeder by constructing a new section of three-phase line between Thorburn Road and Groves Road, as well as an additional single-phase to three-phase upgrade to span across the Trans-Canada Highway into Groves Road. Capital costs associated with this alternative are estimated to be $401,000 in 2024 to construct a new three-phase section of distribution feeder and $120,000 in 2025 to correct identified deficiencies along Groves Road.

The non-wires alternative would utilize commercial-grade battery storage technology to provide capacity to alleviate the overload condition during peak load conditions. A preliminary capital cost estimate for the procurement of a battery storage solution for this application is approximately $1.4 million.[10] This does not include engineering, land procurement, site preparation, battery system installation or interconnection to the distribution system.

Of the technically viable alternatives considered, upgrading the overloaded section of distribution feeder OXP-01 from single-phase to three-phase is least cost. This is therefore the recommended alternative to address the identified overload condition.

*PUL-02*

A 2.5-kilometre section of distribution feeder along Pouch Cove Line is overloaded. Two categories of alternatives that are generally available to address overloaded conductor are not applicable to PUL-02. Feeder balancing is not applicable as the identified section of PUL-02 is single phase. A new feeder build is not feasible due to the magnitude of the associated costs. As a result, the alternatives evaluated to mitigate the overloaded section of distribution feeder PUL-02 include: (i) a load transfer; (ii) upgrading from single-phase to three-phase; and (iii) a non-wires alternative.

The load transfer alternative would involve transfering load from distribution feeder PUL-02 to PUL-03, and would require upgrading 7.8 kilometres of PUL-03 from single-phase to three-phase along Pouch Cove Line. In addition, a new 2.1-kilometre section of three-phase distribution line would be required to connect the overloaded section of distribution feeder PUL-02 to PUL-03. The capital cost of this alternative is estimated to be $1,270,000.

The single-phase to three-phase upgrade alternative would involve an upgrade of a 2.5-kilometre section of PUL-02 from along Pouch Cove Line. The capital cost of this alternative to resolve the overload condition is estimated to be $605,000.

A non-wires alternative would utilize commercial-grade battery storage technology to provide capacity to alleviate the overload condition during peak load conditions. A preliminary capital cost estimate for the procurement of a battery storage solution for this application is

[10] Based on current battery storage costs of $427/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 $1,409,000.

approximately $922,000.[11] This does not include engineering, land procurement, site preparation, battery system installation or interconnection to the distribution system.

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

**JUSTIFICATION**

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

[11] Based on current battery storage costs of $427/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 $922,000.

| | |
|---|---|
| **Title:** | **Distribution Reliability Initiative** |
| **Asset Class:** | **Distribution** |
| **Category:** | **Project** |
| **Investment Classification:** | **Renewal** |
| **Budget:** | **$900,000** |

**PROJECT DESCRIPTION**

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

Newfoundland Power proposes the relocation of a 4.8-kilometre section of Western Avalon ("WAV") Substation distribution feeder WAV-01 in 2024, which will include:

(i) Constructing 6.5-kilometres of new three-phase distribution line along Route 201; and

(ii) Replacing poles and installing midspan structures as required.

This project is proposed to be completed in 2024, with design and procurement completed by the second quarter, and construction completed by the end of the fourth quarter.

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* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2024 for the *Distribution Reliability Initiative* project.

| Table 1<br>Distribution Reliability Initiative Project<br>2024 Budget<br>($000s) | |
|---|---|
| Cost Category | 2024 |
| Material | 193 |
| Labour – Internal | 146 |
| Labour – Contract | 204 |
| Engineering | 127 |
| Other | 230 |
| Total | $900 |

Proposed expenditures for the *Distribution Reliability Initiative* total $900,000 for 2024.

**ASSET BACKGROUND**

Newfoundland Power has been implementing the *Distribution Reliability Initiative* for over 20 years. Projects proposed as part of the *Distribution Reliability Initiative* are determined by: (i) calculating reliability performance indices for all distribution feeders; (ii) analyzing the worst performing feeders and feeder sections to identify the cause of the poor reliability performance; and (iii) completing engineering assessments to determine whether capital improvements would address a feeder's poor reliability performance. The Company's approach to targeting its worst performing feeders for capital improvements is consistent with good utility practice.

Distribution feeder WAV-01 extends from the Chapel Arm area running along Route 201 towards Chance Cove, branching to the communities of Bellevue and Fairhaven. This feeder currently serves approximately 1,300 customers. Outage Management System data for distribution feeder WAV-01 shows that the majority of outage minutes on this feeder are on a specific 4.8-kilometre cross country section of the distribution feeder beyond downline recloser WAV-01-R2, from Long Cove towards Thornlea. Long duration outages on this section are primarily due to equipment failures and tree contacts. The reliability performance experienced by the 658 customers served by this section of WAV-01 feeder has been considerably worse than Newfoundland Power's corporate average over the last three years.

An engineering assessment of the 4.8-kilometre section of WAV-01 feeder has identified that the factors contributing to poor reliability performance are: (i) corroded or damaged conductor; (ii) danger tree contacts;[12] (iii) deteriorated poles, crossarms and insulators; and (iv) inaccessibility of the line. This section of the feeder was originally constructed in the 1960s with #2 Aluminum Conductor Steel Reinforced ("ACSR") conductor. The Company has experienced issues with this particular conductor in the past, as oxidation between the steel core and aluminum outer strands is known to occur. The oxidation is particularly prevalent in coastal environments in which frequent salt spray occurs.

**ASSESSMENT OF ALTERNATIVES**

The 658 customers supplied by the identified 4.8-kilometre section of WAV-01 feeder are experiencing significantly worse reliability compared to the average reliability experienced by Newfoundland Power's customers.[13] An engineering assessment of the identified section of distribution feeder WAV-01 identified the factors contributing to its poor reliability performance are: (i) corroded or damaged conductor; (ii) danger tree contacts; (iii) deteriorated poles, crossarms and insulators; and (iv) inaccessibility of the line.

Newfoundland Power identified and evaluated two alternatives with respect to distribution feeder WAV-01: (i) rebuild the existing 4.8-kilometre section of line in the existing right-of-way; and (ii) relocate the existing 4.8-kilometre section of line to the roadside of Route 201.

The assessment determined that relocating the existing 4.8-kilometre section of line is the least cost alternative to address the poor service reliability experienced by customers supplied from this section of WAV-01 feeder. Additionally, relocating this section of distribution feeder to the roadside of Route 201 will improve access to the line during outage response activities and will improve the efficiency of preventive maintenance and inspection activities.

Relocation of the existing 4.8-kilometre section of distribution feeder WAV-01 to the roadside of Route 201 is therefore the recommended alternative.

---

12 A "Danger Tree" is defined in Newfoundland Power's vegetation management specification as a standing tree, either live or dead, having visible defects, singly or combined, which predisposes it to mechanical failure in whole or in part (whether on its own or from the effects of a storm or disturbance), and which is so located that such a failure has a probability of contacting, or coming in close proximity to, a live electrical conductor. Also, a danger tree is a living, healthy tree that, once cut, has the potential to contact, or come in close proximity to, a live electrical conductor.

13 This 4.8-kilometre section comprises less than 5% of the total length of distribution feeder WAV-01.

## RISK ASSESSMENT

The *Distribution Reliability Initiative* will mitigate risks to the delivery of reliable service to customers on distribution feeder WAV-01.

A total of 658 customers currently experience poor service reliability due the deteriorated condition of a section of distribution feeder WAV-01 downstream of downline recloser WAV-01-R2. 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.

Table 2 summarizes the risk assessment of the 2024 *Distribution Reliability Initiative* project.

Table 2
Distribution Reliability Initiative Project
Risk Assessment Summary

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

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

## JUSTIFICATION

The *Distribution Reliability Initiative* is required to provide customers with reliable service at the lowest possible cost. The project will address the poor service reliability currently experienced by customers serviced by distribution feeder WAV-01. Customers in this area currently experience service reliability that is significantly below the Company average. The proposed project to relocate a section of distribution feeder WAV-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:** | **$888,000** |

## 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.[14]

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

A total of 13 downline reclosers are planned for installation in 2024. These downline reclosers will be installed under three deployment scenarios[15]:

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

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

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

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

[15] 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 2024 and the associated deployment scenario.

Table 1
2024 Downline Recloser Installations

| Feeders | Number of Devices | Deployment Scenario |
|---|---|---|
| PUL-04 | 1 | Scenario 2 |
| BCV-01 | 1 | Scenario 2 |
| BCV-03 | 1 | Scenario 1 |
| OXP-01 | 1 | Scenario 2 |
| PUL-04/BCV-04 TIE | 1 | Scenario 3 |
| OXP-01/BCV-03 TIE | 1 | Scenario 3 |
| GFS-06/GFS-07 TIE | 1 | Scenario 3 |
| BVA-01 | 1 | Scenario 1 |
| BVA-02 | 1 | Scenario 1 |
| BVA-03 | 1 | Scenario 1 |
| BVA-01/BVA-03 TIE | 1 | Scenario 3 |
| BVA-02/BVA-03 TIE | 2 | Scenario 3 |

Procurement of material is expected to commence in the first quarter of 2024. Design work for this project is expected to be completed by the end of the second quarter of 2024. 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 2024 for the *Distribution Feeder Automation* project.

Table 2
Distribution Feeder Automation Project
2024 Budget
($000s)

| Cost Category | 2024 |
|---|---|
| Material | 451 |
| Labour – Internal | 204 |
| Labour – Contract | 65 |
| Engineering | 74 |
| Other | 94 |
| Total | $888 |

Proposed expenditures for the *Distribution Feeder Automation* project total $888,000 for 2024.

**ASSET BACKGROUND**

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

Newfoundland Power established an approach to increasing automation of its distribution system in report *4.5 Distribution Feeder Automation* included with its *2020 Capital Budget Application*.[16] Automation of the distribution system through the installation of downline reclosers provides operational benefits during customer outages, particularly major events.

Because downline reclosers are operated remotely, field crews can focus on restoring service to customers. Restoration efforts are also more efficient as the sectionalizing of feeders means portions no longer need to be patrolled to identify the cause and location of outages.[17] A more efficient response to customer outages improves restoration times and decreases costs to customers.

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

16 There are 132 automated downline reclosers in the Company's service territory as of June 2023.
17 Given the size of Newfoundland Power's service territory, long drives to identify the cause of outages are not uncommon. Reducing the length of distribution feeder to be patrolled reduces the time necessary to locate faults and provides cost benefits to customers.

The operational benefits of downline reclosers are most pronounced during major events.[18] For example, the operation of five downline reclosers during a severe blizzard in January 2020 avoided approximately 3.5 million customer outage minutes without the assistance of field crews. This allowed field crews to focus on restoring service to customers who were affected by the blizzard. The operation of 12 downline reclosers during Hurricane Larry in September 2021 avoided approximately 3.8 million customer outage minutes, allowing field crews to focus on restoration efforts for customers who were affected by the storm. The operation of six downline reclosers during Hurricane Fiona on the west coast in September 2022 avoided approximately 1.7 million customer outage minutes.

While most pronounced during severe weather, the benefits of downline reclosers also materialize during normal, day-to-day operations. Reliability benefits are realized on a regular basis as these devices operate in response to equipment failures to restore service to customers.[19] Efficiency benefits are also routinely realized through a reduction in patrol times for feeders.

The 13 downline reclosers to be installed in 2024 will provide operational benefits in responding to customer outages throughout Newfoundland Power's service territory. Six of the 13 devices will be installed on the Northeast Avalon on distribution feeders supplying customers in the St. John's and Portugal Cove-St. Phillips areas. The remainder will be installed in more rural areas of the Company's service territory.[20] These distribution feeders provide service to approximately 10,000 customers.

**RISK ASSESSMENT**

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

Major components on Newfoundland Power's distribution system are aging beyond the industry average expected service lives, including overhead conductor and wooden support structures. Equipment failures on the distribution system are trending upward, with an increase of approximately 34% over the last decade.[21] At the same time, major events due to severe weather are becoming more frequent throughout the Company's service territory.[22]

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

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

[19] For example, the operation of two downline reclosers in December 2021 quickly restored service to 1,600 customers served by Dunville Substation distribution feeder DUN-01 following an equipment failure.

[20] An outage to customers located in more rural areas of the Company's service territory can result in longer response times. This can be a result of the prolonged time to travel to the area, the length of the distribution feeder requiring patrol, and the time required to locate a fault and begin restoration. The installation of downline reclosers in these areas provides operational efficiencies as the sectionalizing of feeders means portions no longer need to be patrolled to identify the cause and location of outages. Reducing the length of distribution feeder to be patrolled reduces the time necessary to locate faults and provides cost benefits.

[21] See the *2024-2028 Capital Plan, Section 2.4 - Asset Condition Outlook.*

[22] See the *2024-2028 Capital Plan, Section 2.3 - Operations Outlook.*

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 2024 *Distribution Feeder Automation* project.

Table 3
Distribution Feeder Automation Project
Risk Assessment Summary

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

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

**JUSTIFICATION**

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

**Title:** **Distribution Feeder OXP-01 Refurbishment**
**Asset Class:** **Distribution**
**Category:** **Project**
**Investment Classification:** **Renewal**
**Budget:** **$840,000**

## PROJECT DESCRIPTION

The *Distribution Feeder OXP-01 Refurbishment* project involves replacing deteriorated poles, conductor and hardware on Oxen Pond ("OXP") Substation distribution feeder OXP-01. The proposed project includes:

(i) Replacing 3.2 kilometres of 60-year-old, three-phase primary #4 copper ("Cu") conductor;
(ii) Replacing stainless steel brackets on existing transformers;
(iii) Replacing deteriorated crossarms and vintage insulators with armless construction; and
(iv) Replacing deteriorated and overloaded mainline poles.

Design work for the *Distribution Feeder OXP-01 Refurbishment* project is expected to be completed in the first quarter of 2024. Construction will begin in the second quarter of 2024 and is expected to be completed by the end of the third quarter of 2024.

## PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2024 for the *Distribution Feeder OXP-01 Refurbishment* project.

Table 1
Distribution Feeder OXP-01
Refurbishment Project
2024 Budget
($000s)

| Cost Category | 2024 |
|---|---|
| Material | 331 |
| Labour – Internal | 165 |
| Labour – Contract | 318 |
| Engineering | 26 |
| Other | - |
| Total | $840 |

Proposed expenditures for the *Distribution Feeder OXP-01 Refurbishment* project total $840,000 for 2024.

**ASSET BACKGROUND**

Distribution feeder OXP-01 was constructed in the early 1960s and does not meet today's standards.  The feeder serves approximately 1,290 customers in the Pippy Park area of St. John's and extends along Thorburn Road to just inside the Portugal Cove – St. Philips municipal boundary.

Figure 1 is a map showing the location of distribution feeder OXP-01.

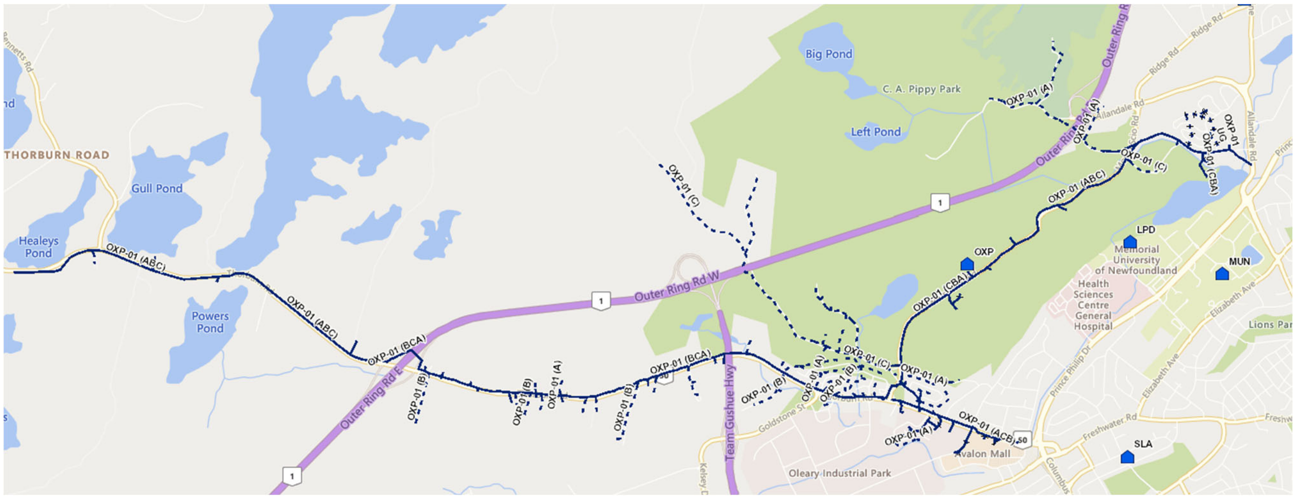



*Figure 1 - Location of Distribution Feeder OXP-01*

The section of three-phase distribution trunk supplying Thorburn Road, west of Team Gushue Highway, was recently inspected in 2022. The inspection identified a significant number of deficiencies on the 3.2-kilometre section of three-phase trunk along Thorburn Road.

This section of distribution feeder OXP-01 is primarily constructed of 1960s vintage infrastructure including sub-standard #4 Cu conductor. There have been numerous splices resulting from previous conductor failures and deficiencies. Repeated repairs of conductor failures and an excessive number of sleeves used to splice conductor can lower the overall strength of the conductor, making it more susceptible to failure.

Figure 2 shows an example of the conductor sleeving on the identified section of distribution feeder OXP-01.

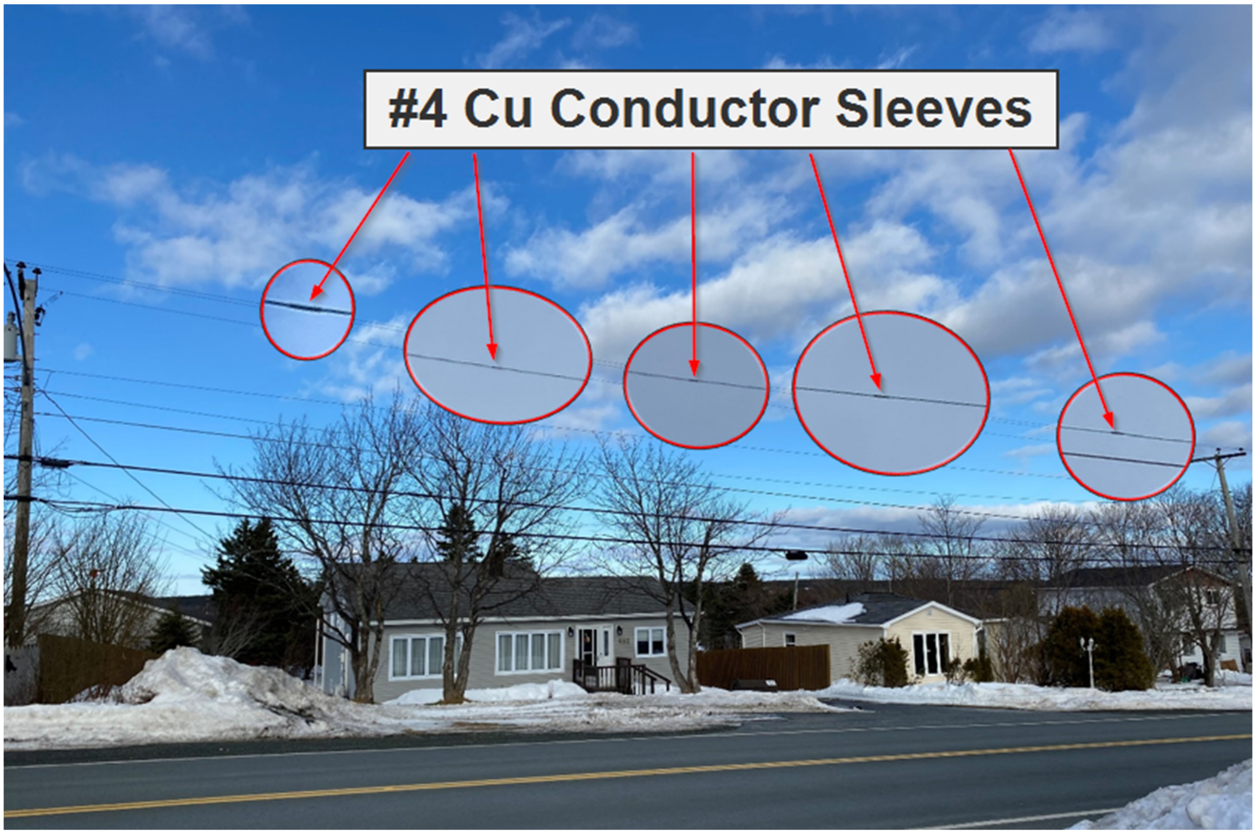



*Figure 2 - #4 Cu Conductor Sleeves*

In addition to the deteriorated conductor, this section of distribution feeder OXP-01 also has deteriorated poles and crossarms. A total of 32 poles, or 40%, require replacement due to deep cracks or rotting. A total of 35 crossarms, or 42%, require replacement due to severe splits and other deterioration. A total of 105 insulators, or 43%, are vintage porcelain insulators that are prone to failure due to separation from the pin which results in the conductor coming free from the crossarm or pole.

Figures 3 to 5 show examples of deteriorated poles and crossarms on the identified section of distribution feeder OXP-01.

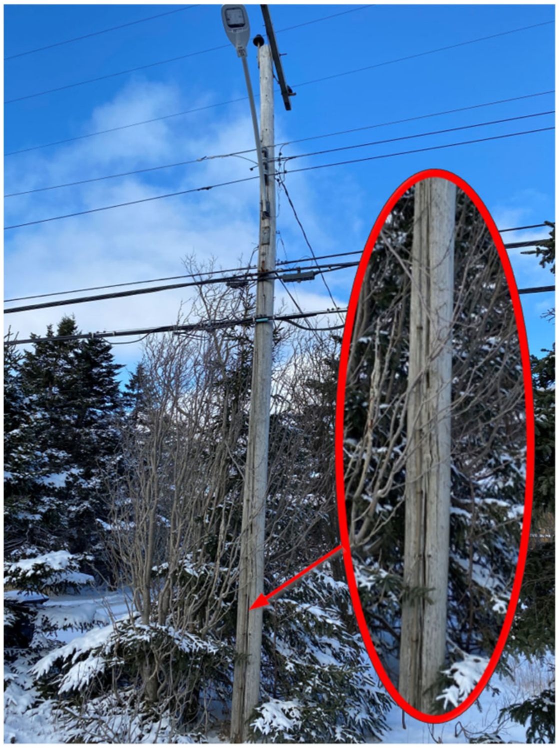


*Figure 3 - Severe Cracking in Pole*

*Figure 4 - Tipped Crossarm with Vintage Insulators*

*Figure 5 - Pole Damage Due to Fault*

**RISK ASSESSMENT**

The *Distribution Feeder OXP-01 Refurbishment* project will mitigate risks to the delivery of reliable service to approximately 580 customers in the Thorburn Road area of St. John's. This section of distribution feeder consists of three-phase front 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. The length of an outage would depend on the amount of time required to dispatch a field crew to isolate and repair the fault.

Equipment failure on distribution feeder OXP-01 is considered likely given the feeder's age and the significant quantity of deterioration identified during inspection.

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

Table 2
Distribution Feeder OXP-01 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 OXP-01 Refurbishment* project would pose a Medium-High (12) risk to the delivery of safe and reliable service to customers.

**JUSTIFICATION**

The *Distribution Feeder OXP-01 Refurbishment* project is required to provide reliable service to customers at the lowest possible cost. A section of distribution feeder OXP-01 has become heavily deteriorated. Addressing these deficiencies is necessary to mitigate risks of equipment failure and potential outages to customers in the Thorburn Road area of St. John's.

**Title:** **Extensions**
**Asset Class:** **Distribution**
**Category:** **Program**
**Investment Classification:** **Access**
**Budget:** **$12,140,000**

## 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.[23]

Table 1 provides the cost per customer connection for the *Extensions* program from 2019 to 2024.

Table 1
Extensions Program
Cost per Customer

| Year | 2019 | 2020 | 2021 | 2022 | 2023F | 2024F |
|---|---|---|---|---|---|---|
| Total (000s) | $13,379 | $10,561 | $12,427 | $12,489 | $12,218 | $12,140 |
| Adjusted Costs (000s)[1] | $15,956 | $12,394 | $13,798 | $13,161 | $12,218 | - |
| New Customers | 2,379 | 2,062 | 2,448 | 2,646 | 2,205 | 2,053 |
| Cost/Customer[1] | $6,707 | $6,011 | $5,636 | $4,974 | $5,541 | $5,913 |

1 2023 dollars.

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

Newfoundland Power is forecasting 2,053 new customer connections in 2024 at a cost per connection under the *Extensions* program of $5,913.

Table 2 provides a breakdown of expenditures proposed for 2024 for the *Extensions* program.

Table 2
Extensions Program
2024 Budget
($000s)

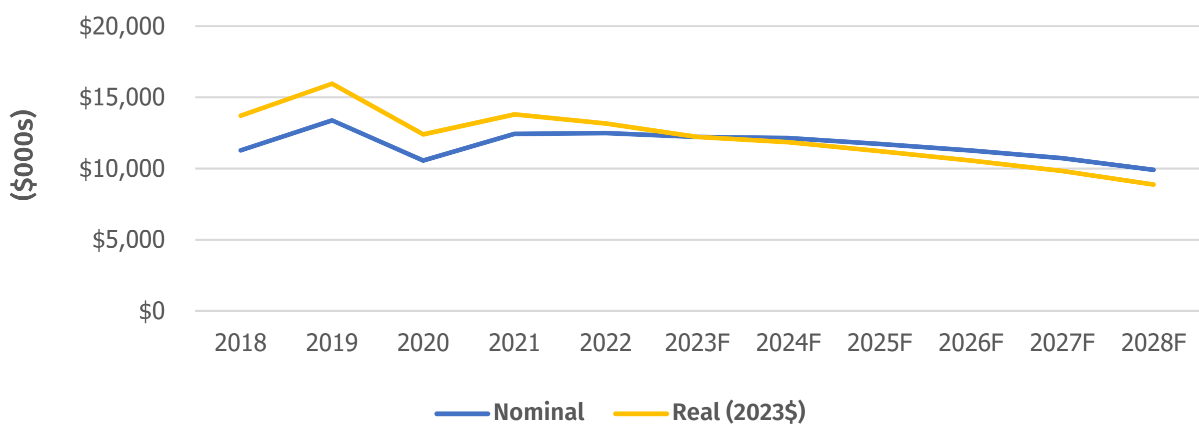
| Cost Category | 2024 |
|---|---|
| Material | 3,991 |
| Labour – Internal | 3,906 |
| Labour – Contract | 2,356 |
| Engineering | 1,406 |
| Other | 481 |
| Total | $12,140 |

Proposed expenditures for the *Extensions* program total $12,140,000 for 2024.

**PROGRAM TREND**

Figure 1 shows historical and forecast expenditures for the *Extensions* program from 2018 to 2028.[24]

**Figure 1**
**Extensions Program Expenditures**
**(2018 - 2028F)**




[24] For forecast expenditures for the *Extensions* program, see the *2024-2028 Capital Plan,* Appendix A, Page A-2.

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 approximately $12.1 million from 2018 to 2023, or approximately $13.5 million when adjusted for inflation. Annual expenditures under this program are forecast to average approximately $11.2 million over the next five years.

**ASSET BACKGROUND**

Newfoundland Power operates approximately 9,500 kilometres of distribution line. Extensions to distribution lines are constructed upon request from developers or contractors constructing new subdivisions, as well as individual customers who require connection to the electrical system. The scope and cost of individual extensions varies depending on the nature of the request and the location of the customer to be connected.

**JUSTIFICATION**

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

**Title:** **Reconstruction**
**Asset Class:** **Distribution**
**Category:** **Program**
**Investment Classification:** **Renewal**
**Budget:** **$6,953,000**

## 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.[25]

Table 1 provides the annual expenditures for the *Reconstruction* program from 2019 to 2023.

Table 1
Reconstruction Program
Historical Expenditures
(000s)

| Year | 2019 | 2020 | 2021 | 2022 | 2023F |
|---|---|---|---|---|---|
| Total | $5,579 | $6,275 | $5,959 | $6,179 | $6,699 |
| Adjusted Costs[1] | $6,661 | $7,360 | $6,647 | $6,560 | $6,699 |

[1] 2023 dollars.

The average annual adjusted cost for the *Reconstruction* program was approximately $6.8 million from 2019 to 2023.

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

Table 2 provides a breakdown of expenditures proposed for 2024 for the *Reconstruction* program.

Table 2
Reconstruction Program
2024 Budget
($000s)

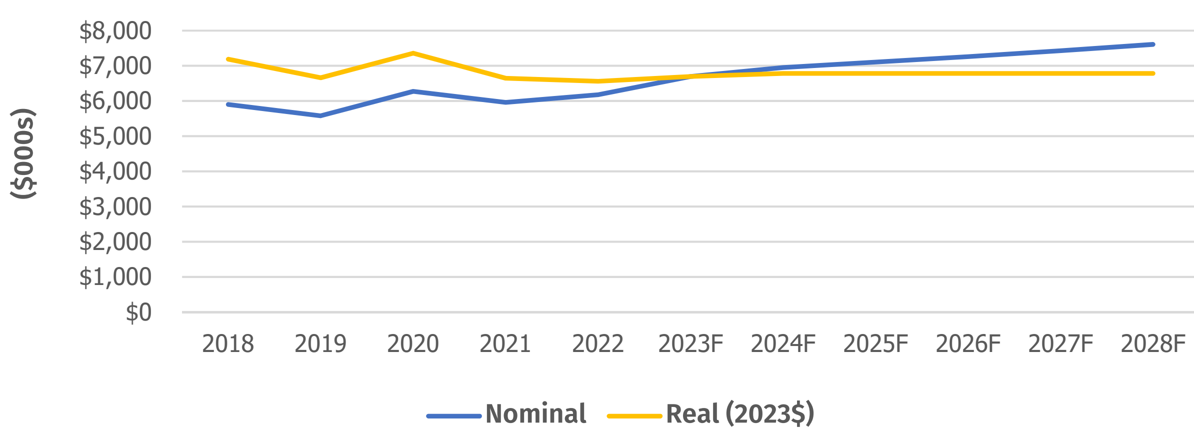
| Cost Category | 2024 |
|---|---|
| Material | 1,497 |
| Labour – Internal | 2,998 |
| Labour – Contract | 1,502 |
| Engineering | 658 |
| Other | 298 |
| Total | $6,953 |

Proposed expenditures for the *Reconstruction* program total $6,953,000 for 2024.

**PROGRAM TREND**

Figure 1 shows historical and forecast expenditures for the *Reconstruction* program from 2018 to 2028.[26]

**Figure 1**
**Reconstruction Program Expenditures**
**(2018 - 2028F)**




[26] For forecast annual expenditures for the *Reconstruction* program, see the *2024-2028 Capital Plan,* Appendix A, Page A-2.

Annual expenditures under this program averaged approximately $6.1 million from 2018 to 2023, or approximately $6.9 million when adjusted for inflation. Annual expenditures are forecast to average approximately $7.3 million over the next five years.

## ASSET BACKGROUND

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

## ASSESSMENT OF ALTERNATIVES

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

## RISK ASSESSMENT

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

The distribution system includes approximately 229,000 wooden support structures and overhead conductor on approximately 9,500 kilometres of distribution line. Industry experience indicates an average expected useful service life of 54 years for distribution wooden support structures and 50 years for distribution overhead conductor. Approximately 13% of wooden support structures on Newfoundland Power's distribution system have exceeded 54 years in service. Approximately 22% 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 34% over the last decade. This increase is primarily being driven by overhead conductor that has become deteriorated due to its age.

An average of 482 deficiencies were corrected annually under the *Reconstruction* program from 2018 to 2022, ranging from 386 in 2022 to 535 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,

[27] For more information, see the *2024-2028 Capital Plan, Section 2.4.2 Distribution.*

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

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

| Table 3<br>Reconstruction Program<br>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:** | **$4,974,000** |

## 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 47 distribution feeders will undergo inspection in 2023 with planned preventative maintenance in 2024:

| | | | | | |
|---|---|---|---|---|---|
| ABC-02 | COB-04 | GIL-02 | KEL-03 | RRD-07 | SJM-14 |
| BCV-01 | DLK-01 | GRH-01 | MSY-04 | RRD-08 | SMV-01 |
| BCV-04 | FRN-01 | HBS-01 | PAB-03 | RRD-10 | SPF-01 |
| BLK-02 | GAL-01 | HBS-02 | PUL-01 | RVH-02 | TRN-01 |
| BUC-01 | GBS-01 | HUM-10 | RBK-01 | SCV-01 | TRN-02 |
| BUC-02 | GBY-02 | KBR-11 | RRD-02 | SCV-02 | WAL-06 |
| BVJ-01 | GDL-02 | KEL-01 | RRD-03 | SJM-04 | WES-02 |
| COB-03 | GDL-03 | KEL-02 | RRD-04 | SJM-13 | |

The specific deficiencies to be corrected on these distribution feeders will depend on the outcomes of the inspections completed throughout 2023, 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.[28]

[28] 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 2019 to 2023.

Table 1
Rebuild Distribution Lines Program
Historical Expenditures
(000s)

| Year | 2019 | 2020 | 2021 | 2022 | 2023F |
|---|---|---|---|---|---|
| Total | $4,371 | $4,477 | $4,143 | $3,956 | $4,945 |
| Adjusted Costs[1] | $5,218 | $5,247 | $4,634 | $4,217 | $4,945 |

1 2023 dollars

The average annual adjusted cost for the *Rebuild Distribution Lines* program was approximately $4.9 million from 2019 to 2023.

Table 2 provides a breakdown of expenditures proposed for 2024 for the *Rebuild Distribution Lines* program.

Table 2
Rebuild Distribution Lines Program
2024 Budget
($000s)

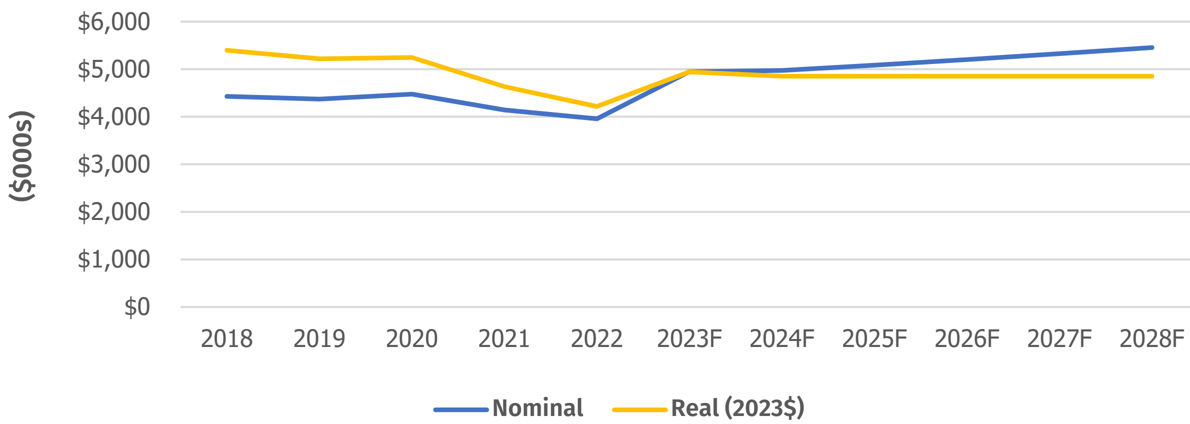
| Cost Category | 2024 |
|---|---|
| Material | 1,204 |
| Labour – Internal | 2,479 |
| Labour – Contract | 735 |
| Engineering | 315 |
| Other | 241 |
| Total | $4,974 |

Proposed expenditures for the *Rebuild Distribution Lines* program total $4,974,000 for 2024.

## PROGRAM TREND

Figure 1 shows historical and forecast expenditures for the *Rebuild Distribution Lines* program from 2018 to 2028.[29]

**Figure 1**
**Rebuild Distribution Lines Program Expenditures**
**(2018 - 2028F)**




Annual expenditures under this program averaged approximately $4.4 million from 2018 to 2023, or approximately $4.9 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* program.

29 For forecast annual expenditures for the *Rebuild Distribution Lines* program, see the *2024-2028 Capital Plan,* Appendix A, Page A-2.

**ASSESSMENT OF ALTERNATIVES**

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

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

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

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

**RISK ASSESSMENT**

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

The distribution system includes approximately 229,000 wooden support structures and overhead conductor on approximately 9,500 kilometres of distribution line. Industry experience indicates an average expected useful service life of 54 years for distribution wooden support structures and 50 years for distribution overhead conductor. Approximately 13% of wooden support structures on Newfoundland Power's distribution system have exceeded 54 years in service. Approximately 22% of distribution overhead conductor has exceeded 50 years in service.[30]

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 34% over the last decade. This increase is primarily being driven by overhead conductor that has become deteriorated due to its age.

An average of 1,862 deficiencies were corrected annually under the *Rebuild Distribution Lines* program from 2018 to 2022, ranging from 1,368 in 2019 to 2,438 in 2021. These deficiencies were corrected through a combination of rebuilding sections of distribution feeders and the selective replacement of line components.

The *Rebuild Distribution Lines* program will address deficiencies on 47 distribution feeders in 2024. These feeders serve an average of approximately 800 customers. The deficiencies on these distribution feeders are likely to result in outages to these customers if not addressed.

30 For more information, see the *2024-2028 Capital Plan, Section 2.4.2 Distribution.*

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:** **$4,066,000**

## 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.[31]

## 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.[32]

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

[31] Also included is distribution work associated with the installation and relocation of communications cables used by the Company's various protection and control systems.
[32] Effective 2023, labour costs associated with this program include a direct allocation of amounts previously included in GEC, as approved in Order No. P.U. 3 (2022).

Table 1 provides annual expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program from 2019 to 2023.

| Table 1<br>Relocate/Replace Distribution Lines for Third Parties Program<br>Historical Expenditures<br>(000s) | | | | | |
|---|---|---|---|---|---|
| Year | 2019 | 2020 | 2021 | 2022 | 2023F |
| Total | $5,192 | $2,745 | $3,060 | $3,055 | $3,803 |
| Adjusted Costs[1] | $6,189 | $3,219 | $3,407 | $3,227 | $3,803 |

[1] 2023 dollars

The average annual adjusted cost for the *Relocate/Replace Distribution Lines for Third Parties* program was approximately $4.0 million from 2019 to 2023.

Table 2 provides a breakdown of expenditures proposed for 2024 for the *Relocate/Replace Distribution Lines for Third Parties* program.

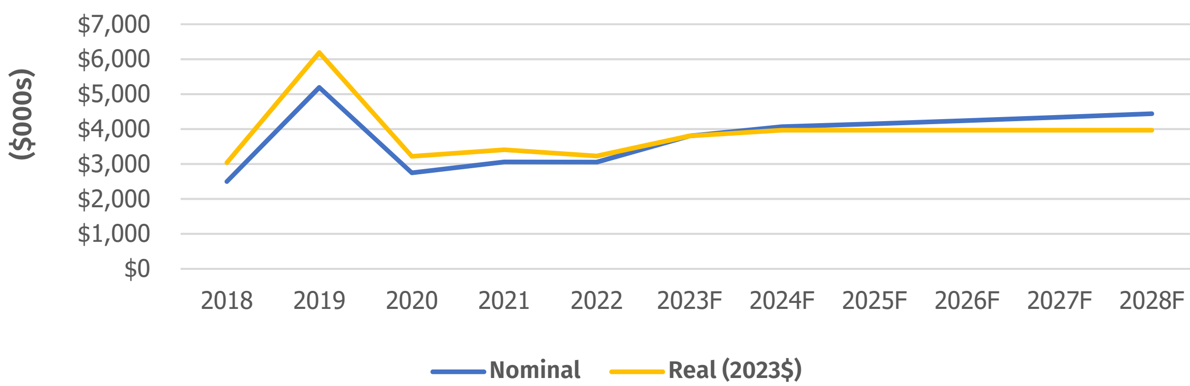
| Table 2<br>Relocate/Replace Distribution Lines<br>for Third Parties Program<br>2024 Budget<br>($000s) | |
|---|---|
| Cost Category | 2024 |
| Material | 962 |
| Labour – Internal | 1,386 |
| Labour – Contract | 921 |
| Engineering | 527 |
| Other | 270 |
| Total | $4,066 |

Proposed expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program total $4,066,000 for 2024.

**PROGRAM TREND**

Figure 1 shows historical and forecast expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program from 2018 to 2028.[33]

**Figure 1**
**Relocate/Replace Distribution Lines for Third Parties**
**Program Expenditures**
**(2018 - 2028F)**




Annual expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program vary depending on the quantity and scope of the requests received.[34] Annual expenditures under this program averaged approximately $3.5 million from 2018 to 2023, or approximately $3.8 million when adjusted for inflation. Annual expenditures are forecast to average approximately $4.2 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 282 requests from third parties were received under the *Relocate/Replace Distribution Lines for Third Parties* program over the last five years, ranging from 120 in 2018 to 425 in 2022.

---

[33] For forecast annual expenditures for the *Relocate/Replace Distribution Lines for Third Parties* program, see the *2024-2028 Capital Plan,* Appendix A, page A-2.

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

**JUSTIFICATION**

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

**Title:** **Replacement Transformers**
**Asset Class:** **Distribution**
**Category:** **Program**
**Investment Classification:** **Renewal**
**Budget:** **$3,681,000**

## 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 2019 to 2023.

Table 1
Replacement Transformers Program
Historical Expenditures
(000s)

| Year | 2019 | 2020 | 2021 | 2022 | 2023F |
|---|---|---|---|---|---|
| Total | $3,019 | $2,983 | $3,356 | $3,873 | $3,345 |
| Adjusted Costs[1] | $3,581 | $3,518 | $3,658 | $3,932 | $3,345 |

[1] 2023 dollars.

The average annual adjusted cost for the *Replacement Transformers* program was approximately $3.6 million from 2019 to 2023.

Table 2 provides a breakdown of expenditures proposed for 2024 for the *Replacement Transformers* program.

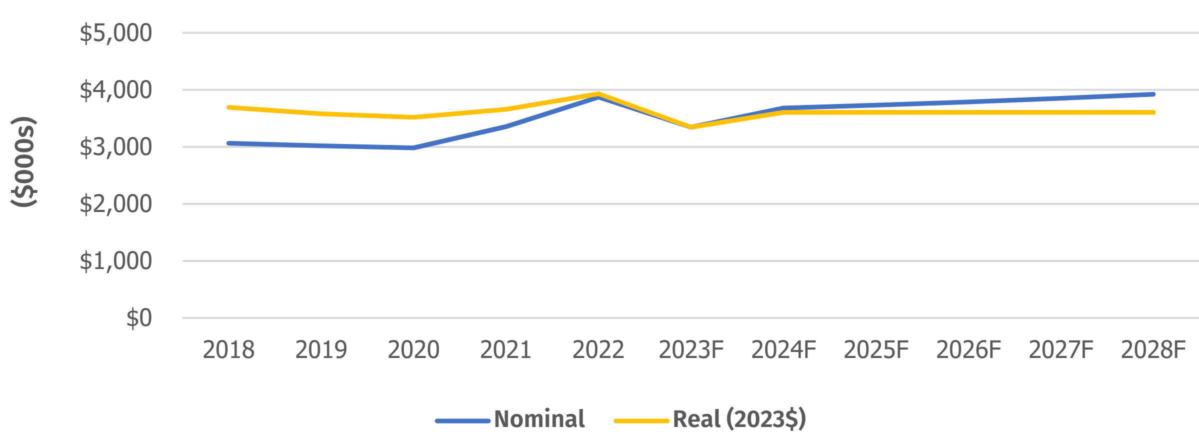
| Table 2<br>Replacement Transformers Program<br>2024 Budget<br>($000s) | |
|---|---|
| Cost Category | 2024 |
| Material | 3,681 |
| Labour – Internal | - |
| Labour – Contract | - |
| Engineering | - |
| Other | - |
| Total | $3,681 |

Proposed expenditures for the *Replacement Transformers* program total $3,681,000 for 2024.

**PROGRAM TREND**

Figure 1 shows historical and forecast expenditures for the *Replacement Transformers* program from 2018 to 2028.[35]

**Figure 1**
**Replacement Transformers Program Expenditures**
**(2018 - 2028F)**




[35] For forecast annual expenditures for the *Replacement Transformers* program, see the *2024-2028 Capital Plan,* Appendix A, Page A-2.

Annual expenditures under this program averaged approximately $3.3 million from 2018 to 2023, or approximately $3.6 million when adjusted for inflation. Annual expenditures are forecast to average approximately $3.8 million over the next five years.

**ASSET BACKGROUND**

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

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

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

**ASSESSMENT OF ALTERNATIVES**

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

**RISK ASSESSMENT**

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

Transformers are replaced upon failure or imminent risk of failure. An average of 611 transformers were replaced annually from 2018 to 2022, ranging from 461 in 2022 to 705 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 litres of oil, while padmount transformers can contain approximately 2,000 litres of oil. Failure and deterioration of transformers can result in oil leaks that lead to environmental contamination.

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

| Table 3<br>Replacement Transformers Program<br>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:** **$3,264,000**

## 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 2019 to 2023.

Table 1
New Transformers Program
Historical Expenditures
(000s)

| Year | 2019 | 2020 | 2021 | 2022 | 2023F |
|---|---|---|---|---|---|
| Total | $2,677 | $2,645 | $2,976 | $3,434 | $2,967 |
| Adjusted Costs[1] | $3,175 | $3,119 | $3,244 | $3,486 | $2,967 |

[1] 2023 dollars.

The average annual adjusted cost for the *New Transformers* program was approximately $3.2 million from 2019 to 2023.

Table 2 provides a breakdown of expenditures proposed for 2024 for the *New Transformers* program.

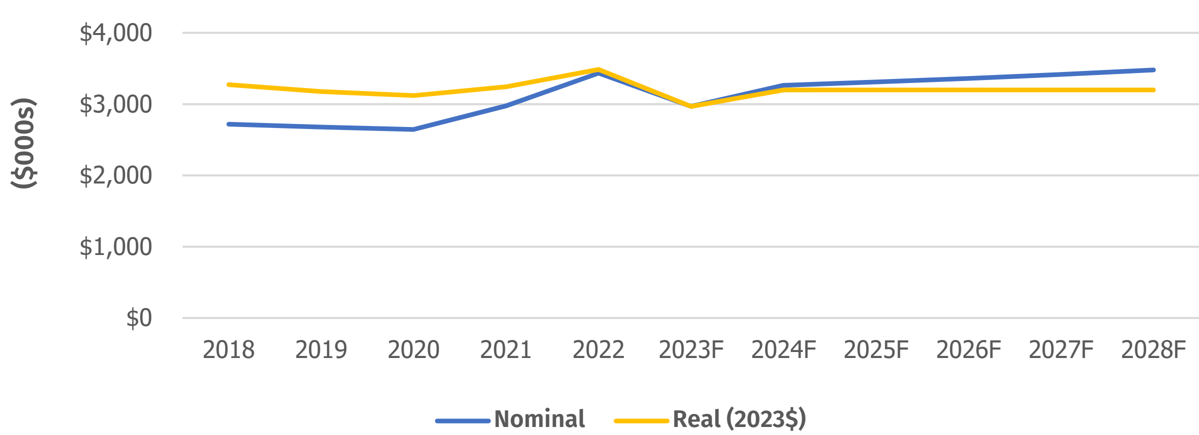
| Table 2<br>New Transformers Program<br>2024 Budget<br>($000s) | |
|---|---|
| Cost Category | 2024 |
| Material | 3,264 |
| Labour – Internal | - |
| Labour – Contract | - |
| Engineering | - |
| Other | - |
| Total | $3,264 |

Proposed expenditures for the *New Transformers* program total $3,264,000 for 2024.

**PROGRAM TREND**

Figure 1 shows historical and forecast expenditures for the *New Transformers* program from 2018 to 2028.[36]

**Figure 1**
**New Transformers Program Expenditures**
**(2018 - 2028F)**




36 For forecast annual expenditures for the *New Transformers* program, see the *2024-2028 Capital Plan,* Appendix A*,* Page A-2.

Annual expenditures under this program averaged approximately $2.9 million from 2018 to 2023, or $3.2 million when adjusted for inflation. Annual expenditures under this program are forecast to average approximately $3.4 million over the next five years.

**ASSET BACKGROUND**

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

The number of new transformers required to be installed varies annually based on customer growth and load density on sections of distribution feeders. An average of approximately 1,100 new transformers were installed annually from 2018 to 2022.

**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:** **$2,847,000**

## 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.[37]

Table 1 provides annual expenditures for the *New Services* program from 2019 to 2024.

Table 1
New Services Program
Cost per Customer

| Year | 2019 | 2020 | 2021 | 2022 | 2023F | 2024F |
|---|---|---|---|---|---|---|
| Total (000s) | $2,769 | $2,283 | $2,936 | $3,469 | $2,916 | $2,847 |
| Adjusted Costs (000s)[1] | $3,311 | $2,674 | $3,288 | $3,723 | $2,916 | - |
| New Customers | 2,379 | 2,062 | 2448 | 2,646 | 2,205 | 2,053 |
| Cost/customer[1] | $1,392 | $1,297 | $1,343 | $1,407 | $1,322 | $1,387 |

[1] 2023 dollars.

Newfoundland Power is forecasting 2,053 new customer connections in 2024 at a cost per connection of $1,387.

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

Table 2 provides a breakdown of expenditures proposed for 2024 for the *New Services* program.

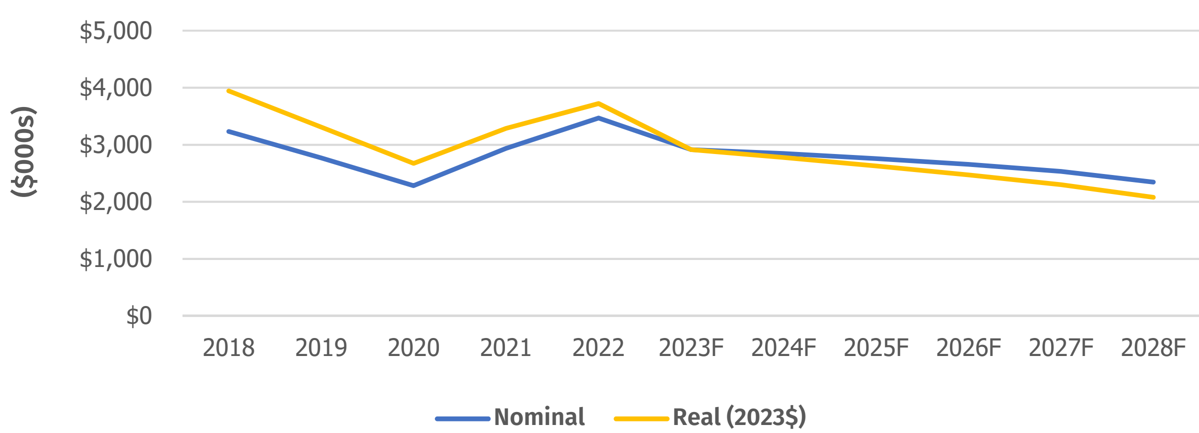
| Table 2<br>New Services Program<br>2024 Budget<br>($000s) | |
|---|---|
| Cost Category | 2024 |
| Material | 871 |
| Labour – Internal | 1,583 |
| Labour – Contract | 130 |
| Engineering | 222 |
| Other | 41 |
| Total | $2,847 |

Proposed expenditures for the *New Services* program total $2,847,000 for 2024.

**PROGRAM TREND**

Figure 1 shows historical and forecast expenditures for the *New Services* program from 2018 to 2028.[38]

**Figure 1**
**New Services Program Expenditures**
**(2018 - 2028F)**




[38] For forecast annual expenditures for the *New Services* program, see the *2024-2028 Capital Plan,* Appendix A, Page A-2.

Annual expenditures under this program averaged approximately $2.9 million from 2018 to 2023, or $3.3 million when adjusted for inflation.[39] Annual expenditures under this program are forecast to average approximately $2.6 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.

---

[39] 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:** **$2,629,000**

## 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.[40]

Table 1 provides the annual expenditures for the *New Street Lighting* program from 2019 to 2023.

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

| Year | 2019 | 2020 | 2021 | 2022 | 2023F |
|---|---|---|---|---|---|
| Total | $2,678 | $2,608 | $1,494 | $2,209 | $2,618 |
| Adjusted Costs[1] | $3,194 | $3,063 | $1,653 | $2,312 | $2,618 |

[1] 2023 dollars.

The average annual adjusted cost for the *New Street Lighting* program was approximately $2.6 million from 2019 to 2023.

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

Table 2 provides a breakdown of expenditures proposed for 2024 for the *New Street Lighting* program.

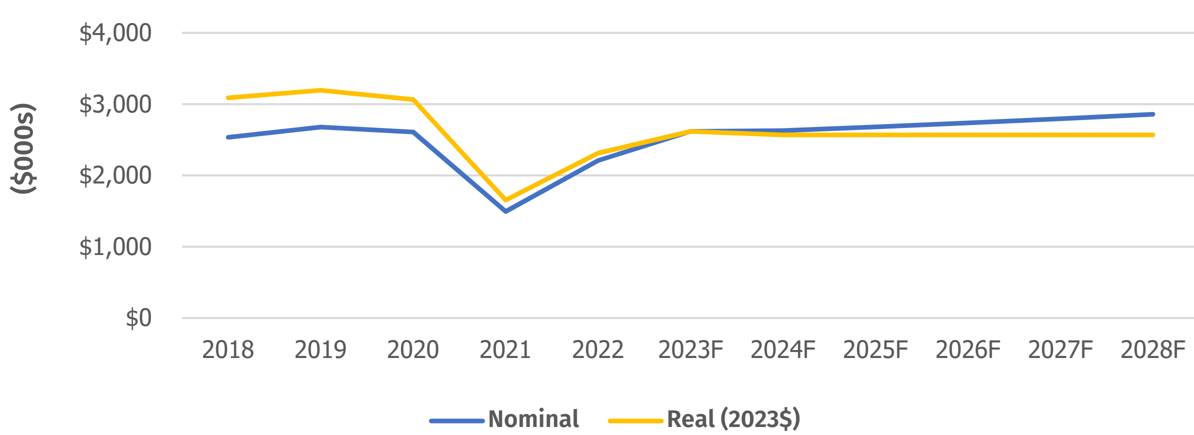
| Table 2<br>New Street Lighting Program<br>2024 Budget<br>($000s) | |
|---|---|
| Cost Category | 2024 |
| Material | 1,672 |
| Labour – Internal | 566 |
| Labour – Contract | 301 |
| Engineering | 60 |
| Other | 30 |
| Total | $2,629 |

Proposed expenditures for the *New Street Lighting* program total $2,629,000 for 2024.

**PROGRAM TREND**

Figure 1 shows historical and forecast annual expenditures for the *New Street Lighting* program from 2018 to 2028.[41]

**Figure 1**
**New Street Lighting Program Expenditures**
**(2018 - 2028F)**




41 For forecast annual expenditures for the *New Street Lighting* program, see *2024-2028 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 $2.4 million from 2018 to 2023, or approximately $2.7 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 567 new street lights were installed annually from 2018 to 2022, ranging from 421 in 2022 to 697 in 2020.

## JUSTIFICATION

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

| | |
|---|---|
| **Title:** | **Replacement Street Lighting** |
| **Asset Class:** | **Distribution** |
| **Category:** | **Program** |
| **Investment Classification:** | **Renewal** |
| **Budget:** | **$863,000** |

## PROGRAM DESCRIPTION

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

## PROGRAM BUDGET

The budget for the *Replacement Street Lighting* program is based on a historical average. Historical annual expenditures for the program over the most recent three-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.[42]

Table 1 provides a breakdown of expenditures proposed for 2024 for the *Replacement Street Lighting* program.

Table 1
Replacement Street Lighting Program
2024 Budget
($000s)

| Cost Category | 2024 |
|---|---|
| Material | 578 |
| Labour – Internal | 138 |
| Labour – Contract | 133 |
| Engineering | 7 |
| Other | 7 |
| Total | $863 |

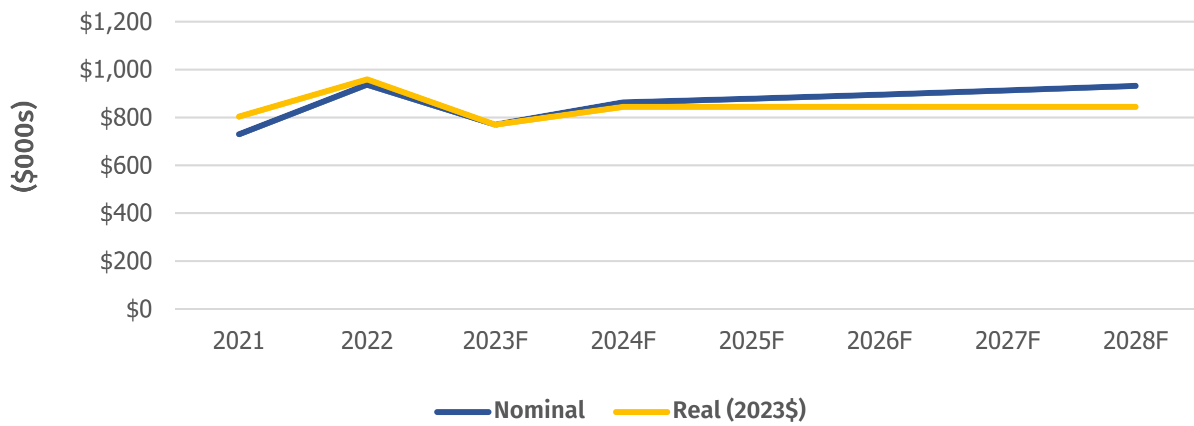
Proposed expenditures for the *Replacement Street Lighting* program total $863,000 for 2024.

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

**PROGRAM TREND**

Figure 1 shows historical and forecast annual expenditures for the *Replacement Street Lighting* program from 2021 to 2028.[43]

**Figure 1**
**Replacement Street Lighting Program Expenditures**
**(2021 - 2028F)**




The scope of the current *Replacement Street Lighting* program was established in 2021. Prior to 2021, the program included costs associated with the replacement of HPS street light fixtures. Annual expenditures under this program averaged approximately $812,000 from 2021 to 2023, or approximately $844,000 when adjusted for inflation. Annual expenditures under this program are forecast to average approximately $896,000 over the next five years.

**ASSET BACKGROUND**

Newfoundland Power currently provides service to approximately 11,000 Street and Area Lighting customers. There are approximately 67,000 street lights in operation throughout the Company's service territory. Approximately 30,000 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.*[44]

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.

---

[43] For forecast annual expenditures for the *Replacement Street Lighting* program, see *2024-2028 Capital Plan,* Appendix A, Page A-2.

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

**RISK ASSESSMENT**

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

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

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

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

Table 2
Replacement Street Lighting Program
Risk Assessment Summary

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

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

**JUSTIFICATION**

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

# SUBSTATIONS

| | |
|---|---|
| **Title:** | **Gambo Substation Refurbishment and Modernization** |
| **Asset Class:** | **Substations** |
| **Category:** | **Project** |
| **Investment Classification:** | **Renewal** |
| **Budget:** | **$5,267,000** |

## PROJECT DESCRIPTION

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

The proposed 2024 scope of work for the *Gambo Substation Refurbishment and Modernization* project includes:

(i) Complete a yard extension;
(ii) Construct a new control building to replace existing building;
(iii) Construct an extension to the 138 kV steel bus structure and remove deteriorated 138 kV wood pole structures;
(iv) Construct new 66 kV and 25 kV steel structures to replace deteriorated wood structures;
(v) Construct new concrete spill containment foundations for existing transformers and existing voltage regulators;
(vi) Install one new 138 kV breaker to replace existing end-of-life breaker and the addition of one new 138 kV tie-breaker;
(vii) Install new 66 kV breaker to replace existing end-of-life breaker;
(viii) Replace deteriorated 138 kV, 66 kV, and 25 kV switches;
(ix) Install 138 kV and 66 kV potential transformers;
(x) Install new 25 kV combined current and potential transformer to replace end-of-life metering tank;
(xi) Replace obsolete electromechanical relays with new digital relays; and
(xii) Upgrade and extend the ground grid.

Engineering design and procurement of long lead time equipment will be completed in the first quarter of 2024. Construction will begin in the second quarter and will be completed early in the fourth quarter of 2024. Commissioning of the substation will be completed by the end of 2024.

Additional information on this project is provided in Appendix A of report *2.1 2024 Substation Refurbishment and Modernization* filed with the Application.

## PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2024 for the *Gambo Substation Refurbishment and Modernization* project.

| Table 1<br>Gambo Substation Refurbishment and Modernization Project<br>2024 Budget<br>($000s) | |
|---|---|
| Cost Category | 2024 |
| Material | 3,754 |
| Labour – Internal | 299 |
| Labour – Contract | 0 |
| Engineering | 563 |
| Other | 651 |
| Total | $5,267 |

Proposed expenditures for the *Gambo Substation Refurbishment and Modernization* project total $5,267,000 for 2024.

**ASSET BACKGROUND**

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

As part of its preventative and corrective maintenance program, Newfoundland Power's substations are inspected eight times annually. Inspection results are incorporated into the Company's annual update of its *Substation Refurbishment and Modernization Plan*. The current plan includes the refurbishment and modernization of 22 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.[45] Continued execution of the *Substation Refurbishment and Modernization Plan* is therefore necessary to replace obsolete and deteriorated equipment and infrastructure.

[45] For details of the assessment, see the *2024 Capital Budget Application,* report *2.1 2024 Substation Refurbishment and Modernization, Section 2.2*.

In 2024, Newfoundland Power is proposing to refurbish and modernize GAM 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: (i) 138 kV and 66 kV circuit breakers; (ii) the electromechanical protection relays; (iii) the 138 kV, 66 kV and 25 kV wood pole structures; and (iv) 138 kV, 66 kV and 25 kV switches. Additionally, new transformer and voltage regulator spill containment foundations and upgrades to the substation's ground grid are necessary.

**ASSESSMENT OF ALTERNATIVES**

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

In the case of GAM Substation, the number of components requiring preventative and corrective maintenance at this time justifies the requirement to refurbish and modernize the substation in 2024. Deferral of the refurbishment and modernization project would increase the risk that components will fail in service, which would result in outages to thousands of customers from Gambo to Lumsden in the Bonavista-North area. Deferring this project is therefore not a viable alternative.

**RISK ASSESSMENT**

The *Gambo Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to customers from Gambo to Lumsden in the Bonavista-North area.

GAM Substation provides service to approximately 1,370 customers in the Gambo area. There are also approximately 3,500 customers from Hare Bay to Lumsden that rely on radial Transmission Line 115L from GAM Substation. Equipment failure in the substation exposes all customers supplied by GAM Substation to the risk of outages. The time to restore service to customers depends on the nature of the failure and could range from several hours up to 36 hours.

GAM Substation contains equipment that is deteriorated, obsolete, and at end of life which increases the probability of outages to customers. Two circuit breakers and a significant quantity of switches require replacement based on their age and mechanical condition. The electromechanical protection relays are obsolete and are no longer industry standard. The wood pole structures and crossarms in the substation are deteriorated and require replacement.

Both power transformers and the voltage regulators in GAM Substation contain large amounts of insulating oil and lack standard spill containment. Proper spill containment is required to mitigate the risk of an environmental incident if an oil spill were to occur. Remediation costs associated with oil spills can be significant. In addition, spill containment will minimize the surface area of an oil spill and thus provides fire protection benefits.

There are deficiencies identified with the ground grid at GAM Substation that pose a risk to safe and reliable operation of the electric equipment. There are sections of the yard with insufficient grounding and there are also missing connections between the main ground grid and substation fence. The purpose of ground grid upgrades is to reduce the risk of exposure to electric shock or electrocution through step and touch potential. An insufficient ground grid can also affect continuity of service if there is an inadequate ground path, which is required for proper equipment operation.

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

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

Table 2
Gambo Substation Refurbishment and Modernization Project
Risk Assessment Summary

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

Overall, the condition of GAM Substation poses a Medium-High (16) risk to the delivery of reliable, safe, and environmentally responsible service to customers. Action is required in 2024 to mitigate these risks for customers.

**JUSTIFICATION**

The *Gambo 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 4,870 customers from Gambo to Lumsden in the Bonavista-North area.

| | |
|---|---|
| **Title:** | **Islington Substation Refurbishment and Modernization** |
| **Asset Class:** | **Substations** |
| **Category:** | **Project** |
| **Investment Classification:** | **Renewal** |
| **Budget (Multi-Year):** | **$308,000 in 2024; $4,706,000 in 2025** |

**PROJECT DESCRIPTION**

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

The proposed 2024 and 2025 scope of work for the *Islington Substation Refurbishment and Modernization* project includes:

(i) Complete a yard extension;
(ii) Construct a new control building;
(iii) Construct new 66 kV and 12.5 kV steel structures;
(iv) Install new power transformer with spill containment foundation to replace ISL-T1;
(v) Install two new 66 kV transmission line breakers and associated switches;
(vi) Construct new spill containment foundation and connect existing voltage regulators;
(vii) Replace all deteriorated 66 kV and 12.5 kV switches;
(viii) Install new 66 kV potential transformers;
(ix) Install new 12.5 kV combined current and potential transformer to replace end-of-life metering tank;
(x) Install new digital relays and the associated communications equipment; and
(xi) Upgrade and extend the ground grid.

Engineering design and procurement of long lead time equipment will be completed in 2024. Construction will begin in the second quarter of 2025 and will be completed early in the fourth quarter of 2025. Commissioning of the substation will be completed during the fourth quarter of 2025.

Additional information on this project is provided in Appendix D of report *2.1 2024 Substation Refurbishment and Modernization* filed with the Application.

**PROJECT BUDGET**

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

Table 1 provides a breakdown of expenditures proposed for 2024 and 2025 for the *Islington Substation Refurbishment and Modernization* project.

Table 1
Islington Substation Refurbishment and Modernization Project
2024-2025 Budget
($000s)

| Cost Category | 2024 | 2025 | Total |
|---|---|---|---|
| Material | 60 | 3,620 | 3,680 |
| Labour - Internal | - | 193 | 193 |
| Labour - Contract | - | - | - |
| Engineering | 241 | 350 | 591 |
| Other | 7 | 543 | 550 |
| Total | $308 | $4,706 | $5,014 |

Proposed expenditures for the *Islington Substation Refurbishment and Modernization* project are $308,000 in 2024 and $4,706,000 in 2025 for a total project cost of $5,014,000.

**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 22 substations over the next five years. The forecast increase in refurbishment and modernization projects reflects the age and condition of the Company's substation assets.

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

46 For details of the assessment, see the *2024 Capital Budget Application,* report *2.1 2024 Substation Refurbishment and Modernization, Section 2.2*.

In 2024 and 2025, Newfoundland Power is proposing to refurbish and modernize ISL Substation. The substation was built in 1974 as a distribution substation. A condition assessment determined the substation contains a significant amount of deteriorated and obsolete equipment. Several pieces of equipment are at end of life, including: (i) power transformer ISL-T1; (ii) 66 kV and 12.5 kV wood pole structures; and (iii) 66 kV and 12.5 kV switches. Additionally, new transformer and voltage regulator spill containment foundations and upgrades to the substation's ground grid are necessary.

**ASSESSMENT OF ALTERNATIVES**

There are generally two alternative approaches to addressing maintenance in substations: (i) the replacement of specific components at various substations, which is prioritized based on the condition and criticality of a specific piece of equipment[47]; and (ii) the refurbishment and modernization of individual substations based on the overall condition of those substations.

In the case of ISL Substation, the number of components requiring preventative and corrective maintenance at this time justifies the requirement to refurbish and modernize the substation in 2024 and 2025.

Deferral of the ISL Substation refurbishment and modernization project would increase the risk that some components will fail in service, which could expose up to approximately 2,900 customers to the risk of outages. Deferring this project is therefore not a viable alternative.

**RISK ASSESSMENT**

The *Islington Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to customers from the Islington and New Harbour areas.

ISL Substation provides service to approximately 1,100 customers in the Islington area. There are also approximately 1,800 customers served by the New Harbour ("NHR") Substation that are affected by faults at ISL Substation as they rely on the same transmission line. Equipment failure in the ISL Substation exposes all customers supplied by ISL and NHR Substations to the risk of outages. The time to restore service to customers depends on the nature of the failure and could range from several hours up to 36 hours.

ISL Substation contains equipment that is deteriorated, obsolete, and at end of life which increases the probability of outages to customers. The 65-year-old power transformer is the second oldest distribution power transformer in the Company's fleet and is approaching end of life. The 12.5 kV wood pole structures in the substation have deteriorated and require replacement. The majority of the switches require replacement based on their age and mechanical condition.

---

[47] Power transformer ISL-T1 will be 67 years old when replaced as part of the *Islington Refurbishment and Modernization* project in 2025. Given industry experience, there is a high risk that the transformer could fail in the near-term. The Company completed an analysis which showed that ISL-T1 would have to remain in service until approximately 75 years of age to offset the added costs of completing the transformer replacement as a separate project in the future. Given the customer risks and costs associated with a failure of ISL-T1, replacing the power transformer in 2025 is consistent with providing reliable service to customers at least cost.

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

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

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

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

Table 2
Islington Substation Refurbishment and Modernization Project
Risk Assessment Summary

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

Overall, the condition of ISL Substation poses a Medium-High (16) risk to the delivery of reliable, safe, and environmentally responsible service to customers. Action is required in 2024 and 2025 to mitigate these risks for customers.

**JUSTIFICATION**

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

| | |
|---|---|
| **Title:** | **Memorial Substation Refurbishment and Modernization** |
| **Asset Class:** | **Substations** |
| **Category:** | **Project** |
| **Investment Classification:** | **Renewal** |
| **Budget:** | **$4,351,000** |

**PROJECT DESCRIPTION**

The *Memorial Substation Refurbishment and Modernization* project involves the replacement and modernization of deteriorated equipment at Memorial ("MUN") Substation located in the City of St. John's. The equipment requiring replacement was identified through inspections, engineering assessments and operating experience.

The proposed 2024 scope of work for the *Memorial Substation Refurbishment and Modernization* project includes:

(i) Construct new transformer spill containment foundations;
(ii) Install a new firewall between power transformers;
(iii) Replace the 66 kV bus structure;
(iv) Replace 66 kV equipment including circuit breakers, switches, and potential transformers;
(v) Install new 12.5 kV structures;
(vi) Replace 12.5 kV equipment including circuit breakers, switches, and potential transformers;
(vii) Replace obsolete electromechanical relays with new digital relays and install the associated communications equipment;
(viii) Construct a new control building; and
(ix) Install new ground grid.

Design work for the *Memorial Substation Refurbishment and Modernization* project will be completed by the end of the second quarter of 2024. 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 C of report *2.1 2024 Substation Refurbishment and Modernization* filed with the Application.

**PROJECT BUDGET**

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

Table 1 provides a breakdown of expenditures proposed for 2024 for the *Memorial Substation Refurbishment and Modernization* project.

Table 1
Memorial Substation Refurbishment and Modernization Project
2024 Budget
($000s)

| Cost Category | 2024 |
|---|---|
| Material | 2,879 |
| Labour – Internal | 169 |
| Labour – Contract | 0 |
| Engineering | 607 |
| Other | 696 |
| Total | $4,351 |

Proposed expenditures for the *Memorial Substation Refurbishment and Modernization* project total $4,351,000 for 2024.

**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 22 substations over the next five years. The forecast increase in refurbishment and modernization projects reflects the age and condition of the Company's substation assets.

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

[48] For details of the assessment, see the *2024 Capital Budget Application,* report *2.1 2024 Substation Refurbishment and Modernization, Section 2.2*.

In 2024, Newfoundland Power is proposing to refurbish and modernize MUN Substation. The substation was built in 1966 as a transmission and distribution substation. An engineering assessment determined the substation contains a significant amount of deteriorated and obsolete equipment. Several pieces of equipment are at end of life, including the 66 kV switches, and the electromechanical protection relays. A new transformer firewall, spill containment foundations and a new ground grid are necessary. The customer owned 12.5 kV switchgear and building is at end of life and is being replaced by the customer.

Power transformer MUN-T2 has failed and been removed from service, and will be replaced in 2024.[49]

**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 specific pieces of equipment; and (ii) the refurbishment and modernization of individual substations based on the overall condition of those substations.

In the case of MUN Substation, the number of components requiring preventative and corrective maintenance at this time justifies the requirement to refurbish and modernize the substation in 2024.[50] The refurbishment and modernization of MUN Substation was planned to be completed in 2023, but was deferred to align with the customer's schedule for upgrades to the substation. Continued deferral of the refurbishment and modernization project will 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 the University.

**RISK ASSESSMENT**

The *Memorial Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to the Company's largest customer.

MUN Substation supplies over 35 buildings with critical loads such as the Health Sciences Centre, Janeway Children's Health and Rehabilitation Centre, student residences, apartment buildings, and a childcare centre. Approximately 15,000 students are currently enrolled at this campus and almost 1,700 students are living in student residences on site. Depending on the length of an outage, a loss of supply to the University could lead to the closure of the majority of campus buildings and normal operations would be suspended.

Both power transformers at MUN Substation lack standard spill containment to protect against environmental hazards. Power transformers contain large amounts of oil as an insulating fluid. Proper spill containment is required to mitigate the risk of an environmental incident if an oil

---

[49] Newfoundland Power filed a supplemental capital expenditure application, *2023 MUN Power Transformer Supplemental Application Supplemental Application,* on March 3, 2023. The replacement of MUN-T2 was approved by the Board in Order No. P.U. 14(2023).

[50] Undertaking the project in 2024 aligns with the planned upgrades by the University on customer owned equipment and the replacement of power transformer MUN-T2.

spill were to occur. If an oil spill were to occur, the oil would soak into the ground and significant efforts would be required for clean-up. These impacts can range from the clean-up costs associated with a spill to the contamination of a water supply. In addition, spill containment will minimize the surface area of an oil spill and thus provides fire protection benefits. The transformers also lack a firewall. Installation of a firewall between the transformers can limit the damage, and potential spread of fire, resulting from a transformer failure.

MUN Substation contains equipment that is deteriorated, obsolete, and at end of life. All the circuit breakers and a significant quantity of switches require replacement based on their age and mechanical condition. The electromechanical protection relays are obsolete and are not industry standard.

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

Given the condition of MUN Substation, the probability of equipment failure is likely.

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

Table 2
Memorial Substation Refurbishment and Modernization Project
Risk Assessment Summary

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

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

**JUSTIFICATION**

The *Memorial Substation Refurbishment and Modernization* project is required to provide reliable service to customers. Addressing deteriorated and obsolete equipment identified through an engineering assessment will support the continued delivery of reliable service to the Company's largest customer.

| | |
|---|---|
| **Title:** | **Old Perlican Substation Refurbishment and Modernization** |
| **Asset Class:** | **Substations** |
| **Category:** | **Project** |
| **Investment Classification:** | **Renewal** |
| **Budget:** | **$3,356,000** |

## PROJECT DESCRIPTION

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

The 2024 scope of work for the *Old Perlican Substation Refurbishment and Modernization* project includes:

(i) Complete a yard extension;
(ii) Construct a new control building;
(iii) Construct new 66 kV and 12.5 kV steel structures to replace deteriorated wood structures;
(iv) Construct new spill containment foundations for existing transformer and existing voltage regulators;
(v) Install one new 66 kV breaker and one new 12.5 kV breaker;
(vi) Replace deteriorated 66 kV and 12.5 kV switches;
(vii) Install new 12.5 kV current transformer and 12.5 kV combined current and potential transformer;
(viii) Install new digital relay and the associated communications equipment; and
(ix) Upgrade and extend the ground grid.

Engineering design and procurement of long lead equipment will be completed in the first quarter of 2024. Construction will begin in the second quarter and will be completed in the fourth quarter of 2024. Commissioning of the substation will be completed by the end of 2024.

Additional information on this project is provided in Appendix B of report *2.1 2024 Substation Refurbishment and Modernization* filed with the Application.

## PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2024 for the *Old Perlican Substation Refurbishment and Modernization* project.

Table 1
Old Perlican Substation
Refurbishment and Modernization Project
2024 Budget
($000s)

| Cost Category | Total |
|---|---|
| Material | 2,143 |
| Labour - Internal | 190 |
| Labour - Contract | 0 |
| Engineering | 555 |
| Other | 468 |
| Total | $3,356 |

Proposed expenditures for the *Old Perlican Substation Refurbishment and Modernization* project total $3,356,000 for 2024.

**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 22 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.[51] Continued execution of the *Substation Refurbishment and Modernization Plan* is therefore necessary to replace obsolete and deteriorated equipment and infrastructure.

[51] For details of the assessment, see the *2024 Capital Budget Application,* report *2.1 2024 Substation Refurbishment and Modernization, Section 2.2*.

In 2024, Newfoundland Power is proposing to refurbish and modernize OPL Substation. The substation was built in 1975 as a distribution substation. An engineering assessment determined the substation contains a significant amount of deteriorated and obsolete equipment. Several pieces of equipment are at end of life, including the 66 kV and 12.5 kV wood pole structures and the 66 kV and 12.5 kV switches. Additionally, new transformer and voltage regulator spill containment foundations and upgrades to the substation's ground grid are necessary.

**ASSESSMENT OF ALTERNATIVES**

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

In the case of OPL Substation, the number of components requiring preventative and corrective maintenance at this time justifies the requirement to refurbish and modernize the substation in 2024.

Deferral of the *Old Perlican Substation Refurbishment and Modernization* project would increase the risk that some components will fail in service, which would result in an outage to approximately 1,800 customers in the Old Perlican, Bay de Verde, and Lower Island Cove area. Deferring this project further is therefore not a viable alternative.

**RISK ASSESSMENT**

The *Old Perlican Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to customers in the Old Perlican, Bay de Verde, and Lower Island Cove area.

OPL Substation provides service to approximately 1,800 customers in this service area. Equipment failure in the substation would expose all customers supplied by the OPL Substation to the risk of outages. The time to restore service to customers would depend on the nature of the failure and could range from several hours up to 36 hours.

OPL Substation contains equipment that is deteriorated and at end of life, which increases the probability of outages to customers. The wood pole structures in the substation are deteriorated and require replacement. The substation switches are aged and have deteriorated requiring replacement due to their mechanical condition. The power transformer is protected by fuses which does not provide industry standard protection.

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

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

Given the condition of OPL Substation, the probability of failure is likely.

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

Table 2
Old Perlican Substation Refurbishment and Modernization Project
Risk Assessment Summary

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

Overall, the condition of OPL Substation provides a Medium-High (16) risk to the delivery of reliable, safe and environmentally responsible service to customers. Action is required in 2024 to mitigate these risks for customers.

**JUSTIFICATION**

The *Old Perlican 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 1,800 customers from the Old Perlican, Bay de Verde, and Lower Island Cove area.

**Title:** **Substation Replacements Due to In-Service Failures**
**Asset Class:** **Substations**
**Category:** **Program**
**Investment Classification:** **Renewal**
**Budget:** **$4,797,000**

## 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.[52]

Table 1 provides the annual expenditures for the *Substation Replacements Due to In-Service Failures* program from 2019 to 2023.

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

| Year | 2019 | 2020 | 2021 | 2022 | 2023F |
|---|---|---|---|---|---|
| Total | $4,532 | $3,684 | $4,113 | $4,562 | $4,422 |
| Adjusted Cost[1] | $5,395 | $4,328 | $4,546 | $4,751 | $4,422 |

[1] 2023 dollars.

The average annual adjusted cost for the *Substation Replacements Due to In-Service Failures* program was approximately $4.7 million from 2019 to 2023.

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

Table 2 provides a breakdown of expenditures proposed for 2024 for the *Substation Replacements Due to In-Service Failures* program.

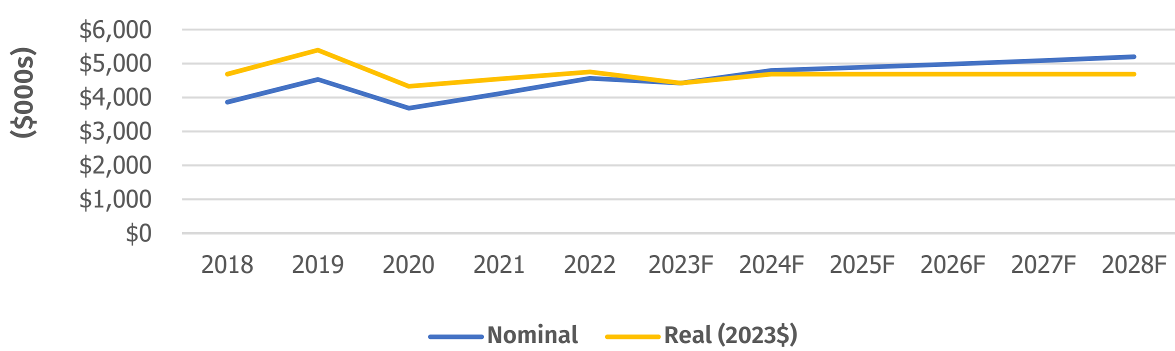
| Table 2<br>Substation Replacements Due to In-Service Failures Program<br>2024 Budget<br>($000s) | |
|---|---|
| Cost Category | 2024 |
| Material | 2,990 |
| Labour – Internal | 1,085 |
| Labour – Contract | 4 |
| Engineering | 359 |
| Other | 359 |
| Total | $4,797 |

Proposed expenditures for the *Substation Replacements Due to In-Service Failures* program total $4,797,000 for 2024.

**PROGRAM TREND**

Figure 1 shows historical and forecast expenditures for the *Substation Replacements Due to In-Service Failures* program from 2018 to 2028.[53]

**Figure 1**
**Substation Replacements Due to In-Service Failures**
**Program Expenditures**
**(2018 - 2028F)**




[53] For forecast annual expenditures for the *Substation Replacements Due to In-Service Failures* program, see the *2024-2028 Capital Plan,* Appendix A, Page A-3.

Annual expenditures under the *Substation Replacements Due to In-Service Failures* program averaged approximately $4.2 million from 2018 to 2023, or approximately $4.7 million when adjusted for inflation.[54] Annual expenditures are forecast to average approximately $5 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 were replaced or repaired under this program from 2018 to 2022.[55] Over the same period, an average of nine circuit breakers and reclosers and ten 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 2024 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.

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

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

**RISK ASSESSMENT**

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

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

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

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

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

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

**JUSTIFICATION**

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

**TRANSMISSION**

| | |
|---|---|
| **Title:** | **Transmission Line 146L Rebuild** |
| **Asset Class:** | **Transmission** |
| **Category:** | **Project** |
| **Investment Classification:** | **Renewal** |
| **Budget (Multi-Year):** | **$2,152,000 in 2024; $9,209,000 in 2025** |

## PROJECT DESCRIPTION

The *Transmission Line 146L Rebuild* project involves rebuilding Transmission Line 146L from Gander ("GAN") Substation to Gambo ("GAM") Substation to address deterioration and deficiencies identified through inspection.

Transmission Line 146L is proposed to be rebuilt as a multi-year project in 2024 and 2025. Engineering and pre-construction activities, including securing environmental and development permits and approvals, acquiring property rights, completing brush clearing of the new right-of-way, collecting topographic data, finalizing the engineering and design, and ordering materials will be completed in the first year. Completing all of this work in the first year allows for the Company to better manage lengthening timelines related to project approvals, environmental assessments, and permitting associated with transmission line rebuild projects. The second year will involve establishing construction contracts, procuring materials, and construction of the new line.

Additional information on this project is provided in report *3.1 2024 Transmission Line Rebuild* filed with the Application.

## PROJECT BUDGET

The budget for the *Transmission Line 146L Rebuild* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2024 and 2025 for the *Transmission Line 146L Rebuild* project.

Table 1
Transmission Line 146L Rebuild Project
2024-2025 Budget
($000s)

| Cost Category | 2024 | 2025 |
|---|---|---|
| Engineering | 161 | 173 |
| Labour – Contract | - | 4,645 |
| Labour – Internal | - | 167 |
| Material | - | 3,884 |
| Other | 1,991 | 340 |
| Total | $2,152 | $9,209 |

Proposed expenditures for the *Transmission Line 146L Rebuild* project total $11,361,000, including $2,152,000 in 2024 and $9,209,000 in 2025.

**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 146L is proposed to be rebuilt over two years starting in 2024.

Transmission Line 146L is a 138 kV line running between GAN and GAM substations. The transmission line serves as a critical element of the Central Newfoundland 138 kV looped transmission network which is supplied primarily from Sunnyside ("SUN") and Stony Brook ("STY") infeed supply points from Hydro's bulk power system. The SUN-STY loop is a key transmission supply network providing power to 35 Newfoundland Power substations.

Transmission Line 146L was originally constructed in 1964 and is 40.7 kilometres in length. The line consists of approximately 160 H-Frame structures with a combination of 244.4 ACSR and 397.5 ACSR conductor.[56] The conductor is approaching the end of the typical useful service life for transmission line conductor.[57]

Transmission Line 146L does not meet current design standards for the construction of overhead lines. The wind loads prescribed by the Canadian Standards Association[58] indicate

56 ASCR is a bare overhead conductor with aluminum outer strands and a steel core.
57 The typical useful service life of transmission overhead conductor is 63 years.
58 Canadian Standards Association CSA C22.3 NO. 1:20 – Overhead Systems.

that the load conditions used in the original design of Transmission Line 146L are below what is required based on historical wind data.[59] The substandard design of this line means it is not built to withstand local climatic conditions, which increases its probability of failure.

In 2023 Newfoundland Power initiated an engineering assessment of Transmission Line 146L in response to the line's deteriorating condition. A detailed inspection of the line was completed to quantify its overall condition. The inspection determined that 104 of 160 H-Frame structures have deficiencies. A total of 94 of 160 H-Frame structures have deteriorated poles, with the majority of these structures having both poles deteriorated. In total, there are 192 poles that require replacement.[60]

**ASSESSMENT OF ALTERNATIVES**

Transmission Line 146L is critical to the reliability of the Central Newfoundland 138 kV looped transmission network. Newfoundland Power evaluated two alternatives to address the deteriorated condition of Transmission Line 146L to mitigate risks to the delivery of reliable service to customers. These are: (i) address all deficiencies identified through inspection and defer the rebuild of the remainder of the line; and (ii) rebuild the existing line in a new, parallel right-of-way.

The assessment of alternatives included a net present value analysis to determine the least-cost alternative to addressing the deteriorated condition of Transmission Line 146L. The assessment determined that rebuilding Transmission Line 146L in a parallel right-of-way is the least-cost alternative to addressing the identified deficiencies.

**RISK ASSESSMENT**

The *Transmission Line 146L Rebuild* project will mitigate risks to the delivery of reliable service to customers supplied by the Central Newfoundland 138 kV looped transmission network. Due to their criticality in serving customers, Newfoundland Power's transmission lines must be maintained to operate to a high standard of reliability.[61] All transmission lines, including Transmission Line 146L, are maintained in accordance with the Company's *Transmission Inspection and Maintenance Practices*.[62]

While the historical reliability performance of Transmission Line 146L has been reasonable, the line's sub-standard design and deteriorated condition exposes it to an increased probability of failure going forward.[63]

---

59 See the *2024 Capital Budget Application,* report *3.1 2024 Transmission Line Rebuild,* page 3.

60 An additional 98 poles were inspected and found to be in moderate condition. These poles are original 1964 vintage and are showing less severe splits and cracks, meaning their condition has started to deteriorate.

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

62 Over the last 10 years, approximately $247,000 has been spent on corrective and preventative maintenance of Transmission Line 146L.

63 There have been three outage events over the last five years due to requirements to undertake preventative and corrective maintenance.

Inspections have identified that 192 poles on this line are deteriorated to the point where replacement is required. A significant quantity of the remaining poles are past the end of their useful service lives while also being in a deteriorated condition. Based on these factors the probability of failure is therefore likely.

Transmission Line 146L plays a critical role in the Central Newfoundland 138 kV transmission system. An outage to Transmission Line 146L results in two sections of the Central Newfoundland 138 kV transmission system becoming radial. When these sections are radially supplied, any single failure on one of these transmission lines could result in outages to between 1,700 and 8,700 customers downstream of the affected line. Transmission Line 146L is also required to maintain normal operating voltages on the transmission system under peak load scenarios.

The criticality of Transmission Line 146L and its increased probability of failure result in a high risk to the delivery of reliable service to a significant number of Newfoundland Power's customers.

Table 2 summarizes the risk assessment of the *Transmission Line 146L Rebuild* project.

Table 2
Transmission Line 146L Rebuild Project
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Transmission Line 146L Rebuild* project would pose a High (20) risk to the delivery of reliable service to customers.

**JUSTIFICATION**

The *Transmission Line 146L Rebuild* project is required to ensure the delivery of reliable service to customers in central Newfoundland. An assessment of alternatives determined that rebuilding Transmission Line 146L in a parallel right-of-way is the least cost option to address existing deterioration and deficiencies, and mitigate risks of equipment failures.

**Title:** **Transmission Line Maintenance**
**Asset Class:** **Transmission**
**Category:** **Program**
**Investment Classification:** **Renewal**
**Budget:** **$2,651,000**

## 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.[64]

Table 1 provides the annual expenditures for the *Transmission Line Maintenance* program from 2019 to 2023.

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

| Year | 2019 | 2020 | 2021 | 2022 | 2023F |
|---|---|---|---|---|---|
| Total | $2,214 | $2,139 | $2,404 | $2,488 | $2,610 |
| Adjusted Cost[1] | $2,633 | $2,517 | $2,643 | $2,563 | $2,610 |

[1] 2023 dollars.

The average annual adjusted cost for the *Transmission Line Maintenance* program was approximately $2.6 million from 2019 to 2023.

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

Table 2 provides a breakdown of expenditures proposed for 2024 for the *Transmission Line Maintenance* program.

Table 2
Transmission Line Maintenance Program
2024 Budget
($000s)

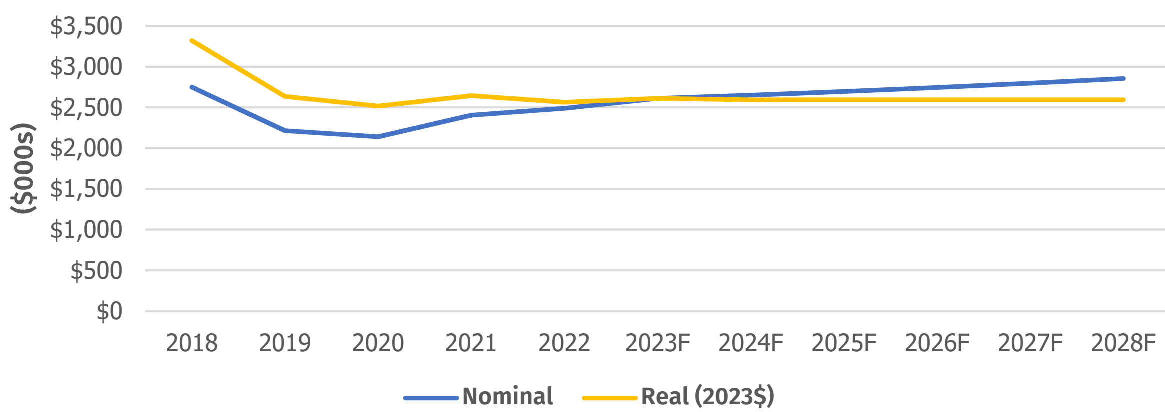
| Cost Category | 2024 |
|---|---|
| Material | 828 |
| Labour – Internal | 306 |
| Labour – Contract | 1,104 |
| Engineering | 116 |
| Other | 297 |
| Total | $2,651 |

Proposed expenditures for the *Transmission Line Maintenance* program total $2,651,000 for 2024.

**PROGRAM TREND**

Figure 1 provides historical and forecast costs for the *Transmission Line Maintenance* program from 2018 to 2028.[65]

**Figure 1**
**Transmission Line Maintenance Program Expenditures**
**(2018 - 2028F)**




[65] For forecast annual expenditures for the *Transmission Line Maintenance* program, see the *2024-2028 Capital Plan,* Appendix A, page A-4.

Annual expenditures under this program averaged approximately $2.4 million from 2018 to 2023, or approximately $2.7 million when adjusted for inflation.[66] Annual expenditures are forecast to average approximately $2.7 million over the next five years.

## ASSET BACKGROUND

Newfoundland Power owns and operates 111 transmission lines, which span approximately 2,100 kilometres. Virtually all of the Company's transmission lines operate at 66 kV or 138 kV.[67] 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 2018 to 2022, an average of 111 poles, 124 framing structures and 1,171 pieces of hardware were replaced annually due to corrective and preventative maintenance requirements.

## ASSESSMENT OF ALTERNATIVES

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

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

## RISK ASSESSMENT

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

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

[66] 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.

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

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

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

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

Table 3
Transmission Line Age

| Age (Years) | 1-10 | 11-20 | 21-30 | 31-40 | 41-50 | 51-60 | 61-65 | Total |
|---|---|---|---|---|---|---|---|---|
| Kilometres | 293 | 262 | 126 | 141 | 753 | 411 | 52 | 2,038 |
| Percentage of Total | 14% | 13% | 6% | 7% | 37% | 20% | 3% | 100% |

Approximately 23% of Newfoundland Power's transmission lines have been in service for over 50 years. An additional 37% of transmission lines have been in service for between 41 and 50 years. As transmission lines age, annual maintenance of these assets will continue to be critical to the provision of reliable service to customers.

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

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

Table 4
Transmission Line Maintenance Program
Risk Assessment Summary

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

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

**JUSTIFICATION**

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

# GENERATION - HYDRO

| | |
|---|---|
| **Title:** | **Lookout Brook Hydro Plant Refurbishment** |
| **Asset Class:** | **Generation – Hydro** |
| **Category:** | **Project** |
| **Investment Classification:** | **Renewal** |
| **Budget (Multi-Year):** | **$362,000 in 2024; and $1,573,000 in 2025** |

## PROJECT DESCRIPTION

The proposed *Lookout Brook Hydro Plant Refurbishment* project involves refurbishing the Lookout Brook hydroelectric plant (the "Lookout Brook Plant" or the "Plant"), located in western Newfoundland near the community of St. George's over two years. The project includes rewinding the Plant generating unit no. 3 ("G3") generator stator, rotor, and exciter. In addition, the Plant roof, crane and G3 main inlet valve will be replaced.[68]

The *Lookout Brook Hydro Plant Refurbishment* project will be completed in 2024 and 2025. In 2024, procurement and design of the generator, exciter and main inlet valve components will occur. Also, engineering and procurement of the powerhouse crane will occur in the first quarter of 2024 with installation during the third quarter of 2024. In 2025, project execution will take approximately 32 weeks to complete. The main inlet valve will be installed in the second quarter of 2025, followed immediately by removal of the stator, rotor and exciter to be shipped offsite. Following the installation of the windings in the third quarter of 2025, the refurbished rotor and exciter will be shipped back to site with unit reassembly and all commissioning completed by the end of the fourth quarter.[69]

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

## PROJECT BUDGET

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

[68] The crane will be replaced in advance of disassembling G3, as heavy lifts are required to disassemble and reassemble the generator and turbine. Also, the G3 main inlet valve replacement will occur early in 2025 thereby allowing generating unit no. 2 to remain in service throughout the overhaul of G3.

[69] The engineering of the building upgrades will occur during the second quarter of 2024 with replacement of the roof, windows and main loading door occurring in the second quarter of 2025.

Table 1 provides a breakdown of expenditures proposed for 2024 and 2025 for the *Lookout Brook Hydro Plant Refurbishment* project.

Table 1
Lookout Brook Hydro Plant Refurbishment Project
2024-2025 Budget
($000s)

| Cost Category | 2024 | 2025 |
|---|---|---|
| Material | 184 | 1,083 |
| Labour – Internal | 64 | 127 |
| Labour – Contract | - | - |
| Engineering | 30 | 60 |
| Other | 84 | 303 |
| Total | $362 | $1,573 |

Proposed expenditures for the *Lookout Brook Hydro Plant Refurbishment* project total $1,935,000, with $362,000 in 2024 and $1,573,000 in 2025.

**ASSET BACKGROUND**

The Lookout Brook Plant was originally commissioned in 1946 with two generating units ("G1 and G2") and was upgraded in 1958 with a third generating unit ("G3"). In 1984, G1 and G2 were replaced with a single larger generating unit ("G4") resulting in the current plant configuration. The Plant has an operating capacity of 5.6 MW under a net head of 154.6 metres. Annual production from the plant is 31.51 GWh or approximately 7% of Newfoundland Power's annual hydroelectric production.[70] The Lookout Brook Plant is operated throughout the year as a source of low-cost energy for Newfoundland Power's customers. The Plant is also routinely placed into service at the request of Hydro.

A condition assessment and corresponding risk assessment determined that the Lookout Brook 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. Equipment identified through the condition assessment includes the powerhouse building, crane, the main inlet valve for generating unit G3 and the rotor, stator, and exciter of unit G3.

[70] 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 31.51 GWh.

## ASSESSMENT OF ALTERNATIVES

Newfoundland Power identified and assessed two alternatives for the *Lookout Brook Hydro Plant Refurbishment* project. The alternatives included: (i) refurbishing the plant in 2024 and 2025; and (ii) deferring the refurbishment to a future year.

The assessment determined that completing the refurbishment in 2024 and 2025 is the least-cost alternative. The assessment was based on marginal supply costs as well as the potentially higher capital costs associated with an unplanned refurbishment if an in-service equipment failure were to occur.

A lifecycle cost analysis of the Lookout Brook Plant completed in connection with this project proposed shows that the benefits of the Plant's production exceed the cost of production.[71] This analysis shows a net benefit of Plant production is between 2.11 ¢/kWh and 2.97 ¢/kWh based on the most recent marginal cost estimates.[72] The lifecycle cost analysis confirms that continued operation of the Plant will provide an economic benefit for Newfoundland Power's customers over the longer term. For more details, see report *4.1 Lookout Brook Hydro Plant Refurbishment*.

## RISK ASSESSMENT

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

The Plant's generator G3 stator windings and rotor pole insulation is original and will be 67 years old in 2025. 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.

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

Table 2
Lookout Brook Hydro Plant Refurbishment Project
Risk Assessment Summary

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

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

71 Details on the benefits of the Plant's production are detailed in Table A-3, Lifecycle Analysis Results on Page A-5 of Appendix A of the *2024 Capital Budget Application* report *4.1 Lookout Brook Plant Refurbishment*.
72 Marginal supply costs are based on Hydro's December 2022 marginal cost update.

**JUSTIFICATION**

The *Lookout Brook Hydro Plant Refurbishment* project is required to provide reliable service to customers at the lowest possible cost. The Lookout Brook Plant continues to provide low-cost energy to customers. Completing required upgrades to the Plant in 2024 and 2025 will minimize Plant downtime and ensure the continued provision of low-cost energy to customers.

**Title:** **Mobile Hydro Plant Surge Tank Refurbishment**
**Asset Class:** **Generation – Hydro**
**Category:** **Project**
**Investment Classification:** **Renewal**
**Budget:** **$977,000**

## PROJECT DESCRIPTION

The *Mobile Hydro Plant Surge Tank Refurbishment* project involves the refurbishment of the surge tank at the Company's Mobile hydroelectric generating plant (the "Mobile Plant" or the "Plant"). The 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 2024 *Mobile Hydro Plant Surge Tank Refurbishment* project is in addition to the previously approved multi-year project that was approved for the Plant as part of the *2023 Capital Budget Application*. The 2024 project will include:

(i) Refurbishing the surge tank including the removal and replacement of the exterior protective coating system;
(ii) Installing cross bracing wear plates;
(iii) Replacing the surge tank access system protective coating system; and
(iv) Rehabilitating the interior protective coating system.[73]

The engineering and procurement will be completed in the first quarter of 2024. The Plant will be taken out of service starting in June 2024 for the previously approved capital project. The completion of the surge tank scope of work listed above will utilize the same plant outage. As previously submitted, the Plant will be out of service for approximately 26 weeks while all work is completed and commissioned.

Additional information regarding the previously approved project can be found in the *2023 Capital Budget Application*. Additional information on the proposed 2024 project is provided in report *4.2 Mobile Hydro Plant Surge Tank Refurbishment*.

## PROJECT BUDGET

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

[73] Work on the surge tank requires utilizing specialized work methods which will include articulating lifts, rope access and confined space work.

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

| Table 1<br>Mobile Hydro Plant Surge Tank Refurbishment Project<br>2024 Budget<br>($000s) | |
|---|---|
| Cost Category | 2024 |
| Material | 903 |
| Labour – Internal | 7 |
| Labour – Contract | - |
| Engineering | 40 |
| Other | 27 |
| Total | $977 |

Proposed expenditures for the *Mobile Hydro Plant Surge Tank Refurbishment* project total $977,000 for 2024.

**ASSET BACKGROUND**

The surge tank was constructed in 1999 to replace the original surge tank installed in 1951.[74] The surge tank supporting structure is constructed of hollow structural steel with bar type steel cross bracing. The surge tank is 61.1-metre tall, with a 1.83-metre diameter steel pipe riser and a 5.17-metre diameter steel surge bowl. The main structural steel system has a protective coating system for corrosion resistance while the pipe riser and surge tank bowl have external cladding and internal protective coating system for corrosion resistance. The surge tank has been in service for 24 years.

Newfoundland Power commissioned Kleinschmidt Canada Inc. ("Kleinschmidt") to conduct an internal and external condition assessment of the surge tank to identify and document deterioration.[75]

Kleinschmidt determined that the surge tank protective coating system is experiencing failure throughout the structure, including complete protective coating loss in the vicinity of the structural connections, and distributed areas of coating loss on the remaining structural members. The exterior cladding system on the surge tank riser and bowl is in good condition with no significant material loss or loose connections. The cross bracing is not showing

[74] The original surge tank required replacement after 48 years in service as a result of structural steel material loss due to failure of the protective coating system.

[75] The detailed inspection report can be found in report *4.2 Mobile Hydro Plant Surge Tank Refurbishment*, Appendix B, *Surge Tank Inspection Report – Mobile Development*.

significant material loss but are in contact with each other where they intersect, which will lead to material loss over time. The surge tank ladder system has complete protective coating loss. The interior coating system is mostly in good condition with localized protective coatings loss near the operational water level as well as along weld seams.

**RISK ASSESSMENT**

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

An updated economic analysis of the Mobile Plant completed in connection with this proposed project shows that the benefits of the Plant's production exceed the cost of production.[76] This economic analysis shows a net benefit of Plant production is between 4.52 ¢/kWh and 6.05 ¢/kWh based on the most recent marginal cost estimates.[77]

Protective coatings are designed to protect structural steel systems from corrosion. In areas subject to salt spray, such as coastal environments, the expected life is shorter than in less corrosive environments. Protective coating systems require replacement to ensure continued protection of the structural steel elements. If protective coating systems are not replaced, bare steel will be exposed and corrosion will occur, resulting in material loss. The ability of the structural steel to resist the applied loads will be reduced as material loss occurs. In the case of surge tanks, steel loss will result in decreased resistance to loading conditions and ultimately surge tank collapse.

Protective coating systems are an integral part of surge tank structural systems. A specified material thickness of steel is required to resist the applied loads on the structure. For the surge tank, the applied load is predominantly from the weight of water in the tank and wind loads on the structure. If left exposed to environmental conditions, corrosion will occur and material thickness will be lost until failure occurs. Over time this material loss will degrade the capability of the surge tank to resist wind loading that occurs naturally.

If protective coating systems are not replaced, the surge tank life expectancy will be reduced. Unprotected structural steel will experience progressive material loss until failure occurs. By replacing the protective coating system prior to material loss, the service life of the surge tank will be increased. A properly protected steel surge tank can have a service life exceeding 80 years.[78]

Based on the current condition of the Mobile Plant surge tank, the probability of failure is possible.

---

[76] Details on the benefits of the Plant's production are detailed in Table A-2, Lifecycle Analysis Results on Page A-3 of Appendix A of the *2024 Capital Budget Application* report *4.2 Mobile Hydro Plant Surge Tank Refurbishment*.

[77] Marginal supply costs are based on Hydro's December 2022 marginal cost update.

[78] To achieve a service life exceeding 80 years, routine inspections and protective coating replacements are required.

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

Table 2
Mobile Hydro Plant Surge Tank Refurbishment Project
Risk Assessment Summary

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

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

**JUSTIFICATION**

The *Mobile Hydro Plant Surge Tank 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:** **Hydro Facility Rehabilitation**
**Asset Class:** **Generation – Hydro**
**Category:** **Project**
**Investment Classification:** **Renewal**
**Budget:** **$794,000**

## PROJECT DESCRIPTION

The *Hydro Facility Rehabilitation* project involves the replacement or refurbishment of deteriorated hydro plant components that have been identified through routine inspections, operating experience and engineering studies. For 2024, the *Hydro Facility Rehabilitation* proposed project includes:

(i) *Pittman's Pond Headgate Replacement* – Capital expenditures of $564,000 are required to replace the deteriorated headgate structure at Pittman's Pond Plant, part of the Pittman's Pond hydroelectric development. To facilitate construction a coffer dam will be constructed upstream of the intake. The headgate will be replaced and a new electrical gate operator will be installed. Design work will be completed by the end of the second quarter and site work will be completed by the fourth quarter of 2024.

(ii) *Lockston Powerhouse Crane* – Capital expenditures of $160,000 are required to replace the deteriorated crane in the Lockston Plant powerhouse. Design work will be completed by the end of the second quarter and the replacement will be completed by the fourth quarter of 2024.

(iii) *Generation Control Systems Upgrades* – Capital expenditures of $70,000 are required to replace obsolete protection and control systems at the Hearts Content Plant. Design work will be completed by the end of the second quarter and the replacement will be completed in the fourth quarter of 2024.

## 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 2024 for the *Hydro Facility Rehabilitation* project.

Table 1
Hydro Facility Rehabilitation Project
2024 Budget
($000s)

| Cost Category | 2024 |
|---|---|
| Material | 624 |
| Labour – Internal | 38 |
| Labour – Contract | - |
| Engineering | 84 |
| Other | 48 |
| Total | $794 |

Proposed expenditures for the *Hydro Facility Rehabilitation* project total $794,000 for 2024.

**ASSET BACKGROUND**

Newfoundland Power operates 23 hydro plants throughout its service territory that generate a combined annual normal 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 inspections by plant operators, maintenance activities and replacement and refurbishment projects. The three items proposed for refurbishment in 2024 are:

(i) *Pittman's Pond Headgate Replacement ($564,000)*

The Pittman's Pond gatehouse houses the mechanical gate operator and the intake gate at the Pittman's Pond hydroelectric development.[79] The Pittman's Pond gatehouse was refurbished in 2016; however, the original 1959 vintage intake gate and gate operator were deemed serviceable and retained.

The intake gate condition has since deteriorated and no longer reliably isolates the penstock from the Pittman's Pond reservoir. During an incident of penstock damage in 2022, the gate was unable to prevent the flow of water into the penstock from

[79] An intake gate is the operational isolation point upstream of the penstock. The intake gate provides the ability to quickly isolate the penstock from the upstream reservoir for both planned and emergency maintenance work in addition to enabling planned capital work both to the penstock and to plant systems such as turbines and main inlet valves. This capability is essential for systems with wood stave penstocks such as Pittman's Pond as wood stave penstocks are more susceptible to failure than other penstock technologies.

Pittman's Pond. The concrete intake structure is deteriorated which inhibits dewatering the intake.[80] The Pittman's Pond reservoir impounds the storage for both Pittman's Pond and New Chelsea hydro plants. Failure of the head gate would impact production and both plants. Replacement of the intake gate is required to ensure continued safe operation of both plants.

(ii) *Lockston Powerhouse Crane ($160,000)*

Newfoundland Power has overhead powerhouse cranes inspected by a certified third party on an annual basis. These cranes are utilized for operations activities as well as during plant maintenance and major refurbishment work.

The Lockston powerhouse crane is original to the 1956 construction of the Plant. The crane has failed its third-party inspection and has been identified as lacking functional capabilities and is experiencing safety concerns with its hoist. Due to its age and configuration, refurbishment of the existing trolley and hoist is not feasible and the crane must be replaced.

(iii) *Generation Control Systems ($70,000)*

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.[81] 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 the Company's 23 hydroelectric facilities rely on some form of PLC technology.[82]

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.[83] 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.[84]

---

80 Stoplog installation slots and stoplogs form a secondary isolation point normally utilized for gate maintenance and replacement. The stoplog slots require rehabilitation and cannot be safely utilized to dewater the intake gate work site. The installation of an upstream coffer dam is required to rehabilitate the stoplog slots as well as replace the intake gate.

81 Replacement parts for the older electromechanical technology were no longer available. 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.

82 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.

83 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.

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

To ensure reliable operation of the Company's hydro plants, 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.

In 2024, the PLC system at the Hearts Content Plant 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 approximately $18 million annually, while the capacity-related value is estimated at approximately $15 million annually. When the Company's hydro plants are out of service, customers lose the benefit of this low-cost production.

For 2024, the *Hydro Facility Rehabilitation* project will address deteriorated and obsolete components at three facilities. The components to be addressed under the project include the Pittman's Pond intake gate, Lockston powerhouse crane and Hearts Content PLC. Combined, these three hydro plants represent 4.6% of the annual normal 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 2024 *Hydro Facility Rehabilitation* project.

Table 2
Hydro Facility Rehabilitation Project
Risk Assessment Summary

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

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

**JUSTIFICATION**

The *Hydro Facility Rehabilitation* project is required to provide reliable service to customers at least cost. Maintaining Newfoundland Power's hydro plants requires the replacement of deteriorated and failed equipment, components and systems. This includes the replacement of the Pittman's Pond gatehouse and Lockston Powerhouse Crane in 2024 and the upgrade of the PLC system at the Heart's Content Plant. Completing these upgrades will ensure the continued operation of these hydro plants and the continued provision of low-cost energy to customers.

**INFORMATION SYSTEMS**

| | |
|---|---|
| **Title:** | **Application Enhancements** |
| **Asset Class:** | **Information Systems** |
| **Category:** | **Project** |
| **Investment Classification:** | **General Plant** |
| **Budget:** | **$1,892,000** |

**PROJECT DESCRIPTION**

The *Application Enhancements* project includes the enhancement or replacement of six software applications in 2024 to reduce costs to customers or improve customer service delivery. The proposed 2024 project includes:

(i) Digital Forms Portfolio Enhancement;
(ii) Workforce Management System Enhancement;
(iii) Daily Time Entry Application Enhancement;
(iv) Webchat Enhancement;
(v) IT Service Management System Enhancement; and
(vi) takeCHARGE Website Enhancement.

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

Execution of the 2024 *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 2024 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 2024 for the *Application Enhancements* project.

| Table 1<br>Application Enhancements Project<br>2024 Budget<br>($000s) | |
|---|---|
| Cost Category | 2024 |
| Material | 175 |
| Labour – Internal | 1,255 |
| Labour – Contract | - |
| Engineering | - |
| Other | 462 |
| Total | 1,892 |

Proposed expenditures for the *Application Enhancements* project total $1,892,000 for 2024.

**ASSET BACKGROUND**

The items included under the 2024 *Application Enhancements* project are:

(i) *Digital Forms Portfolio Enhancement ($227,000)*

Newfoundland Power routinely seeks to digitize paper-based forms through its Digital Forms Portfolio. The Digital Forms Portfolio Enhancement will digitize existing manual processes for vegetation management deficiencies and work assignments. On average, 4,500 vegetation management deficiencies are identified annually that require follow up to address. These deficiencies are logged manually. Associated work packages are then created which prioritize and assign them to utility arborists. Digitizing this process via Digital Forms will improve both efficiency and work package quality. It will also compile information in a centralized database, which will result in more efficient record keeping and a reduction in manual processes.

(ii) *Workforce Management System Enhancement ($374,000)*

The Company's Workforce Management System ensures the effective and efficient management of field work, including the scheduling, dispatching and monitoring of field crews. The proposed enhancement would expand the current software solution to an additional 62 employees in the Electrical Maintenance and Metering groups. Expanding the Company's Workforce Management System will provide operating efficiencies by reducing manual efforts for the dispatching and monitoring of work tasks. The system will utilize existing mobile device technology to provide real-time data updates on work orders completed in the field, which will assist in the assignment and prioritization of tasks in real time.

(iii) *Daily Time Entry Application Enhancement ($224,000)*

Newfoundland Power implemented its current Daily Time Entry Application in 2012. A total of 144 Powerline Technicians and 14 Line Supervisors use the application on a daily basis. Powerline Technicians are required to record their hours worked each day and associate them with specific job assignments, such as a capital project. This enhancement involves pre-populating project numbers in the Daily Time Entry Application by pulling the employee's daily work assignments from the Company's Workforce Management System. This enhancement is justified on a reduction in manual data entry which will improve operating efficiency and data quality.

(iv) *Webchat Enhancement ($274,000)*

This item involves implementing an automated webchat for customers to interact with Newfoundland Power using an artificial intelligence service and identity verification. In 2021, Newfoundland Power implemented a webchat service as an additional communication channel for customers using its website. Implementing automated webchat will keep pace with customers' increasing expectations for digital communication. The service will be available 24 hours a day, seven days a week, and will provide an avenue for customers to obtain information outside of regular business hours. This service will initially enable customers to report a power outage, check power outage status, determine their account balance, enroll in e-billing, and inquire on energy usage details. Incorporating automated Webchat with Newfoundland Power's website is justified on the basis of improved customer service.

(v) *IT Service Management System Enhancement ($250,000)*

This item involves enhancing the Company's IT Service Management System by implementing the Software Asset Management module. Newfoundland Power manages over 300 licenses that support the applications, operating systems, databases, cybersecurity tools and other software used to provide service to its customers. Today these software licenses are manually managed using a number of different systems and spreadsheets, which are reviewed multiple times a year for compliance. Licencing models have become more complex in recent years. Each license must be reviewed periodically to ensure compliance and adjusted based on increases or decreases in the number of allowable users.

Implementing a Software Asset Management module would automatically analyze software licenses and report on non-compliance. It will also ensure that software contracts and licenses remain right-sized for business requirements. In addition, employees will no longer be required to manually review each software license to assess these requirements. Enhancing the IT Service Management is justified on the basis of improved operating efficiencies.

(vi) *takeCHARGE Website Enhancement ($71,000)*

This enhancement will update the takeCHARGE website to ensure customers continue to have access to up-to-date information on customer energy conservation and electrification initiatives. The takeCHARGE website has been an integral part of the Company's customer energy conservation programs since 2009. The website serves as the primary communication channel to provide customers with information on available programs and rebates, as well as energy conservation education and awareness resources. There were over 660,000 visits to the takeCHARGE website in 2022.

(vii) *Various Minor Enhancements ($472,000)*

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

Examples of enhancements previously completed under this item include: (i) the development of a customer-facing streetlight outage map on the Newfoundland Power website; (ii) compliance reporting enhancements for the heavy fleet record of duty system; (iii) automation of financial reporting processes; (iv) improved performance testing of the high volume call answering system during upgrades and patching; and (v) the development of dashboards for the System Control Centre to track emergency calls from customers.

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

## ASSESSMENT OF ALTERNATIVES

The application enhancements identified for 2024 will advance operational efficiency and provide quantifiable cost savings for customers. Deferring the 2024 *Application Enhancements* project would defer the realization of these cost savings and customer service benefits. Deferring this project is therefore not a viable alternative.

## RISK ASSESSMENT

The *Application Enhancements* project provides an economic benefit to customers by enhancing software applications to reduce manual processes and by replacing software applications with lower-cost alternatives.

The Digital Forms Portfolio Enhancement, Workforce Management System Enhancement, Daily Time Entry Application Enhancement and IT Service Management System Enhancement will provide a combined positive net present value for customers of approximately $236,000. The Webchat Enhancement will improve customer service by offering another communication channel that will be available continuously. The takeCHARGE Website Enhancement will improve the information available to customers on energy conservation and electrification, and the Various Minor Enhancements item will provide flexibility to take advantage of opportunities to improve the Company's operating efficiency throughout the year. In addition to cost savings and customer service improvements, implementing these items in 2024 will also provide improved record keeping for auditing and regulatory compliance purposes and enhanced functionality for managing employee processes.

These cost savings and customer benefits have been confirmed through detailed assessments, including net present value analyses.

Table 2 summarizes the risk assessment of the 2024 *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 2024 *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:** **$964,000**

## PROJECT DESCRIPTION

The *Shared Server Infrastructure* project proposes the addition, upgrade and replacement of computer hardware components and related technology associated with shared server infrastructure and peripheral equipment. For 2024, four items are proposed to improve the functionality of Newfoundland Power's shared server infrastructure. These include: (i) Server Infrastructure Upgrades; (ii) Operations Server Infrastructure Upgrades; (iii) Enterprise Printing Upgrades; and (iv) a Mail Inserter Replacement.

Implementing this functionality will support the performance and cybersecurity of the computing hardware that underpins the operation of software applications used in providing safe and reliable service to customers at least cost.

## PROJECT BUDGET

The budget for the *Shared Server Infrastructure* project is based on cost estimates for the individual budget items.

Table 1 provides a breakdown of expenditures proposed for 2024 for the *Shared Server Infrastructure* project.

Table 1
Shared Server Infrastructure Project
2024 Budget
($000s)

| Cost Category | 2024 |
|---|---|
| Material | 665 |
| Labour – Internal | 259 |
| Labour – Contract | - |
| Engineering | - |
| Other | 40 |
| Total | $964 |

Proposed expenditures for the *Shared Server Infrastructure* project total $964,000 for 2024.

**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.

Four upgrades are proposed for 2024:

(i) *Server Infrastructure Upgrades ($405,000)*

Upgrades are required in 2024 to extend the useful service life of existing server infrastructure. Infrastructure upgrades include installing additional components to increase disk storage and expand processor and memory capacity to accommodate growth in information storage needs and improve the performance of Company applications. As applications are upgraded and accumulate data over time, they require additional processors and memory to maintain an acceptable level of performance. Upgrades are also required to maintain vendor support of the server operating system as well as to meet cybersecurity requirements.[85]

(ii) *Operations Server Infrastructure Upgrade ($160,000)*

Upgrades are required in 2024 to replace operations servers used to manage devices on the distribution system, such as downline reclosers, substation circuit breakers, automated switches and protection devices. These devices are used to allow the Company to efficiently and safely provide service to customers. The secure and responsive operation of these devices is necessary to ensure the delivery of safe and reliable service to customers. As of 2024, the existing servers will be in service for seven years and will have reached the end of their useful lives.

(iii) *Enterprise Printing Upgrades ($318,000)*

Upgrades are required in 2024 to replace multi-function printers and plotters throughout Newfoundland Power's operations. Multi-function printers and plotters are used daily in activities required to provide service to customers. Multi-function printers are used daily to print contracts, reports, permits, and to scan documents used in all aspects of Company operations. Plotters are used in electricity system design. The average age of devices to be replaced in 2024 is 11 years. These devices will no

85 Microsoft Windows Operating Systems require continual upgrading to maintain vendor support and to continue receiving the latest cybersecurity updates. Upgrades to hardware are often tied directly to software licensing requirements by the vendor and require adjustments to maintain license compliance.

longer will be supported by the vendor for service or replacement parts and require replacement.

(iv) *Mail Inserter Replacement ($81,000)*

Upgrades are required in 2024 to replace Newfoundland Power's mail inserter. The mail inserter is a core component used to provide customers with their bills along with other information and correspondence. It automates high volume work activities by inserting bills and other correspondence in envelopes for distribution to customers. The mail inserter processes approximately 120,000 bills and correspondence to customers monthly. Like many pieces of equipment, mail inserters have moving parts and components that wear down and break as they are used. The manufacturer provides continual support by replacing these worn components on a regular basis as a part of a maintenance agreement. The current mail inserter has been in service for 12 years and is no longer supported by the manufacturer for service or spare parts. It has therefore reached the end of its useful service life and requires replacement.

**ASSESSMENT OF ALTERNATIVES**

Each year, an assessment is completed to identify shared server infrastructure requirements and alternatives available to meet those requirements. The assessment involves identifying server infrastructure and peripheral equipment that either: (i) requires lifecycle replacement based on age and risk of failure; (ii) can be upgraded to extend its useful service life; (iii) must be added based on new computing requirements; or (iv) requires upgrading as part of cybersecurity management. The annual assessment considers multiple factors, including vendor support and product roadmaps, the current performance of components, associated costs, the criticality of a component and the consequence in the event of a failure. Upgrades that are not critical to Newfoundland Power's operations are deferred.

Approximately 59% of proposed 2024 expenditures relate to routine upgrades and additions to Newfoundland Power's shared server infrastructure, including the replacement of infrastructure supporting the operation of critical electrical system devices. These upgrades are necessary to accommodate growth in information storage needs, improve performance of Company applications and maintain vendor support. Deferring these upgrades would threaten the secure and reliable operation of hardware and software used in providing service to customers, and would not be prudent.

Approximately 41% of proposed 2024 expenditures relate to the replacement of Newfoundland Power's enterprise printing infrastructure and mail inserter. This critical infrastructure underpins the Company's ability to print documentation required in day-to-day operations and to provide correspondence to customers. Deferring these upgrades would expose the components to risk of failure and would impede the Company's ability to provide adequate service to customers.

**RISK ASSESSMENT**

The *Shared Server Infrastructure* project will mitigate risks to the delivery of safe and reliable service to customers.

Newfoundland Power's shared server infrastructure enables the operation of software applications used in providing service to customers, including the SCADA system, and the storage of customer and Company information necessary to run those applications. Instability within computing hardware could result in compromising customer or Company information, losing a software application that is critical to serving customers, or losing the ability to remotely control and monitor the electrical system. The failure of a server could require several days to address.

Research by Gartner Inc. indicates that servers have a useful life of approximately five years.[86] As a result of appropriate investments in its shared server infrastructure, the Company's servers experience an average useful life of about seven years. The probability of instability within computing hardware would be likely if computing hardware is not upgraded and extended beyond its useful life.

Table 2 summarizes the risk assessment of the *Shared Server Infrastructure* project.

Table 2
Shared Server Infrastructure Project
Risk Assessment Summary

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

Based on this assessment, not proceeding with the *Shared Server Infrastructure* project would pose a High (20) risk to the delivery of safe and reliable service to customers.

**JUSTIFICATION**

The *Shared Server Infrastructure* project is required to provide safe and reliable service to customers at the lowest possible cost. Management of server equipment through this project is essential to the secure and reliable operation of Company technologies used in the provision of service to customers.

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

**Title:** **System Upgrades**
**Asset Class:** **Information Systems**
**Category:** **Project**
**Investment Classification:** **General Plant**
**Budget:** **$957,000**

## PROJECT DESCRIPTION

The *System Upgrades* project involves upgrades to third-party software products that comprise Newfoundland Power's information systems. System upgrades proposed for 2024 involve the Company's customer website, Financial Management System and SCADA system.

Upgrades to the customer website and Financial Management System are critical to ensure continued vendor support that include bug fixes and security patches. Upgrades to the SCADA system align with industry best practices and maintain system performance, address bug fixes and ensure the latest security updates. The *System Upgrades* project also includes an item for other minor software applications that have either reached the end of vendor support, require bug fixes, security patches, or changes to comply with technology, regulatory or legislative requirements.

## PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2024 for the *System Upgrades* project.

Table 1
System Upgrades Project
2024 Budget
($000s)

| Cost Category | 2024 |
|---|---|
| Material | - |
| Labour – Internal | 718 |
| Labour – Contract | - |
| Engineering | - |
| Other | 239 |
| Total | $957 |

Proposed expenditures for the *System Upgrades* project total $957,000 for 2024.

**ASSET BACKGROUND**

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

The system upgrades proposed for 2024 are:

(i) *Customer Website Upgrade ($363,000)*

This item involves upgrading the software used to manage and operate Newfoundland Power's customer website to a version that continues to be fully supported by the vendor.

The customer website is a key component of Newfoundland Power's customer service delivery. Customers access the website to manage their accounts, obtain outage-related information, and access programs and services. The website is currently the most frequently used communication channel for customers. An average of approximately 2.5 million customer inquiries were received annually from 2018 to 2022. Approximately 79% of these inquiries were completed via the website.

The website software: (i) supports all customer interactions completed via the website including Webchat; (ii) provides the navigation functionality required for customers to navigate the website; (iii) enables 50 self-service functions available to customers[87]; and (iv) provides customers the option of using the website via mobile devices.

The website software was last upgraded in 2021. Upgrading the website software in 2024 is required to ensure continued vendor support and continued availability and performance of the website for customers. Remaining current with the latest versions of software will also help protect customer's personal information against evolving cybersecurity threats.

The project is anticipated to commence in the first quarter of 2024 and will be completed in the third quarter.

(ii) *Financial Management System Upgrade ($116,000)*

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

[87] Examples of self-service options include the ability to apply for electrical service, subscribe to the Equal Payment Plan, sign up for ebills and report outages.

Newfoundland Power's Financial Management System was implemented in 2002. It is used on a daily basis to manage the Company's financial resources, project accounting, and procurement and inventory processes. The Financial Management System communicates with other Company information systems to ensure the automatic flow of information relating to purchasing functions, electronic invoicing and warehouse management. This automation achieves efficiencies in the day-to-day management of financial processes.

For 2024, the proposed upgrade of the Company's Financial Management System will apply the latest software release available from the vendor. Commencing with the 2023 upgrade, the vendor introduced a new policy that requires upgrades on an annual cycle. The 2024 upgrade is required in order to receive vendor support, bug fixes, new features and security updates necessary to keep pace with evolving cybersecurity threats.

The project is anticipated to commence in the second quarter of 2024 and will be completed in the third quarter.

(iii) *SCADA System Upgrade ($93,000)*

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 2024, the proposed upgrade of the Company's SCADA system will ensure consistent and effective system operation and will apply the latest security updates and available features. The upgrade will ensure the SCADA system continues to provide real-time monitoring of the Company's electrical system assets across its service territory.

The project is anticipated to commence in the first quarter of 2024 and will be completed in the second quarter.

(iv) *Various Minor Upgrades ($385,000)*

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 improves software stability.

New versions of third-party software products are generally designed to address identified deficiencies, thereby improving performance and allowing the Company to take advantage of new functionality. New software versions also typically include necessary cybersecurity improvements. Newfoundland Power assesses these security improvements to ensure the Company maintains a secure computing environment. The timing of the upgrades is based on a review of the risks and operational experience of the systems under consideration.

The process of estimating the budget for *Various Minor Upgrades* is based on the historical average cost of executing this work over the most recent three-year period adjusted for inflation.

**ASSESSMENT OF ALTERNATIVES**

In considering whether to complete a system upgrade, Newfoundland Power considers the criticality of the system to its operations, the benefits of the upgrade, and whether the upgrade is required to maintain vendor support.

Certain upgrades are relatively minor, do not address material issues with the software, and are not required to maintain vendor support. These software versions can often be skipped and a system upgrade can be deferred to a future version. Other times, a software version provides critical cybersecurity patches, is required as a condition of maintaining vendor support, or provides material improvements in system performance. These upgrades cannot typically be deferred to a future version without threatening system security or performance.

Vendor-mandated upgrades periodically involve major new releases. These upgrades can be substantial in scope and cost, involving substantive changes to a system's architecture, user interface or functionality. When substantial system upgrades are required, Newfoundland Power will consider whether implementing an alternative software product would be lower cost than upgrading existing software.

The upgrades proposed for 2024 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 $93,000 to $363,000 and do not constitute major product releases that warrant consideration of system replacement. Completing the required system upgrades in 2024 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 2024 is essential to Newfoundland Power's operations. Upgrades of the Customer Website and Financial Management System are necessary to ensure continued vendor support and to provide for the latest security patches and bug fixes for those systems. The criticality of the SCADA system necessitates annual upgrades to maximize system performance and security. Ensuring continued vendor support mitigates risks associated with system failures.

Failure of these systems would have serious consequences to the delivery of safe and reliable service to customers. As examples, a security failure of the SCADA system could expose the electrical system to external interference, and a security failure of the Customer Website could compromise customer personal information.

System upgrades are becoming more frequent due to changes in vendor requirements and the need to manage cybersecurity risks. The system upgrades proposed for 2024 are necessary to mitigate risks of information system failure by implementing the latest bug fixes and cybersecurity patches and to maintain vendor support. As these improvements address known issues with information systems, such as cybersecurity vulnerabilities, the probability of failure is considered likely if these upgrades are not completed.

Table 2 summarizes the risk assessment of the 2024 *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 2024 *System Upgrades* project would pose a Medium-High (16) risk to the delivery of safe and reliable service to customers.

**JUSTIFICATION**

The *System Upgrades* project is required to ensure the secure and reliable operation of information systems that are essential to the delivery of service to customers. The proposed upgrades will implement the latest bug fixes and cybersecurity patches available from the vendors and will ensure vendor support is maintained for those systems.

| | |
|---|---|
| **Title:** | **Cybersecurity Upgrades** |
| **Asset Class:** | **Information Systems** |
| **Category:** | **Project** |
| **Investment Classification:** | **General Plant** |
| **Budget:** | **$930,000** |

## PROJECT DESCRIPTION

The *Cybersecurity Upgrades* project involves upgrades to the Company's cybersecurity infrastructure. Proposed 2024 capital expenditures include new technologies and enhancements to existing technologies that will reduce risk and enhance security in the areas of network and firewall security in Operation Technologies and SCADA environments, as well as enhance privileged access security and security logging.

## 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 2024 for the *Cybersecurity Upgrades* project.

Table 1
Cybersecurity Upgrades Project
2024 Budget
($000s)

| Cost Category | 2024 |
|---|---|
| Material | 113 |
| Labour – Internal | 627 |
| Labour – Contract | - |
| Engineering | - |
| Other | 190 |
| Total | $930 |

Proposed expenditures for the *Cybersecurity Upgrades* project total $930,000 for 2024.

## ASSET BACKGROUND

Cybersecurity risk assessments are completed annually on assets in Newfoundland Power's corporate, Operations Technology and SCADA environments. These assessments are performed with the help of an external third party and utilize controls based on industry best practices, standards and frameworks. The risk assessments identify any areas where Newfoundland Power is at a higher cybersecurity risk level and require work to lower risk and help protect assets and customer and Company information.

Risk assessments routinely identify the need for new or enhanced technology to help mitigate risk. In 2024, upgrades are required to enhance: (i) network security through segmentation and the enablement of security services for network traffic; (ii) technologies used to monitor and log security threats; and (iii) secure privileged access for Company applications. These security enhancements are critically important to the day-to-day provision of safe and reliable service to customers.

## RISK ASSESSMENT

The *Cybersecurity Upgrades* project will mitigate risks to the delivery of safe and reliable service to customers by protecting Newfoundland Power's operations and the electrical system against cybersecurity threats.

Newfoundland Power continually assesses its infrastructure to identify measures to improve the Company's cybersecurity. The cybersecurity measures identified for implementation in 2024 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.[88] Continual improvements in cybersecurity resilience and response capabilities are necessary to respond to this evolving threat.

[88] A 2022 global survey conducted by Gartner Inc., a leading technology advisory firm, indicated that spending in the information security and risk management market was projected to grow at 12.22% in 2022. Spending on information security and risk management is expected to reach $261.9 billion in spending in 2026. See Gartner Inc., *Forecast Analysis: Information Security and Risk Management, Worldwide*, September 15, 2022.

Table 2 summarizes the risk assessment of the *Cybersecurity Upgrades* project.

Table 2
Cybersecurity Upgrades Project
Risk Assessment Summary

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

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

**JUSTIFICATION**

The *Cybersecurity Upgrades* project is required to maintain safe and reliable service to customers as investments in cybersecurity are essential to protecting customer and Company information and protecting the electricity system from external interference.

**Title:** **Microsoft Enterprise Agreement**
**Asset Class:** **Information Systems**
**Category:** **Project**
**Investment Classification:** **General Plant**
**Budget (Multi-Year):** **$297,000 in 2024; $297,000 in 2025; and $297,000 in 2026**

## PROJECT DESCRIPTION

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

The annual agreement is a fixed price based on the number of eligible employees that use Microsoft software products on Company-assigned personal computers. In 2024, a three-year agreement will be entered into to renew the Microsoft Enterprise Agreement.[89] Under this agreement, the Company will continue to distribute its purchasing costs for these licenses over three years.

## PROJECT BUDGET

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

Table 1 provides a breakdown of expenditures proposed for 2024 for the *Microsoft Enterprise Agreement* project.

Table 1
Microsoft Enterprise Agreement
2024 Budget
($000s)

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

[89] The existing Microsoft Enterprise Agreement will conclude on May 31, 2024. The terms of the next agreement will be from June 1, 2024 to May 31, 2027.

Proposed expenditures for the *Microsoft Enterprise Agreement* project total $891,000, with $297,000 in 2024, $297,000 in 2025 and $297,000 in 2026.

**ASSET BACKGROUND**

Newfoundland Power has had the Microsoft Enterprise Agreement in place providing access to the latest versions of software products for over 15 years. Software licenced under this agreement includes the Windows operating system for each Company-assigned personal computer, the Microsoft Office suite of programs, Microsoft Teams, Exchange and SharePoint. This software is required to operate software systems used by all employees in delivering safe and reliable service to customers.

The terms of the agreements are typically three years in duration, with requirements reviewed and adjusted annually. Purchasing Microsoft software under an enterprise agreement provides cost savings by availing of volume pricing discounts offered by Microsoft. It also provides upgrades to Microsoft technology at no additional cost.

**RISK ASSESSMENT**

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

Each Company-assigned personal computer requires the Windows Operating System in order to operate software. This is essential for operating the 190 software applications required to provide least-cost, reliable service to customers. Failure to obtain the latest available upgrades to the Windows Operating System would have serious consequences to the delivery of safe and reliable service to customers. As examples, a security failure by using an unsupported operating system could compromise key systems and introduce security vulnerabilities. Failure of the Company's email system could compromise customer or Company information and disrupt communications with customers and among employees.

As the existing Microsoft Enterprise Agreement is expiring in 2024, the probability of adverse consequences arising from losing access to this software is likely.

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

Table 2
Microsoft Enterprise Agreement
Risk Assessment Summary

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

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

**JUSTIFICATION**

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

## GENERAL PROPERTY

**Title:** **Gander Building Renovation**
**Asset Class:** **General Property**
**Category:** **Project**
**Investment Classification:** **General Plant**
**Budget (Multi-Year):** **$175,000 in 2024; $760,000 in 2025**

## PROJECT DESCRIPTION

The *Gander Building Renovation* project involves capital improvements to replace deteriorated and deficient building components at Newfoundland Power's Gander Area Office Building (the "Gander Building"). The building's roofing and cladding systems will be renovated and replaced where required to mitigate water infiltration into the building structure. The heating, ventilation and air conditioning ("HVAC") unit will be replaced and associated ductwork modifications will be completed to address deficiencies with building ventilation and air conditioning. Asbestos plaster will be removed and drywall will be replaced. Light fixtures will be replaced with light emitting diode ("LED") lighting for improved energy efficiency.

The renovations will be completed over two years to accommodate long lead times for the procurement of the building's HVAC unit. Design and procurement will be completed in 2024. Construction will begin in 2025 and will be completed by the end of the fourth quarter.

## PROJECT BUDGET

The budget for the *Gander Building Renovation* project is based on a detailed engineering estimate.

Table 1 provides a breakdown of expenditures proposed for 2024 an 2025 for the *Gander Building Renovation* project.

Table 1
Gander Building Renovation Project
2024-2025 Budget
($000s)

| Cost Category | 2024 | 2025 |
|---|---|---|
| Material | 116 | 531 |
| Labour – Internal | 2 | 8 |
| Labour – Contract | - | - |
| Engineering | 42 | 105 |
| Other | 15 | 116 |
| Total | $175 | $760 |

Proposed expenditures for the *Gander Building Renovation* project total $935,000, including $175,000 in 2024 and $760,000 in 2025.

**ASSET BACKGROUND**

Newfoundland Power maintains area and district office buildings throughout its service territory. These buildings serve as the base of operations for employees working to provide service to customers. As building components deteriorate and operational requirements evolve, there is an ongoing requirement to renovate, upgrade or replace equipment and systems at these facilities to extend their useful service lives.

The Gander Building is Newfoundland Power's centre of operations for the Gander area in Central Newfoundland. The building was originally constructed in 1975, with additions to the original structure in 1987 and 1997.[90] The building is the base of operations for 23 employees and equipment necessary to serve customers in the area.[91] Employees at the Gander Building provide service to approximately 17,000 customers from Glenwood to Charlottetown and as far north as Musgrave Harbour.

A condition assessment of the building was completed in 2022. The condition assessment indicated that portions of the building's roofing and cladding systems have failed and others require remediation. The roofing and cladding system constructed in 1997 has failed, with multiple leaks present. Repair attempts on the roofing and cladding system in the form of patching have not been successful.

Figure 1 shows the roofing system constructed in 1997.

*Figure 1 - 1997 Vintage Roofing System at Gander Building*

90 Upgrades completed since building construction include replacement of the 1975 vintage roofing system in 2004, installation of a backup diesel generator in 2014, and customer service security enhancements in 2017.
91 Office staff at the Gander Building include customer service representatives, engineering technologists, planners, line staff, material handlers, and meter readers.

Figure 2 shows the building cladding constructed in 1997.

*Figure 2 - Cladding at Gander Building*

Figure 3 shows an example of water ingress to the building as a result of a failure of the roofing and cladding system.

*Figure 3 - Water Ingress Exhibited at Gander Building*

The exterior HVAC unit was installed in 1987 as part of the addition to the building. The unit has experienced numerous breakdowns in the last five years. Failure of the HVAC system leads to inadequate heating and cooling for employees working in the building. Without adequate ventilation, the building does not meet the Newfoundland and Labrador Occupational Health and Safety Regulations.[92] Additionally, the HVAC system uses Freon R-22 as a refrigerant, which is not environmentally friendly and is required to be phased out of use in commercial air conditioning equipment by 2030.[93]

The condition assessment also identified asbestos plaster present throughout the facility. Asbestos is a known carcinogen and is regulated pursuant to the *Asbestos Abatement Regulations, 1998 (Newfoundland and Labrador Regulation 111/98)*. All asbestos will be removed from the building to ensure the safety of employees working in the building.

The building has traditional commercial light fixtures. Installing LED lighting fixtures will improve the building's energy efficiency.

**RISK ASSESSMENT**

The *Gander Building Renovation* project will mitigate risks associated with the safe and reliable delivery of service to customers by maintaining adequate workspaces for employees.

Correcting deteriorated and deficient equipment at the Gander Building is necessary to maintain the facility as an adequate workspace for employees. The Gander Building allows Newfoundland Power to provide a reasonable response time to trouble calls received from approximately 17,000 customers in the area.[94]

Not proceeding with the *Gander Building Renovation* project proposed for 2024 could hinder Company operations at the Gander Building and expose employees to potential safety hazards due to the failure of building components. This could negatively impact Newfoundland Power's response time to customers in the area. Historical performance of the building's HVAC and roofing and cladding systems indicates the probability of equipment failure is likely if left unaddressed.

---

92 Section 45 of the *Occupational Health and Safety Regulations, 2009 (Newfoundland and Labrador Regulation 70/09)* details ventilation requirements for a workspace.

93 Canada has guaranteed phase-out level of Hydrochlorofluorocarbons ("HCFC") through the *Ozone-depleting Substances Regulations, 1998* made under the *Canadian Environmental Protection Act, 1999,* which imposed the *Montreal Protocol*. R-22 are ozone-depleting refrigerants and, under the terms of the Montreal Protocol, will be 99.5% phased out by 2020 and completely eliminated by 2030. After 2020, R-22 refrigerant will no longer be imported or manufactured in Canada.

94 The Company targets a two-hour response time to customers for trouble calls. The time required to travel to Musgrave Harbour, which is served from the Gander Building, to the next closest operations centres in Grand Falls-Windsor or Clarenville exceeds two hours.

Table 2 summarizes the risk assessment of the *Gander Building Renovation* project.

| Table 2<br>Gander Building Renovation Project<br>Risk Assessment Summary | | |
|---|---|---|
| Consequence | Probability | Risk |
| Moderate (3) | Likely (4) | Medium-High (12) |

Based on this assessment, deferring the *Gander Building Renovation* project would pose a Medium-High (12) risk to the delivery of safe and reliable service to customers.

**JUSTIFICATION**

The *Gander Building Renovations* project is required to address deteriorated components at Newfoundland Power's Gander Building. Addressing deteriorated building components is necessary to maintain the safety and adequacy of the building for employees.

# TRANSPORTATION

**Title:** **Replace Vehicles and Aerial Devices 2024-2025**
**Asset Class:** **Transportation**
**Category:** **Project**
**Investment Classification:** **General Plant**
**Budget (Multi-Year):** **$1,940,000 in 2024; $2,869,000 in 2025**

## PROJECT DESCRIPTION

The *Replace Vehicles and Aerial Devices 2024-2025* project involves the addition and replacement of heavy/medium duty fleet, light duty fleet, passenger and off-road vehicles. Due to long delivery times, Newfoundland Power initiated a multi-year approach to procuring heavy and medium duty fleet vehicles in 2022.

Table 1 summarizes the quantity of vehicles to be replaced in 2024 and 2025 under this project.

Table 1
2024-2025 Proposed Vehicle Replacements

| Category | 2024 No. of Units | 2025 No. of Units |
|---|---|---|
| Passenger Vehicles | 25 | - |
| Light Duty Vehicles | 1 | - |
| Heavy/Medium Duty Vehicles | - | 6 |
| Total | 26 | 6 |

Newfoundland Power has identified 25 passenger vehicles and one light duty vehicle for replacement in 2024 and six heavy/medium duty vehicles for replacement in 2025. The project also includes expenditures for the replacement of miscellaneous off-road vehicles in 2024.[95] 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 2024-2025* project is based upon the cost estimates of the quantity and types of units to be replaced.

95 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 2024-2025* project for 2024 and 2025.

Table 2
Replace Vehicles and Aerial Devices
2024-2025 Project
Budget
($000s)

| Cost Category | 2024 | 2025 |
|---|---|---|
| Material | 1,803 | 2,869 |
| Labour – Internal | 137 | - |
| Labour – Contract | - | - |
| Engineering | - | - |
| Other | - | - |
| Total | $1,940 | $2,869 |

Proposed expenditures for the *Replace Vehicles and Aerial Devices 2024-2025* project total approximately $4,809,000, including $1,940,000 in 2024 and $2,869,000 in 2025.

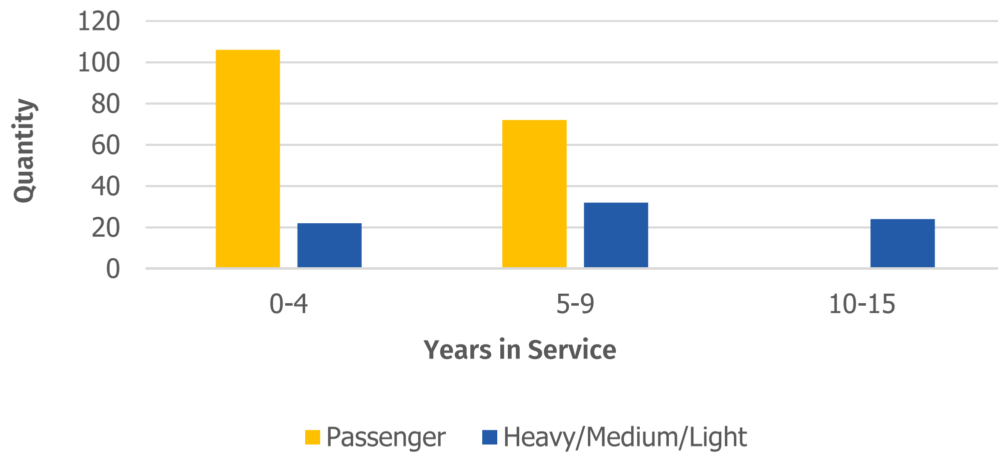
**ASSET BACKGROUND**

Newfoundland Power maintains a fleet of over 250 vehicles, including heavy/medium duty, light-duty, passenger and off-road vehicles. An adequate fleet of vehicles is necessary to ensure a prompt response to customer outages, customers' service requests and other operational requirements.

Heavy-duty fleet vehicles consist of dual axle material handlers with aerial devices, while medium duty fleet vehicles consist of single axle line trucks with aerial devices. Both are primarily used by powerline technician crews for construction and maintenance of the electrical system and in restoring service to customers. Light-duty vehicles consist of service trucks with aerial devices, which are primarily used by powerline technican crews, and heavy-duty vans, which are used by employees at the electrical maintenance centre. Passenger vehicles consist of pickup trucks, SUVs and cars and are primarily used by field workers who require reliable transportation to complete work duties. An adequate fleet of vehicles is necessary to complete capital projects and electrical system maintenance, and ensure a prompt response to customer outages, customers' service requests and other operational requirements.

Figure 1 shows the age distribution of Newfoundland Power's vehicles.

**Figure 1**
**Age Distribution of Vehicles**




Approximately 31% of Newfoundland Power's heavy, medium and light duty vehicles have been in service for 10 years or more. Approximately 40% 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.[96] 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

[96] Newfoundland Power's replacement criteria for vehicles were described in the *2016 Capital Budget Application* report *5.1 Vehicle Replacement Criteria*. This report also compared the criteria to those used by other Canadian electrical utilities. It shows the current approach of the Company is consistent with current Canadian utility practice and the least-cost delivery of service to customers.

repair may not ultimately extend the service life of a vehicle due to heavy rust or other deficiencies. Replacement would still be required over the near term, thereby increasing overall costs to customers.

As a result, there is no viable alternative to replacing vehicles that, based on their condition, have reached the end of their useful service lives.

**RISK ASSESSMENT**

The *Replace Vehicles and Aerial Devices 2024-2025* project will mitigate risks to the delivery of safe and reliable service to customers.

Newfoundland Power responds to on average over 46,000 customer requests in the field annually, including approximately 13,000 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 2024 and 2025 will undergo detailed inspections by certified mechanics to confirm they are in poor condition and can no longer be economically maintained for service. The probability of failure if these vehicles were to remain in service is therefore likely.

Table 3 summarizes the risk assessment of the *Replace Vehicles and Aerial Devices 2024-2025* project.

Table 3
Replace Vehicles and Aerial Devices 2024-2025 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 2024-2025* project would pose a Medium-High (16) risk to the delivery of reliable service to customers.

**JUSTIFICATION**

The *Replace Vehicles and Aerial Devices 2024-2025* 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 2024 and 2025 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:** | **$4,500,000** |

## 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.[97] 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*.[98]

## 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.*

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

# 2024 CAPITAL PROJECTS AND PROGRAMS

# $750,000 AND UNDER

## Distribution

### Distribution Feeder GDL-02 Refurbishment

*Budget: $667,000 Investment Classification: Renewal Category: Project*

This project involves replacing deteriorated underground infrastructure on Loop 11 of Glendale ("GDL") Substation distribution feeder GDL-02. Loop 11 of distribution feeder GDL-02 is deteriorated and is experiencing increased rates of equipment failure. This project is required to provide reliable service to customers at the lowest possible cost as it will address identified deficiencies and mitigate risks of equipment failure and potential outages to customers in the Smallwood Drive area of Mount Pearl.

### Replacement Meters

*Budget: $571,000 Investment Classification: Renewal Category: Program*

This program involves the replacement of deteriorated meters for existing customers and the sampling and replacement of meters in accordance with the requirements of the Electricity and Gas Inspection Act (Canada). This program is required to provide reliable service to customers as it permits the replacement of deteriorated or failed meters. The program is also required to maintain compliance with government regulations.

### Replacement Services

*Budget: $457,000 Investment Classification: Renewal Category: Program*

This program involves the replacement of existing service wires to customers' premises upon failure, as well as the installation of larger service wires to accommodate customers' additional loads. This program is required to provide safe and reliable service to customers as it permits the replacement of failed service wires that are necessary to supply customers' premises.

### New Meters

*Budget: $302,000 Investment Classification: Access Category: Program*

This program involves the purchase and installation of meters for new customers. Newfoundland Power Inc. ("Newfoundland Power" or the "Company") is forecasting the requirement to install meters to serve 2,053 new customer connections in 2024. This program is required to provide equitable access to an adequate supply of power as it permits the installation of meters required to service customers' premises.

**Distribution**

## Allowance for Funds Used During Construction

*Budget: $260,000* *Investment Classification: Mandatory* *Category: Project*

This project is charged on distribution work orders with an estimated expenditure of less than $50,000 and a construction period in excess of three months. This project is required to implement the Company's capital program and is justified on the same basis as the distribution capital expenditures to which it relates.

## Distribution Feeder BIG-02 Relocation

*Budget: $196,000* *Investment Classification: Renewal* *Category: Project*

This project is required to execute the *Transmission Line 24L Relocation* project and will also address the feeder's deteriorated condition. The project involves relocating 1.6 kilometres of Big Pond ("BIG") Substation distribution feeder BIG-02 to the new Transmission Line 24L poles.

## Substations

### Substation Protection and Control Replacements

*Budget: $635,000* *Investment Classification: Renewal* *Category: Program*

This program involves replacing substation protection and control systems, including Supervisory Control and Data Acquisition ("SCADA") system equipment and protection relay devices. This program is required to provide reliable service to customers at the lowest possible cost as it permits the replacement of obsolete protection and controls systems at substations.

### Substation Ground Grid Upgrades

*Budget: $580,000* *Investment Classification: Service Enhancement* *Category: Project*

This project involves upgrading substation ground grids to ensure compliance with *ANSI/IEEE Standard 80-2013 Guide for Safety in AC Substation Grounding*. Deteriorated ground grids in substations can result in unsafe conditions for employees working in the substations with the potential for serious injury or fatality. This project is required to maintain safe and adequate facilities as it will permit the correction of ground grid deficiencies identified at Newfoundland Power's substations.

### PCB Removal

*Budget: $544,000* *Investment Classification: Mandatory* *Category: Project*

This project is required to remove polychlorinated biphenyls ("PCB") with concentrations greater than 50 parts-per-million ("ppm") from substation equipment. This 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.

### Oxen Pond Substation Bus Upgrade

*Budget: $451,000* *Investment Classification: System Growth* *Category: Project*

This project involves increasing the capacity of the two existing 66 kV buses in Oxen Pond ("OXP") Substation. This project will address existing and forecast overload conditions. This project is necessary to continue providing customers in the St. John's area with equitable access to adequate service.

**Substations**

**Oxen Pond Substation Switch Replacements**

*Budget: $316,000* *Investment Classification: Renewal* *Category: Project*

This project involves replacing nine 66 kV switches that have reached the end of their useful lives in OXP Substation. This project will be coordinated with the *Oxen Pond Substation Bus Upgrade* project as it requires the 66 kV buses to be offloaded to facilitate switch replacements. Completing this project will support the continued delivery of reliable service to customers in the St. John's area.

**Transmission**

**Transmission Line 24L Relocation**

*Budget: $701,000* *Investment Classification: Renewal* *Category: Project*

This project involves relocating a 1.6-kilometre section of Transmission Line 24L from the shoreline of Bay Bulls Big Pond to the roadside of the Southern Shore Highway. Due to increased water levels, the poles installed along the shoreline are now within the high-water mark of the pond. The resulting water and ice pressure have caused poles on this section of Transmission Line 24L to lean excessively, putting the line at risk of failure. This project is required to address existing deficiencies on this transmission line and prevent future equipment failures due to its current location. This work is necessary to ensure the continued delivery of reliable service to customers on the Southern Shore of the Avalon Peninsula.

## Generation – Hydro

### Hydro Plant Replacements Due to In-Service Failures

*Budget: $716,000* *Investment Classification: Renewal* *Category: Program*

This program involves the replacement or refurbishment of hydro plant equipment due to damage, deterioration, corrosion, technical obsolescence, and in-service failure. This program is required to provide reliable service to customers at the lowest possible cost. The Company's hydro plants continue to provide low-cost energy for customers, localized reliability benefits and a contribution to system capacity.

## Generation – Thermal

### Thermal Plant Replacements Due to In-Service Failures

*Budget: $311,000* *Investment Classification: Renewal* *Category: Program*

This program involves the replacement or refurbishment of deteriorated thermal plant components that are identified through routine inspections, operating experience and engineering studies. Thermal generating facilities are operated to provide service to customers during planned and unplanned outages. The refurbishment or replacement of equipment that has failed in service or is at imminent risk of failure is necessary to ensure the continued operation of thermal generating facilities.

## Information Systems

### Personal Computer Infrastructure

*Budget: $720,000* *Investment Classification: General Plant* *Category: Program*

This program is necessary for the replacement or upgrade of personal computers ("PCs") that have reached the end of their service lives. These PCs are essential to the Company's operations and provision of customer service. This program is required to provide reliable service to customers at the lowest possible cost as it permits the replacement of PCs and other equipment that have reached the end of their useful service lives.

### Network Infrastructure

*Budget: $420,000* *Investment Classification: General Plant* *Category: Project*

This project involves the addition and replacement of network components that provide employees with access to applications and data used in providing efficient and effective service to customers. This project is required to provide reliable service to customers at the lowest possible cost as it permits the replacement of obsolete network equipment that is essential to the Company's day-to-day operations.

## Telecommunications

### Fibre Optic Cable Build

*Budget: $380,000* *Investment Classification: General Plant* *Category: Project*

This project involves extending the connectivity between Newfoundland Power's two data centres located on the Northeast Avalon Peninsula. This project is required to provide reliable service to customers at the lowest possible cost as it ensures critical systems that are essential to the Company's day-to-day operations have sufficient capacity and redundancy.

### Communications Equipment Upgrades

*Budget: $122,000* *Investment Classification: General Plant* *Category: Program*

This program involves the replacement or upgrade of communications equipment, including radio communications equipment associated with electrical system operations, and data communications equipment providing remote monitoring and control capabilities associated with the Company's SCADA system. Adequate communications equipment is essential for the safe and efficient operation of field crews working to provide service to customers. This program is required to provide reliable service to customers at the lowest possible cost as it permits the replacement of failed, obsolete or deteriorated communications equipment.

## General Property

### Additions to Real Property

*Budget: $655,000* *Investment Classification: General Plant* *Category: Program*

This program involves upgrading, refurbishing and replacing equipment and facilities due to damage, deterioration, corrosion, in-service failure, and organizational changes. Newfoundland Power maintains district and area offices throughout its service territory to ensure a prompt response to customer outages and other service requests, and facilities for the Company's employees and customers. Building components and systems addressed under this program have failed or are at imminent risk of failure.

### Tools and Equipment

*Budget: $570,000* *Investment Classification: General Plant* *Category: Program*

This program is necessary to add or replace tools and equipment used in day-to-day operations to provide safe and reliable service to customers. Newfoundland Power requires an adequate supply of tools, equipment, and office furniture to provide reliable service to customers. The replacement of deteriorated and obsolete equipment is necessary on an ongoing basis to ensure the safety of employees working in offices and the field and to ensure a prompt response to customer outages.

### Energized Conductor Support Tools

*Budget: $539,000* *Investment Classification: General Plant* *Category: Project*

This project involves procuring two new pieces of equipment to support the use of hot line work methods when conducting maintenance on single-pole structures on 66 kV and 138 kV transmission lines. This project is required to facilitate the safe and efficient use of hotline work methods in completing maintenance on radial transmission lines. This project would enable Newfoundland Power to continue providing safe and reliable service to its customers at the lowest possible cost.

### Physical Security Upgrades

*Budget: $401,000* *Investment Classification: General Plant* *Category: Program*

This program involves upgrading physical security infrastructure at Newfoundland Power's facilities throughout its service territory. This program is required to maintain safe and adequate facilities as it permits upgrades to security infrastructure at Company facilities to ensure the safety of employees and the general public.

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

| | 2022 | 2021 |
|---|---|---|
| **Net Plant Investment** | | |
| Plant Investment | 2,178,072 | 2,104,248 |
| Accumulated Depreciation | (914,827) | (869,423) |
| Contributions in Aid of Construction | (45,171) | (44,780) |
| | $1,218,074 | $1,190,045 |
| **Additions to Rate Base** | | |
| Deferred Pension Costs | 95,095 | 88,888 |
| Credit Facility Costs | 87 | 96 |
| Cost Recovery Deferral – Conservation | 19,359 | 16,421 |
| Cost Recovery Deferral – 2022 Revenue Shortfall | 459 | - |
| Cost Recovery Deferral – Load Research and Retail Rate Design Review | 20 | - |
| Customer Finance Programs | 1,472 | 1,755 |
| | $116,492 | $107,160 |
| **Deductions from Rate Base** | | |
| Weather Normalization Reserve | 6,576 | 2,020 |
| Demand Management Incentive Account | 107 | (1,342) |
| Other Post-Employment Benefits | 80,151 | 73,566 |
| Customer Security Deposits | 1,270 | 1,401 |
| Accrued Pension Obligation | 5,300 | 5,168 |
| Accumulated Deferred Income Taxes | 18,076 | 15,976 |
| | $111,480 | $96,789 |
| **Year End Rate Base** | 1,223,086 | 1,200,416 |
| **Average Rate Base Before Allowances** | 1,211,751 | 1,184,330 |
| **Rate Base Allowances** | | |
| Materials and Supplies Allowance | 11,978 | 8,339 |
| Cash Working Capital Allowance | 6,705 | 10,277 |
| **Average Rate Base at Year End** | $1,230,434 | $1,202,946 |

# 2024 Capital Budget Overview

## June 2023

# TABLE OF CONTENTS

Page

## 1.0 APPLICATION OVERVIEW

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") 2024 Capital Budget totals approximately $115.3 million. The 2024 Capital Budget includes:

(i) Proposed single-year projects and programs in excess of $750,000 in the amount of $84,583,000;
(ii) Proposed single-year projects and programs $750,000 and under in the amount of $10,514,000;
(iii) Proposed multi-year projects with capital expenditures of $5,234,000 in 2024, $19,414,000 in 2025 and $297,000 in 2026; and
(iv) Previously approved multi-year projects with capital expenditures of $14,921,000 in 2024.

The 2024 Capital Budget includes 22 recurring capital programs and 38 capital projects, five of which have been previously approved. The 2024 Capital Budget is approximately $7.6 million less than the approved *2023 Capital Budget Application*.[1]

Approximately half of the capital expenditures included in the 2024 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 2024 Capital Budget associated with the replacement and refurbishment of existing assets reflects the age and condition of Newfoundland Power's electrical system. For example, the Company is proposing the rebuild of transmission line 146L as a two-year multi-year project beginning in 2024. Inspections of the line show the line has deteriorated considerably over time.

Approximately one quarter of capital expenditures included in the 2024 Capital Budget are associated with requirements to connect new customers and respond to system load growth. The Company is forecasting 2,053 new customer connections in 2024, as well as the requirement to address load growth on three distribution feeders due to residential development on the Northeast Avalon and in the Corner Brook area.

The remaining one quarter of capital expenditures included in the 2024 Capital Budget are associated with general plant, service enhancement and mandatory expenditures. The largest driver of expenditures in these areas is the *LED Street Lighting Replacement* project which provides customers with lower rates for better quality lighting with a budget of approximately $5.5 million in 2024.

Overall, the 2024 Capital Budget represents the capital additions and improvements necessary to continue providing safe and reliable service to customers at the lowest possible cost.

[1] The Board approved the *2023 Capital Budget Application* in the amount of $122,869,000 in Order No. P.U. 38 (2022).

# 2.0 APPLICATION CONTEXT

## 2.1 Regulatory Framework

Newfoundland Power is the primary distributor of electricity in the Province of Newfoundland and Labrador. The Company serves approximately 87% of all customers in the province.

Newfoundland Power's operations, including its capital investments, are regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") pursuant to the *Public Utilities Act* and the *Electrical Power Control Act, 1994*.[2] The *Public Utilities Act* requires a public utility to provide services and facilities that are reasonably safe and adequate and just and reasonable.[3] The *Electrical Power Control Act, 1994* contains the provincial power policy, which requires that power be delivered to customers at the lowest possible cost, in an environmentally responsible manner, consistent with reliable service.[4]

The Board provided updated provisional *Capital Budget Application Guidelines* (the "Provisional Guidelines") effective January 2022. In issuing the Provisional Guidelines, the Board noted that:

> "*While strict adherence to all aspects of the provisional guidelines may not be possible, the Board asks that the stakeholders make best efforts to respect the spirit and intent of the guidelines*."[5]

The capital expenditures proposed as part of Newfoundland Power's *2024 Capital Budget Application* (the "Application") are necessary to meet the Company's statutory obligations under the *Public Utilities Act* and the *Electrical Power Control Act, 1994*. The Application is organized to comply with the spirit and intent of the Provisional Guidelines. Appendix A summarizes how the capital expenditures proposed in the Application are organized according to the Provisional Guidelines.

## 2.2 Capital Planning at Newfoundland Power

### *2.2.1 General*

Newfoundland Power's annual capital expenditures are the product of a comprehensive capital planning process. The Company's capital planning process applies sound engineering and objective data to determine which expenditures are required annually to provide customers with access to safe and reliable service at the lowest possible cost.

---

2 Section 41 of the *Public Utilities Act* requires, among other provisions, that a public utility submit an annual capital budget of proposed improvements or additions to its property to the Board for its approval.
3 See Section 37(1) of the *Public Utilities Act*.
4 See Section 3 of the *Electrical Power Control Act, 1994*.
5 See correspondence from the Board regarding *Provisional Capital Budget Application Guidelines*, dated December 20, 2021.

The capital planning process commences each year with an update of the Company's five-year capital plan. The capital plan provides a forecast of capital expenditures across all asset classes for the next five years, including the upcoming budget year. The capital plan is updated annually based on the most recent information of forecast customer requirements, asset condition, operational requirements and other factors.

Newfoundland Power's annual capital expenditures include a combination of recurring programs and specific projects. The capital planning process for programs and projects is described below.

### *2.2.2 Capital Program Planning*

Programs include capital investments related to high-volume, repetitive work that is required on an ongoing basis. Programs include:

(i) Capital work required to connect new customers to the electrical system, such as the installation of services and meters;
(ii) Corrective and preventative maintenance programs necessary to maintain the electrical system, including the replacement of equipment that has failed or deteriorated; and
(iii) Capital expenditures necessary to replace or add specific materials used in providing service to customers, such as personal computers, tools and equipment.

Programs required to connect new customers to the electrical system are generally budgeted on the basis of forecast customer requirements. Each year, Newfoundland Power updates its capital plan to reflect its most recent Customer, Energy and Demand Forecast. The Customer, Energy and Demand Forecast estimates new customer connections that are expected over the next five years based on economic inputs from the Conference Board of Canada, such as forecast housing starts. This data is then used to determine forecast expenditures to connect new customers, including forecast expenditures for meters, services, and extensions to the distribution system.

Programs required to complete corrective and preventative maintenance of the electrical system are generally budgeted on the basis of historical expenditures and forecast inflation.[6] Capital requirements for corrective and preventative maintenance programs tend to be reasonably stable over time. Each year, the Company updates its forecast expenditures for these programs based on the most recent five-year average of expenditures and the latest forecast of inflation. This budgeting methodology helps to ensure forecast expenditures reflect the Company's most recent experience with maintaining the electrical system.

Capital expenditures for programs required to replace or add specific materials used in providing service to customers are generally budgeted based on a combination of historical

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

expenditures, forecast inflation, and identified operational requirements. For example, identified operational requirements could include the need to purchase a specific quantity of personal computers.

In forecasting program expenditures, Newfoundland Power reviews any recent variances in actual costs from approved budgets and the reasons for those variances. If significant variances are observed in consecutive years, an analysis is undertaken to determine whether a different budgeting methodology would be more reflective of forecast requirements.[7]

### *2.2.3 Capital Project Planning*

Projects include capital investments for identifiable assets where the required work has a defined schedule, scope and budget based on detailed engineering estimates.

Forecast expenditures related to projects are updated annually to reflect the latest:

(i) Condition assessments of electrical system assets. Information on asset condition is obtained through annual inspection programs, engineering reviews and recent operating experience. This information identifies equipment that is deteriorated, deficient, or has failed and requires replacement or refurbishment to extend its useful service life.

(ii) Forecasts of electrical system load. System load forecasts are produced annually using computer modelling to determine any areas where capital expenditures are required to respond to customers' changing electrical system requirements.

(iii) Changes in economic factors or industry requirements. This can include any changes in engineering standards, regulatory requirements, or economic factors, such as marginal system costs, 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 alternatives for executing the required work. This includes both alternatives to the scope of a

---

[7] 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 pages 32-33 of Schedule B to that application.

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

The 2024 Capital Budget includes seven capital projects that were planned for 2024 but have been deferred to future years. There are also five capital projects that were previously deferred or modified and are now proposed for 2024, and two capital projects that were planned for future years but were advanced to 2024. Appendix B provides the list of the capital projects that were deferred, modified or advanced.

The prioritization and potential deferral of capital expenditures are assessed based on potential risks to customers. This includes engineering assessments of the likelihood that an asset will fail and the potential reliability, safety, environmental or economic consequences for customers if failure were to occur. In 2022 following the issuance of Provisional Guidelines, Newfoundland Power developed a risk matrix to standardize its approach to communicating risks associated with proposed capital expenditures. Appendix C provides the risk matrix methodology and a prioritized list of 2024 capital expenditures.

## 2.3 Balancing Cost and Service

### *2.3.1 Service Reliability*

Newfoundland Power owns and operates approximately 9,500 kilometres of distribution line, approximately 2,100 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.[8] Long-term asset management strategies, such as the *Substation Refurbishment and Modernization Plan* and *Transmission Line Rebuild Strategy,* provide a structured approach to maintaining the condition of a large volume of electrical system assets. Annual inspections support routine preventative and corrective maintenance programs, with substations inspected eight times annually, transmission lines inspected annually, and distribution lines inspected on a seven-year cycle.

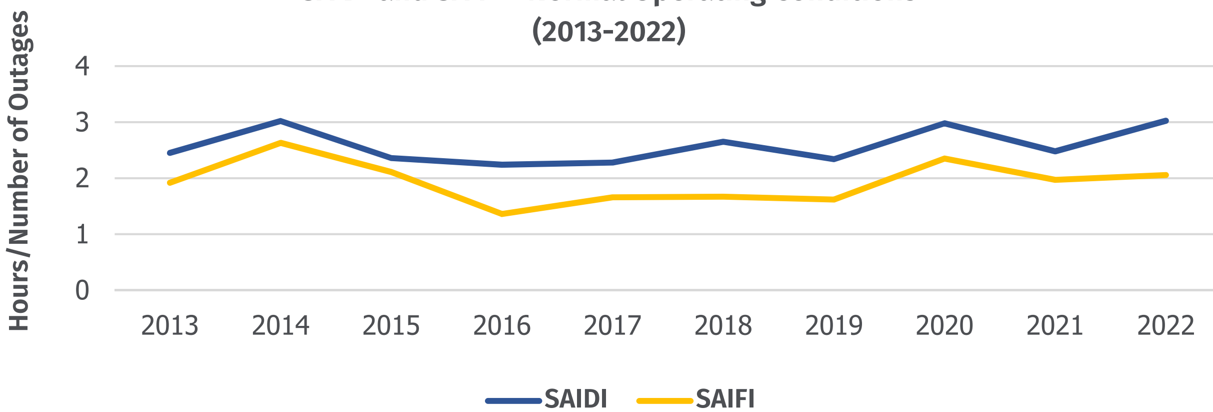
The service reliability experienced by customers also reflects the Company's response when outages occur. Newfoundland Power's operational response requires the deployment of a skilled workforce throughout its service territory, including powerline technicians, technologists and engineers. A combination of operational technologies and adequate tools and equipment are necessary to ensure the effective and efficient deployment of the Company's workforce.

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

Annual capital expenditures are essential to maintaining both electrical system condition and the Company's operational response. The most recent independent review of Newfoundland Power's engineered operations was conducted by The Liberty Consulting Group ("Liberty") in 2014 and found that the Company's asset management practices and operations conform to good utility practices.[9]

Figure 1 shows the average duration ("SAIDI") and frequency ("SAIFI") of outages to Newfoundland Power's customers from 2013 to 2022 under normal operating conditions.[10]

**Figure 1**
**Newfoundland Power**
**SAIDI and SAIFI - Normal Operating Conditions**
**(2013-2022)**



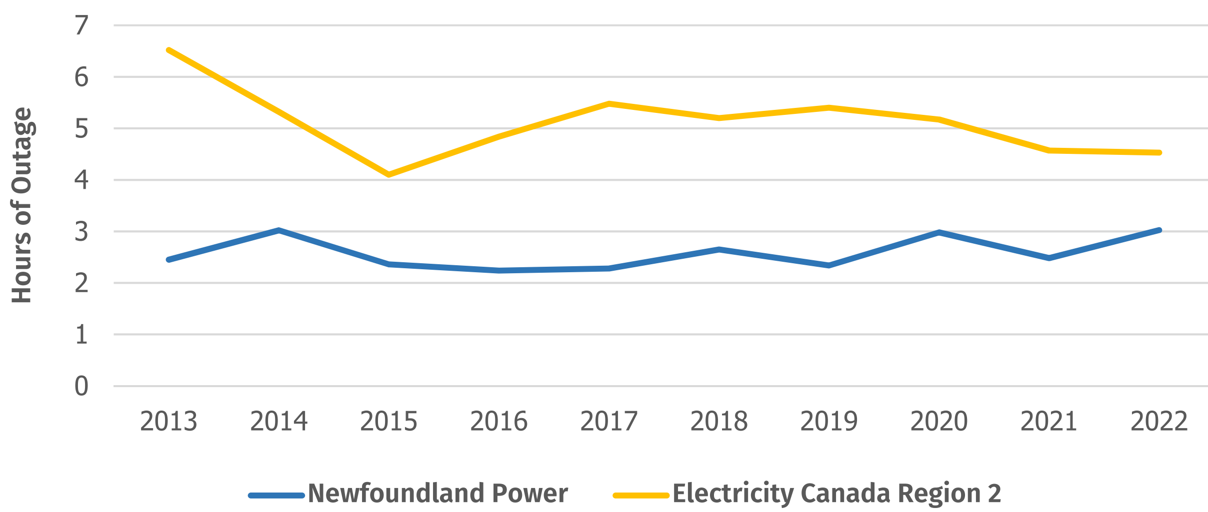

9 Liberty concluded that: "*Newfoundland Power's planning and design of its system, its asset management practices, its system operations, its outage management and emergency practices and its customer communications processes all conform to good utility practices.*" See Liberty, *Executive Summary of Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power Inc.*, December 17, 2014, page ES-1.

10 Newfoundland Power calculates its SAIDI ("System Average Interruption Duration Index") and SAIFI ("System Average Interruption Frequency Index") in accordance with industry guidelines. SAIDI is calculated by dividing the total number of customer outage minutes by the total number of customers served. SAIFI is calculated by dividing the total number of customer interruptions by the total number of customers served. The data shown in Figure 1 does not include customer outages due to major events or loss of supply from Newfoundland and Labrador Hydro.

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.

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 2013 to 2022.[11]

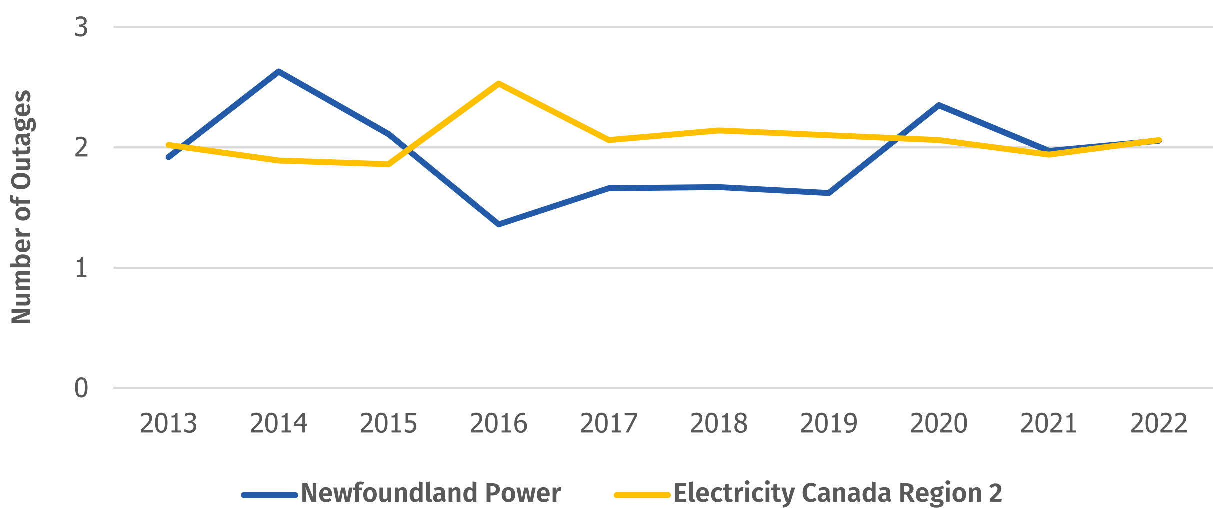
**Figure 2**
**Newfoundland Power vs. Canadian Average**
**SAIDI - Normal Operating Conditions**
**(2013-2022)**




---

[11] The Canadian average reflects Region 2 utilities of Electricity Canada. Region 2 utilities include Canadian utilities that serve a mix of urban and rural markets. These are ATCO Electric, BC Hydro, FortisAlberta, FortisBC, Hydro One, Hydro-Québec, Manitoba Hydro, Maritime Electric, NB Power, Newfoundland and Labrador Hydro, Newfoundland Power, Newmarket-Tay Power Distribution, Nova Scotia Power, Northwest Territories Power Corporation, SaskPower, Elexicon Energy, Waterloo North Hydro, ATCO Electric Yukon and Yukon Energy.

**Figure 3**
**Newfoundland Power vs. Canadian Average**
**SAIFI - Normal Operating Conditions**
**(2013-2022)**




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 2013.[12] The average frequency of customer outages has been consistent with the Canadian average over this period.[13]

Newfoundland Power is focused on maintaining current levels of overall service reliability for its customers under normal operating conditions. The Company's annual targets for service reliability are based on the most recent five-year average.

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

### *2.3.2 Capital Expenditures*

Newfoundland Power's annual capital expenditures reflect the capital additions, replacements and refurbishments necessary each year to provide safe and reliable service to customers at the lowest possible cost.

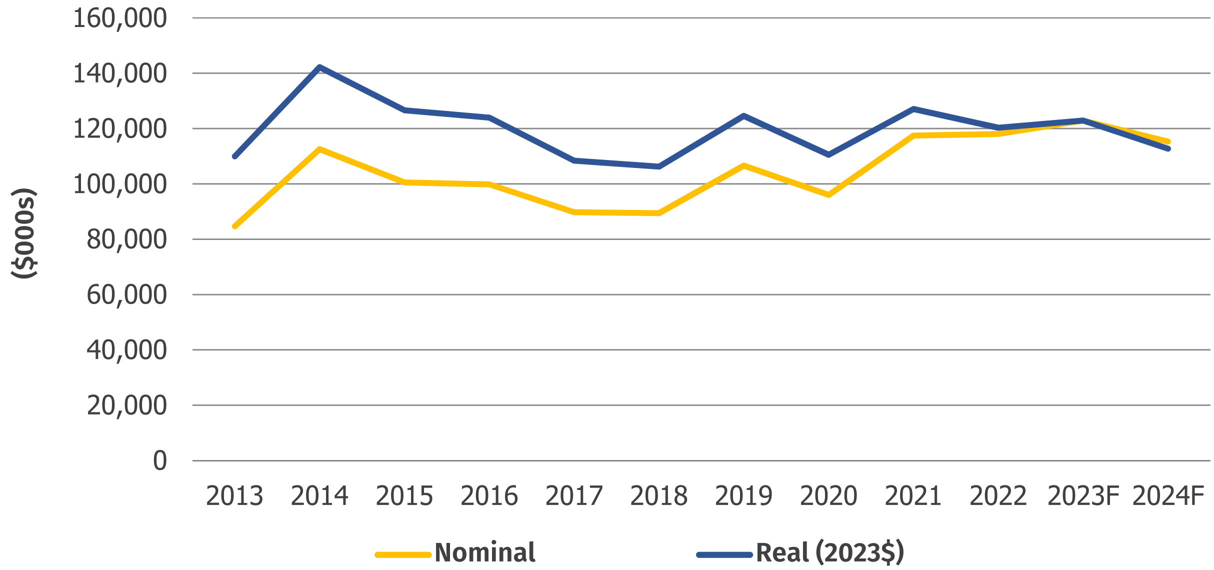
---

12 Newfoundland Power's SAIDI averaged approximately 2.6 hours/year from 2013 to 2022. This compares to an Electricity Canada average SAIDI of 5.1 hours/year over the same period.

13 Newfoundland Power's SAIFI averaged approximately 1.9 outages/year from 2013 to 2022. This compares to an Electricity Canada average SAIFI of 2.1 outages/year over the same period.

Figure 4 provides Newfoundland Power's actual and inflation-adjusted capital expenditures from 2013 to 2023 and the 2024 Capital Budget.

**Figure 4**
**Newfoundland Power Capital Expenditures**
**(2013-2024F)**




Newfoundland Power's capital expenditures have averaged approximately $103 million annually from 2013 to 2023, or $120 million when adjusted for inflation. On an inflation-adjusted basis, annual expenditures have ranged from approximately $106 million in 2018 to $142 million in 2014. The 2024 Capital Budget of approximately $115.3 million is within this range.

### *2.3.3 Customer Rates*

A primary determinant of Newfoundland Power's customer rates is the Company's revenue requirement. Revenue requirement is the aggregate amount of forecast revenue required in a year to cover the Company's cost of serving customers, including operating costs, taxes, depreciation and allowed return on rate base.[14] Customer rates also reflect Newfoundland Power's Customer, Energy and Demand forecasts and Board-approved rate structures.[15]

The capital projects proposed in the Application are estimated to increase the Company's annual revenue requirement by approximately $4 million on a *pro forma* basis. The estimate includes increases in depreciation, return on rate base and income taxes.

---

[14] See Order No. P.U. 7 (2002-2003), page 31.
[15] See Order No. P.U. 40 (2005), page 13.

The estimate also includes reduced operating costs as a result of the *LED Street Lighting Replacement* and *Application Enhancements* projects, and the customer benefit associated with the continued operation of the Mobile and Lookout Brook hydro plants.[16]

The *pro forma* analysis is practically limited as it does not include potentially higher revenues from growth-related projects, or the long-term effect that fully justified capital expenditures have on minimizing revenue requirements.[17]

The Board has previously recognized the complex relationship between capital investments, revenue requirements and customer rates.[18] The Board has also recognized that fully justified capital expenditures contribute to the delivery of least-cost service to customers.[19]

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

---

16 The proposed refurbishment of the Company's Mobile and Lookout Brook hydro plants included in the Application will result in the continued provision of low-cost electricity production to customers.

17 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.

18 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*."

19 In Order No. P.U. 7 (2002-2003), the Board stated: "*From a regulatory perspective, efficient operations, fully justified capital expenditures and a low cost capital structure all combine to minimize revenue requirement, and hence provide least cost electricity to ratepayers*."

Table 1 shows Newfoundland Power's actual and inflation-adjusted contribution to revenue requirement in 2015 and 2024.[20]

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

| | 2015 | 2024[21] | Change |
|---|---|---|---|
| Actual | 212.9[22] | 239.3 | 12% |
| Inflation-Adjusted[23] | 274.9 | 239.3 | -13% |

Newfoundland Power's contribution to revenue requirement increased by approximately 12% from 2015 to 2024. On an inflation-adjusted basis, the Company's contribution to revenue requirement decreased by approximately 13%.

Table 2 compares Newfoundland Power's total contribution to average customer rates in cents per kWh in 2015 and 2024.

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

| | 2015 | 2024[24] | Change |
|---|---|---|---|
| Actual | 3.65 | 4.23 | 16% |
| Inflation-Adjusted[25] | 4.71 | 4.23 | -10% |

20 Based on the Company's 2014 and 2023 test year revenue requirements, excluding purchased power costs. Purchased power costs from Newfoundland and Labrador Hydro account for approximately 65% of the Company's overall revenue requirement.

21 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.

22 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.

23 Inflation adjusted based on the GDP Deflator for Canada.

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.

Newfoundland Power's contribution to average customer rates increased by approximately 16% from 2015 to 2024. On an inflation-adjusted basis, the Company's contribution to average customer rates decreased by 10%.

While Newfoundland Power's contribution to revenue requirement and customer rates has decreased on an inflation-adjusted basis over the past decade, the Company's annual capital investments have averaged over $100 million per year over this period.

In Newfoundland Power's view, the Company's approach to capital planning tends to minimize overall costs to customers over the longer term. This is consistent with the least-cost delivery of reliable service to customers.

### *2.3.4 Atlantic Canadian Comparison*

The four primary distributors of electricity in Atlantic Canada are: (i) Newfoundland Power; (ii) Nova Scotia Power; (iii) NB Power; and (iv) Maritime Electric. Each of these utilities serves customers in a mix of urban and rural areas.

Table 3 compares Newfoundland Power to other Atlantic Canadian utilities on the basis of: (i) growth in aggregate capital investment in transmission and distribution ("T&D") assets from 2012 to 2021; and (ii) the average duration of customer outages over the same period.

Table 3
Atlantic Canadian Comparison
Capital Investment and Service Reliability

| | Capital Investment ($Millions)[26] | | | Service Reliability (SAIDI) |
|---|---|---|---|---|
| Utility | 2012 | 2021 | Growth | 2012-2021 |
| Newfoundland Power | 1,024 | 1,536 | 50% | 2.7 |
| Atlantic Canadian Utilities[27] | 1,193 | 1,738 | 46% | 3.9 |

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 $3,578 million in 2012 ($3,578 million / 3 = $1,193 million) and $5,214 million in 2021 ($5,314 million / 3 = $1,738 million).

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 2021, with investments among other Atlantic Canadian utilities ranging from 34% to 61%.

Over the same period, the Company's customers have experienced 31% fewer outage hours in comparison to customers of other Atlantic Canadian utilities.[28] The Company's average outage duration was among 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.

## 3.0 SUMMARY OF 2024 EXPENDITURES

### 3.1 2024 Capital Budget Overall

Newfoundland Power's 2024 Capital Budget totals approximately $115.3 million, including approximately $10.5 million of 2024 expenditures that are $750,000 and under and approximately $14.9 million of 2024 expenditures that were previously approved by the Board. There has been no change in the scope, nature or magnitude of the previously approved capital expenditures.[30] Appendix E provides an update on previously approved multi-year projects.

The Application also proposes six new multi-year projects. The multi-year projects include expenditures of approximately $5.2 million in 2024.

The following sections provide breakdowns of the 2024 Capital Budget by asset class, category, investment classification and materiality.

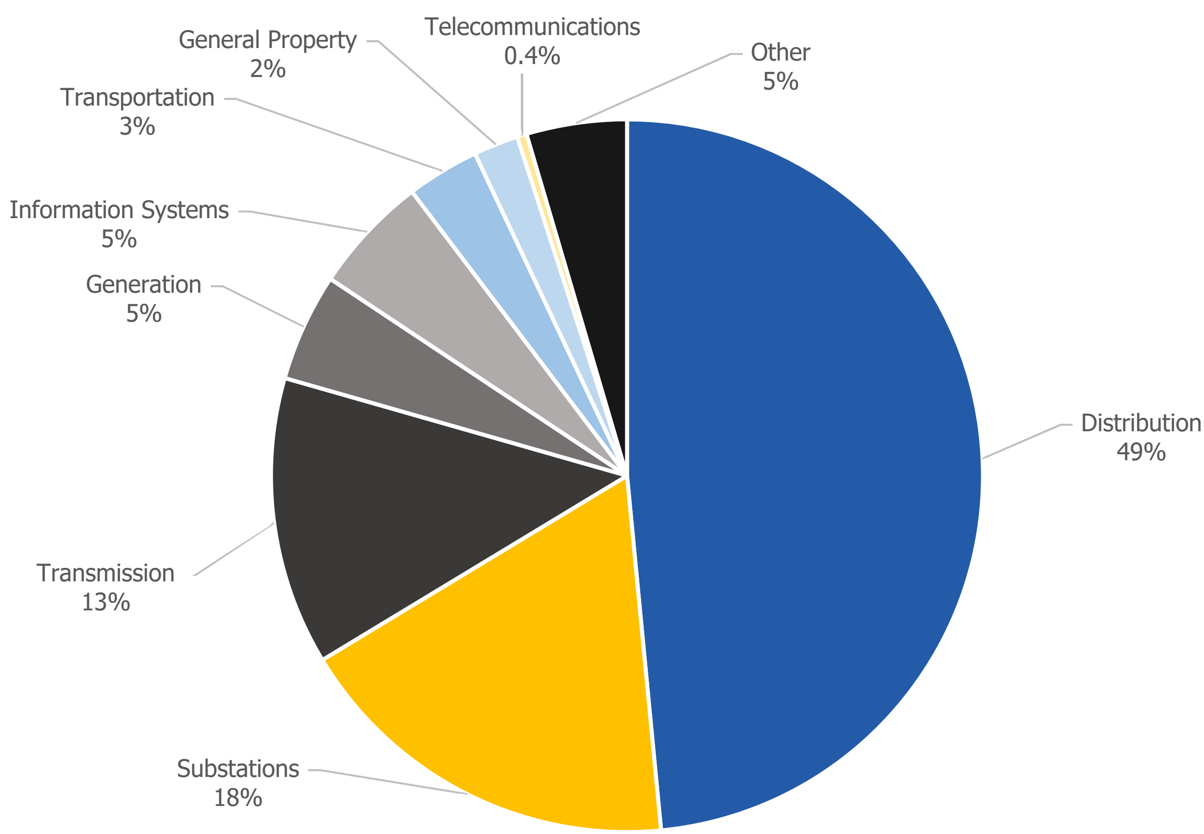
[28] (2.7 – 3.9) / 3.9 = -0.31, or -31%.
[29] The average SAIDI for the other Atlantic Canadian utilities ranged from 2.6 to 4.5.
[30] For expenditures incurred to date as part of these projects, see the *2023 Capital Expenditure Status Report* provided with the Application.

### 3.2 2024 Capital Budget by Asset Class

Newfoundland Power organizes its annual capital budget by asset class.

Figure 5 provides the 2024 Capital Budget by asset class, including previously approved multi-year projects.

**Figure 5**
**2024 Capital Budget by Asset Class**




The Distribution asset class accounts for approximately 49% of capital expenditures for 2024. 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 Substations asset class accounts for approximately 18% of capital expenditures for 2024. The majority of substation expenditures relate to the refurbishment and modernization of the Gambo, Memorial, Old Perlican and Islington substations at a combined cost of $13.3 million in 2024.

The Transmission asset class accounts for approximately 13% of capital expenditures for 2024. The majority of transmission expenditures relate to the rebuilding of transmission lines constructed in the 1960s and 1970s. This includes a multi-year project to rebuild deteriorated Transmission Line 146L in central Newfoundland at a cost of $2.2 million in 2024 and $9.2 million in 2025. Transmission expenditures in 2024 also include approximately $9.6 million associated with previously approved multi-year projects.[31]

The Generation asset class accounts for approximately 5% of capital expenditures for 2024. This includes a multi-year project to refurbish the Lookout Brook hydro plant at a cost of approximately $0.4 million in 2024 and $1.6 million in 2025. Generation expenditures also include refurbishment of the Mobile hydro plant in 2024 with approximately $1 million to refurbish the surge tank and the second year of the multi-year project to refurbish the plant at a cost of approximately $2.5 million, as approved by the Board in Order No. P.U. 38 (2022).

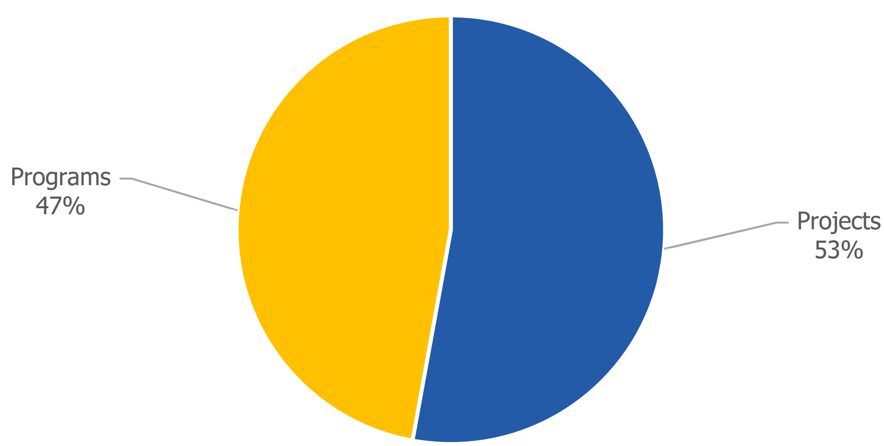
The Information Systems asset class accounts for approximately 5% of capital expenditures for 2024. Reduced capital expenditures in this asset class are a result of the conclusion of the *Customer Service System Replacement* project approved by the Board in Order No. P.U. 12 (2021).

The remaining asset classes account for between 1% and 5% of capital expenditures for 2024.

## 3.3 2024 Capital Budget by Category

Figure 6 provides a breakdown of Newfoundland Power's 2024 Capital Budget by category, including previously approved multi-year projects.

**Figure 6**
**2024 Capital Budget by Category**



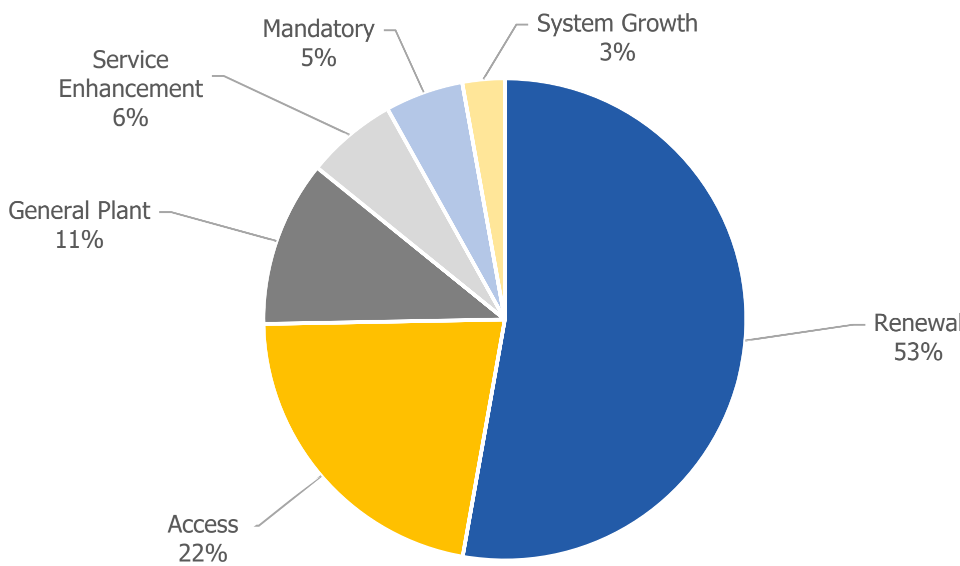

[31] This includes approximately $5.3 million for the rebuild of Transmission Line 55L as approved in Order No. P.U. 38 (2022), and $4.3 million for the rebuild of Transmission Line 94L as approved in Order No. P.U. 36 (2021).

Newfoundland Power's 2024 Capital Budget includes 38 capital projects and 22 capital programs. Capital projects account for approximately 53% of capital expenditures for 2024, with the remaining 47% attributable to recurring programs.

## 3.4 2024 Capital Budget by Investment Classification

Figure 7 shows Newfoundland Power's 2024 Capital Budget by investment classification, including previously approved multi-year projects.

**Figure 7**
**2024 Capital Budget by Investment Classification**




Renewal expenditures account for approximately 53% of capital expenditures for 2024. 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 2024. Capital work under the *Transmission Line Rebuild Strategy* and *Substation Refurbishment and Modernization Plan* account for an additional one third of Renewal expenditures in 2024.

Access expenditures account for approximately 22% of capital expenditures for 2024. 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 2,053 new customer connections in 2024.

General Plant expenditures account for approximately 11% of capital expenditures for 2024. Information Systems expenditures account for over half of all General Plant expenditures. These expenditures are driven by the need to maintain the reliability and security of software and hardware that support the provision of service to customers. Expenditures within the

Transportation asset class are the next largest driver of General Plant expenditures, reflecting the routine replacement of vehicles that have reached the end of their service lives.

Service Enhancement expenditures account for approximately 6% of capital expenditures for 2023. The *LED Street Lighting Replacement* project accounts for the majority of Service Enhancement expenditures in 2024. This project is being completed as part of a six-year plan that commenced in 2021 to provide all Street and Area Lighting customers with LED fixtures. LED street light fixtures offer lower rates, better quality lighting and a more reliable street lighting service.

Mandatory expenditures account for approximately 5% of capital expenditures for 2024. The primary drivers within this classification are Federal Government regulations mandating the removal 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 3% of capital expenditures in 2024. There are two capital projects proposed for 2024 to address system growth. The *Feeder Additions for Load Growth* project addresses localized load growth on three distribution feeders on the Northeast Avalon and in the Corner Brook area. The *Oxen Pond Substation Bus Upgrade* project addresses existing and forecast overload conditions on the substations 66 kV infrastructure.

## 3.5 2024 Capital Budget by Materiality

Table 4 provides an overview of the 2024 Capital Budget by materiality, including previously approved multi-year projects.[32]

Table 4
2024 Capital Budget by Materiality

| Threshold | Quantity of Projects/Programs | Total Expenditures ($000s) | Percentage of Total Expenditures |
|---|---|---|---|
| Less than $1 million[33] | 34 | 19,849 | 17% |
| $1 million - $5 million | 18 | 53,482 | 47% |
| Greater than $5 million | 8 | 41,921 | 36% |
| Total | 60 | 115,252 | 100% |

32 Multi-year capital projects are assigned to a materiality threshold based on the total proposed amount, including the amount proposed for the budget year and any proposed future commitments.

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

Of the 60 total capital projects and programs included in the 2024 Capital Budget, 52 are less than $5 million. The eight capital projects and programs greater than $5 million include the previously approved *Transmission Line 94L Rebuild* project and *Transmission Line 55L Rebuild* project. There has been no change in the nature, scope or magnitude of these two projects.

The remaining six capital programs and projects greater than $5 million that are proposed for 2024 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 $12.1 million for 2024. 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 $7.0 million for 2024. The budget estimate is based on historical expenditures over the most recent five-year period.

(iii) ***Transmission Line 146L Rebuild project***, which includes a multi-year project to rebuild Transmission Line 146L serving customers in central Newfoundland. Capital expenditures for this multi-year project total $2.2 million in 2024 and $9.2 million in 2025. The budget estimate is based on detailed engineering estimates.

(iv) ***Gambo Substation Refurbishment and Modernization project***, which involves the refurbishment of deteriorated components at Gambo Substation in central Newfoundland identified through engineering assessments. Capital expenditures for this project total approximately $5.3 million in 2024. The budget estimate is based on detailed engineering estimates.

(v) ***Islington Substation Refurbishment and Modernization project***, which includes a multi-year project to refurbish deteriorated components identified through engineering assessments at Islington Substation in the Islington area. Capital expenditures for this project total approximately $5.0 million over a two-year period. The budget estimate is based on detailed engineering estimates.

(vi) ***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 2024. The budget estimate is based on detailed engineering estimates.

Including previously approved expenditures, the eight capital projects and programs exceeding $5 million in materiality account for approximately 36% of capital expenditures for 2024.

# APPENDIX A:

## Capital Expenditure Classification and Categorization Summary

Table A-1
2024 Capital Budget
Proposed Single-Year Projects and Programs in Excess of $750,000

| INVESTMENT CLASSIFICATION | BUDGET ($000s) | ASSET CLASS | CATEGORY |
|---|---|---|---|
| Mandatory | | | |
| General Expenses Capitalized | 4,500 | GEC | Project |
| Allowance for Unforeseen Items | 750 | Unforeseen Allowance | Project |
| *Total Mandatory* | $5,250 | | |
| Access | | | |
| Extensions | 12,140 | Distribution | Program |
| Relocate/Replace Distribution Lines for Third Parties | 4,066 | Distribution | Program |
| New Transformers | 3,264 | Distribution | Program |
| New Services | 2,847 | Distribution | Program |
| New Street Lighting | 2,629 | Distribution | Program |
| *Total Access* | $24,946 | | |
| System Growth | | | |
| Feeder Additions for Load Growth | 2,811 | Distribution | Project |
| *Total System Growth* | $2,811 | | |
| Renewal | | | |
| Reconstruction | 6,953 | Distribution | Program |
| Gambo Substation Refurbishment and Modernization | 5,267 | Substations | Project |
| Rebuild Distribution Lines | 4,974 | Distribution | Program |

Table A-1
2024 Capital Budget
Proposed Single-Year Projects and Programs in Excess of $750,000

| INVESTMENT CLASSIFICATION | BUDGET ($000s) | ASSET CLASS | CATEGORY |
|---|---|---|---|
| Substation Replacements Due to In-Service Failures | 4,797 | Substations | Program |
| Memorial Substation Refurbishment and Modernization | 4,351 | Substations | Project |
| Replacement Transformers | 3,681 | Distribution | Program |
| Old Perlican Substation Refurbishment and Modernization | 3,356 | Substations | Project |
| Transmission Line Maintenance | 2,651 | Transmission | Program |
| Mobile Hydro Plant Surge Tank Refurbishment | 977 | Generation – Hydro | Project |
| Distribution Reliability Initiative | 900 | Distribution | Project |
| Replacement Street Lighting | 863 | Distribution | Program |
| Distribution Feeder OXP-01 Refurbishment | 840 | Distribution | Project |
| Hydro Facility Rehabilitation | 794 | Generation – Hydro | Project |
| *Total Renewal* | $40,404 | | |
| Service Enhancement | | | |
| LED Street Lighting Replacement | 5,541 | Distribution | Project |
| Distribution Feeder Automation | 888 | Distribution | Project |
| *Total Service Enhancement* | $6,429 | | |
| General Plant | | | |
| Application Enhancements | 1,892 | Information Systems | Project |
| Shared Server Infrastructure | 964 | Information Systems | Project |

| Table A-1<br>2024 Capital Budget<br>Proposed Single-Year Projects and Programs in Excess of $750,000 | | | |
|---|---|---|---|
| INVESTMENT CLASSIFICATION | BUDGET ($000s) | ASSET CLASS | CATEGORY |
| System Upgrades | 957 | Information Systems | Project |
| Cybersecurity Upgrades | 930 | Information Systems | Project |
| *Total General Plant* | $4,743 | | |
| Total | $84,583 | | |

| Table A-2<br>2024 Capital Budget<br>Proposed Single-Year Projects and Programs $750,000 and Under | | | |
|---|---|---|---|
| INVESTMENT CLASSIFICATION | BUDGET ($000s) | ASSET CLASS | CATEGORY |
| Mandatory | | | |
| PCB Removal | 544 | Substations | Project |
| Allowance for Funds Used During Construction | 260 | Distribution | Project |
| *Total Mandatory* | $804 | | |
| Access | | | |
| New Meters | 302 | Distribution | Program |
| *Total Access* | $302 | | |
| System Growth | | | |
| Oxen Pond Substation Bus Upgrade | 451 | Substations | Project |
| *Total System Growth* | $451 | | |
| Renewal | | | |
| Hydro Plant Replacements Due to In-Service Failures | 716 | Generation – Hydro | Program |
| Transmission Line 24L Relocation | 701 | Transmission | Project |
| Distribution Feeder GDL-02 Refurbishment | 667 | Distribution | Project |
| Substation Protection and Control Replacements | 635 | Substations | Program |
| Replacement Meters | 571 | Distribution | Program |
| Replacement Services | 457 | Distribution | Program |
| Oxen Pond Substation Switch Replacements | 316 | Substations | Project |

| Table A-2<br>2024 Capital Budget<br>Proposed Single-Year Projects and Programs $750,000 and Under | | | |
|---|---|---|---|
| INVESTMENT CLASSIFICATION | BUDGET ($000s) | ASSET CLASS | CATEGORY |
| Thermal Plant Replacements Due to In-Service Failures | 311 | Generation – Thermal | Program |
| Distribution Feeder BIG-02 Relocation | 196 | Distribution | Project |
| *Total Renewal* | $4,570 | | |
| Service Enhancement | | | |
| Substation Ground Grid Upgrades | 580 | Substations | Project |
| *Total Service Enhancement* | $580 | | |
| General Plant | | | |
| Personal Computer Infrastructure | 720 | Information Systems | Program |
| Additions to Real Property | 655 | General Property | Program |
| Tools and Equipment | 570 | General Property | Program |
| Energized Conductor Support Tools | 539 | General Property | Project |
| Network Infrastructure | 420 | Information Systems | Project |
| Physical Security Upgrades | 401 | General Property | Program |
| Fibre Optic Cable Build | 380 | Telecommunications | Project |
| Communications Equipment Upgrades | 122 | Telecommunications | Program |
| *Total General Plant* | $3,807 | | |
| Total | $10,514 | | |

| Table A-3<br>2024 Capital Budget<br>Proposed Multi-Year Projects | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | BUDGET ($000s) | | | |
| TITLE | ASSET CLASS | INVESTMENT CLASSIFICATION | PROJECT / PROGRAM | 2024 | 2025 | 2026 | Total |
| Transmission Line 146L Rebuild | Transmission | Renewal | Project | 2,152 | 9,209 | - | 11,361 |
| Lookout Brook Hydro Plant Refurbishment | Generation – Hydro | Renewal | Project | 362 | 1,573 | - | 1,935 |
| Islington Substation Refurbishment and Modernization | Substations | Renewal | Project | 308 | 4,706 | - | 5,014 |
| Gander Building Renovation | General Property | General Plant | Project | 175 | 760 | - | 935 |
| Replace Vehicles and Aerial Devices 2024-2025 | Transportation | General Plant | Project | 1,940 | 2,869 | - | 4,809 |
| Microsoft Enterprise Agreement | Information Systems | General Plant | Project | 297 | 297 | 297 | 891 |
| | | | Total | $5,234 | $19,414 | $297 | $24,945 |

Table A-4
2024 Capital Budget
Previously Approved Multi-Year Projects

| TITLE | ASSET CLASS | INVESTMENT CLASSIFICATION | PROJECT/ PROGRAM | BUDGET ($000s) | | | |
|---|---|---|---|---|---|---|---|
| | | | | 2022 | 2023 | 2024 | Total |
| Mobile Hydro Plant Refurbishment[34] | Generation - Hydro | Renewal | Project | - | 1,666 | 2,480 | 4,146 |
| Transmission Line 94L Rebuild[35] | Transmission | Renewal | Project | 4,473 | 4,346 | 4,276 | 13,095 |
| Transmission Line 55L Rebuild[36] | Transmission | Renewal | Project | - | 5,328 | 5,284 | 10,612 |
| Distribution Reliability Initiative (SUM-01)[37] | Distribution | Renewal | Project | - | 656 | 1,015 | 1,671 |
| Replace Vehicles and Aerial Devices 2023-2024[38] | Transportation | General Plant | Project | - | 2,833 | 1,866 | 4,699 |
| | | | Total | $4,473 | $14,829 | $14,921 | $34,223 |

34 Approved in Order No. P.U. 38 (2022). See the *2023 Capital Budget Application*, Schedule B, pages 114 to 117.
35 Approved in Order No. P.U. 36 (2021). See the *2022 Capital Budget Application*, Schedule B, pages 18 to 20.
36 Approved in Order No. P.U. 38 (2022). See the *2023 Capital Budget Application*, Schedule B, pages 105 to 107.
37 Approved in Order No. P.U. 38 (2022). See the *2023 Capital Budget Application*, Schedule B, pages 8 to 11.
38 Approved in Order No. P.U. 38 (2022). See the *2023 Capital Budget Application*, Schedule B, pages 182 to 186.

# APPENDIX B:

## Deferred, Modified and Advanced Capital Expenditures

## Deferred, Modified and Advanced Capital Expenditures

The Provisional Guidelines require an explanation of capital expenditures planned for the year but were modified, re-prioritized or deferred until a future year. The Provisional Guidelines also require an explanation of which capital expenditures are proposed for the year after having been deferred in a previous year.

Table B-1 lists the capital expenditures proposed for 2024 that were deferred from previous years or modified through the Company's capital planning process.

Table B-1
2024 Capital Expenditures Deferred or Modified from Previous Years

| Project | Description |
|---|---|
| Lookout Brook Hydro Plant Refurbishment | The Lookout Brook Hydro Plant requires refurbishment. The refurbishment of this plant was originally planned for 2023.[39] The project was deferred to 2024 to allow further assessment of the condition of the plant and associated infrastructure. The assessment has now been completed and the multi-year refurbishment project is proposed for 2024 and 2025. |
| Transmission Line 146L Rebuild | Transmission Line 146L is a 41 kilometre line that runs from Gander Substation to Gambo Substation in central Newfoundland. The wood poles on this line are heavily deteriorated and require replacement. The project was most recently planned for 2023.[40] 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 multi-year project is proposed for 2024 and 2025. |
| Gambo Substation Refurbishment and Modernization | Gambo Substation located in central Newfoundland requires refurbishment and modernization to replace and upgrade deteriorated equipment. The project was most recently planned for 2023.[41] 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 2024. |

[39] The five-year capital plan filed with the *2020 Capital Budget Application* included the refurbishment of the Lookout Brook Hydro Plant beginning in 2023.
[40] The five-year capital plan filed with the *2019 Capital Budget Application* included the rebuild of Transmission Line 146L beginning in 2023.
[41] The five-year capital plan filed with the *2019 Capital Budget Application* included the refurbishment and modernization of Gambo Substation in 2023.

| Table B-1<br>2024 Capital Expenditures Deferred or Modified from Previous Years | |
|---|---|
| Project | Description |
| Memorial Substation Refurbishment and Modernization | Memorial Substation located at Memorial University requires refurbishment and modernization to replace and upgrade deteriorated equipment. The project was most recently planned for 2023.[42] The project was deferred to align with the University's schedule for upgrades to the customer owned equipment in 2023 and 2024. |
| 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 2024, but the scope was modified through the Company's annual review process. |

Table B-2 lists the capital expenditures that were planned for 2024 but have been deferred to subsequent years, and the amount of reduction.

| Table B-2<br>Capital Projects Deferred from 2024 to Subsequent Years | |
|---|---|
| Project | Description |
| Mobile Plant Substation Refurbishment and Modernization | The substation at the Mobile Plant requires refurbishment and modernization to replace and upgrade deteriorated equipment. The project was originally planned for 2024 to coincide with the plant refurbishment. The project has been deferred to allow further engineering assessment of the components in the substation. The project is now planned for 2026. |
| Lockston Substation Refurbishment and Modernization | Lockston Substation on the Bonavista Peninsula requires refurbishment and modernization to replace and upgrade deteriorated equipment. The project was originally planned for 2024. The project has been deferred to allow further engineering assessment of the components in the substation. The project is now planned for 2026 and 2027. |

[42] The five-year capital plan filed with the *2023 Capital Budget Application* included the refurbishment and modernization of Memorial Substation in 2024.

Table B-2
Capital Projects Deferred from 2024 to Subsequent Years

| Project | Description |
|---|---|
| Tors Cove Hydro Plant Refurbishment | The Tors Cove Hydro Plant on the Avalon Peninsula requires refurbishment to replace deteriorated equipment. The project was originally planned for 2024 and 2025. The project has been deferred to allow further engineering assessment of the components in the plant. The project is now planned for 2026 and 2027. |
| Mobile Hydro Plant Penstock Refurbishment | The refurbishment of the penstock at the Mobile Hydro Plant has been deferred to allow further engineering assessment of the penstock. The project was originally planned for 2024. The project is now planned for 2025. |
| Province Wide Radio System Replacement | The replacement of the Company's VHF radio system was originally planned for 2024. The project has been deferred to allow further assessment of alternatives, including options currently being explored by government. The project is now planned for 2025. |
| 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 2024. 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 2026 and 2027. |
| System Upgrades | *System Upgrades* is an annual capital project to upgrade third-party software products that comprise Newfoundland Power's information systems. The project originally planned for 2024 included the Company's asset management system. It has been deferred to align with the end of vendor support as of December 31, 2026 and the timing of the Company's ongoing asset management review. |

Table B-3 lists the capital expenditures that were planned for future years but have been advanced to 2024.

| Table B-3<br>2024 Capital Projects Advanced from Future Years | |
|---|---|
| Project | Description |
| Islington Substation Refurbishment and Modernization | Islington Substation located in Heart's Delight-Islington requires refurbishment and modernization to replace and upgrade deteriorated equipment and to replace an aging power transformer. The project was originally planned for 2025 as a single-year project. The project has been advanced to 2024 and 2025 as a result of a shift to multi-year projects for substation refurbishments and to address long lead times associated with the delivery of power transformers. |
| Old Perlican Substation Refurbishment and Modernization | Old Perlican Substation located in Old Perlican requires refurbishment and modernization to replace and upgrade deteriorated equipment. The project was originally planned for 2025 as a single-year project. The project has been advanced to 2024 resulting from engineering assessments which identified a significant quantity of deteriorated equipment. |

# APPENDIX C:

## Prioritized List of 2024 Capital Expenditures

## Prioritized List of 2024 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.[43]

To comply with the spirit and intent of the Provisional Guidelines, Newfoundland Power conducted a review of Canadian utility practice to assess alternative options to evaluate risks in a manner that could produce a list identifying the relative priority of capital expenditures. The review determined that practices for assessing risks vary among utilities.

Following this review, a risk matrix methodology was developed. The risk matrix methodology is designed to assess the risks of not proceeding with capital expenditures identified in the Renewal, Service Enhancement and General Plant investment classifications. The methodology is consistent with Newfoundland Power's long-term approach to assessing risks and provides reasonable consistency in communicating the results of those assessments across asset classes. This, in turn, allows capital expenditures to be presented in the form of a prioritized list with the level of priority based on the degree of risk mitigation provided.

The risk matrix methodology and prioritized list of capital expenditures for 2024 are provided below. The Company expects its approach may evolve going forward as its asset management review is completed.

---

[43] 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. The methodologies used by other utilities to assess risk include: (i) determining risk based on engineering judgment; (ii) using weighted formulas that apply risk-related criteria; (iii) risk matrices that assess probability and consequence; and (iv) advanced software, such as the CopperLeaf Portfolio.

### *Risk Matrix Methodology*

The risk matrix is used to evaluate: (i) the potential consequences of not completing an identified project or program; and (ii) the probability of those consequences occurring if the project or program did not proceed.

Figure C-1 shows the risk matrix.

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

*Figure C-1 - Risk Matrix*

Using the risk matrix, capital projects and programs can receive a score of 1 to 25 based on the assessment of probability and consequence. Values of 1 to 4 are considered Low priority (shaded in green). Values of 5 to 9 are considered Medium priority (shaded in yellow). Values of 10 to 16 are considered Medium-High priority (shaded in orange). Values of 20 or 25 are considered High priority (shaded in red).

The assessment of consequences considered risks to four principal business objectives:

- *Reliability* – Maintain long-term reliable service.
- *Safety* – Protect safety of employees and the public.
- *Environment* – Avoid environmental degradation.
- *Economic* – Advance operational efficiency and effectiveness.

These business objectives are consistent with Newfoundland Power's statutory obligations.[44] 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:<br>1 – Less than 100 customers<br>2 – 100 to 500 customers<br>3 – 500 to 1,000 customers<br>4 – 1,000 to 5,000 customers<br>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:<br>1 – First Aid<br>2 – One Medical Aid<br>3 – Multiple Medical Aids<br>4 – Lost Time/Restricted Work<br>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:<br>1 – Immaterial Impact<br>2 – Internal Impact Only<br>3 – Isolated Off-Site Impact<br>4 – Widespread Off-Site Impact<br>5 – Regulatory Requirement Breached | Examples of other considerations include potential impact on local wildlife and biodiversity. |
| Economic | Overall customer benefit:<br>1 – Immaterial NPV<br>2 – $10,000 to $100,000 NPV<br>3 – $100,000 to $500,000 NPV<br>4 – $500,000 to $1,000,000 NPV<br>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. |

44 As outlined in section 2.1, Newfoundland Power is required to provide services and facilities that are reasonably safe and adequate and just and reasonable and to provide customers with reliable service at the lowest possible cost. The Company must also comply with various other provincial and federal regulations, as well as industry standards including environmental, health and safety regulations.

Probability is assessed from the perspective of how likely the identified consequence is to occur if a capital project or program did not proceed.

Probability is based on engineering judgement using a scale of 0% to 100% as follows:

- *Near Certain (5)* – Probable within a range of 91% to 100%.
- *Likely (4)* – Probable within a range of 76% to 90%.
- *Possible (3)* – Probable within a range of 26% to 75%.
- *Unlikely (2)* – Probable within a range of 11% to 25%.
- *Rare (1)* – Probable within a range of 0% to 10%.

For Renewal and General Plant expenditures, the probability value is determined primarily based on asset condition. This includes the level of deterioration identified, obsolescence and other deficiencies. Assessments of probability also consider previous operating experience, including any history of equipment failure, and whether an asset has exceeded its expected useful service life.

For Service Enhancement expenditures, the probability value is determined based on whether the benefit is quantifiable through an economic analysis or can reasonably be expected based on past experience. Potential risks to achieving the benefit are considered in assessing probability, including the results of any associated sensitivity analyses.

## *Prioritized List of 2024 Capital Expenditures*

Table C-2 provides the prioritized list of 2024 capital expenditures in excess of $750,000 by investment classification. In accordance with the Provisional Guidelines, the list is organized by investment classification with previously approved multi-year projects at the top. See Schedule B to the Application for an explanation of the priority scores assigned to each capital project and program in the Renewal, Service Enhancement and General Plant investment classifications.[45]

Table C-2
Prioritized List of 2024 Capital Expenditures

| Project/Program Name | Priority Score |
|---|---|
| *Previously Approved Multi-Year Projects* | |
| Replace Vehicles and Aerial Devices 2023-2024 | - |
| Distribution Reliability Initiative | - |
| Transmission Line 55L Rebuild | - |
| Mobile Hydro Plant Refurbishment | - |
| Transmission Line 94L Rebuild | - |
| *Mandatory* | |
| General Expenses Capitalized | - |
| Allowance for Unforeseen Items | - |
| *Access* | |
| Extensions | - |
| New Transformers | - |
| New Services | - |
| New Street Lighting | - |
| Relocate/Replace Distribution Lines for Third Parties | - |
| *System Growth* | |
| Feeder Additions for Load Growth | - |
| *Renewal, Service Enhancement, General Plant* | |
| Substation Replacements Due to In-Service Failures | 25 |
| Transmission Line Maintenance | 25 |

45 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 2024 Capital Expenditures

| Project/Program Name | Priority Score |
|---|---|
| Reconstruction | 25 |
| Transmission Line 146L Rebuild | 20 |
| Rebuild Distribution Lines | 20 |
| Lookout Brook Hydro Plant Refurbishment | 20 |
| Replacement Transformers | 20 |
| LED Street Lighting Replacement | 20 |
| Distribution Feeder Automation | 20 |
| Cybersecurity Upgrades | 20 |
| Shared Server Infrastructure | 20 |
| Replace Vehicles and Aerial Devices 2024-2025 | 16 |
| System Upgrades | 16 |
| Microsoft Enterprise Agreement | 16 |
| Hydro Facility Rehabilitation | 16 |
| Gambo Substation Refurbishment and Modernization | 16 |
| Islington Substation Refurbishment and Modernization | 16 |
| Memorial Substation Refurbishment and Modernization | 16 |
| Old Perlican Substation Refurbishment and Modernization | 16 |
| Substation Protection and Control Replacements | 16 |
| Distribution Reliability Initiative | 15 |
| Mobile Hydro Plant Surge Tank Refurbishment | 15 |
| Replacement Street Lighting | 15 |
| Application Enhancements | 15 |
| Distribution Feeder OXP-01 Refurbishment | 12 |
| Gander Building Renovation | 12 |

# APPENDIX D:

## List of Worst Performing Feeders

## *List of Worst Performing Feeders*

The Board's Provisional Guidelines require the utility to provide a list of it's 10 worst performing feeders, including relevant outage statistics compared to the utility average for the past 10 years. The Provisional Guidelines require the list be provided with and without major events.

Newfoundland Power completes an annual assessment of its worst performing feeders as part of its *Distribution Reliability Initiative.* Each distribution feeder is assessed based on its performance over the most recent five-year period. This timeframe is consistent with standard utility practice, as assessments of worst performing feeders typically use three to seven year time horizons.

The Company's assessment excludes planned outages and outages due to loss of supply and major events. This is consistent with standard industry practice as major events are typically driven by severe weather rather than the condition of the electrical system and are outside of the utility's control.[46] 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.

[46] 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<br>Unscheduled Distribution-Related Outages<br>10-Year Average<br>(2013-2022)<br>Sorted by Customer Minutes of Interruption | | | | |
|---|---|---|---|---|
| Feeder | Annual Customer Interruptions | Annual Customer Minutes of Interruption | Annual Distribution SAIFI | Annual Distribution SAIDI |
| SUM-01 | 6,478 | 858,336 | 3.58 | 7.89 |
| DOY-01 | 5,330 | 537,265 | 3.06 | 5.13 |
| DUN-01 | 4,600 | 517,613 | 4.42 | 8.34 |
| GLV-02 | 6,028 | 511,967 | 3.95 | 5.60 |
| DLK-03 | 3,297 | 413,384 | 2.37 | 4.99 |
| SCR-01 | 2,482 | 412,624 | 2.57 | 7.12 |
| BOT-01 | 3,350 | 404,880 | 1.95 | 3.94 |
| BVS-04 | 3,694 | 363,187 | 2.34 | 3.84 |
| LEW-02 | 4,242 | 362,823 | 2.98 | 4.38 |
| BLK-01 | 4,122 | 348,977 | 2.47 | 3.50 |
| Company Average | 1,177 | 91,894 | 1.41 | 1.83 |

Table D-2
Unscheduled Distribution-Related Outages
10-Year Average
(2013-2022)
Sorted by Distribution SAIFI

| Feeder | Annual Customer Interruptions | Annual Customer Minutes of Interruption | Annual Distribution SAIFI | Annual Distribution SAIDI |
|---|---|---|---|---|
| SJM-11 | 7,972 | 243,632 | 5.48 | 2.81 |
| BHD-01 | 5,028 | 324,528 | 5.32 | 5.71 |
| SCT-01 | 3,435 | 220,406 | 4.78 | 5.07 |
| DUN-01 | 4,600 | 517,613 | 4.42 | 8.34 |
| SCT-02 | 1,097 | 95,680 | 4.28 | 6.22 |
| TWG-03 | 1,217 | 60,815 | 4.17 | 3.40 |
| GLV-02 | 6,028 | 511,967 | 3.95 | 5.60 |
| TWG-02 | 2,720 | 161,883 | 3.87 | 3.86 |
| ABC-02 | 3,830 | 279,431 | 3.75 | 4.58 |
| SUM-01 | 6,478 | 858,336 | 3.58 | 7.89 |
| Company Average | 1,177 | 91,894 | 1.41 | 1.83 |

| Table D-3<br>Unscheduled Distribution-Related Outages<br>10-Year Average<br>(2013-2022)<br>Sorted by Distribution SAIDI | | | | |
|---|---|---|---|---|
| Feeder | Annual Customer Interruptions | Annual Customer Minutes of Interruption | Annual Distribution SAIFI | Annual Distribution SAIDI |
| SBK-01[47] | 3 | 1,610 | 1.27 | 12.74 |
| DUN-01 | 4,600 | 517,613 | 4.42 | 8.34 |
| SUM-02 | 1,834 | 297,636 | 3.03 | 8.16 |
| SUM-01 | 6,478 | 858,336 | 3.58 | 7.89 |
| SCR-01 | 2,482 | 412,624 | 2.57 | 7.12 |
| LGL-01 | 636 | 140,785 | 1.73 | 6.65 |
| SCT-02 | 1,097 | 95,680 | 4.28 | 6.22 |
| GBS-02 | 755 | 134,160 | 1.94 | 5.98 |
| RVH-02 | 469 | 54,552 | 3.02 | 5.83 |
| NCH-03 | 4 | 421 | 3.55 | 5.81 |
| Company Average | 1,177 | 91,894 | 1.41 | 1.83 |

[47] 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<br>Unscheduled Distribution-Related Outages<br>10-Year Average<br>(2013-2022)<br>Sorted by Distribution CHIKM | |
|---|---|
| Feeder | Annual Distribution CHIKM |
| KBR-10 | 298 |
| SJM-06 | 267 |
| WAV-03 | 232 |
| SLA-13 | 232 |
| PAB-05 | 197 |
| PEP-04 | 180 |
| SLA-10 | 178 |
| KBR-13 | 174 |
| KEN-03 | 168 |
| PEP-01 | 165 |
| Company Average | 48 |

Table D-5
Unscheduled Distribution-Related Outages
10-Year Average
(2013-2022)
Sorted by Distribution CIKM

| Feeder | Annual Distribution CIKM |
|---|---|
| KBR-10 | 253 |
| SJM-11 | 244 |
| KBR-13[48] | 234 |
| SJM-04 | 218 |
| SLA-10 | 193 |
| KEN-03 | 184 |
| PAB-03 | 180 |
| PAB-05 | 169 |
| HWD-07 | 168 |
| PEP-01 | 164 |
| Company Average | 37 |

48 Kings Bridge ("KBR") Substation distribution feeder KBR-13 was placed into service in 2017, as such, ten years of historical reliability data is not available for this feeder. The average is therefore 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 2024 Capital Budget includes five capital projects that were previously approved by the Board. Capital expenditures for these project total approximately $14,921,000 in 2024.

The following section provides an update on each multi-year project for 2024 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** |
| **2024 Expenditures:** | **$4,276,000** |

The rebuilding of Transmission Line 94L was included in the *Transmission Line Rebuild* project filed with Newfoundland Power's *2022 Capital Budget Application*.[49] 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. The Board approved the rebuilding of Transmission Line 94L as a three-year project in Order No. P.U. 36 (2021).

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 | 2022B[50] | 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 $4,276,000 in 2024. While the project is being executed as approved, the timing of the project approval, along with environmental assessment and permitting delays, has resulted in expenditures being carried forward with a greater proportion of the project expected to be executed in 2023 and 2024. For expenditures incurred to date, see the *2022 Capital Expenditures Report* filed by the Company on March 31, 2023 and the *2023 Capital Expenditure Status Report* filed with the Application.

49 See Newfoundland Power's *2022 Capital Budget Application,* report *3.1 2022 Transmission Line Rebuild.*
50 Includes a carryover of forecast expenditures of $3,921,000 from 2022 to 2023. See Newfoundland Power's *2022 Capital Expenditure Report*, page 14 of 14.

| | |
|---|---|
| **Title:** | **Transmission Line 55L Rebuild** |
| **Asset Class:** | **Transmission** |
| **Category:** | **Project** |
| **Investment Classification:** | **Renewal** |
| **2024 Expenditures:** | **$5,284,000** |

The rebuilding of Transmission Line 55L was included in the *Transmission Line Rebuild* project filed with Newfoundland Power's *2023 Capital Budget Application*.[51] Transmission Line 55L is a 66 kV radial line running between Blaketown and Clarkes Pond substations. The line was constructed in 1971 and serves 3,419 customers in the Placentia area. Inspections completed in 2022 determined that this transmission line is heavily deteriorated.

The Board approved the rebuilding of Transmission Line 55L as a two-year project in Order No. P.U. 38 (2022). The rebuilding of Transmission Line 55L is proceeding as approved. Brush clearing is being completed in the second quarter of 2022 and construction is expected to commence in the third quarter. A 24.1-kilometre section of line will be rebuilt in 2023 while the remaining 21.2 kilometres will be rebuilt in 2024.

Table E-2 provides the approved expenditures for the *Transmission Line Rebuild* project for 55L.

Table E-2
Transmission Line 55L Rebuild Project
Multi-Year Expenditures
($000s)

| Cost Category | 2023F | 2024F |
|---|---|---|
| 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 |

Expenditures for the *Transmission Line 55L Rebuild* project total approximately $10,612,000, including $5,284,000 in 2024. For expenditures incurred to date, see the *2023 Capital Expenditure Status Report* filed with the Application.

51 See Newfoundland Power's *2023 Capital Budget Application,* report *3.1 2023 Transmission Line Rebuild.*

**Title:** **Mobile Hydro Plant Refurbishment**
**Asset Class:** **Generation – Hydro**
**Category:** **Project**
**Investment Classification:** **Renewal**
**2024 Expenditures:** **$2,480,000**

The *Mobile Hydro Plant Refurbishment* project was included as a multi-year project in Newfoundland Power's *2023 Capital Budget Application*.[52] Newfoundland Power conducted a detailed condition assessment of the Plant, and determined that the powerhouse building roof is leaking and existing heating and lighting systems are inadequate. The Plant contains 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.

The Board approved the *Mobile Hydro Plant Refurbishment* as a two-year project in Order No. P.U. 38 (2022). The plant refurbishment is proceeding as approved. Engineering design and procurement of replacement components is being 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.

Table E-3 provides the approved expenditures for the *Mobile Hydro Plant Refurbishment* project.

Table E-3
Mobile Hydro Plant Refurbishment Project
Multi-Year Expenditures
($000s)

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

Expenditures for the *Mobile Hydro Plant Refurbishment* project total approximately $4,146,000, including $2,480,000 in 2024. For expenditures incurred to date, see the *2023 Capital Expenditure Status Report* filed with the Application.

52 See Newfoundland Power's *2023 Capital Budget Application,* report *4.2 Mobile Hydro Plant Refurbishment.*

| | |
|---|---|
| **Title:** | **Distribution Reliability Initiative** |
| **Asset Class:** | **Distribution** |
| **Category:** | **Project** |
| **Investment Classification:** | **Renewal** |
| **2024 Expenditures:** | **$1,015,000** |

The refurbishment of distribution feeder SUM-01 was included in the *Distribution Reliability Initiative* project filed with Newfoundland Power's *2023 Capital Budget Application*.[53] Distribution feeder SUM-01 serves 1,812 customers on New World Island. 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.

The Board approved the refurbishment of Distribution Feeder SUM-01 as a two-year project in Order No. P.U. 38 (2022). The refurbishment of Distribution Feeder SUM-01 is proceeding as approved.

Table E-4 provides the approved expenditures for the *Distribution Reliability Initiative* project for SUM-01.

Table E-4
Distribution Reliability Initiative Project
Multi-Year Expenditures
($000s)

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

Expenditures for the *Distribution Reliability Initiative* total approximately $1,671,000, including $1,015,000 in 2024. For expenditures incurred to date, see the *2023 Capital Expenditure Status Report* filed with the Application.

53 See Newfoundland Power's *2023 Capital Budget Application,* report *1.1 2023 Distribution Reliability Initiative.*

| | |
|---|---|
| **Title:** | **Replace Vehicles and Aerial Devices 2023-2024** |
| **Asset Class:** | **Transportation** |
| **Category:** | **Project** |
| **Investment Classification:** | **General Plant** |
| **2024 Expenditures:** | **$1,866,000** |

The *Replace Vehicles and Aerial Devices 2023-2024* project was included as a multi-year project in Newfoundland Power's *2023 Capital Budget Application.*[54]

The *Replace Vehicles and Aerial Devices 2023-2024* involves the addition and replacement of heavy/medium-duty, light-duty, passenger and off-road vehicles. In 2022, due to long delivery times associated with the purchase of medium/heavy-duty vehicles, the Company shifted to a multi-year project for vehicle purchases.

The Board approved the *Replace Vehicles and Aerial Devices 2023-2024* project as a two-year project in Order No. P.U. 38 (2022). The project is proceeding as approved. Newfoundland Power identified 28 passenger vehicles and four light duty vehicles for replacement in 2023 and four heavy/medium duty vehicles for replacement in 2024.

Table E-5 provides the approved expenditures for the *Replace Vehicles and Aerial Devices 2023-2024* project.

Table E-5
Replace Vehicles and Aerial Devices 2023-2024 Project
Multi-Year Expenditures
($000s)

| Cost Category | 2023F | 2024F |
|---|---|---|
| Material | 2,701 | 1,866 |
| Labour – Internal | 127 | - |
| Other | 5 | - |
| Total | $2,833 | $1,866 |

Expenditures for the *Replace Vehicles and Aerial Devices 2023-2024* project total approximately $4,699,000 with $1,866,000 for 2024. For expenditures incurred to date, see the *2023 Capital Expenditure Status Report* filed with the Application.

[54] See Newfoundland Power's *2023 Capital Budget Application, Schedule B,* pages 182-186.


NEWFOUNDLAND POWER
A FORTIS COMPANY

# 2024-2028 Capital Plan

## June 2023

# TABLE OF CONTENTS

**Page**

# 1.0 PLAN OVERVIEW

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") prepares a five-year capital plan to provide reasonable 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 $131.2 million from 2024 to 2028. This level of investment is expected to be required to continue providing customers with access to safe and reliable service at the lowest possible cost.

Newfoundland Power's operations are focused on maintaining current levels of overall service reliability for customers. While the Company is targeting stability in its reliability performance, the age of its electrical system poses an increasing risk to this objective. The risk of equipment failure is expected to increase as many assets approach or exceed the end of their expected useful service lives, including substation power transformers, distribution and transmission wooden support structures and overhead conductor.

Newfoundland Power is currently undertaking a review of its asset management practices and has developed a framework for scope, stages and timelines for the review. Through this review, the Company is aiming to ensure the next generation of its asset management technology can effectively meet future requirements.

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 $74 million of annual capital expenditures from 2024 to 2028, or 56% 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. While customer connections are forecast to decline over the next five years, system load growth driven by residential development in urban areas, electrification of heating systems, and electric vehicle adoption is forecast to offset this decline. Responding to customer and system growth is forecast to account for an average of approximately $28.9 million of annual capital expenditures from 2024 to 2028, or 22% of total annual expenditures.

## 2.0 PLANNING CONTEXT

### 2.1 General

Newfoundland Power's investment priorities and five-year capital plan reflect the capital expenditures necessary to meet its statutory obligations under the *Public Utilities Act* and *Electrical Power Control Act, 1994*. The capital plan is updated annually with the latest forecasts of customer and system load growth, anticipated operational requirements and electrical system condition. This section provides an overview of forecast requirements in these areas, which form the basis of the Company's investment priorities over the next five years.

### 2.2 Customer Outlook

Newfoundland Power has an obligation to provide customers with equitable access to an adequate supply of power.[1] Capital investments are required annually to connect new customers to the electrical system and to respond to increases in electrical system load.

The Company has experienced declining requests for new service connections in recent years due to a decrease in new home construction throughout its service territory. At the same time, system load growth has been concentrated in urban areas.[2] These trends are expected to continue.

Table 1 provides the forecast number of new customer connections from 2024 to 2028.

Table 1
Forecast New Customer Connections
(2024F-2028F)

| | 2024F | 2025F | 2026F | 2027F | 2028F |
|---|---|---|---|---|---|
| New Customer Connections | 2,053 | 1,943 | 1,828 | 1,702 | 1,537 |

New customer connections are forecast to decline from 2,053 in 2024 to 1,537 in 2028. Approximately 37% of new customer connections over the next five years are forecast to occur in the province's largest urban centre, the Northeast Avalon.

System load growth is expected to continue to be driven by residential development in urban areas, government plans to electrify heating systems in provincial buildings, and residential electrification of heating systems.[3] Efforts to electrify provincial buildings and other

1 See section 3(b)(ii) of the *Electrical Power Control Act, 1994.*

2 For example, of 19 *Feeder Additions for Load Growth* projects completed over the last five years, 17 projects have been on the Avalon Peninsula, including 13 on the Northeast Avalon.

3 Transformer capacity additions at Kelligrews and Hardwoods substations are forecast to be required to respond to load growth on the Northeast Avalon.

electrification opportunities are expected to be pursued as part of the Provincial Government's *Renewable Energy Plan*.[4] In addition, the Provincial Government in partnership with the Federal Government, recently announced the expansion of a rebate program to support approximately 10,000 homeowners to transition their homes from oil heat to electric heat.[5]

System load growth is also expected to be affected by electric vehicle ("EV") adoption over the forecast period. Load growth associated with EVs is expected to increase annually, with the potential for approximately 38,000 EVs on the province's roads in the next ten years, requiring more than 260 GWh of energy.[6] Newfoundland Power has designed an *EV Load Management Pilot Project* to study options for managing the impact of EVs on peak demand.[7]

Over the longer term, increased peak demand due to EV adoption may result in dynamic rate structures becoming cost-effective for customers. A 2019 market potential study completed by Dunsky Energy Consulting determined that dynamic rates may become cost-effective for customers between 2030 and 2034.[8] Dynamic rate structures will take several years and require investments in Advanced Metering Infrastructure ("AMI").[9] The Company anticipates commencing a transition to meters with advanced functionality such as interval data, time-of-use data, demand read and reset, and remote disconnect capabilities as early as 2027.

Should customer connections and system load growth vary from forecast, the capital investments required to accommodate this growth will also vary.

## 2.3 Operations Outlook

Newfoundland Power has an obligation to provide reliable service to its customers at the lowest possible cost. Providing customers with reliable service requires capital investments to maintain the condition of the electrical system and the Company's operational response capabilities when outages occur.

---

4 See the Provincial Government's *Renewable Energy Plan,* section *1.4 Electrify Transport and Space-Heating*.

5 In a news release dated March 13, 2023, the Provincial and Federal Governments announced the new multi-year program to expand their collective efforts for residential home heating rebates. The initiative will assist residents looking to switch from oil furnaces to electricity heating technologies.

6 Dunsky Energy + Climate Advisors estimated that the province will have 38,000 EVs in the next ten years. By 2040, Dunsky estimates that there will be more than 160,000 EVs in Newfoundland and Labrador. See Newfoundland and Labrador Hydro's *Reliability and Resource Adequacy - 2022 Update, Volume III: Long-Term Resource Plan,* pages 44-45, October 3, 2022.

7 Newfoundland Power filed an application associated with the *EV Load Management Pilot Project* with the Board on June 2, 2023.

8 See *Schedule E – Potential Study Addendum: Demand Response Assessment* filed as part of the *Electrification, Conservation and Demand Management Plan: 2021-2025*.

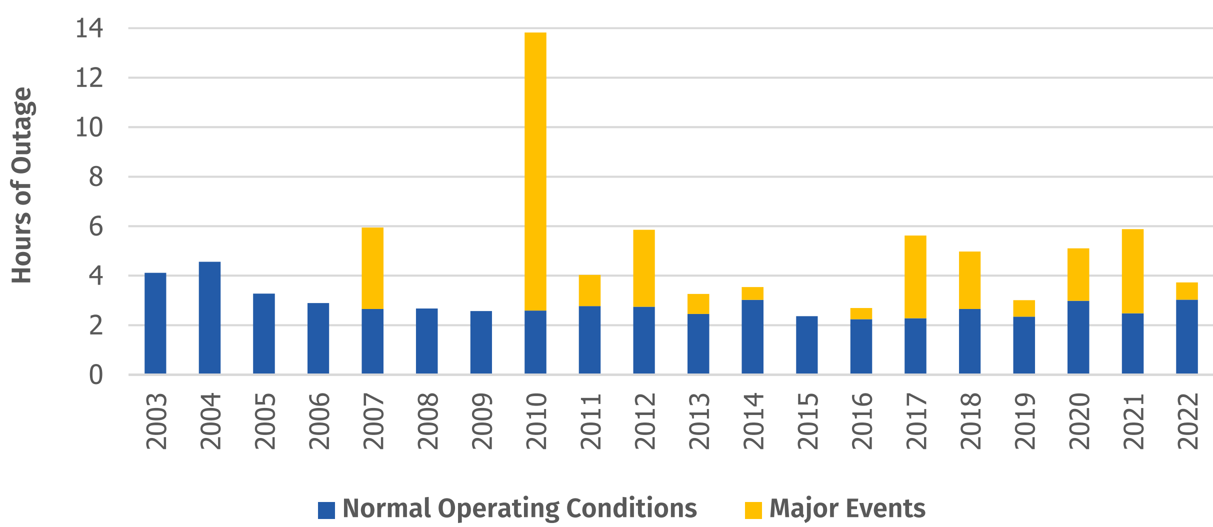
9 For example, Newfoundland Power's deployment of Automated Meter Reading technology required over five years to implement. The deployment of AMI would be more substantial as, in addition to replacing existing meters, the Company would be required to implement new communications infrastructure, a meter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

Customers have indicated a reasonable level of satisfaction with Newfoundland Power's service delivery over the last decade.[10] The Company's operations are focused on maintaining current levels of overall service reliability for customers. Annual performance targets for service reliability are established based on the Company's performance over the most recent five-year period, excluding major events.

For 2024, Newfoundland Power is targeting an average annual frequency of 2.0 outages per customer and an average duration of 2.7 outage hours per customer. Annual performance targets over the ensuing five years are expected to be reasonably consistent with current targets, but may vary depending on actual results over this period.

Figure 1 shows the average duration of outages experienced by Newfoundland Power's customers from 2003 to 2022 including major events.[11]

**Figure 1**
**Newfoundland Power**
**Outage Duration Including Major Events**
**(2003 to 2022)**




Major customer outages due to severe weather have become more frequent in the Company's service territory, causing customer outages in nine of the last ten years compared to just four years in the prior decade.

---

10 Overall customer satisfaction with Newfoundland Power's service averaged 86% from 2013 to 2022. Customer satisfaction averaged 93% when customers were surveyed about their direct interactions with field staff, including technologists and field service representatives.

11 Major events generally affect the duration of outages more than the frequency of outages. For example, a hurricane may result in a single outage that lasts several days. From 2003 to 2022, major events have resulted in an average SAIFI of 0.3, ranging as high as an average SAIFI of 1.2 in 2010.

While the Company aims to maintain a consistent level of service reliability for customers, severe weather events can have a significant impact on the service provided to customers. Such events exceed the design parameters of the electrical system and may result in widespread damage and extended customer outages. Recent examples include a severe blizzard in January 2020 and Hurricane Fiona in September 2022.[12] 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.[13]

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.[14] This risk highlights the importance of ensuring the electrical system is resilient and designed to standards that reflect local climatic conditions, as well as the importance of maintaining effective emergency response capabilities through measures such as electrical system automation.[15]

The reliability of bulk electricity supply from Newfoundland and Labrador Hydro ("Hydro") also affects the reliability experienced by Newfoundland Power's customers. Hydro's *Reliability and Resource Adequacy Study – 2022 Update* recommends that the Holyrood Thermal Generating Station, as well as the Hardwoods Gas Turbine, remain available as backup generation in the event of a prolonged outage of the Labrador Island Link and until long-term supply sources have been reviewed, approved, and constructed.[16] Without their replacement, Hydro states that the Island Interconnected System will be significantly capacity constrained.[17] Hydro also proposes beginning the regulatory process to seek approval to construct Bay d'Espoir Unit 8.[18] It is currently uncertain what supply resources will be required to ensure adequate reliability for Newfoundland Power's customers in the future. Hydro has indicated that new generation could require eight years to implement from the time of recommendation to commissioning.[19] These matters are currently under review as part of the Board's *Reliability and Resource Adequacy Study Review*.

---

12 Hurricane Fiona in September 2022 resulted in wind gusts in excess of 170 kilometres per hour. Over a three-day period, Newfoundland Power experienced island wide outages resulting from extreme winds and storm surges associated with Hurricane Fiona. Newfoundland Power employees worked throughout the period to restore power to customers and address safety issues associated with damage caused by the storm. In particular, restoration efforts were impacted on the west coast of the island in the Wreckhouse area, where winds exceeded 120 kilometres per hour all day and into the late evening.

13 For example, capital expenditures of approximately $7.5 million were required to restore service to customers in 2010 following a severe ice storm and Hurricane Igor. These expenditures were approved in Order Nos. P.U. 17 (2010) and P.U. 35 (2010).

14 The Federal Government has recognized the importance of adapting the Atlantic energy sector to climate change. The Federal Government states "Adaptation to climate change by the energy sector in the Atlantic provinces will require re-examination of design standards for transmission and distribution infrastructure, to enable it to better withstand extreme weather events." See *From Impacts to Adaptation: Canada in a Changing Climate 2007*, Government of Canada, page 154.

15 The principal design standard for distribution and transmission line design in Canada is the CSA standard C22.3 No.1-15, Overhead Systems. This standard recognizes four classifications of weather load conditions for ice accumulation, wind loading, and temperature. These are: (i) medium loading B; (ii) medium loading A; (iii) heavy; and (iv) severe. Newfoundland Power's service territory has heavy and severe loading classifications. Only two other provinces are identified as having severe weather loading areas. These are: (i) parts of northern and southern Manitoba; and (ii) rural parts of eastern Quebec, including the Gaspe Peninsula.

16 See Hydro's *Reliability and Resource Adequacy Study – 2022 Update,* October 3, 2022, page P.6.

17 See Hydro's *Reliability and Resource Adequacy Study – 2022 Update, Volume III: Long Term Resource Plan*, October 3, 2022, page 51, lines 25-27.

18 See Hydro's *Reliability and Resource Adequacy Study – 2022 Update,* October 3, 2022, page P.6.

19 See Hydro's *Reliability and Resource Adequacy Study – 2022 Update*, page 4.

Newfoundland Power's capital plan currently includes the retirement of the Wesleyville and Greenhill gas turbines and replacement with a single mobile gas turbine. As a result of Hydro's *Reliability and Resource Adequacy Study – 2022 Update*, the Company has initiated a review of this plan to evaluate the benefits of continuing to operate stationary units in these areas. The evaluation of alternatives will be coordinated with Hydro to examine the impact that any generation addition or removal will have on Hydro's *Reliability and Resource Adequacy Study*.

Newfoundland Power's operations and capital investments must adapt to increasing cybersecurity risks. Cybersecurity risks have increased materially for critical infrastructure operators in recent years, including electric utilities. Newfoundland Power expects that more frequent upgrades of its operations technologies and computing hardware will be required going forward to manage increasing cybersecurity risks.

Market conditions following the COVID-19 pandemic continue to pose a risk to Newfoundland Power's *2024-2028 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 pressure on materials also increased following the COVID-19 pandemic. In response, the Company has increased its use of multi-year capital projects. This includes substation refurbishment and modernization projects where power transformer replacements are required and the procurement of heavy-duty fleet vehicles. The Company continues to monitor market conditions to assess potential impacts on its operations.

## 2.4 Asset Condition Outlook

### *2.4.1 General*

Newfoundland Power's electrical system is maintained through a combination of preventative and corrective maintenance programs and long-term asset management strategies. The most recent independent review of Newfoundland Power's engineered operations was conducted by The Liberty Consulting Group in 2014. The review found that the Company's asset management conforms to good utility practice.[20]

A significant portion of Newfoundland Power's electrical system assets were constructed in the 1960s and 1970s following provincial electrification efforts in rural areas. As a result, a large quantity of assets with expected useful service lives of between 50 and 60 years, such as conductor and wooden support structures, are now aging beyond their expected useful service lives. While age is not the primary determinant as to whether an asset requires refurbishment or replacement, it provides a reasonable indication of the probability that an asset may begin to fail.

[20] 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.

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 1,200 equipment failures per year were experienced on the distribution system from 2018 to 2022, which represents a 34% increase compared to the previous five-year period.[21] The upward trend in equipment failures is primarily driven by overhead conductor that has become deteriorated due to its age and exposure to climatic conditions.[22]

Newfoundland Power is exposed to increasing risk of equipment failure going forward due to the age of its electrical system. As detailed below, significant portions of major equipment in the distribution, transmission and substation asset classes have exceeded or are approaching the end of their useful service lives.

Maintaining the safe and reliable operation of the electrical system will require increased investments in the planned refurbishment and replacement of electrical system assets. Newfoundland Power is undertaking a review of its asset management practices to ensure its practices continue to be adequate, given the age of its electrical system, and remain consistent with industry best practices. The Company has developed a framework for the asset management review which provides information on the scope, stages and timelines for the review.

The asset management review is expected to require two years to complete. This timeline is driven, in part, by the upcoming obsolescence of Newfoundland Power's core asset management technology. This technology has been in service for approximately two decades and is expected to reach end of life in 2026.[23] Through this review, the Company is aiming to ensure the next generation of its asset management technology can effectively meet future requirements.

During a current state assessment, Newfoundland Power has benchmarked its asset management maturity against clauses of ISO 55001.[24] This is a standard approach used by utilities to understand the current state of their asset management and provides a tool against which progress can be monitored along their asset management journey. Opportunities for assessment were identified and categorized in three areas: (i) organizational approach; (ii) plans and processes; and (iii) data and technology. The target state assessment will evaluate the costs and benefits of the identified opportunities to determine whether they would support Newfoundland Power's objective of continuing to provide safe and reliable service to its customers at the lowest possible cost. The results of the target state assessment will inform the development of an implementation plan to guide the next phase of Newfoundland Power's asset management journey. Opportunities will be prioritized for implementation based on the costs and benefits to Newfoundland Power's customers and its operations.

---

21 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.*

22 On average, 197 conductor failures occurred annually from 2013 to 2017. This compares to an average of 325 conductor failures annually from 2018 to 2022.

23 Newfoundland Power was notified by the vendor of its asset management technology that the software will no longer be supported as of December 31, 2026.

24 ISO 55001 is an internationally recognized standard for asset management practices.

The implementation of these opportunities, if determined to be beneficial, is expected to require a phased approach over several years. Opportunities will be prioritized for the asset classes that are most critical in serving customers. Newfoundland Power notes that its asset management review is a long-term initiative. The framework for conducting the review was completed in 2022 and the results of the review are expected to be available in 2024.

### *2.4.2 Distribution*

Newfoundland Power operates approximately 300 distribution feeders. Distribution feeders are inspected on a seven-year cycle to identify deficiencies. High-priority deficiencies are corrected during the year in which they are identified through the *Reconstruction* program. Other deficiencies are corrected in a planned manner in the following year through the *Rebuild Distribution Lines* program and individual refurbishment projects for feeders where deterioration is most pronounced.

The distribution system performance is addressed through the longstanding *Distribution Reliability Initiative* project, which targets the worst performing feeders for capital investment.[25]

Newfoundland Power's distribution system includes approximately 229,000 wooden support structures and overhead conductor on approximately 9,500 kilometres of distribution line. Industry experience indicates an average expected useful service life of 54 years for distribution wooden support structures and 50 years for distribution overhead conductor.[26]

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.

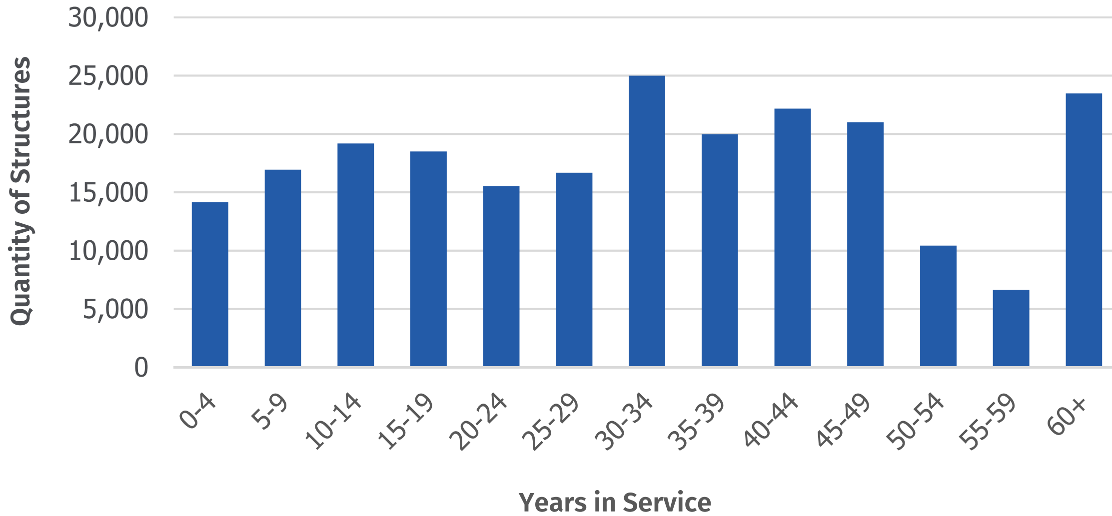
---

25 The *Distribution Reliability Initiative* project has evolved in recent years to include isolated specific sections of feeders or neighbourhoods that are experiencing poor reliability performance. Newfoundland Power implemented a new Outage Management System in 2019. The system is capable of providing outage data with greater granularity and precision than was previously possible. This data is incorporated into the *Distribution Reliability Initiative* to permit a more targeted approach to required capital upgrades.

26 The average industry expected useful service lives of distribution assets were derived from information filed with the Federal Energy Regulatory Commission ("FERC"). Electric utilities subject to FERC's jurisdiction are required to file a Form 1 report annually. Form 1 reports are publicly available and provide financial and operational information for electric utilities. A total of 38 utilities were included in the analysis.

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

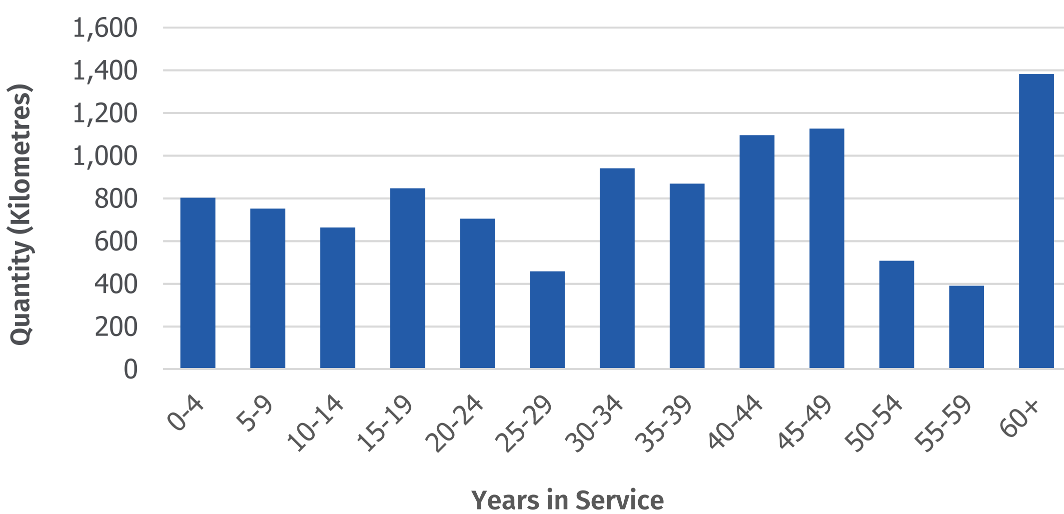
**Figure 2**
**Distribution Wooden Support Structures**
**Asset Age**




Approximately 13% of distribution wooden support structures have exceeded the average industry expected useful service life of 54 years. An additional 14% of distribution wooden support structures will reach 54 years in service over the next decade.

Figure 3 provides the age distribution of overhead conductor on the Company's distribution system.

**Figure 3**
**Distribution Overhead Conductor**
**Asset Age**



Approximately 22% of distribution overhead conductor has currently exceeded the average industry expected useful service life of 50 years. An additional 21% of distribution overhead conductor will reach 50 years in service within the next decade.

### 2.4.3 Transmission

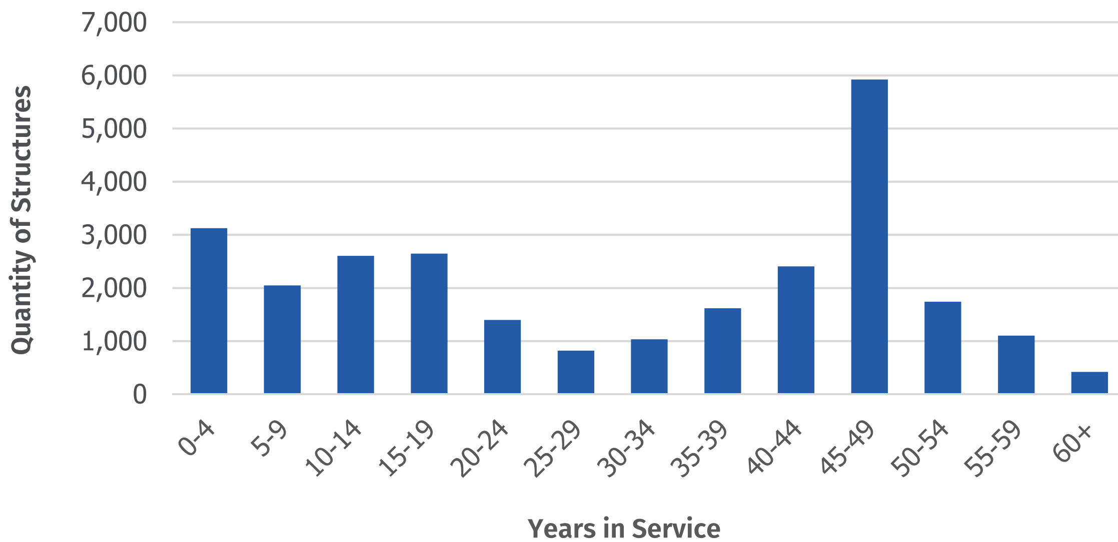
Transmission lines are the backbone of the electricity system serving customers. Transmission lines are inspected annually to identify deficiencies. Deficiencies are prioritized for correction based on severity through the annual *Transmission Line Maintenance* program. The condition of the transmission system is also maintained through planned rebuild projects completed in accordance with the *Transmission Line Rebuild Strategy*, which targets the Company's oldest and most deteriorated transmission lines.

Newfoundland Power's transmission system includes approximately 27,000 wooden support structures and overhead conductor on approximately 2,100 kilometres of transmission line. Industry experience indicates an average expected useful service life of 58 years for transmission wooden support structures and 63 years for transmission overhead conductor.[27]

The Company's operations are exposed to an increasing risk of equipment failure on the transmission system going forward due to the age of wooden support structures and overhead conductor.

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

**Figure 4**
**Transmission Wooden Support Structures**
**Asset Age**

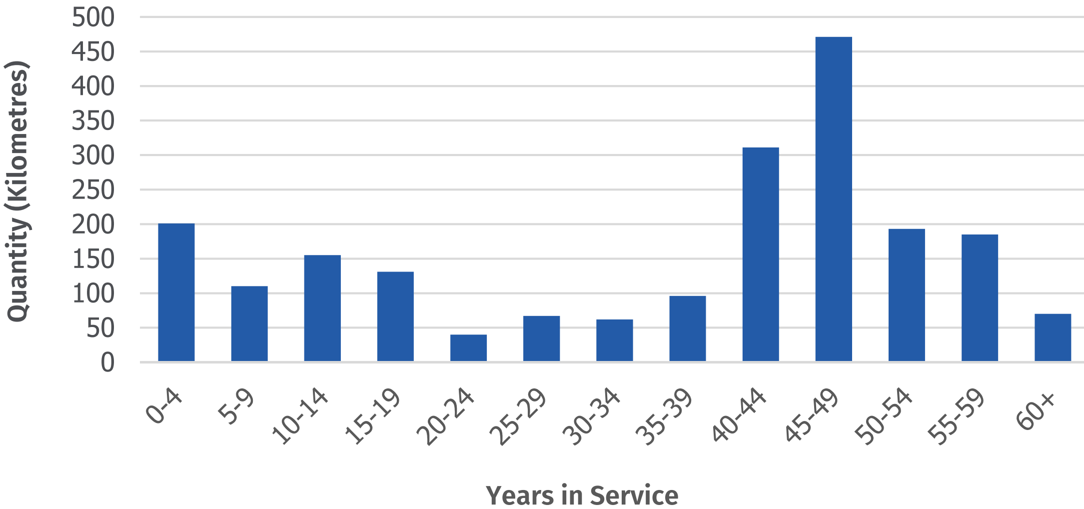



[27] The average industry expected useful service lives of transmission assets were derived from information filed with FERC. A total of 38 utilities were included in the analysis.

Approximately 2% of transmission wooden support structures have exceeded the average industry expected useful service life of 58 years.[28] An additional 11% of transmission wooden support structures will reach 58 years in service over the next decade.

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

**Figure 5**
**Transmission Overhead Conductor**
**Asset Age**




Approximately 3% of transmission overhead conductor has currently exceeded the average industry expected useful service life of 63 years. An additional 18% of transmission overhead conductor will reach 63 years in service within the next decade.

### *2.4.4 Substations*

Newfoundland Power operates 131 substations throughout its service territory. Substations are inspected eight times annually to identify deficiencies and required maintenance. Equipment that fails in service or is at imminent risk of failure is addressed under the *Substation Replacements Due to In-Service Failures* program. Major refurbishment projects are implemented in accordance with the Company's *Substation Refurbishment and Modernization Plan*. The Company has also recently implemented a component-based program to address obsolete substation protection and control systems within Newfoundland Power's substations.

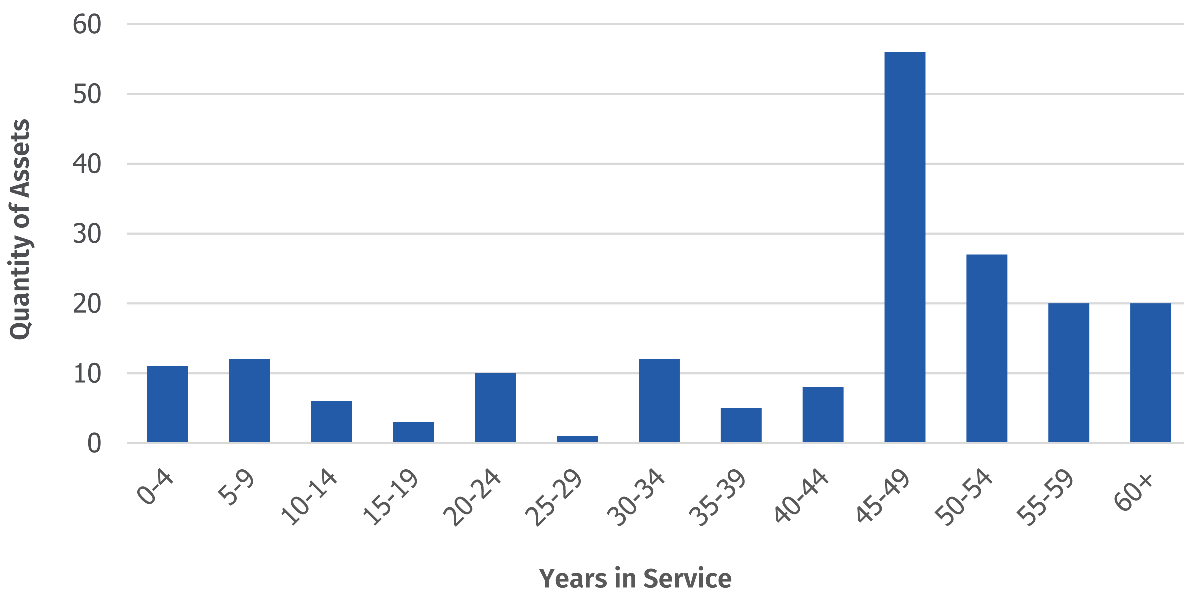
---

[28] This is a result of the execution of the Company's *Transmission Line Rebuild Strategy* which commenced in 2006 and will be approximately 85% complete by the end of 2024. The strategy outlined a long-term plan to rebuild the Company's aging transmission lines.

The most critical equipment in substations is power transformers. There are currently 191 power transformers in operation at Newfoundland Power's substations. Industry experience suggests the service life of a power transformer is typically between 30 to 50 years under ideal conditions.[29] Based on the current age profile, the Company's power transformers are exposed to a high risk of equipment failure.

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

**Figure 6**
**Substation Power Transformeres**
**Asset Age**




Approximately 35% of substation power transformers have exceeded the industry expected useful service life of 50 years. An additional 34% 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.

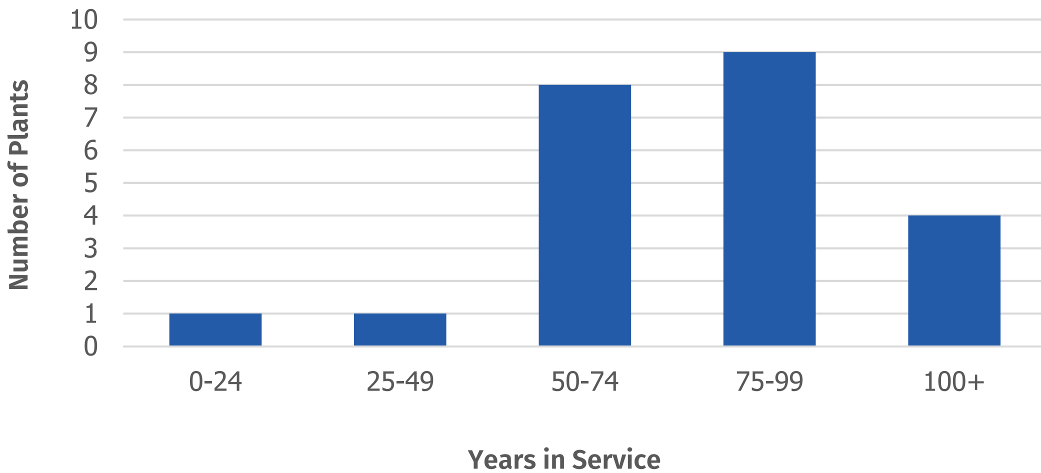
---

[29] Practical conditions, such as high ambient temperature, high loading and fault exposure, can reduce the expected service life of power transformers. High temperatures have an adverse effect on the insulating properties inside the transformer and cause the premature aging of power transformers. Insulation deterioration on the windings naturally occurs over time and is accelerated by exposure to high temperatures. Insulation that is found to be degraded is a major indicator that a power transformer has reached end of life. See International Council on Large Electric Systems ("CIGRE"), *Asset Management Decision Making Using Different Risk Assessment Methodologies*, 2013, page 94.

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 number of hydro plants in operation by age as of 2022.

**Figure 7**
**Hydro Plants**
**Asset Age**




Of Newfoundland Power's 23 hydro plants, 17 have been in service for between 50 and 100 years and four have been in service for over 100 years. Many of these plants have undergone refurbishment projects to extend their useful service lives, including generator and turbine refurbishments, protection and control upgrades, and penstock replacements. Based on the current age profile, refurbishment projects are expected to continue to be required to extend the useful service lives of these hydro plants when proven economic for customers.[30]

Newfoundland Power's Greenhill and Wesleyville gas turbines have been in service for 47 years and 53 years, respectively. Inspections have identified that both gas turbines are approaching end of life. In addition, thermal generation units in Port aux Basques have been in service since

[30] In circumstances where the life extension of a hydro plant is not economic compared with the cost of replacement energy and capacity, the Company will include in the economic analysis the cost associated with decommissioning the hydro plant including the environment and sediment management costs.

the 1960s and are also approaching the end of their useful service lives.[31] Refurbishment or replacement projects are expected to be required for the Company's thermal generation assets.[32]

## 3.0 SUMMARY OF PLANNED EXPENDITURES

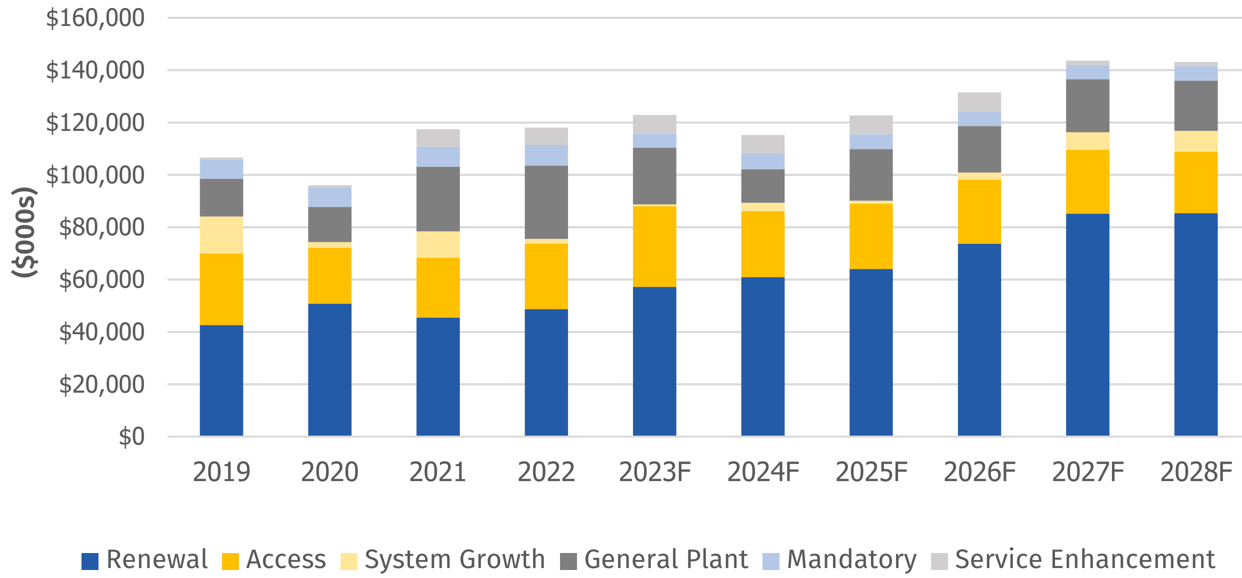
### 3.1 General

Newfoundland Power's *2024-2028 Capital Plan* forecasts average annual capital expenditures of approximately $131.2 million from 2024 to 2028. This section provides a breakdown of forecast capital expenditures by investment classification and asset class.[33]

### 3.2 Planned Expenditures by Investment Classification

Figure 8 provides historical and forecast capital expenditures from 2019 to 2028 by investment classification.

**Figure 8**
**Capital Expenditures by Investment Classification**
**(2019-2028F)**




---

31 The thermal generation supplying the Port aux Basques area consists of the diesel generating unit PAB-G1, which was placed into service in 1969, and the Mobile Gas Turbine #1 ("MGT"), which was placed into service in 1974. MGT is no longer able to be transported due to the deteriorated condition of the trailer chassis. It is now permanently stationed at the Company's Grand Bay Substation on the southwest coast of Newfoundland. This thermal generation, along with Rose Blanche Hydro Plant and other mobile generators, supply the Port aux Basques area for planned and unplanned outages on Hydro's transmission lines TL214 and TL215.

32 These refurbishment or replacement projects will be informed by the Board's ongoing *Reliability and Resource Adequacy Study Review*.

33 Capital expenditures are organized by investment classification in accordance with the Board's provisional *Capital Budget Application Guidelines* effective January 2022.

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 56% of capital expenditures from 2024 to 2028, compared to approximately 44% 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, the planned replacement of the Wesleyville and Greenhill gas turbines with a new mobile unit,[34] and the requirement to address aging thermal generation in Port aux Basques.

Expenditures in other investment classifications are expected to be reasonably stable over the forecast period.

Access and System Growth investments are forecast to account for approximately 22% of annual capital expenditures over the forecast period. This reflects a forecast decline in customer connections over the next five years, which will be offset by increased electrification efforts in both transportation and heating system conversions. Approximately $3 million of investments in each of 2027 and 2028 relate to transformer capacity additions at Kelligrews and Hardwoods substations to respond to load growth on the Northeast Avalon. Investments are also driven by increased system load due to EV adoption, with planned expenditures of approximately $3.7 million by 2028 for distribution system upgrades.

General Plant investments are forecast to account for approximately 14% of annual capital expenditures over the next five years. General Plant investments are expected to continue to be driven by expenditures in the Information Systems asset class. Information Systems account for 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 4% 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.

[34] Options to address the deteriorated condition of the Wesleyville and Greenhill gas turbines are under review as a result of Hydro's *Reliability and Resource Adequacy Study – 2022 Update* and the uncertainty around supply resources.

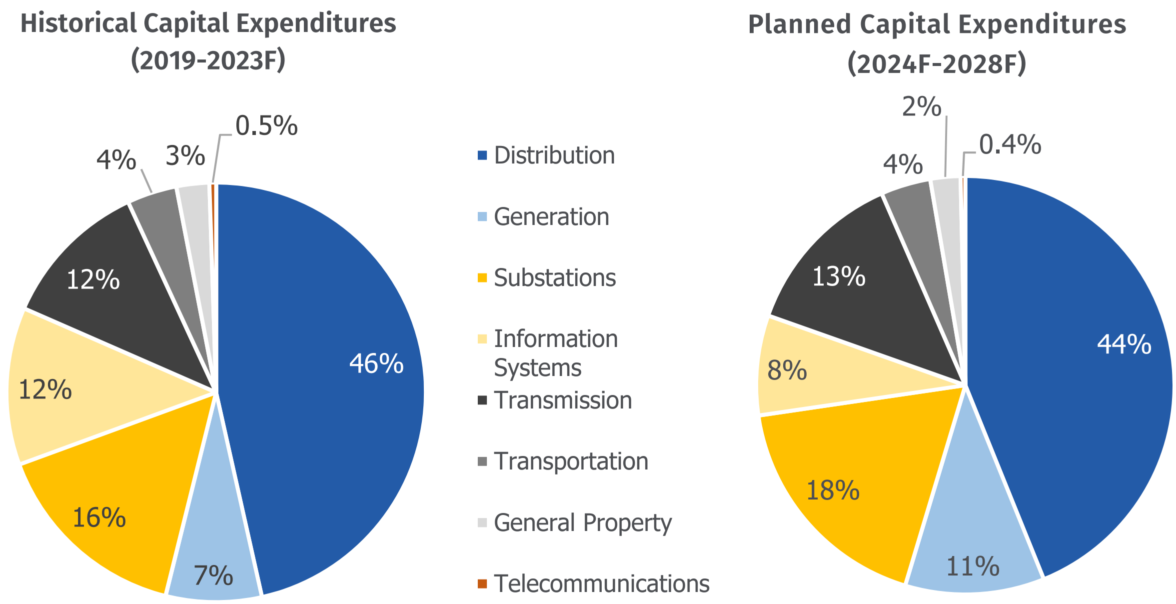
Mandatory investments are forecast to account for approximately 4% of annual capital expenditures over the next five years. Mandatory investments reflect conclusion of the *PCB Removal* project in 2025. Expenditures after 2025 reflect capital expenditures resulting from Board Orders, including *General 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.[35]

**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 2024 to 2028. 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.

35 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 2019 to 2028.

Table 2
Distribution
Capital Expenditures
($000s)

| Actual/Forecast | | | | | Average |
|---|---|---|---|---|---|
| 2019 | 2020 | 2021 | 2022 | 2023F | 2019-2023F |
| 46,801 | 44,391 | 50,866 | 50,434 | 53,671 | 49,233 |
| **Plan** | | | | | **Average** |
| 2024F | 2025F | 2026F | 2027F | 2028F | 2024F-2028F |
| 55,865 | 55,033 | 56,938 | 54,287 | 54,307 | 55,286 |

Distribution capital expenditures are forecast to average approximately $55.3 million annually from 2024 to 2028. This compares to an average of approximately $49.2 million annually over the previous five-year period.[36]

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 $12.5 million annually. Refurbishment projects for individual distribution feeders are expected to increase over the forecast period, with annual expenditures increasing from approximately $1.5 million in 2024 to approximately $5.5 million in 2028.

Expenditures related to the *Distribution Reliability Initiative* are forecast to average approximately $1.9 million annually as the Company continues to target the worst performing feeders, or specific sections of feeders, on its distribution system.[37]

[36] The increase in Distribution capital expenditures over the period from 2021 to 2026 is attributed to the *LED Street Light Replacement* project.

[37] 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 *2024 Capital Budget Application,* report *1.1 Distribution Reliability Initiative.*

### *3.3.3 Substations*

Table 3 provides historical and forecast substations capital expenditures from 2019 to 2028.

Table 3
Substations
Capital Expenditures
($000s)

| Actual/Forecast | | | | | Average |
|---|---|---|---|---|---|
| 2019 | 2020 | 2021 | 2022 | 2023F | 2019-2023F |
| 17,133 | 14,720 | 15,507 | 14,196 | 20,672 | 16,446 |
| **Plan** | | | | | **Average** |
| 2024F | 2025F | 2026F | 2027F | 2028F | 2024F-2028F |
| 20,605 | 20,824 | 23,299 | 23,799 | 25,160 | 22,737 |

Substations expenditures are forecast to average approximately $22.7 million annually from 2024 to 2028. This compares to an average of approximately $16.4 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 23 substations, including the Oxen Pond, Gambo, Memorial, and Old Perlican substations in 2024, and a two-year project at Islington Substation commencing in 2024. 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 $14.9 million from 2024 to 2028.[38]

Forecast substation expenditures also include approximately $5.0 million annually to address in-service equipment failures in substations, as well as other expenditures to upgrade or replace deficient equipment and respond to system load growth. An addition to the spare transformer inventory is planned for 2026.

[38] The Company is forecasting the requirement to replace five substation power transformers over the next five years. These transformers have been identified based on their age relative to the rest of the Company's fleet, and will be further evaluated through detailed condition assessments as they move from the forecast year to the budget year.

### 3.3.4 Transmission

Table 4 provides historical and forecast transmission capital expenditures from 2019 to 2028.

Table 4
Transmission
Capital Expenditures
($000s)

| Actual/Forecast | | | | | Average |
|---|---|---|---|---|---|
| 2019 | 2020 | 2021 | 2022 | 2023F | 2019-2023F |
| 11,940 | 10,069 | 11,274 | 15,587 | 12,284 | 12,231 |
| **Plan** | | | | | **Average** |
| 2024F | 2025F | 2026F | 2027F | 2028F | 2024F-2028F |
| 15,064 | 13,488 | 15,109 | 17,987 | 20,521 | 16,434 |

Transmission capital expenditures are forecast to average approximately $16.4 million annually from 2024 to 2028. This compares to an average of approximately $12.2 million annually over the previous five-year period.

Increased transmission expenditures are driven by an increase in the kilometres of transmission line to be rebuilt annually to complete the *Transmission Line Rebuild Strategy*.[39] As of the end of 2022, execution of this strategy will be 79% complete. Forecast expenditures from 2024 to 2028 include rebuild projects on ten transmission lines throughout the Company's service territory. The average annual cost of transmission line rebuild projects is approximately $12.8 million from 2024 to 2028.

Forecast transmission expenditures also include capital maintenance of transmission line structures at an annual average cost of approximately $2.7 million.[40]

39 The lines remaining to be completed in the 2024 to 2028 period include three 138 kV H-frame construction transmission lines. The extended line length for these rebuilds, and the 138 kV H-frame construction, are the primary drivers for the increase in transmission expenditures.

40 Newfoundland Power is currently undertaking a review of its asset management practices. Newfoundland Power's capital plan does not include any forecast transmission capital maintenance expenditures associated with any changes to the Company's transmission line asset management practices, including the chemical re-treatment of transmission line wood poles, resulting from this review. Any changes to Newfoundland Power's transmission line asset management practices would be included as part of a future capital budget application.

### *3.3.5 Generation*

Table 5 provides historical and forecast generation capital expenditures from 2019 to 2028.

Table 5
Generation
Capital Expenditures
($000s)

| Actual/Forecast | | | | | Average |
|---|---|---|---|---|---|
| 2019 | 2020 | 2021 | 2022 | 2023F | 2019-2023F |
| 10,086 | 6,833 | 9,766 | 2,635 | 9,811 | 7,826 |
| **Plan** | | | | | **Average** |
| 2024F | 2025F | 2026F | 2027F | 2028F | 2024F-2028F |
| 5,640 | 8,318 | 13,058 | 22,051 | 18,723 | 13,558 |

Generation capital expenditures are forecast to average approximately $13.6 million annually from 2024 to 2028.[41] This compares to an average of approximately $7.8 million annually over the previous five-year period.

Increased generation expenditures include the planned purchase of a second mobile gas turbine that will replace the existing Greenhill and Wesleyville gas turbines.[42] The cost of purchasing a second mobile gas turbine is approximately $7.5 million in 2026 and $9.9 million in 2027. Expenditures of approximately $10 million in 2028 are forecast to address aging thermal generation in Port aux Basques.[43]

Increased generation expenditures also reflect a forecast requirement to undertake refurbishment projects at nine hydro plants over the next five years. The average annual cost of hydro plant refurbishment projects is approximately $3.4 million from 2024 to 2028.

---

41 Generation-Hydro capital expenditures are forecast to average approximately $7.8 million annually from 2024 to 2028. Generation-Thermal capital expenditures are forecast to average approximately $5.8 million annually from 2024 to 2028.

42 Options to address the deteriorated condition of the Wesleyville and Greenhill gas turbines are under review as a result of Hydro's *Reliability and Resource Adequacy Study – 2022 Update* and the uncertainty around supply resources.

43 Newfoundland Power has two thermal generation plants located in Port aux Basques. These include: (i) the 6.0 MW MGT which was brought into service in 1974; and (ii) the 2.5 MW Port au Basques diesel generator which was brought into service in 1969. Customers on the southwest portion of the province are served by Hydro's radial transmission line TL214. The thermal generation plants located in Port aux Basques are utilized when Hydro is completing maintenance on the transmission line or in response to unscheduled outages to the line.

### *3.3.6 Information Systems*

Table 6 provides historical and forecast information systems capital expenditures from 2019 to 2028.

Table 6
Information Systems
Capital Expenditures
($000s)

| Actual/Forecast | | | | | Average |
|---|---|---|---|---|---|
| 2019 | 2020 | 2021 | 2022 | 2023F | 2019-2023F |
| 7,034 | 7,347 | 15,468 | 21,493 | 12,940 | 12,856 |
| **Plan** | | | | | **Average** |
| 2024F | 2025F | 2026F | 2027F | 2028F | 2024F-2028F |
| 6,180 | 11,019 | 9,575 | 11,052 | 10,778 | 9,721 |

Information systems capital expenditures are forecast to average approximately $9.7 million annually from 2024 to 2028. This compares to an average of approximately $12.9 million annually over the previous five-year period.

The decrease in information systems expenditures is a result of the conclusion of the *Customer Service System Replacement* project in 2023. Expenditures from 2024 to 2028 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, Asset Management, and Outage Management System, among others.

### *3.3.7 Transportation*

Table 7 provides historical and forecast transportation capital expenditures from 2019 to 2028.

Table 7
Transportation
Capital Expenditures
($000s)

| Actual/Forecast | | | | | Average |
|---|---|---|---|---|---|
| 2019 | 2020 | 2021 | 2022 | 2023F | 2019-2023F |
| 4,223 | 3,515 | 4,555 | 3,089 | 4,968 | 4,070 |
| **Plan** | | | | | **Average** |
| 2024F | 2025F | 2026F | 2027F | 2028F | 2024-2028F |
| 3,806 | 4,867 | 4,839 | 5,525 | 5,298 | 4,867 |

Transportation capital expenditures are forecast to average approximately $4.9 million annually from 2024 to 2028. This compares to an average of approximately $4.1 million annually over the previous five-year period.

The increase in transportation capital expenditures from 2024 through 2028 primarily reflects inflation and the number of heavy, medium, and light duty fleet and passenger vehicles forecast to be replaced over the period.

### *3.3.8 General Property*

Table 8 provides historical and forecast general property capital expenditures from 2019 to 2028.

| Table 8<br>General Property<br>Capital Expenditures<br>($000s) | | | | | |
|---|---|---|---|---|---|
| Actual/Forecast | | | | | Average |
| 2019 | 2020 | 2021 | 2022 | 2023F | 2019-2023F |
| 2,862 | 2,459 | 2,703 | 2,855 | 2,505 | 2,677 |
| Plan | | | | | Average |
| 2024F | 2025F | 2026F | 2027F | 2028F | 2024F-2028F |
| 2,340 | 2,960 | 3,065 | 3,255 | 2,987 | 2,921 |

General Property capital expenditures are forecast to average approximately $2.9 million annually from 2024 to 2028. 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. Expenditures over the 2024 to 2028 period are driven by 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 2019 to 2028.

Table 9
Telecommunications
Capital Expenditures
($000s)

| Actual/Forecast | | | | | Average |
|---|---|---|---|---|---|
| 2019 | 2020 | 2021 | 2022 | 2023F | 2019-2023F |
| 312 | 112 | 511 | 571 | 1,268 | 555 |

| Plan | | | | | Average |
|---|---|---|---|---|---|
| 2024F | 2025F | 2026F | 2027F | 2028F | 2024F-2028F |
| 502 | 925 | 328 | 441 | 134 | 466 |

Telecommunications capital expenditures are forecast to average approximately $0.5 million annually from 2024 to 2028. This compares to an average of approximately $0.6 million annually over the previous five-year period.

Expenditures from 2024 to 2028 are comparable to the previous five-year average. Telecommunications expenditures over the next five years are primarily driven by the replacement of the Company's Very High Frequency ("VHF") mobile radio system in 2025 and the construction of fibre optic cables.[44]

[44] 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. The budget estimate of $0.8 million is currently based on the purchase of mobile radio units which are compatible with the new public safety radio system.

# APPENDIX A:

## Capital Projects and Programs: 2024-2028

Table A-1
2024-2028 Capital Plan
By Asset Class
($000s)

| Asset Class | 2024F | 2025F | 2026F | 2027F | 2028F |
|---|---|---|---|---|---|
| Distribution | 55,865 | 55,033 | 56,938 | 54,287 | 54,307 |
| Substations | 20,605 | 20,824 | 23,299 | 23,799 | 25,160 |
| Transmission | 15,064 | 13,488 | 15,109 | 17,987 | 20,521 |
| Generation | 5,640 | 8,318 | 13,058 | 22,051 | 18,723 |
| Information Systems | 6,180 | 11,019 | 9,575 | 11,052 | 10,778 |
| Transportation | 3,806 | 4,867 | 4,839 | 5,525 | 5,298 |
| General Property | 2,340 | 2,960 | 3,065 | 3,255 | 2,987 |
| Telecommunications | 502 | 925 | 328 | 441 | 134 |
| Allowance for Unforeseen Items | 750 | 750 | 750 | 750 | 750 |
| General Expenses Capitalized | 4,500 | 4,500 | 4,500 | 4,500 | 4,500 |
| Total | $115,252 | $122,684 | $131,461 | $143,647 | $143,158 |

| Table A-2<br>2024-2028 Capital Plan<br>Distribution<br>($000s) | | | | | |
|---|---|---|---|---|---|
| | 2024F | 2025F | 2026F | 2027F | 2028F |
| Project | | | | | |
| Feeder Additions for Load Growth | 2,811 | 1,150 | 2,384 | 2,470 | 1,960 |
| Distribution Reliability Initiative | 1,915 | 1,500 | 1,750 | 2,000 | 2,250 |
| Distribution Feeder Automation | 888 | 899 | 909 | 920 | 931 |
| LED Street Lighting Replacement | 5,541 | 5,654 | 5,738 | 0 | 0 |
| Distribution Feeder GDL-02 Refurbishment | 667 | 0 | 0 | 0 | 0 |
| Distribution Feeder OXP-01 Refurbishment | 840 | 0 | 0 | 0 | 0 |
| Distribution Feeder Refurbishments | 0 | 2,681 | 3,001 | 4,720 | 5,508 |
| Allowance for Funds Used During Construction | 260 | 263 | 266 | 269 | 273 |
| Distribution Feeder BIG-02 Relocation | 196 | 0 | 0 | 0 | 0 |
| Program | | | | | |
| Extensions | 12,140 | 11,725 | 11,264 | 10,722 | 9,906 |
| Reconstruction | 6,953 | 7,104 | 7,262 | 7,431 | 7,608 |
| Rebuild Distribution Lines | 4,974 | 5,086 | 5,202 | 5,326 | 5,456 |
| New Services | 2,847 | 2,758 | 2,656 | 2,533 | 2,345 |
| Replacement Services | 457 | 467 | 478 | 490 | 502 |
| New Meters | 302 | 291 | 279 | 566 | 522 |
| Replacement Meters | 571 | 703 | 731 | 1,525 | 1,415 |
| New Transformers | 3,264 | 3,310 | 3,359 | 3,417 | 3,479 |
| Replacement Transformers | 3,681 | 3,732 | 3,788 | 3,853 | 3,924 |
| New Street Lighting | 2,629 | 2,681 | 2,736 | 2,795 | 2,858 |
| Replacement Street Lighting | 863 | 878 | 895 | 913 | 932 |
| Relocate/Replace Distribution Lines for Third Parties | 4,066 | 4,151 | 4,240 | 4,337 | 4,438 |
| Total | $55,865 | $55,033 | $56,938 | $54,287 | $54,307 |

Table A-3
2024-2028 Capital Plan
Substations
($000s)

| | 2024F | 2025F | 2026F | 2027F | 2028F |
|---|---|---|---|---|---|
| Project | | | | | |
| PCB Removal | 544 | 125 | 0 | 0 | 0 |
| Substation Ground Grid Upgrades | 580 | 609 | 640 | 672 | 705 |
| Oxen Pond Substation Bus Upgrade | 451 | 0 | 0 | 0 | 0 |
| Oxen Pond Substation Switch Replacement | 316 | 0 | 0 | 0 | 0 |
| Gambo Substation Refurbishment & Modernization | 5,267 | 0 | 0 | 0 | 0 |
| Memorial Substation Refurbishment & Modernization | 4,351 | 0 | 0 | 0 | 0 |
| Old Perlican Substation Refurbishment & Modernization | 3,356 | 0 | 0 | 0 | 0 |
| Islington Substation Refurbishment & Modernization | 308 | 4,706 | 0 | 0 | 0 |
| Substation Spare Power Transformer Inventory | 0 | 40 | 1,950 | 0 | 0 |
| Substation Refurbishment & Modernization | 0 | 9,807 | 14,812 | 14,110 | 15,597 |
| Substation Feeder Termination | 0 | 0 | 250 | 250 | 0 |
| Additions Due to Load Growth | 0 | 0 | 0 | 3,000 | 3,000 |
| Program | | | | | |
| Substation Replacements Due to In-Service Failures | 4,797 | 4,887 | 4,982 | 5,087 | 5,198 |
| Substation Protection and Control Replacements | 635 | 650 | 665 | 680 | 660 |
| Total | $20,605 | $20,824 | $23,299 | $23,799 | $25,160 |

| Table A-4<br>2024-2028 Capital Plan<br>Transmission<br>($000s) | | | | | |
|---|---|---|---|---|---|
| | 2024F | 2025F | 2026F | 2027F | 2028F |
| Project | | | | | |
| Transmission Line 94L Rebuild[45] | 4,276 | 0 | 0 | 0 | 0 |
| Transmission Line 55L Rebuild[46] | 5,284 | 0 | 0 | 0 | 0 |
| Transmission Line 146L Rebuild | 2,152 | 9,209 | 0 | 0 | 0 |
| Transmission Line 24L Relocation | 701 | 0 | 0 | 0 | 0 |
| Transmission Line Rebuild | 0 | 1,584 | 12,366 | 14,191 | 14,667 |
| Transmission Line Additions | 0 | 0 | 0 | 1,000 | 3,000 |
| Program | | | | | |
| Transmission Line Maintenance | 2,651 | 2,695 | 2,743 | 2,796 | 2,854 |
| Total | $15,064 | $13,488 | $15,109 | $17,987 | $20,521 |

45 Multi-year capital project approved in Order No. P.U. 36 (2021).
46 Multi-year capital project approved in Order No. P.U. 38 (2022).

Table A-5
2024-2028 Capital Plan
Generation
($000s)

| | 2024F | 2025F | 2026F | 2027F | 2028F |
|---|---|---|---|---|---|
| Project | | | | | |
| Hydro Facility Rehabilitation | 794 | 940 | 959 | 978 | 998 |
| Mobile Hydro Plant Refurbishment[47] | 2,480 | 0 | 0 | 0 | 0 |
| Mobile Hydro Plant Surge Tank Refurbishment | 977 | 0 | 0 | 0 | 0 |
| Mobile Hydro Plant Penstock Refurbishment | 0 | 639 | 0 | 0 | 0 |
| Lookout Brook Hydro Plant Refurbishment | 362 | 1,573 | 0 | 0 | 0 |
| Tors Cove Hydro Plant Refurbishment | 0 | 0 | 511 | 6,006 | 0 |
| Horsechops Hydro Plant Refurbishment | 0 | 2,468 | 0 | 0 | 3,066 |
| Rose Blanche Hydro Plant Refurbishment | 0 | 950 | 0 | 0 | 0 |
| Cape Broyle Hydro Plant Refurbishment | 0 | 702 | 3,050 | 0 | 0 |
| Lawn Hydro Plant Refurbishment | 0 | 0 | 0 | 0 | 3,226 |
| Victoria Hydro Plant Refurbishment | 0 | 0 | 0 | 4,087 | 0 |
| Morris Hydro Plant Refurbishment | 0 | 0 | 0 | 0 | 319 |
| Gas Turbine Replacement | 0 | 0 | 7,470 | 9,890 | 0 |
| Port aux Basques Thermal Generation | 0 | 0 | 0 | 0 | 10,000 |
| Program | | | | | |
| Hydro Plant Replacements Due to In-Service Failures | 716 | 729 | 744 | 760 | 776 |
| Thermal Plant Replacements Due to In-Service Failures | 311 | 317 | 324 | 330 | 338 |
| Total | $5,640 | $8,318 | $13,058 | $22,051 | $18,723 |

47 Multi-year capital project approved in Order No. P.U. 38 (2022).

Table A-6
2024-2028 Capital Plan
Information Systems
($000s)

| | 2024F | 2025F | 2026F | 2027F | 2028F |
|---|---|---|---|---|---|
| Project | | | | | |
| System Upgrades | 957 | 5,488 | 2,695 | 4,404 | 3,715 |
| Application Enhancements | 1,892 | 1,439 | 1,393 | 918 | 1,292 |
| Cybersecurity Upgrades | 930 | 940 | 950 | 960 | 970 |
| Microsoft Enterprise Agreement | 297 | 297 | 297 | 320 | 320 |
| Network Infrastructure | 420 | 475 | 800 | 700 | 525 |
| Operations Technology | 0 | 750 | 2,000 | 1,500 | 1,250 |
| Shared Server Infrastructure | 964 | 900 | 700 | 1,500 | 1,946 |
| Program | | | | | |
| Personal Computer Infrastructure | 720 | 730 | 740 | 750 | 760 |
| Total | $6,180 | $11,019 | $9,575 | $11,052 | $10,778 |

Table A-7
2024-2028 Capital Plan
Transportation
($000s)

| | 2024F | 2025F | 2026F | 2027F | 2028F |
|---|---|---|---|---|---|
| Project | | | | | |
| Replace Vehicles and Aerial Devices 2023-2024[48] | 1,866 | 0 | 0 | 0 | 0 |
| Replace Vehicles and Aerial Devices 2024-2025 | 1,940 | 2,869 | 0 | 0 | 0 |
| Replace Vehicles and Aerial Devices 2025-2026 | 0 | 1,998 | 2,449 | 0 | 0 |
| Replace Vehicles and Aerial Devices 2026-2027 | 0 | 0 | 2,390 | 2,963 | 0 |
| Replace Vehicles and Aerial Devices 2027-2028 | 0 | 0 | 0 | 2,562 | 2,543 |
| Replace Vehicles and Aerial Devices 2028-2029 | 0 | 0 | 0 | 0 | 2,755[49] |
| Total | $3,806 | $4,867 | $4,839 | $5,525 | $5,298 |

48 Multi-year capital project approved in Order No. P.U. 38 (2022).
49 First year of a two-year multi-year project in 2028 and 2029.

Table A-8
2024-2028 Capital Plan
General Property
($000s)

| | 2024F | 2025F | 2026F | 2027F | 2028F |
|---|---|---|---|---|---|
| Project | | | | | |
| Company Building Renovations | 175 | 1,310 | 1,390 | 1,550 | 1,250 |
| Energized Conductor Support Tools | 539 | 0 | 0 | 0 | 0 |
| Program | | | | | |
| Additions to Real Property | 655 | 665 | 676 | 688 | 701 |
| Physical Security Upgrades | 401 | 407 | 413 | 421 | 429 |
| Tools and Equipment | 570 | 578 | 586 | 596 | 607 |
| Total | $2,340 | $2,960 | $3,065 | $3,255 | $2,987 |

Table A-9
2024-2028 Capital Plan
Telecommunications
($000s)

| | 2024F | 2025F | 2026F | 2027F | 2028F |
|---|---|---|---|---|---|
| Project | | | | | |
| Fibre Optic Cable Build | 380 | 0 | 200 | 310 | 0 |
| Radio System Replacement | 0 | 800 | 0 | 0 | 0 |
| Program | | | | | |
| Communications Equipment Upgrades | 122 | 125 | 128 | 131 | 134 |
| Total | $502 | $925 | $328 | $441 | $134 |

| Table A-10<br>2024-2028 Capital Plan<br>Allowance for Unforeseen Items<br>($000s) | | | | | |
|---|---|---|---|---|---|
| | 2024F | 2025F | 2026F | 2027F | 2028F |
| Project | | | | | |
| Allowance for Unforeseen Items | 750 | 750 | 750 | 750 | 750 |
| Total | $750 | $750 | $750 | $750 | $750 |

| Table A-11<br>2024-2028 Capital Plan<br>General Expenses Capitalized<br>($000s) | | | | | |
|---|---|---|---|---|---|
| | 2024F | 2025F | 2026F | 2027F | 2028F |
| Project | | | | | |
| General Expenses Capitalized | 4,500 | 4,500 | 4,500 | 4,500 | 4,500 |
| Total | $4,500 | $4,500 | $4,500 | $4,500 | $4,500 |


NEWFOUNDLAND POWER
A FORTIS COMPANY

# 2023 Capital Budget Expenditure Status Report

## June 2023

**Newfoundland Power Inc.**

**2023 Capital Budget Expenditure**
**Status Report**

## Compliance Matter

The 2023 Capital Budget Expenditure Status 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. 38 (2022):

> *Unless otherwise directed by the Board, Newfoundland Power shall provide, in conjunction with the 2024 capital budget application, a status report on the 2023 capital budget expenditures showing for each project:*
> *(i) the approved budget for 2023;*
> *(ii) the expenditures prior to 2023;*
> *(iii) the 2023 expenditures to the date of the application;*
> *(iv) the remaining projected expenditures for 2023;*
> *(v) the variance between the projected total expenditures and the approved budget; and*
> *(vi) an explanation of the variance.*

## Overview

Page 1 of the 2023 Capital Budget Expenditure Status Report outlines the forecast variances from budget of the 2023 capital expenditures approved by the Board. The detailed tables on pages 2 to 6 provide additional detail on the capital expenditures for 2023 which were approved in Order No. P.U. 38 (2022). The additional detail is organized by single-year projects approved for 2023, multi-year projects approved to commence in 2023 and previously approved multi-year projects with expenditures occurring in 2023.

The *Capital Budget Application Guidelines (Provisional)* require variance explanations to be provided for variances of more than 10% of approved expenditure and $100,000 or greater. For the 2023 Capital Budget Expenditure Status Report, there are no projects that meet the criteria for variance explanations.

Newfoundland Power will provide updated information to the Board in its regular reporting and upon request of the Board.

**Newfoundland Power Inc.**
**2023 Capital Budget Expenditure Status Report**
**Capital Expenditure Overview**
**($000)**

| | Annual Budget | Expenditures | | Annual Forecast | |
|---|---|---|---|---|---|
| | | Actual | Forecast | | |
| **Asset Class and Project Description** | **2023 Budget** | **January to April** | **May to December** | **2023 Forecast** | **Variance** |
| Generation - Hydro | 9,476 | 423 | 9,053 | 9,476 | 0 |
| Generation - Thermal | 335 | 24 | 311 | 335 | 0 |
| Substations | 20,672 | 2,071 | 18,601 | 20,672 | 0 |
| Transmission | 12,284 | 267 | 12,017 | 12,284 | 0 |
| Distribution | 53,671 | 17,746 | 35,925 | 53,671 | 0 |
| General Property | 2,505 | 450 | 2,055 | 2,505 | 0 |
| Transportation | 4,968 | 853 | 4,115 | 4,968 | 0 |
| Telecommunication | 1,268 | 162 | 1,106 | 1,268 | 0 |
| Information Systems | 12,940 | 1,826 | 11,114 | 12,940 | 0 |
| Unforeseen Items | 750 | 0 | 750 | 750 | 0 |
| General Expenses Capitalized | 4,000 | 1,758 | 2,242 | 4,000 | 0 |
| **Total** | **122,869** | **25,580** | **97,289** | **122,869** | **0** |
| | | | | | |
| **Expenditure Type** | | | | | |
| Single-Year Projects | 92,698 | 24,053 | 68,645 | 92,698 | 0 |
| Multi-Year Projects Commencing in 2023 | 10,483 | 231 | 10,252 | 10,483 | 0 |
| Multi-Year Projects Commencing Prior to 2023 | 19,688 | 1,296 | 18,392 | 19,688 | 0 |
| **Total** | **122,869** | **25,580** | **97,289** | **122,869** | **0** |

**Newfoundland Power Inc.**
**2023 Capital Budget Expenditure Status Report**
**Single-Year Projects and Programs[1]**
**($000)**

| Asset Class and Project Description | Annual Budget 2023 Budget | Expenditures Actual January to April | Expenditures Forecast May to December | Annual Forecast 2023 Forecast | Variance | Notes |
|---|---|---|---|---|---|---|
| **Generation - Hydro** | | | | | | |
| Sandy Brook Hydro Plant Generator Refurbishment | 1,577 | 61 | 1,516 | 1,577 | 0 | |
| Hydro Facility Rehabilitation | 877 | 123 | 754 | 877 | 0 | |
| Hydro Plant Replacements Due to In-Service Failures | 662 | 97 | 565 | 662 | 0 | |
| **Total Generation - Hydro** | **3,116** | **281** | **2,835** | **3,116** | **0** | |
| **Generation - Thermal** | | | | | | |
| Thermal Plant Replacements Due to In-Service Failures | 335 | 24 | 311 | 335 | 0 | |
| **Total Generation - Thermal** | **335** | **24** | **311** | **335** | **0** | |
| **Substations** | | | | | | |
| Walbournes Substation Refurbishment and Modernization | 4,955 | 493 | 4,462 | 4,955 | 0 | |
| Molloy's Lane Substation Refurbishment and Modernization | 4,827 | 453 | 4,374 | 4,827 | 0 | |
| Long Pond Substation Capacity Expansion | 3,313 | 179 | 3,134 | 3,313 | 0 | |
| Substation Spare Transformer Inventory | 1,500 | 0 | 1,500 | 1,500 | 0 | |
| Substation Protection and Control Replacements | 667 | 82 | 585 | 667 | 0 | |
| Substation Ground Grid Upgrades | 563 | 0 | 563 | 563 | 0 | |
| PCB Bushing Phase-Out | 425 | 4 | 421 | 425 | 0 | |
| Substation Replacements Due to In-Service Failures | 4,422 | 860 | 3,562 | 4,422 | 0 | |
| **Total Substations** | **20,672** | **2,071** | **18,601** | **20,672** | **0** | |
| **Transmission** | | | | | | |
| Transmission Line Maintenance | 2,610 | 220 | 2,390 | 2,610 | 0 | |
| **Total Transmission** | **2,610** | **220** | **2,390** | **2,610** | **0** | |

**Newfoundland Power Inc.**
**2023 Capital Budget Expenditure Status Report**
**Single-Year Projects and Programs[1]**
**($000)**

| Asset Class and Project Description | Annual Budget | Expenditures | | Annual Forecast | | |
|---|---|---|---|---|---|---|
| | 2023 Budget | Actual January to April | Forecast May to December | 2023 Forecast | Variance | Notes |
| **Distribution** | | | | | | |
| LED Street Lighting Replacement Program | 5,453 | 2,567 | 2,886 | 5,453 | 0 | |
| Corner Brook Acute Care Hospital Redundant Supply | 2,690 | 20 | 2,670 | 2,690 | 0 | |
| Distribution Feeder Automation | 1,054 | 158 | 896 | 1,054 | 0 | |
| Feeder Additions for Load Growth | 670 | 44 | 626 | 670 | 0 | |
| Distribution Feeder SLA-05 Refurbishment | 565 | 4 | 561 | 565 | 0 | |
| Distribution Feeder PEP-02 Refurbishment | 550 | 0 | 550 | 550 | 0 | |
| Allowance for Funds Used During Construction | 247 | 91 | 156 | 247 | 0 | |
| Extensions | 12,218 | 3,839 | 8,379 | 12,218 | 0 | |
| Reconstruction | 6,699 | 1,880 | 4,819 | 6,699 | 0 | |
| Rebuild Distribution Lines | 4,945 | 2,176 | 2,769 | 4,945 | 0 | |
| Relocate/Replace Distribution Lines for Third Parties | 3,803 | 934 | 2,869 | 3,803 | 0 | |
| Replacement Transformers | 3,345 | 2,433 | 912 | 3,345 | 0 | |
| New Transformers | 2,967 | 914 | 2,053 | 2,967 | 0 | |
| New Services | 2,916 | 1,077 | 1,839 | 2,916 | 0 | |
| New Street Lighting | 2,618 | 670 | 1,948 | 2,618 | 0 | |
| Replacement Street Lighting | 770 | 240 | 530 | 770 | 0 | |
| Replacement Meters | 662 | 418 | 244 | 662 | 0 | |
| Replacement Services | 546 | 74 | 472 | 546 | 0 | |
| New Meters | 297 | 205 | 92 | 297 | 0 | |
| **Total Distribution** | **53,015** | **17,744** | **35,271** | **53,015** | **0** | |
| **General Property** | | | | | | |
| Company Building Renovations | 741 | 28 | 713 | 741 | 0 | |
| Physical Security Upgrades | 576 | 90 | 486 | 576 | 0 | |
| Additions to Real Property | 654 | 119 | 535 | 654 | 0 | |
| Tools and Equipment | 534 | 213 | 321 | 534 | 0 | |
| **Total General Property** | **2,505** | **450** | **2,055** | **2,505** | **0** | |

**Newfoundland Power Inc.**
**2023 Capital Budget Expenditure Status Report**
**Single-Year Projects and Programs[1]**
**($000)**

| Asset Class and Project Description | Annual Budget 2023 Budget | Expenditures Actual January to April | Expenditures Forecast May to December | Annual Forecast 2023 Forecast | Variance | Notes |
|---|---|---|---|---|---|---|
| **Telecommunications** | | | | | | |
| Communications Equipment Upgrades | 118 | 2 | 116 | 118 | 0 | |
| **Total Telecommunications** | **118** | **2** | **116** | **118** | **0** | |
| **Information Systems** | | | | | | |
| Application Enhancements | 1,538 | 333 | 1,205 | 1,538 | 0 | |
| Shared Server Infrastructure | 1,176 | 190 | 986 | 1,176 | 0 | |
| System Upgrades | 962 | 96 | 866 | 962 | 0 | |
| Cybersecurity Upgrades | 882 | 388 | 494 | 882 | 0 | |
| Network Infrastructure | 419 | 100 | 319 | 419 | 0 | |
| Personal Computer Infrastructure | 600 | 396 | 204 | 600 | 0 | |
| **Total Information Systems** | **5,577** | **1,503** | **4,074** | **5,577** | **0** | |
| **Unforeseen Allowance** | | | | | | |
| Allowance for Unforeseen Items | 750 | 0 | 750 | 750 | 0 | |
| **Total Unforeseen Allowance** | **750** | **0** | **750** | **750** | **0** | |
| **General Expenses Capitalized** | | | | | | |
| General Expenses Capitalized | 4,000 | 1,758 | 2,242 | 4,000 | 0 | |
| **Total General Expenses Capitalized** | **4,000** | **1,758** | **2,242** | **4,000** | **0** | |
| **Total** | **92,698** | **24,053** | **68,645** | **92,698** | **0** | |

1. Approved in Order No. P.U. 38 (2022).

**Newfoundland Power Inc.**
**2023 Capital Budget Expenditure Status Report**
**Multi-Year Projects Commencing in 2023[1]**
**($000)**

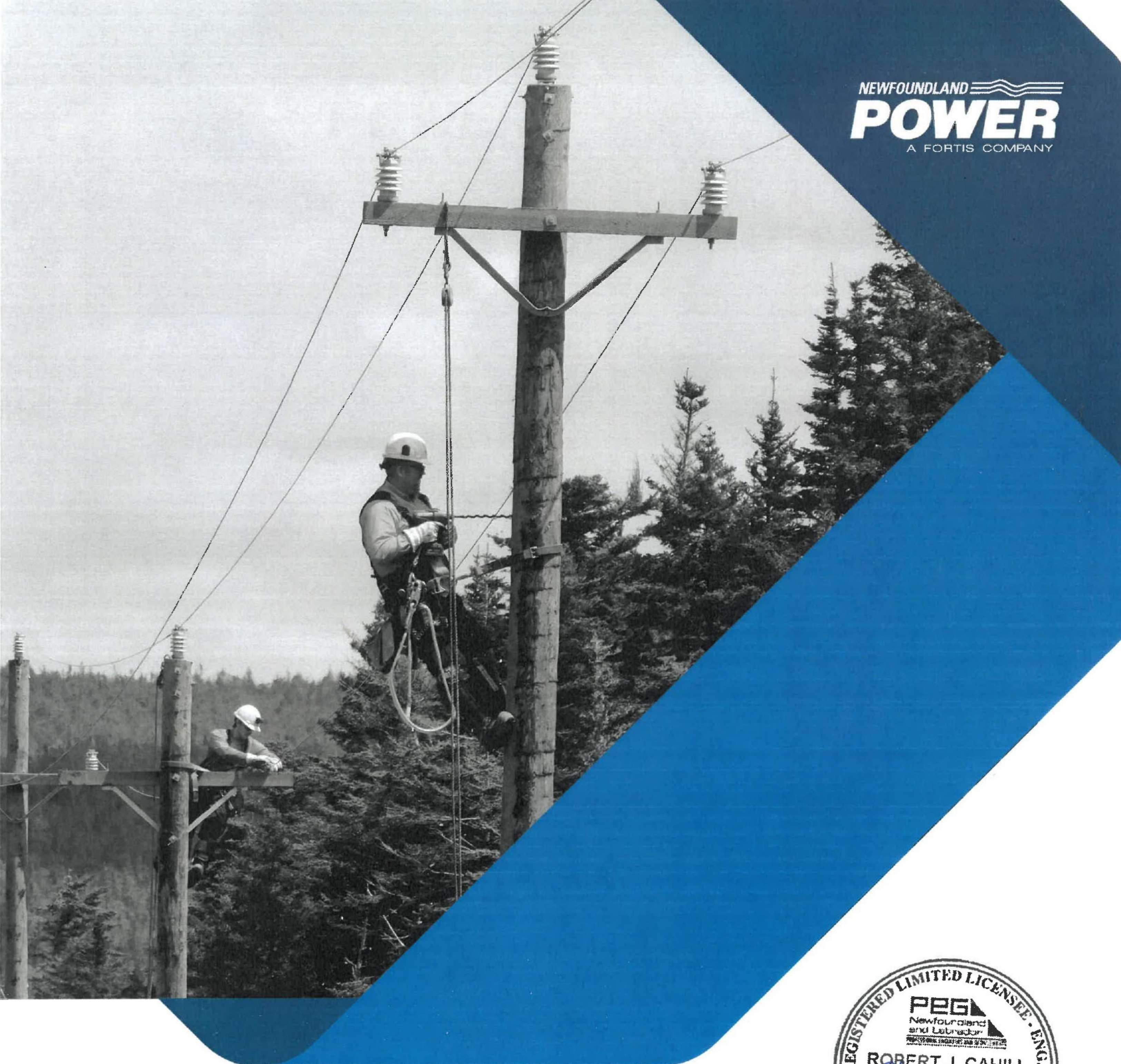
| | 2023 Summary | | | | | | Overall Project Summary | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Annual Budget | Expenditures | | Annual Forecast | Variance | Notes | Total Project Budget | Total Project Spend to Date | Total Project Forecast | Variance | Notes |
| | | Actual | Forecast | | | | | | | | |
| **Asset Class and Project Description** | **2023 Budget** | **January to April** | **May to December** | **2023 Forecast** | **2023 Forecast vs Budget** | | **2023 - 2024** | **YTD April 2023** | **2023 - 2024** | **Total Forecast vs Budget** | |
| **Generation - Hydro** | | | | | | | | | | | |
| Mobile Hydro Plant Refurbishment | 1,666 | 75 | 1,591 | 1,666 | 0 | | 4,146 | 75 | 4,146 | 0 | |
| **Total Generation - Hydro** | **1,666** | **75** | **1,591** | **1,666** | **0** | | **4,146** | **75** | **4,146** | **0** | |
| **Transmission** | | | | | | | | | | | |
| Transmission Line 55L Rebuild | 5,328 | 47 | 5,281 | 5,328 | 0 | | 10,612 | 47 | 10,612 | 0 | |
| **Total Transmission** | **5,328** | **47** | **5,281** | **5,328** | **0** | | **10,612** | **47** | **10,612** | **0** | |
| **Distribution** | | | | | | | | | | | |
| Distribution Reliability Initiative (SUM-01) | 656 | 2 | 654 | 656 | 0 | | 1,671 | 2 | 1,671 | 0 | |
| **Total Distribution** | **656** | **2** | **654** | **656** | **0** | | **1,671** | **2** | **1,671** | **0** | |
| **Transportation** | | | | | | | | | | | |
| Replace Vehicles and Aerial Devices 2023-2024 | 2,833 | 107 | 2,726 | 2,833 | 0 | | 4,699 | 107 | 4,699 | 0 | |
| **Total General Property** | **2,833** | **107** | **2,726** | **2,833** | **0** | | **4,699** | **107** | **4,699** | **0** | |
| **Total** | **10,483** | **231** | **10,252** | **10,483** | **0** | | **21,128** | **231** | **21,128** | **0** | |

1. Approved in Order No. P.U. 38 (2022).

**Newfoundland Power Inc.**
**2023 Capital Budget Expenditure Status Report**
**Multi-Year Projects Approved in Previous Years**
**($000)**

| | 2023 Summary | | | | | | Overall Project Summary | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Annual Budget | Expenditures | | Annual Forecast | Variance | Notes | Total Project Budget | Total Project Spend to Date | Total Project Forecast | Variance | Notes |
| | | Actual | Forecast | | | | | | | | |
| **Asset Class and Project Description** | **2023 Budget** | **January to April** | **May to December** | **2023 Forecast** | **2023 Forecast vs Budget** | | **2021 - 2024** | **2021 - April 2023** | **2021 - 2024** | **Total Forecast vs Budget** | |
| **Generation - Hydro** | | | | | | | | | | | |
| Sandy Brook Plant Penstock Replacement[1] | 4,694 | 67 | 4,627 | 4,694 | 0 | | 5,094 | 342 | 4,969 | -125 | |
| **Total Generation - Hydro** | **4,694** | **67** | **4,627** | **4,694** | **0** | | **5,094** | **342** | **4,969** | **-125** | |
| **Transmission** | | | | | | | | | | | |
| Transmission Line 94L Rebuild[1] | 4,346 | 0 | 4,346 | 4,346 | 0 | | 13,095 | 1,367 | 13,095 | 0 | |
| **Total Transmission** | **4,346** | **0** | **4,346** | **4,346** | **0** | | **13,095** | **1,367** | **13,095** | **0** | |
| **Transportation** | | | | | | | | | | | |
| Replace Vehicles and Aerial Devices 2022-2023[1] | 2,135 | 746 | 1,389 | 2,135 | 0 | | 5,224 | 2,867 | 5,224 | 0 | |
| **Total General Property** | **2,135** | **746** | **1,389** | **2,135** | **0** | | **5,224** | **2,867** | **5,224** | **0** | |
| **Telecommunications** | | | | | | | | | | | |
| St. John's Teleprotection System Replacement[1] | 1,150 | 160 | 990 | 1,150 | 0 | | 1,600 | 610 | 1,600 | 0 | |
| **Total Telecommunications** | **1,150** | **160** | **990** | **1,150** | **0** | | **1,600** | **610** | **1,600** | **0** | |
| **Information Systems** | | | | | | | | | | | |
| Microsoft Enterprise Agreement[2] | 245 | 0 | 245 | 245 | 0 | | 735 | 578 | 823 | 88 | |
| Customer Service System Replacement[3] | 5,917 | 0 | 5,917 | 5,917 | 0 | | 31,646 | 15,806 | 31,646 | 0 | |
| Workforce Management System Replacement[1] | 1,201 | 323 | 878 | 1,201 | 0 | | 2,009 | 1,163 | 2,041 | 32 | |
| **Total Information Systems** | **7,363** | **323** | **7,040** | **7,363** | **0** | | **34,390** | **17,547** | **34,510** | **120** | |
| **Total** | **19,688** | **1,296** | **18,392** | **19,688** | **0** | | **59,403** | **22,733** | **59,398** | **-5** | |

1. Approved in Order No. P.U. 36 (2021).
2. Approved in Order No. P.U. 37 (2020).
3. Approved in Order No. P.U. 12 (2021).




REGISTERED LIMITED LICENSEE · ENG. L.
PEG Newfoundland and Labrador
ROBERT J. CAHILL
SIGNATURE
2023-06-13
DATE
NEWFOUNDLAND & LABRADOR

# 1.1 Distribution Reliability Initiative

## June 2023

Prepared by: Bob Cahill, Eng. L.

# TABLE OF CONTENTS

Page

## 1.0 INTRODUCTION

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") *Distribution Reliability Initiative* targets the Company's worst performing feeders and sections of feeders for capital upgrades. Customers served by these feeders experience service reliability that is considerably below the Company's corporate average. By targeting the worst performing feeders for capital upgrades, Newfoundland Power aims to maintain an adequate and equitable level of service reliability for customers throughout its service territory at the lowest possible cost.

The *Distribution Reliability Initiative* involves: (i) calculating reliability performance indices for all feeders; (ii) analyzing the reliability data for the worst performing feeders to identify the cause of the poor reliability performance; and (iii) completing engineering assessments for those feeders where poor reliability performance cannot be directly related to isolated events that have already been addressed.

Newfoundland Power implemented a new Outage Management System in 2019. The system 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 2024, Newfoundland Power is proposing to rebuild a section of Western Avalon ("WAV") Substation distribution feeder WAV-01. The rebuild will involve relocating a 4.8-kilometre section of existing three-phase distribution line between the communities of Long Cove and Thornlea to the roadside of Route 201. The project is proposed to be completed in 2024 at a cost of $900,000.

## 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. In 2023, 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 69%.[1]

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.

In 2019, Newfoundland Power implemented a new Outage Management System. The system is capable of providing outage data with much greater granularity allowing Newfoundland Power to isolate specific sections of feeders that are experiencing poor reliability performance. The

---

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 8.34 hours. The average outage duration following capital upgrades was 2.62 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.

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.

Outage Management System allows Newfoundland Power's technical staff to identify specific areas where reliability performance is comparable to the Company's worst performing feeders.

The decision to make upgrades to improve the reliability performance of the worst performing feeders or specific sections of feeders is based on engineering assessments.

## 3.0 DISTRIBUTION FEEDER ASSESSMENT

### 3.1 General

The 2024 *Distribution Reliability Initiative* targets a specific section of distribution feeder WAV-01. Distribution feeder WAV-01 is one of three feeders leaving WAV Substation. It extends from the Chapel Arm area travelling along Route 201 towards Chance Cove, and branching to the communities of Bellevue and Fairhaven. This feeder currently serves approximately 1,300 customers. The total length of the feeder, including all taps, is approximately 83 kilometres.

Figure 1 shows a map illustrating the route of distribution feeder WAV-01 and its service area.

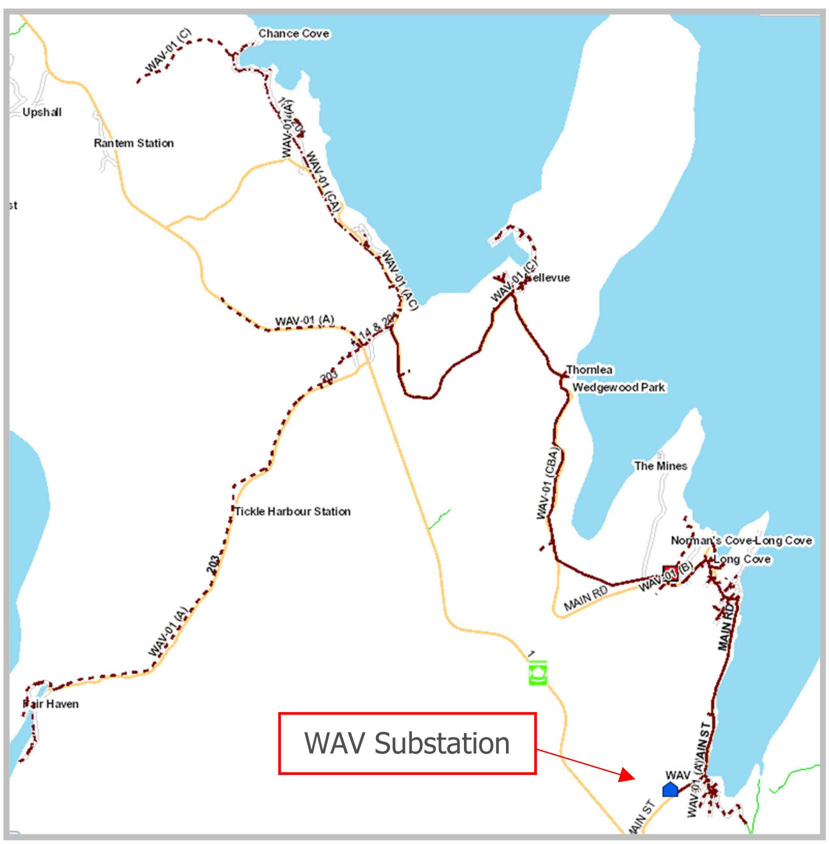



*Figure 1 - Location of Distribution Feeder WAV-01*

## 3.2 Reliability Performance

Table 1 summarizes the feeder-level reliability data from 2018 to 2022 for distribution feeder WAV-01 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, 2022

| Feeder | Customer Minutes of Outage | SAIFI | SAIDI | CHIKM | CIKM |
|---|---|---|---|---|---|
| WAV-01 | 262,309 | 1.85 | 3.35 | 51 | 29 |
| Corporate Average | 96,188 | 1.40 | 1.87 | 50 | 38 |

At the feeder level, WAV-01 is experiencing below average reliability performance for three out of four indicators.

Outage Management System data for distribution feeder WAV-01 shows that the majority of outage minutes on this feeder are on a specific 4.8-kilometre cross country section of the distribution feeder beyond downline recloser, WAV-01-R2, from Long Cove towards Thornlea.[8] Long duration outages on this section are primarily due to equipment failures and danger tree contacts.[9] The reliability performance experienced by the 658 customers served by this section of WAV-01 feeder has been considerably worse than Newfoundland Power's corporate average over the last three years.[10]

8 WAV-01-R2 is a fully automated downline recloser. These devices provide the capability to remotely and automatically sectionalize distribution feeders for fault conditions downstream of the recloser.

9 A "danger tree" as defined in Newfoundland Power's vegetation management specification is a standing tree, either live or dead, having visible defects, singly or combined, which predisposes it to mechanical failure in whole or in part (whether on its own or from the effects of a storm or disturbance), and which is so located that such a failure has a probability of contacting, or coming in close proximity to, a live electrical conductor. Also, a danger tree is a live, healthy tree that, once cut, has the potential to contact, or come in close proximity to, a live electrical conductor.

10 The new Outage Management System was implemented in September, 2019. As a result, three-year average reliability data is available.

Table 2 summarizes the reliability data from 2020 to 2022 for the section of distribution feeder WAV-01 downstream of WAV-01-R2, and provides a comparison to the corporate average for Newfoundland Power's distribution system.

Table 2
Distribution Interruption Statistics
3-Year Average to December 31, 2022

| Feeder Section | Customer Minutes of Outage | SAIFI | SAIDI |
|---|---|---|---|
| Downstream WAV-01-R2[11] | 341,260 | 3.98 | 8.77 |
| Corporate Average (5-Year) | 96,188 | 1.40 | 1.87 |

The average SAIDI for customers along this section of feeder is 8.77 or approximately five times the corporate average for SAIDI, the average SAIFI is 3.98, or approximately three times the corporate average for SAIFI.[12]

The reliability performance of the identified section of WAV-01 feeder is consistent with what would generally be considered a worst performing feeder in the electric utility industry.[13]

### 3.3 Engineering Assessment

Distribution feeder WAV-01 is a 12.5 kV distribution feeder originally constructed in the 1960s. The main three-phase trunk portion of WAV-01 feeder is approximately 25 kilometres in length and extends from the Chapel Arm area along Route 201 towards Bellevue. A two-phase trunk section of feeder extends approximately 10 kilometres from the three-phase trunk to Chance Cove, and a single-phase section extends approximately 16 kilometres into Fair Haven. 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.

A section of WAV-01 feeder downstream of downline recloser WAV-01-R2 leaves the main road in Long Cove and is located across-country for approximately 4.8 kilometres to Route 201. The location of this section of line makes access difficult, which can lead to delays in restoration times. For example, accessing the line to complete repairs and outage restoration activities requires the use of off-road vehicles which further delays restoration times.

---

11 The reliability data for distribution feeder WAV-01 downstream of WAV-01-R2 is provided by the Company's Outage Management System. This data is only available for the three years since 2019. As a result, the reliability data here is different from the five-year average data provided in Table 1.

12 Comparisons to CHIKM and CIKM are excluded from Table 2 as these indices are typically used to identify issues with shorter feeders located in urban settings.

13 The standards used by electric utilities in identifying worst performing feeders vary. Examples of standards include feeders where the SAIDI exceeds the corporate average by 300% and feeders where the SAIDI is in the top 10% for two consecutive years. This is consistent with Newfoundland Power's characterization of the identified section of WAV-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.

Figure 2 shows the 4.8-kilometre cross country section of WAV-01 feeder downstream of downline recloser WAV-01-R2.

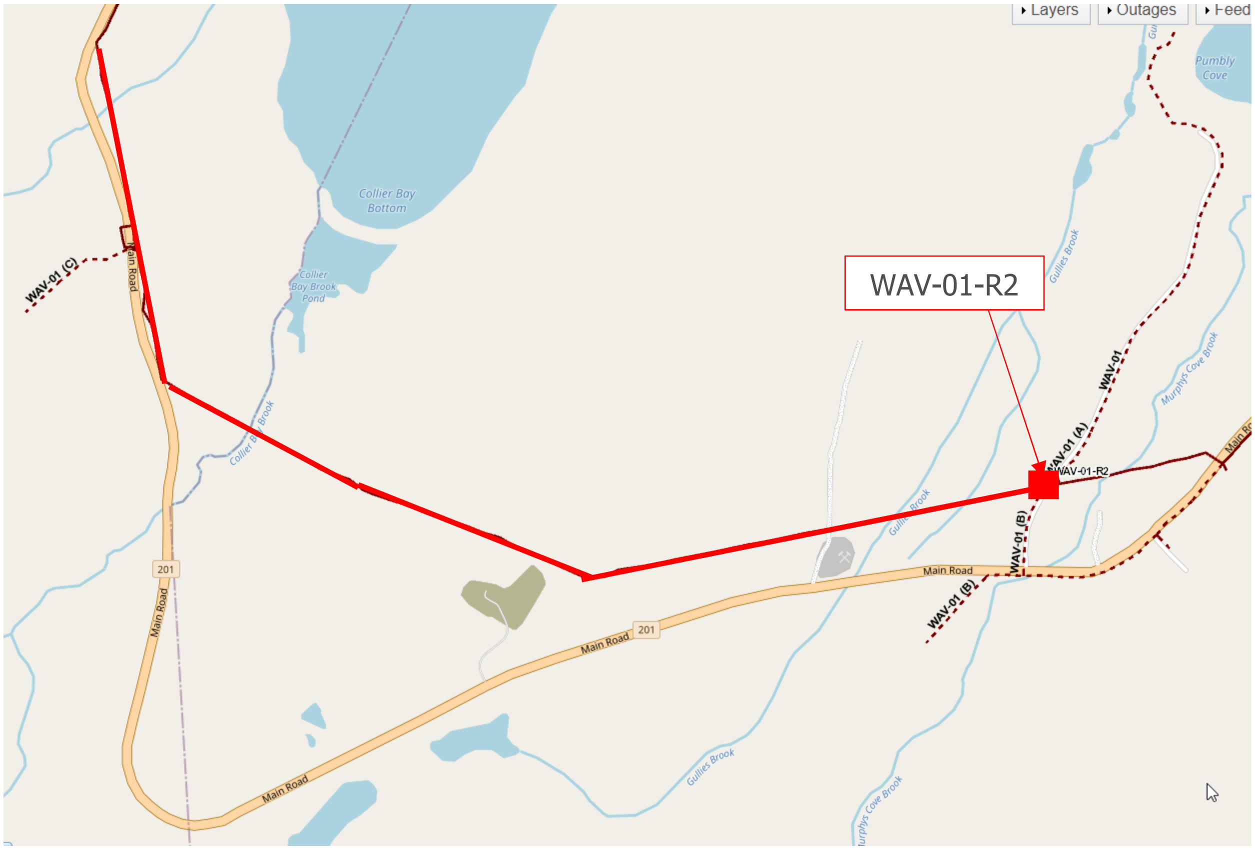
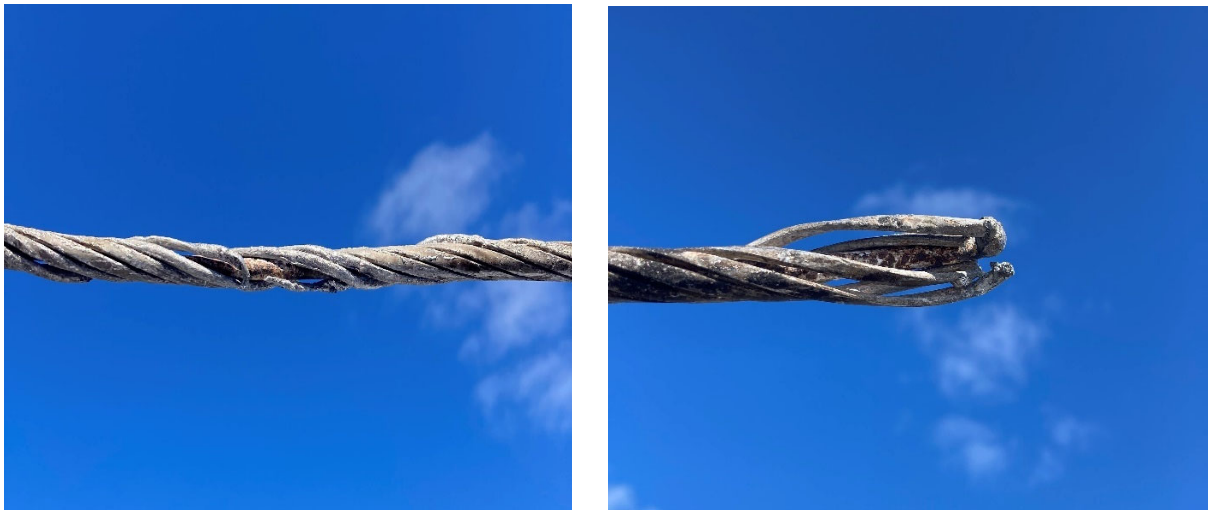



*Figure 2 - Location of Cross Country Section of Distribution Feeder WAV-01*

An engineering assessment of the 4.8-kilometre section of WAV-01 feeder has identified that the factors contributing to poor reliability performance are: (i) corroded or damaged conductor; (ii) danger tree contacts; (iii) deteriorated poles, crossarms and insulators; and (iv) inaccessibility of the line.

This section of feeder is constructed using #2 Aluminum Conductor Steel Reinforced ("ACSR") conductor. The Company has experienced issues with this particular conductor, as oxidation between the steel core and aluminum outer strands is known to occur. The oxidation is particularly prevalent in coastal environments in which frequent salt spray occurs. This is the case for distribution feeder WAV-01, which is adjacent to the coastline. The conductor on the identified section of distribution feeder is in very poor condition, with deterioration and separation of the conductor strands.

Figures 3 and 4 shows the typical type of conductor deterioration present on this section of distribution feeder WAV-01.



*Figures 3 and 4 - #2 ACSR Conductor Deterioration*

As shown in Figures 3 and 4, 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.

Due to the deteriorated condition of the conductor, it cannot be safely repaired using hotline work methods.[14] Completing maintenance on this section of feeder requires an outage to the 658 customers downstream of downline recloser WAV-01-R2.[15]

14 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.

15 As examples, maintenance could include the installation of replacement conductor or maintenance involving the transfer of existing conductor to new poles.

Figure 5 shows an example of the inaccessible location of the line as well as the existing right-of-way.

*Figure 5 - Cross Country Right-of-Way*

The right-of-way along the 4.8-kilometre section of feeder has been maintained to the full 7.4 metre width. However, tree contacts have been a cause of customer outages due to danger trees outside the maintained right-of-way contacting the line when they fall. The geographic location of the feeder also extends response times, resulting in longer duration outages to customers.

The majority of the poles, crossarms and insulators on the 4.8-kilometre section of feeder are of the original 1960s vintage. Figure 6 shows an example of deteriorated crossarms, insulators and poles that have resulted in outages to customers supplied by this section of feeder.

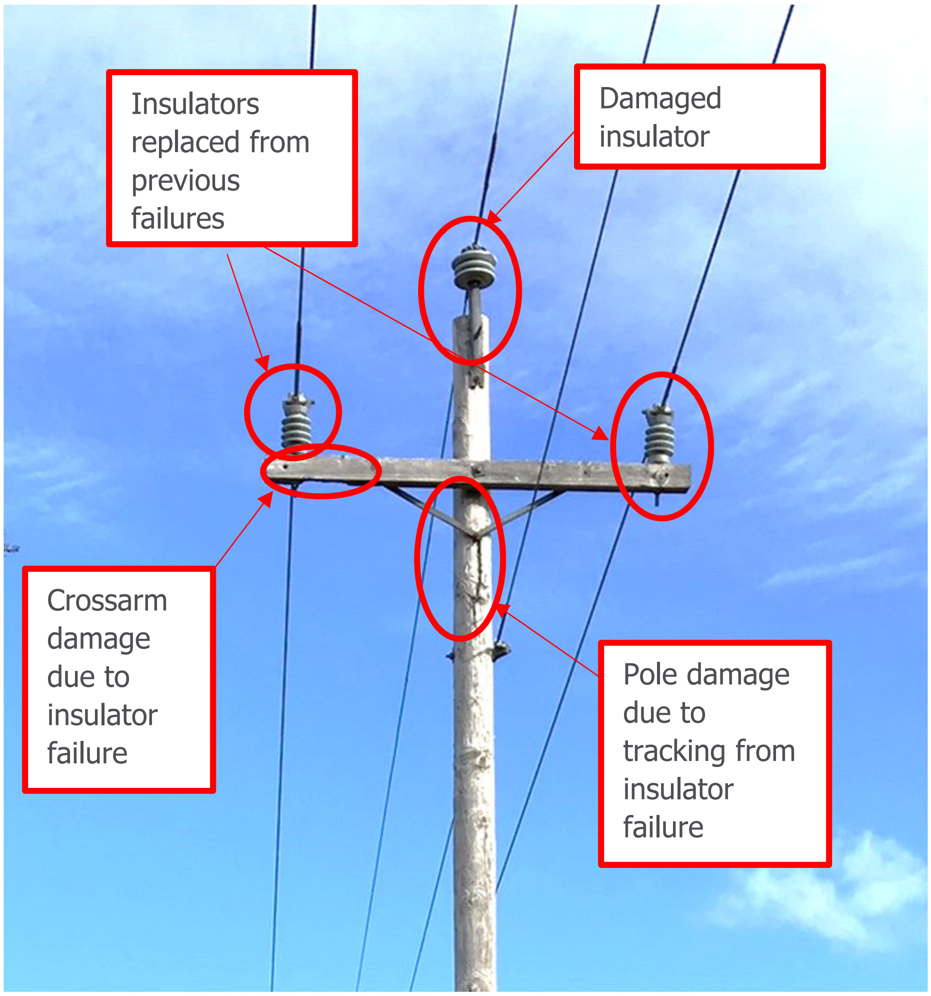



*Figure 6 - Damaged crossarms, poles and insulators*

Inspections have identified 51 deficiencies on this 4.8-kilometre section of feeder, including 27 deteriorated poles and crossarms.

# 4.0 ASSESSMENT OF ALTERNATIVES

## 4.1 General

The 658 customers supplied by the identified 4.8-kilometre section of WAV-01 feeder are experiencing significantly worse reliability compared to the average reliability experienced by Newfoundland Power's customers.[16] An engineering assessment of the identified section of distribution feeder WAV-01 identified the factors contributing to its poor reliability performance are: (i) corroded or damaged conductor; (ii) danger tree contacts; (iii) deteriorated poles, crossarms and insulators; and (iv) inaccessibility of line.

A significant number of deficiencies and outage incidents have been identified on this specific section of WAV-01 feeder. The risk of equipment failure and outages to customers is therefore considered high, and will continue to increase if this project is deferred.

Customers supplied from this section of feeder are experiencing outages that are five times longer and three times more frequent than the Company average. Deferring the upgrades of WAV-01 feeder would result in customers continuing to experience poor service reliability. This would be inconsistent with maintaining adequate and equitable levels of service reliability for customers throughout Newfoundland Power's service territory.

Two alternatives were identified and evaluated with respect to distribution feeder WAV-01. The two alternatives are: (i) rebuild the existing 4.8-kilometre section of line in the existing right-of-way; and (ii) relocate the existing 4.8-kilometre section of line to the roadside of Route 201.

## 4.2 Alternative 1 – Rebuild in Existing Right-of-Way

Alternative 1 involves rebuilding the 4.8-kilometre three-phase section of WAV-01 feeder in the existing right-of-way from Long Cove to Thornlea. This would include replacing all deteriorated poles and crossarms, and upgrading the primary conductor to standard 4/0 AASC. The existing right-of-way would also be widened as required to prevent tree contacts from danger trees outside of the existing right-of-way.

This alternative would require the temporary installation and operation of portable generation to mitigate lengthy outages that customers would experience during completion of the work identified in this alternative. Completing the work identified in this alternative using hot line work methods is not possible due to the inaccessible location and condition of the infrastructure on this section of feeder. The identified section of feeder is located cross-country and is not truck accessible. In addition, the condition of the infrastructure on this section of feeder creates a safety risk for employees completing hot line work. Given that there are no tie points with other feeders in the area, there is no way to transfer the load to maintain supply to the 658 customers downstream.

The total capital cost of Alternative 1 is $1,027,000.

---

[16] This 4.8-kilometre section comprises less than 5% of the total length of distribution feeder WAV-01.

### 4.3 Alternative 2 – Relocation of Distribution Line to Route 201

Alternative 2 involves relocating the 4.8-kilometre section of WAV-01 feeder to the roadside of Route 201.

Under this alternative, a new 6.5-kilometre, three-phase section of distribution feeder would be constructed along the route of an existing communications line along the roadside of Route 201. This communications line was originally built in the 1990s. The addition of a new three-phase distribution feeder along the route of the existing communications line would require the replacement of the majority of the existing poles, as well as the installation of midspan poles where required to meet current design standards.

This alternative would not require the installation and operation of portable generation to complete the work as the new line could be built while the existing line remains energized and supplying customers. Once construction of the new line is completed, downstream customers would be transferred to the new line.

The total capital cost of Alternative 2 is $900,000.

## 5.0 PROJECT SCOPE

The assessment of alternatives determined that Alternative 2 is the least cost alternative to address the poor service reliability experienced by customers supplied from the 4.8-kilometre section of WAV-01 feeder downstream of downline recloser WAV-01-R2. The relocation of the 4.8-kilometre section of distribution feeder to the roadside of Route 201 will also improve access to the line during outage response activities and will result in efficiencies in preventative maintenance and inspection activities.

The project scope to complete the relocation of the identified section of WAV-01 feeder includes:

- (i) Constructing 6.5-kilometres of new three-phase distribution line along Route 201; and
- (ii) Replacing poles and installing midspan structures as required.

This project is proposed to be completed in 2024, with design and procurement completed by the second quarter, and construction completed by the end of the fourth quarter.

## 6.0 PROJECT COST

Table 3 provides a detailed cost breakdown of the project to be completed on distribution feeder WAV-01.

Table 3
Distribution Reliability Initiative
Project Cost
($000s)

| Description | 2024 |
|---|---|
| Engineering | 127 |
| Labour - Contract | 204 |
| Labour - Internal | 146 |
| Material | 193 |
| Other | 230 |
| Total | $900 |

The total cost to complete the rebuild and relocation of the identified section of WAV-01 feeder in 2024 is $900,000.

## 7.0 CONCLUSION

The *Distribution Reliability Initiative* targets areas where customers experience among the worst reliability in Newfoundland Power's service territory for capital upgrades. This targeted approach is consistent with maintaining adequate and equitable levels of service reliability for customers at the lowest possible cost.

The Company reviewed the performance indices and Outage Management System data for distribution feeder WAV-01 and identified that the 658 customers supplied by the section of feeder downstream of WAV-01-R2 are experiencing significantly worse reliability performance than the Company average. An engineering assessment determined that capital upgrades to rebuild and relocate a 4.8-kilometre section of the feeder to Route 201 would address the poor service reliability experienced by these customers. A project in 2024 is proposed to address these deficiencies at a total cost of $900,000.

# APPENDIX A:

## Distribution Reliability Data: Worst Performing Feeders

Table A-1
Unscheduled Distribution-Related Outages
5-Year Average
(2018-2022)
Sorted by Customer Minutes of Interruption

| Feeder | Annual Customer Interruptions | Annual Customer Minutes of Interruption | Annual Distribution SAIFI | Annual Distribution SAIDI |
|---|---|---|---|---|
| SUM-01 | 7,206 | 1,204,804 | 3.96 | 11.04 |
| DOY-01 | 7,001 | 751,252 | 3.99 | 7.12 |
| GLV-02 | 9,171 | 657,878 | 5.97 | 7.15 |
| DLK-03 | 4,741 | 578,538 | 3.33 | 6.85 |
| BVS-04 | 6,047 | 548,648 | 3.77 | 5.69 |
| BOT-01 | 3,830 | 464,124 | 2.21 | 4.48 |
| DUN-01 | 4,929 | 437,793 | 4.67 | 6.91 |
| BLK-01 | 4,868 | 401,277 | 2.94 | 4.06 |
| MIL-02 | 3,799 | 376,596 | 2.51 | 4.15 |
| HOL-03 | 3,198 | 376,125 | 3.07 | 6.02 |
| WAL-02 | 4,645 | 361,391 | 3.27 | 4.23 |
| BLK-02 | 3,978 | 346,625 | 1.90 | 2.77 |
| LEW-02 | 5,129 | 338,114 | 3.39 | 3.73 |
| GFS-06 | 4,075 | 337,009 | 2.12 | 2.92 |
| BLA-01 | 3,011 | 333,842 | 2.59 | 4.79 |
| Company Average | 1,201 | 96,188 | 1.40 | 1.87 |

| Table A-2<br>Unscheduled Distribution-Related Outages<br>5-Year Average<br>(2018-2022)<br>Sorted by Distribution SAIFI | | | | |
|---|---|---|---|---|
| Feeder | Annual Customer Interruptions | Annual Customer Minutes of Interruption | Annual Distribution SAIFI | Annual Distribution SAIDI |
| GLV-02 | 9,171 | 657,878 | 5.97 | 7.15 |
| LEW-03 | 5,463 | 187,523 | 4.78 | 2.74 |
| DUN-01 | 4,929 | 437,793 | 4.67 | 6.91 |
| SCT-01 | 3,417 | 290,833 | 4.62 | 6.58 |
| SUM-02 | 2,549 | 239,103 | 4.22 | 6.57 |
| DOY-01 | 7,001 | 751,252 | 3.99 | 7.12 |
| SUM-01 | 7,206 | 1,204,804 | 3.96 | 11.04 |
| BVS-04 | 6,047 | 548,648 | 3.77 | 5.69 |
| LEW-02 | 5,129 | 338,114 | 3.39 | 3.73 |
| DLK-03 | 4,741 | 578,538 | 3.33 | 6.85 |
| WAL-02 | 4,645 | 361,391 | 3.27 | 4.23 |
| LEW-04 | 1,756 | 91,672 | 3.24 | 2.82 |
| BUC-02 | 516 | 75,519 | 3.24 | 7.91 |
| ABC-01 | 2,594 | 224,744 | 3.23 | 4.66 |
| SMV-01 | 3,572 | 252,342 | 3.22 | 3.79 |
| Company Average | 1,201 | 96,188 | 1.40 | 1.87 |

| Table A-3<br>Unscheduled Distribution-Related Outages<br>5-Year Average<br>(2018-2022)<br>Sorted by Distribution SAIDI | | | | |
|---|---|---|---|---|
| Feeder | Annual Customer Interruptions | Annual Customer Minutes of Interruption | Annual Distribution SAIFI | Annual Distribution SAIDI |
| SBK-01[1] | 4 | 2,848 | 1.93 | 22.39 |
| SUM-01 | 7,206 | 1,204,804 | 3.96 | 11.04 |
| BUC-02 | 516 | 75,519 | 3.24 | 7.91 |
| LGL-01 | 698 | 160,772 | 1.97 | 7.59 |
| GLV-02 | 9,171 | 657,878 | 5.97 | 7.15 |
| DOY-01 | 7,001 | 751,252 | 3.99 | 7.12 |
| DUN-01 | 4,929 | 437,793 | 4.67 | 6.91 |
| DLK-03 | 4,741 | 578,538 | 3.33 | 6.85 |
| SCT-01 | 3,417 | 290,833 | 4.62 | 6.58 |
| SUM-02 | 2,549 | 239,103 | 4.22 | 6.57 |
| SCT-02 | 353 | 100,058 | 1.37 | 6.52 |
| NCH-03[2] | 3 | 381 | 3.00 | 6.35 |
| GBS-02 | 330 | 118,489 | 1.05 | 6.19 |
| HOL-03 | 3,198 | 376,125 | 3.07 | 6.02 |
| BVS-04 | 6,047 | 548,648 | 3.77 | 5.69 |
| Company Average | 1,201 | 96,188 | 1.40 | 1.87 |

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.

2 NCH-03 serves only a RCMP radio tower close to the Company's Pittman's Pond hydroelectric plant. The site has backup battery power and can tolerate extended outages.

| Table A-4<br>Unscheduled Distribution-Related Outages<br>5-Year Average<br>(2018-2022)<br>Sorted by Distribution CHIKM | |
|---|---|
| Feeder | Annual Distribution CHIKM |
| PEP-04 | 349 |
| KBR-10 | 331 |
| SJM-06 | 298 |
| PAB-05 | 297 |
| KBR-13 | 270 |
| WAV-03 | 258 |
| WAL-01 | 231 |
| KBR-15 | 229 |
| PAB-03 | 211 |
| TWG-02 | 200 |
| WAL-02 | 198 |
| MOL-04 | 189 |
| LGL-01 | 181 |
| HUM-09 | 181 |
| SUM-01 | 180 |
| Company Average | 50 |

| Table A-5<br>Unscheduled Distribution-Related Outages<br>5-Year Average<br>(2018-2022)<br>Sorted by Distribution CIKM | |
|---|---|
| Feeder | Annual Distribution CIKM |
| KBR-10 | 320 |
| KEN-03 | 240 |
| KBR-13 | 234 |
| PEP-04 | 212 |
| PAB-03 | 209 |
| SJM-06 | 184 |
| WAL-05 | 178 |
| SLA-10 | 174 |
| MOL-04 | 168 |
| PEP-01 | 166 |
| KEN-01 | 165 |
| PAB-05 | 164 |
| WAL-01 | 156 |
| WAL-02 | 153 |
| HWD-07 | 151 |
| Company Average | 38 |

# APPENDIX B:

## Worst Performing Feeders: Summary of Data Analysis

| Worst Performing Feeders<br>Summary of Data Analysis | |
|---|---|
| Feeder | Comments |
| ABC-01 | Poor reliability statistics were primarily driven by wind events. No work is required at this time. |
| BLA-01 | Poor reliability statistics were driven by wind and vegetation-related events in 2022. No work is required at this time. |
| BLK-01 | Poor reliability was principally driven by three conductor breakages and an insulator failure in 2018. No work is required at this time. |
| BLK-02 | Poor reliability was principally driven by weather related events 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. |
| 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. |
| GBS-02 | Poor reliability statistics were driven by a wind-related event and conductor failures in 2022. 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. |

| Worst Performing Feeders<br>Summary of Data Analysis | |
|---|---|
| Feeder | Comments |
| 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. |
| HOL-03 | Reliability is worsening principally due to conductor and vegetation issues. The feeder will continue to be monitored and will potentially require future capital investment to address reliability performance. |
| HUM-09 | Poor reliability statistics are primarily driven by vegetation issues. 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. |
| KBR-10 | There were several outages in 2020 due to adverse weather and trees. No work is required at this time. |
| KBR-13 | Tree issues in 2020 contributed to reduced reliability in that year. No work is required at this time. |
| KBR-15 | Reliability is worsening due to conductor and insulator issues. No work is proposed at this time but conductor issues are expected to increase. The feeder will continue to be monitored and will potentially require future capital investment to address reliability performance. |
| KEN-01 | Poor reliability is primarily related to a substation breaker failure in 2022. No work is required at this time. |
| KEN-03 | Poor reliability statistics were driven by 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-02 | Poor reliability statistics can be attributed to a wind event and a broken pole in 2022. 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. |
| LGL-01 | Poor reliability was driven by a conductor failure and weather events in 2022. No work is required at this time. |
| MIL-02 | Poor reliability is primarily due to lightning in 2020 and vegetation issues in 2022. No work is required at this time. |

| Worst Performing Feeders<br>Summary of Data Analysis | |
|---|---|
| Feeder | Comments |
| MOL-04 | Poor reliability statistics were driven by damaged conductor in 2019. No work is required at this time. |
| NCH-03 | NCH-03 serves only a RCMP radio tower close to the Company's Pittman's Pond hydroelectric plant. The site has emergency standby generators and backup battery power so it can tolerate extended outages. 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. |
| PEP-01 | Poor reliability statistics are due to conductor and insulator issues, primarily during wind events. 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. |
| PEP-04 | Poor reliability can be attributed primarily to an underground cable failure in 2018. 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. |
| SCT-01 | Poor reliability statistics were driven by 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 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. |

| Worst Performing Feeders<br>Summary of Data Analysis | |
|---|---|
| Feeder | Comments |
| SMV-01 | Poor reliability statistics are attributable to an insulator failure during a wind event in 2022. No work is required at this time. |
| SUM-01 | Poor reliability statistics were 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. |
| TWG-02 | Poor reliability statistics were caused by several conductor issues in 2020. No work is required at this time. |
| WAL-01 | Poor reliability is driven by a vehicle accident in 2021. No work is required at this time. |
| WAL-02 | Poor reliability statistics were driven by wind and tree-related events in 2020. No work is required at this time. |
| WAL-05 | Poor reliability is driven by tree-related issues. No work is required at this time. |
| WAV-03 | Poor reliability statistics were caused by wind-related issues in 2019. No work is required at this time. |

# APPENDIX C:

## Photographs of Distribution Feeder WAV-01


*Figure C-1 - Deteriorated Conductor*


*Figure C-2 - Deteriorated pole, crossarm, insulators and conductor*


*Figure C-3 - Deteriorated pole and crossarm*

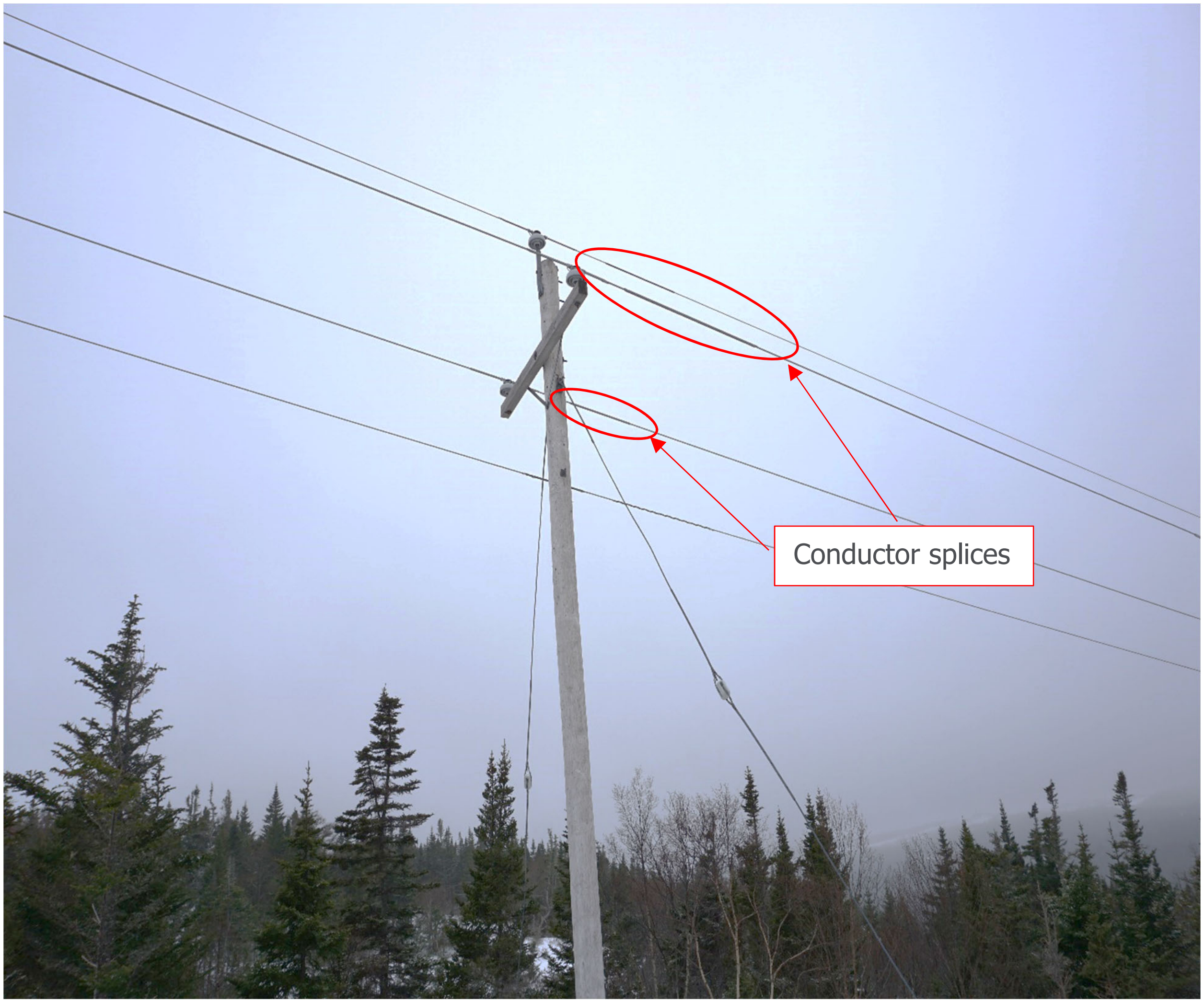


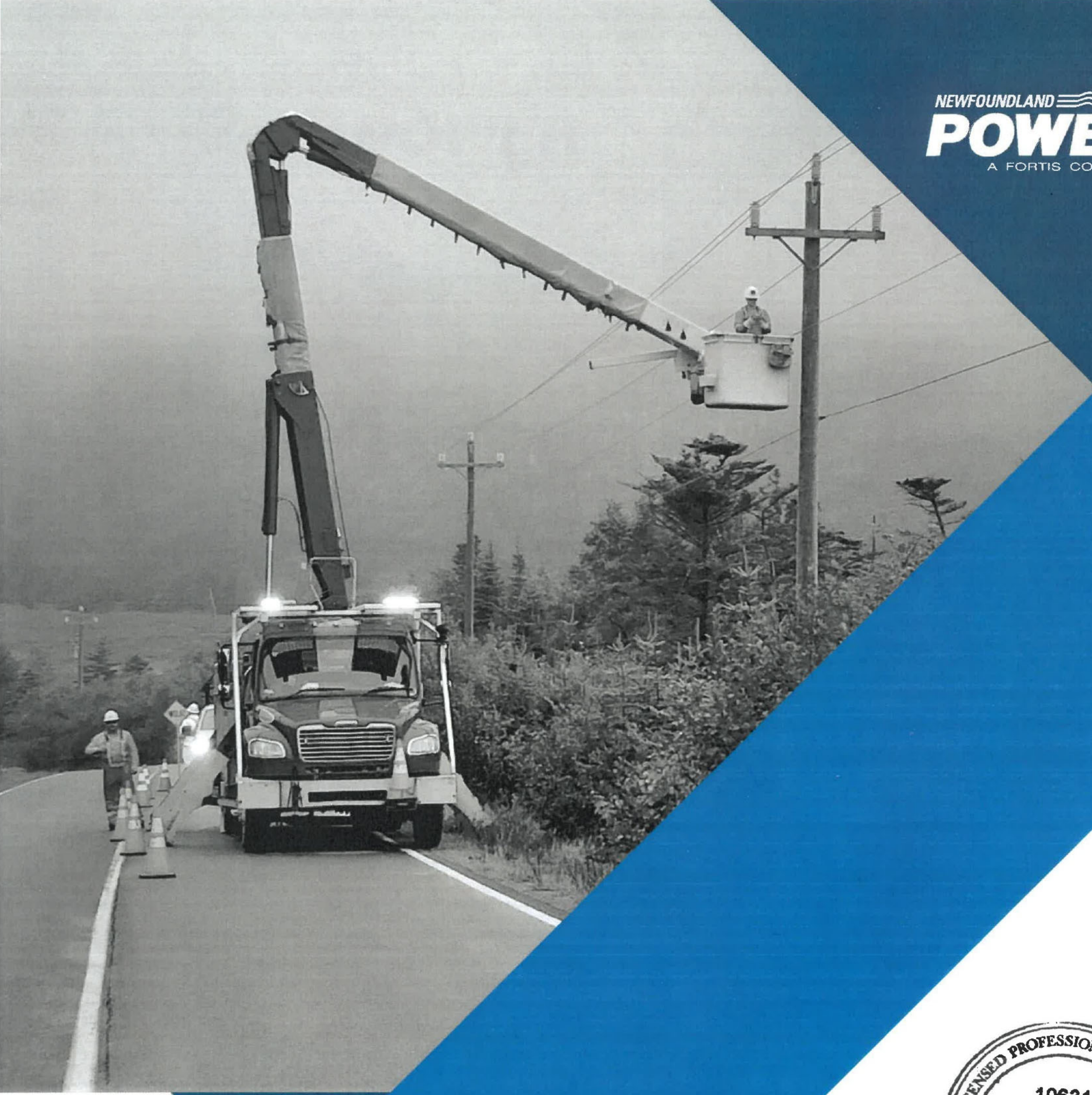

*Figure C-4 - Previous Conductor Failures*


*Figure C-5 – Deteriorated Crossarm*


*Figure C-6 – Deteriorated Crossarm*


*Figure C-7 – Deteriorated Insulator*

*Figure C-8 – Deteriorated Pole and Crossarm*



NEWFOUNDLAND
POWER
A FORTIS COMPANY

LICENSED PROFESSIONAL ENGINEER
10631
TONY S. JONES
Tony Jones
SIGNATURE
2023-06-13
DATE
NEWFOUNDLAND & LABRADOR

# 1.2 Feeder Additions for Load Growth

## June 2023

Prepared by: Tony Jones, P. Eng.

# TABLE OF CONTENTS

Page

## 1.0 INTRODUCTION

As load increases on an electrical system, the components of the system can become overloaded. These overload conditions can occur 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 three overload conditions to be addressed in 2024 by upgrading existing distribution lines. The overload conditions described in this report can each be attributed to residential growth in specific areas of the Company's service territory.

## 2.0 OVERLOADED CONDUCTORS

### 2.1 General

An overloaded section of conductor on a distribution line is at risk of failure. Failures are caused by overheating of the conductor as the load exceeds the conductor's capacity ratings. As a result, the conductor will have excessive sag, which may result in the conductor coming into contact with other conductors or the conductor breaking, causing a fault and subsequent customer outage and safety hazard. Overloaded conductor can also have a negative impact on restoration efforts following customer outages due to increased conductor loading associated with cold load pick-up.

Newfoundland Power analyzes its distribution feeders using a distribution feeder computer modelling application to identify sections of feeders that may be overloaded. The results are followed up with field verifications to ensure the accuracy of information.[2]

---

1 Feeder balancing involves transferring load from one phase to another on a three-phase distribution feeder in order to balance the amount of load on each phase. Load transfers involve transferring load from one feeder to another adjacent feeder.

2 Where necessary, load measurements are taken to verify the results of the computer modelling. The analysis uses conductor capacity ratings based on Newfoundland Power's *Distribution Planning Guidelines*. These ratings are shown in Appendix A.

### 2.2 Alternatives to Address Overloaded Conductor

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

*(i)* ***Feeder Balancing -*** In some cases, conductor may be overloaded on only one phase of a three-phase line. In this situation, it may be possible to 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. In some cases, transferring load to an adjacent feeder may require building new sections of three-phase distribution line.

*(iii)* ***Feeder Upgrades -*** In some cases, overload conditions can be eliminated by increasing the conductor size on the overloaded section, upgrading overloaded single-phase sections to three phase, or building new sections of distribution feeder.

*(iv)* ***New Feeder -*** In cases where the feeder conductor leaving a substation is overloaded, and none of the above alternatives can be used to resolve the overload condition, the addition of a new feeder from the substation may be required to transfer a portion of load from the overloaded conductor.

*(v)* ***Non-Wires Alternatives -*** Non-wires alternatives comprise a broad category that encompasses various innovative alternatives to standard “poles and wires” solutions. These include, but are not limited to, distributed energy resources, microgrids and battery storage.

## 3.0 PROJECT DESCRIPTION

### 3.1 Overloaded Single-Phase 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 CYME Power Engineering software to identify single-phase lines that may be overloaded.[3] Load measurements were subsequently taken to verify the results of the computer simulation.[4]

The analysis identified three locations where single-phase lines are overloaded and mitigation of the overload condition is required, each of which is described below.

## 3.2 Distribution Feeder BVS-04 Upgrade

Distribution feeder BVS-04 leaves Bayview ("BVS") Substation in Corner Brook and extends southwest along the Trans Canada Highway ("TCH") to supply customers in Massey Drive, Watsons Pond Industrial Park, Pinchgut Lake, Georges Lake, Spruce Brook, and Gallants. This distribution feeder serves approximately 1,660 residential and commercial customers in the area.

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. Further growth on these taps are also expected as a result of electrification in general and increased penetration of electric vehicles over the coming years.

4 Newfoundland Power forecasts load at the substation transformer and distribution feeder levels annually. In the case of distribution feeders, total feeder load is allocated across the feeder to approximate load at each distribution transformer downstream from the substation, based on their individual capacities. As the Company does not currently utilize Advanced Metering Infrastructure meters, loading on individual sections of distribution line can only be approximated by the modeling software, and must be verified in the field when warranted by operational concerns such as protection device trips or inquiries regarding new developments.

Figure 1 illustrates the route of distribution feeder BVS-04.

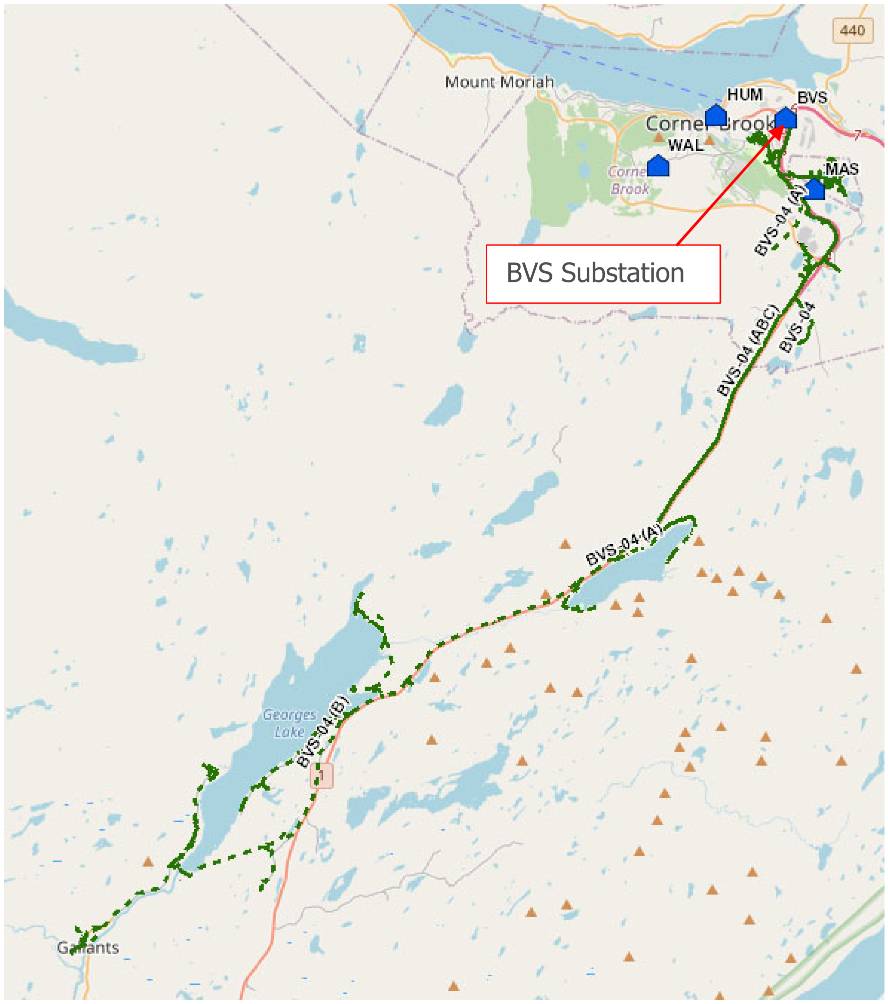



*Figure 1 – Distribution Feeder BVS-04*

An 11.0-kilometre section of single-phase distribution feeder is overloaded. This section of line extends southwest on the TCH to serve customers in the areas of Pinchgut Lake, Georges Lake, Spruce Brook, and Gallants. Load growth on this section of line is mainly attributed to new customer connections and service upgrades in the areas of Pinchgut Lake and Georges Lake. The number of customers supplied by this line has increased by 49% over the last 15 years.[5] Annual increases in customers reflect a shift from what was once a predominantly cabin area to year-round permanent residences. As a result, new service connections and service upgrades have been requested more frequently.

An analysis of distribution feeder BVS-04 was completed using CYME Power Engineering software and verified using actual load measurements. The analysis showed that the load on

[5] There were 320 customers supplied by this section of line in 2008 and 478 customers in 2022, an increase of 158 customers (158 / 320 = 0.494, or 49%).

the identified single-phase section of the feeder is approximately 125 amps, which exceeds the Company's planning criteria for maximum current on a single-phase distribution line.[6]

Three categories of alternatives that are generally available to address overloaded conductor are not applicable to BVS-04. Feeder balancing is not applicable as the identified section of BVS-04 is single phase. A load transfer is not applicable as there is no adjacent feeder. A new feeder build is not applicable due to the magnitude of the associated costs. As a result, the alternatives evaluated to mitigate the overloaded section of distribution feeder BVS-04 include: (i) upgrading the tap from single-phase to three-phase; and (ii) a non-wires alternative.

### *Alternative 1: Upgrade Section to Three-Phase*

This alternative would involve upgrading an 11.0-kilometre section of single-phase distribution line along the TCH from Pinchgut Lake to Georges Lake to three-phase 1/0 AASC conductor to resolve the overload condition. The capital cost of this work is estimated to be $1,736,000.

Figure 2 illustrates the work that would be required under this alternative.

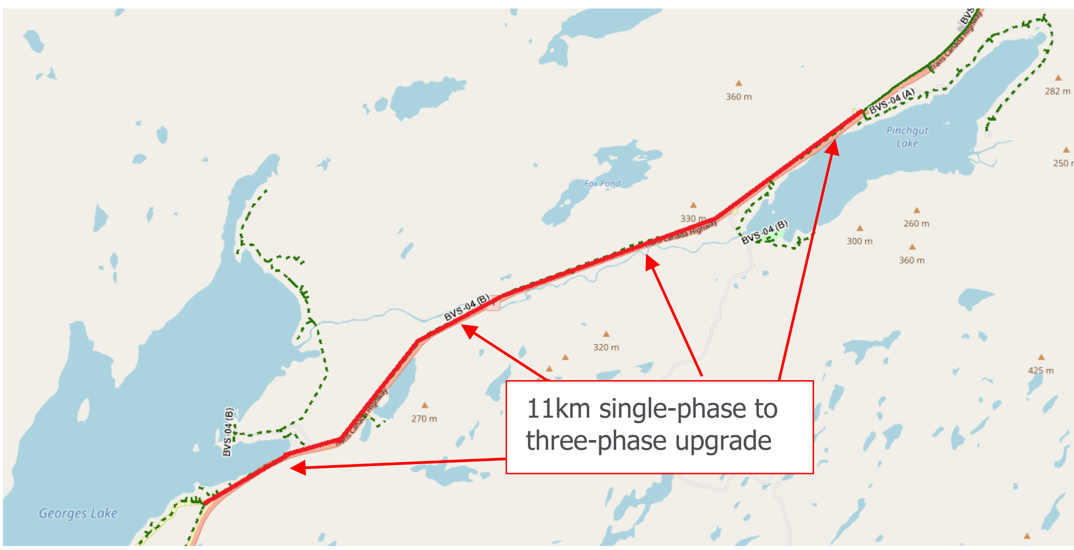



*Figure 2 – Distribution Feeder BVS-04 Upgrade*

### *Alternative 2: Non-Wires Alternative*

This alternative would utilize commercial-grade battery storage technology to provide capacity to alleviate the overload condition during peak load conditions. Based on verified load readings and distribution feeder modelling, approximately 17 hours of capacity would be required to alleviate the overload conditions on this section of line during peak load. A preliminary capital cost estimate for the procurement of a battery storage solution for this application is

6 Newfoundland Power's planning criteria for maximum current on a single-phase distribution line is 85 amps.

approximately $2.1 million.[7] This estimate does not include engineering, land 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 BVS-04 from single-phase to three-phase is least cost. This is therefore the recommended alternative to address the identified overload condition.

### 3.3 Distribution Feeder OXP-01 Upgrade

Distribution feeder OXP-01 leaves Oxen Pond ("OXP") Substation in St. John's and extends along Mount Scio Road east toward Allandale Road and west toward Thorburn Road. This distribution feeder serves approximately 1,290 residential and commercial customers in the St. John's area.

Figure 3 illustrates the route of distribution feeder OXP-01.

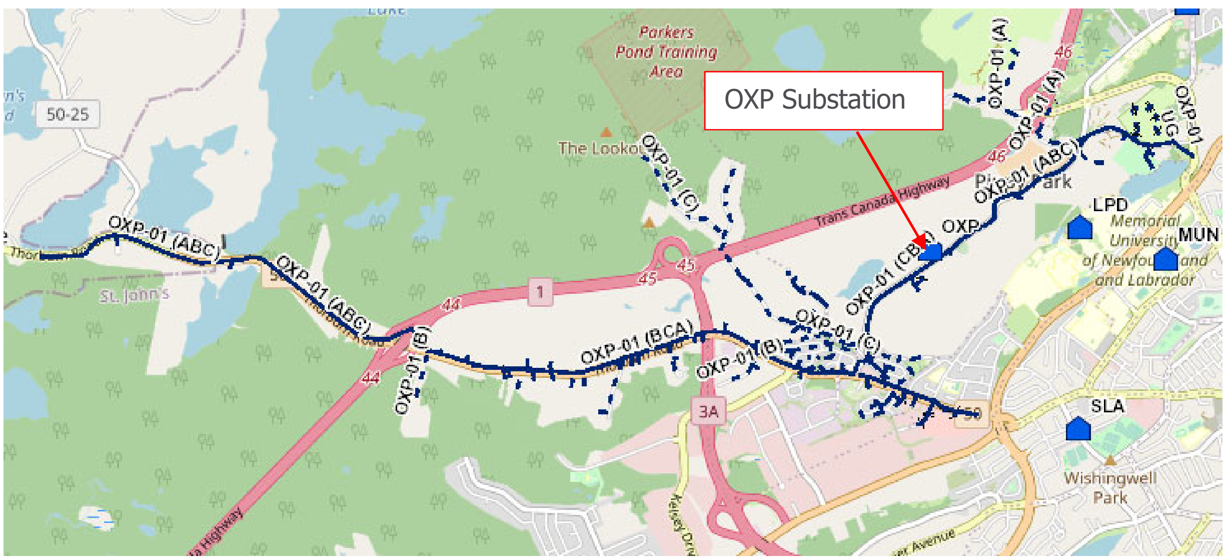



*Figure 3 – Distribution Feeder OXP-01*

A 1.5-kilometre section of single-phase distribution line along Groves Road is overloaded. Load growth on this single-phase section of line can be attributed to customer connection growth along Groves Road and electrical service upgrades in the area. The number of customers supplied by this line has increased by 64% over the last 15 years.[8] Additional load growth in

---

7 To offload this single-phase section to be within Newfoundland Power's planning limits of 85 amps, a 4.9 MWh battery storage system would be required to provide sufficient on-peak capacity. The preliminary procurement cost of this solution is $2,092,000 based on current battery storage costs of $427/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. This does not include operating and maintenance costs.

8 There were 86 customers supplied by this section of line in 2008 and 141 customers in 2022, an increase of 55 customers (55 / 86 = 0.64, or 64%).

this area is expected to continue with a large amount of vacant land available for development and older homes completing electrical upgrades. Lots in the Groves Road area, extending along Pitcher's Path and Gillies Road, are typically oversized and developed with executive-style houses.

An analysis of distribution feeder OXP-01 was completed using CYME Power Engineering software and verified using actual load measurements. The analysis showed that the load on the identified single-phase section of the feeder is approximately 180 amps, which exceeds the Company's planning criteria for maximum current on a single-phase distribution line.[9]

Three categories of alternatives that are generally available to address overloaded conductor are not applicable to distribution feeder OXP-01. Feeder balancing is not applicable as the identified section of OXP-01 is single phase. A load transfer is not applicable as there is no adjacent feeder available. A new feeder build is not applicable due to the magnitude of the associated costs. As a result, the alternatives evaluated to mitigate the overloaded section of distribution feeder OXP-01 include: (i) upgrading the tap from single-phase to three-phase; (ii) upgrading the feeder by building a new three-phase section along Team Gushue Highway; and (iii) a non-wires alternative.

### *Alternative 1: Upgrade Single-Phase Section to Three-Phase 1/0 AASC*

This alternative would involve upgrading the overloaded 1.5-kilometre section of distribution feeder OXP-01 from single phase to three-phase 1/0 AASC conductor. The overloaded section of OXP-01 consists of substandard #4 Cu conductor and 23 deteriorated poles that require replacement. Upgrading the overloaded section of OXP-01 from single phase to three phase would address these deficiencies, which would otherwise require correction through the Company's capital maintenance program.

The capital cost of this alternative is $470,000 in 2024. This corresponds to $546,000 on a net present value basis.[10]

---

9 Newfoundland Power's planning criteria for maximum current on a single-phase distribution line is 85 amps.

10 Alternative 2 for OXP-01 includes multi-year expenditures. As a result, net present value analyses ("NPV") were completed to assess OXP-01 alternatives. The alternatives assessed for BVS-04 and PUL-02 included only single-year expenditures, and as a result, NPV analyses were not required for those feeder projects.

Figure 4 illustrates the work required for this alternative.

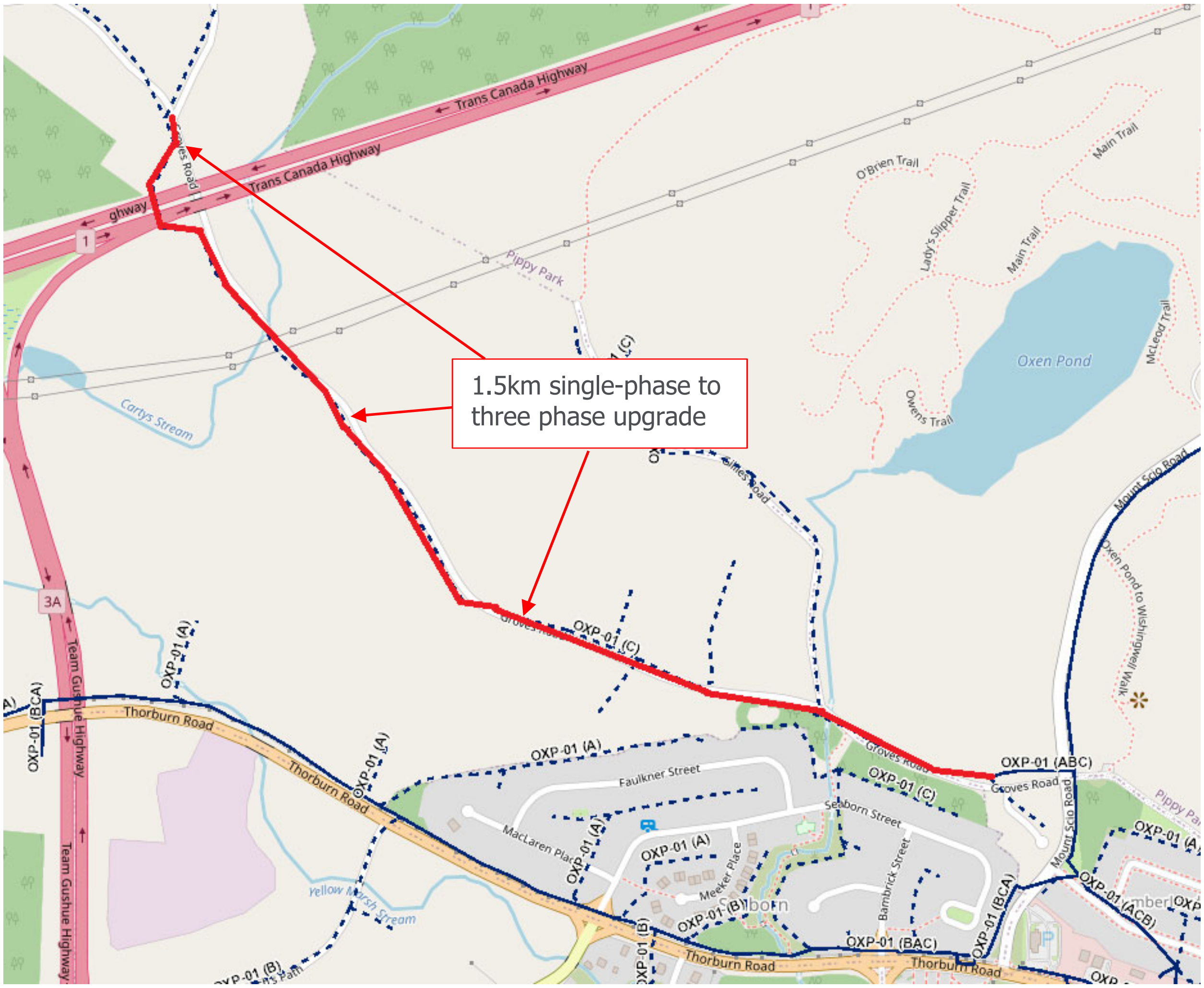



*Figure 4 – OXP-01 Upgrades Along Groves Road*

### *Alternative 2: Build New Three-Phase Section Along Team Gushue Highway*

This alternative would involve reducing the load on the single-phase section of distribution feeder OXP-01 along Groves Road by constructing a new section of three-phase line between Thorburn Road and Groves Road. The new section of line would run along the eastern side of the Team Gushue Highway and follow the offramp eastbound onto the TCH. An additional single-phase to three-phase upgrade would also be required to span across the TCH into Groves Road. Under this alternative, the replacement of substandard conductor and 23 deteriorated poles identified on the Groves Road section of distribution feeder OXP-01 would be deferred to 2025 when the feeder is scheduled for maintenance.

Capital costs associated with this alternative are estimated to be $401,000 in 2024 to construct a new three-phase section of distribution feeder and $120,000 in 2025 to correct identified deficiencies. This corresponds to a net present value of approximately $597,000.

Figure 5 illustrates the work that would be required under this alternative.


*Figure 5 – New Three-Phase Section of OXP-01 Along Team Gushue Highway*

### *Alternative 3: Non-Wires Alternative*

This alternative would utilize commercial-grade battery storage technology to provide four hours of on-peak capacity supply and eliminate the overload condition. Preliminary capital costs associated with the procurement of a battery storage solution for this application are estimated to be approximately $1.4 million.[11] This estimate does not include engineering, land

[11] The load on the single-phase section of OXP-01 is forecasted to reach 200 amps over the next 20 years. To offload this single-phase section to be within Newfoundland Power's planning limits of 85 amps, a 3.3 MWh battery storage system would be required to provide four hours of on-peak capacity. Based on current battery storage costs of $427/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 $1,409,000. This does not include operating and maintenance costs.

procurement, site preparation, battery system installation or interconnection to the distribution system. Under this alternative, the replacement of substandard conductor and 23 deteriorated poles identified on the Groves Road section of distribution feeder OXP-01 would be deferred to 2025 when the feeder is scheduled for maintenance.

### *Recommended Alternative*

The alternative of installing battery storage was eliminated from consideration due to its higher capital costs. Of the two remaining technically viable alternatives, upgrading the overloaded section of distribution feeder OXP-01 from single phase to three phase is least cost on a net present value basis. This alternative is therefore recommended to address the identified overload condition.

## 3.4 Distribution Feeder PUL-02 Upgrade

Distribution feeder PUL-02 leaves Pulpit Rock ("PUL") Substation and extends north along the Torbay Bypass Road. The distribution feeder serves approximately 1,900 residential and commercial customers in the Torbay, Flatrock and Pouch Cove areas.

Figure 6 illustrates the route of distribution feeder PUL-02.

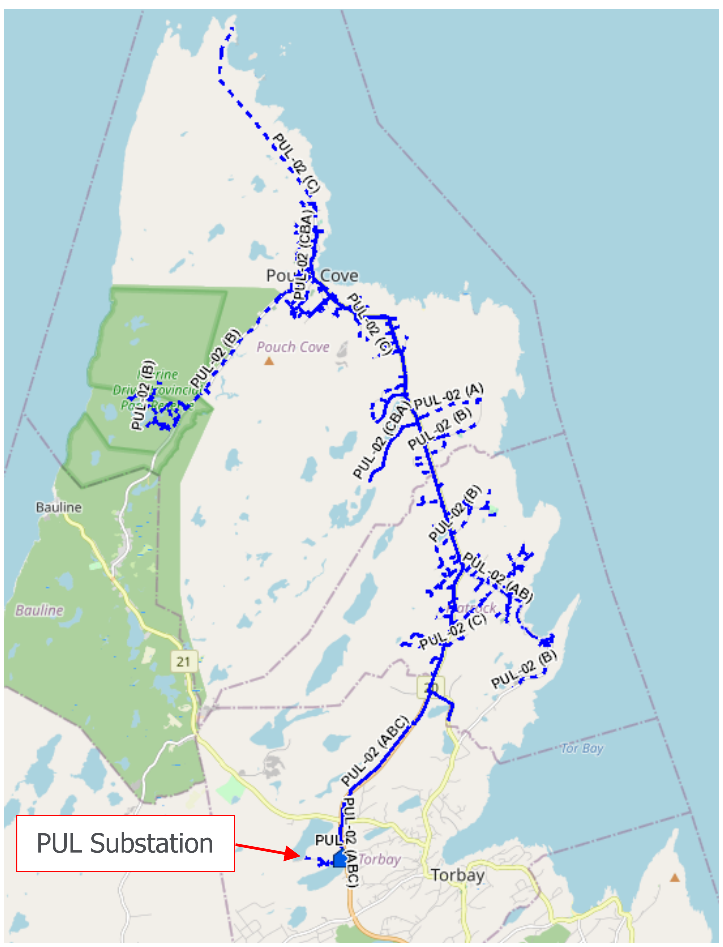



*Figure 6 – Distribution Feeder PUL-02*

A 2.5-kilometre section of single-phase distribution line is overloaded. This section of distribution line extends southwest from Main Road in Pouch Cove along Kirby's Lane and Pouch Cove Line. Load growth on this single-phase line is mainly attributed to customer connection growth, as well as electrical service upgrades in the area. The number of customers supplied by this line has increased by 112% over the last 15 years.[12]

An analysis of distribution feeder PUL-02 was completed using CYME Power Engineering software and verified using actual load measurements. The analysis showed that the load on the identified single-phase section of the feeder is approximately 132 amps, which exceeds the Company's planning criteria for maximum current on a single-phase distribution line.[13]

Two categories of alternatives that are generally available to address overloaded conductor are not applicable to distribtion feeder PUL-02. Feeder balancing is not applicable as the identified section of PUL-02 is single phase. A new feeder build is not applicable due to the magnitude of the associated costs. As a result, the alternatives evaluated to mitigate the overloaded section of distribution feeder PUL-02 include: (i) a load transfer; (ii) upgrading from single-phase to three-phase; and (iii) a non-wires alternative.

### *Alternative 1: Load Transfer to Distribution Feeder PUL-03*

This alternative would involve transferring load from distribution feeder PUL-02 to PUL-03. This would require reconductoring 7.8 kilometres of PUL-03 from single-phase to three-phase along Pouch Cove Line. In addition, a new 2.1-kilometre section of three-phase distribution line would be required to connect the overloaded section of distribution feeder PUL-02 to PUL-03. Costs associated with the work are estimated to be $1,270,000.

---

12 There were 73 customers supplied by this section of line in 2008 and 155 customers in 2022, an increase of 82 customers (82 / 73 = 1.123, or 112%).

13 Newfoundland Power's planning criteria for maximum current on a single-phase distribution line is 85 amps.

Figure 7 illustrates the work that would be required under this alternative.

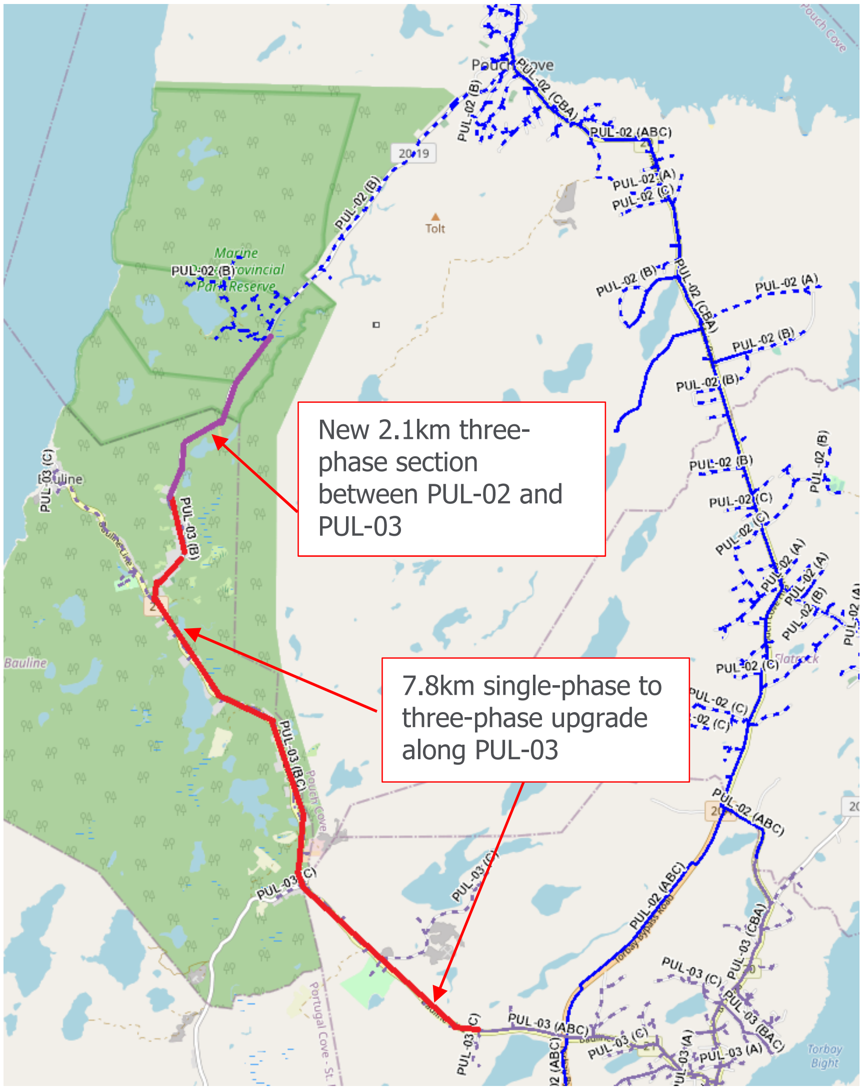



*Figure 7 – Distribution Feeder PUL-03 Upgrades Along Middle Cove Road and Marine Drive*

### *Alternative 2: Upgrade Single-Phase Section to Three-Phase 1/0 AASC*

This alternative would involve upgrading the 2.5-kilometre section of single-phase distribution line along Pouch Cove Line to three-phase 1/0 AASC conductor to resolve the overloaded conductor. The capital cost associated with this work is estimated to be $605,000.

Figure 8 illustrates the work that would be required under this alternative.

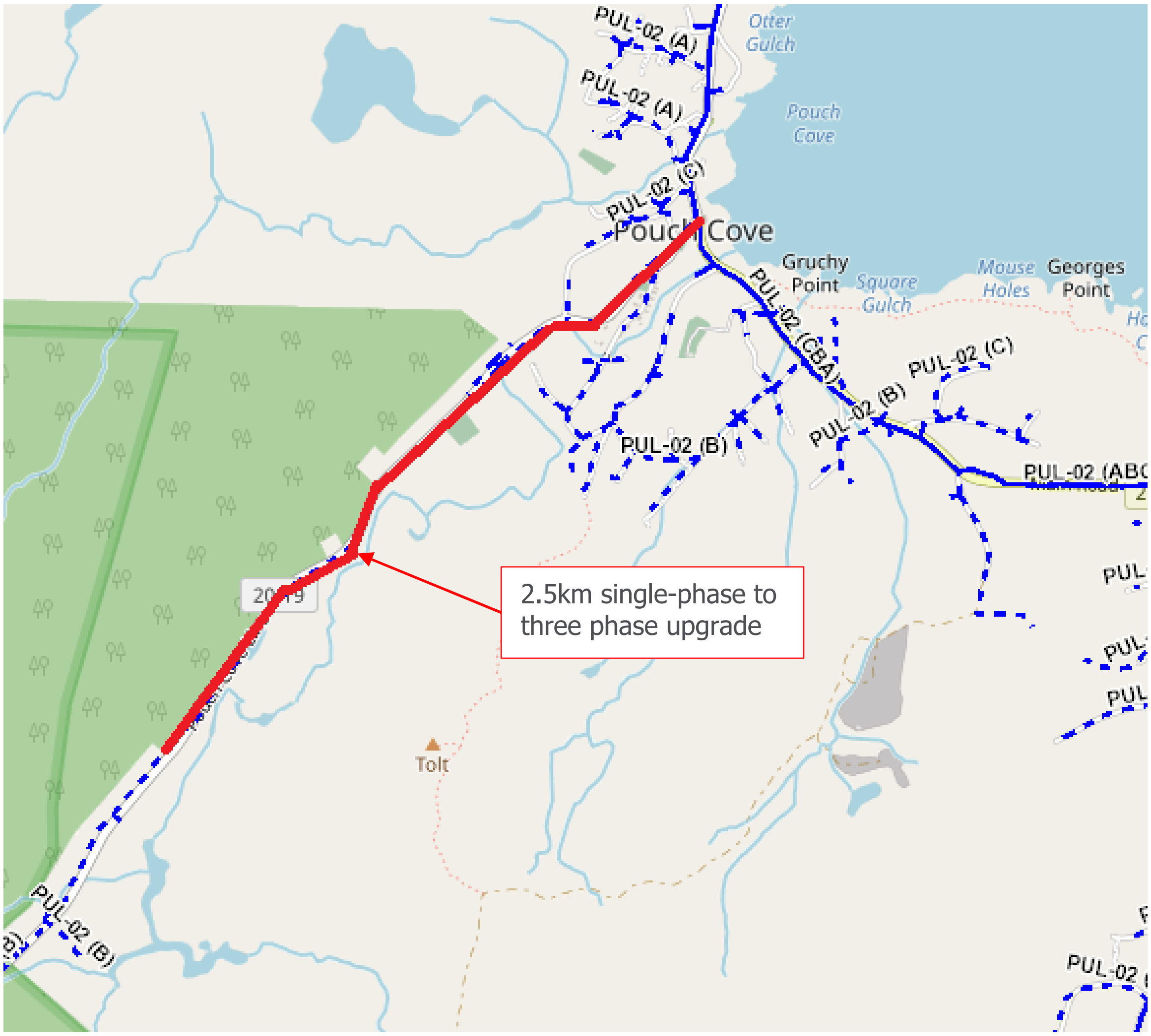



*Figure 8 – Distribution Feeder PUL-02 Upgrades Along Pouch Cove Line*

### *Alternative 3: Non-Wires Alternative*

This alternative would utilize commercial-grade battery storage technology to provide four hours of on-peak capacity to eliminate the overload condition. Preliminary capital cost estimates associated with the procurement of a battery storage solution for this application are approximately $922,000.[14] This estimate does not include engineering, land procurement, site preparation, battery system installation or interconnection to the distribution system.

[14] The load on the single-phase section of distribution feeder PUL-02 is forecasted to reach 160 amps over the next 20 years. To offload this single-phase section to be within Newfoundland Power's planning limits of 85 amps, a 2.16 MWh battery storage system would be required to provide four hours of on-peak capacity. Based on current battery storage costs of $427/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 $922,000. This does not include operating and maintenance costs.

***Recommended Alternative***

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

## 4.0 PROJECT COST

Table 1 provides the cost of the *Feeder Additions for Load Growth* project to address overload conditions on distribution feeders BVS-04, OXP-01 and PUL-02 in 2024.

Table 1
Feeder Additions for Load Growth Project
2024 Project Cost
($000s)

| Cost Category | BVS-04 | OXP-01 | PUL-02 | Total |
|---|---|---|---|---|
| Material | 232 | 148 | 160 | 540 |
| Labour – Internal | 420 | 144 | 189 | 753 |
| Labour - Contract | 340 | 157 | 228 | 725 |
| Engineering | 228 | 21 | 28 | 277 |
| Other | 516 | 0 | 0 | 516 |
| Total | 1,736 | 470 | 605 | 2,811 |

The total cost of the *Feeder Additions for Load Growth* project is $2,811,000 in 2024.

## 5.0 CONCLUSION

The *Feeder Additions for Load Growth* project for 2024 includes:

(i) Upgrading a 11-kilometre single-phase section of distribution feeder BVS-04 along the Trans Canada Highway in Corner Brook to three-phase 1/0 AASC;
(ii) Upgrading a 1.5-kilometre single-phase section of distribution feeder OXP-01 along Groves Road in St. John’s to three-phase 1/0 AASC; and
(iii) Upgrading a 2.5-kilometre single-phase section of distribution feeder PUL-02 along Pouch Cove Line in Pouch Cove to three-phase 1/0 AASC.

These upgrades are the least-cost solutions to address overload conditions resulting from customer growth in Corner Brook, St. John’s and Pouch Cove. Completing this work in 2024 will ensure the continued provision of safe and reliable service to customers in these areas.

# APPENDIX A:

## Distribution Planning Guidelines
## Conductor Ampacity Ratings

Table A-1
Aerial Conductor Ampacity Ratings

| Size and Type | Continuous Winter Rating[1] | 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.

NEWFOUNDLAND POWER
A FORTIS COMPANY

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
MICHAEL J.T. POWER
SIGNATURE
June 13, 2023
DATE
NEWFOUNDLAND & LABRADOR

# 2.1 2024 Substation Refurbishment and Modernization

## June 2023

Prepared by: Michael Power, P. Eng.

# TABLE OF CONTENTS

Page

## 1.0 INTRODUCTION

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") operates 131 substations located throughout its service territory. These include: (i) generation substations that connect generating plants to the electrical system; (ii) transmission substations that connect transmission lines of different voltages; and (iii) distribution substations that connect the low-voltage distribution system to the high-voltage transmission system.[1] The equipment in substations ensures the electrical system operates safely and at appropriate voltage levels.

Substation assets are critical to electrical system reliability. A single substation outage can result in a loss of service to thousands of customers. Because of the critical role they play in the electrical system, substations must be designed and maintained to provide a high degree of reliability.

Newfoundland Power introduced its *Substation Refurbishment and Modernization Plan* as part of its *2007 Capital Budget Application.*[2] The plan focuses on the refurbishment and modernization of individual substations based on the condition of core infrastructure and equipment.

In 2024, the Company is proposing to refurbish and modernize: (i) Gambo ("GAM") Substation in the town of Gambo at a cost of $5,267,000; (ii) Old Perlican ("OPL") Substation in the town of Old Perlican at a cost of $3,356,000; and (iii) Memorial University ("MUN") Substation in the City of St. John's at a cost of $4,351,000. In 2024, the Company is also proposing to commence a two-year project to refurbish and modernize Islington ("ISL") Substation in the town of Heart's Delight-Islington at a total cost of $5,014,000. All four of these substations contain a considerable amount of deteriorated and obsolete equipment that pose a risk to their reliable operation.

Due to supply chain constraints and procurement lead times for electrical equipment, Newfoundland Power will transition to multi-year substation refurbishment and modernization projects going forward. This will provide the ability to complete design, procurement, and contract approval in year one and construction and commissioning in a subsequent year. This transition will begin with ISL Substation, which will be a two-year project, as the substation requires a new power transformer that has a procurement lead time greater than one year. Over the next few years all refurbishment and modernization projects that require equipment having long procurement lead times will be completed as multi-year projects.[3]

This report provides an update on Newfoundland Power's *Substation Refurbishment and Modernization Plan* and the overall condition of substation assets, and details the four projects proposed as part of the *2024 Capital Budget Application* in the appendices that follow.

---

[1] Newfoundland Power's substations may serve multiple purposes and can be classified as any combination of the generation, transmission, and distribution functions.

[2] Newfoundland Power's *Substation Refurbishment and Modernization Plan* is an element of the *Substation Strategic Plan* filed with its *2007 Capital Budget Application*.

[3] Equipment with long procurement lead times used in refurbishment and modernization projects include power transformers, circuit breakers, reclosers, and steel bus structures.

# 2.0 BACKGROUND

## 2.1 Substation Refurbishment and Modernization Plan

Good utility practice involves a structured and comprehensive approach to preventative and corrective maintenance for critical substation assets. Maintenance programs are intended to keep critical assets in good working order, prolong their life and protect against in-service failures with significant consequences.

Newfoundland Power's substations are inspected eight times annually. These inspections identify preventative and corrective maintenance necessary to ensure the reliable operation of critical substation assets.

Inspection results are incorporated into the Company's annual update of its *Substation Refurbishment and Modernization Plan*. Under this plan, the maintenance cycle for major substation equipment is coordinated with the individual refurbishment and modernization projects. This coordination provides productivity and service benefits for customers.

Table 1 provides the latest update of the *Substation Refurbishment and Modernization Plan*.

Table 1
Substation Five-Year Forecast
2024 to 2028

| Substation Designations | Cost Estimates ($000s) | | | | |
|---|---|---|---|---|---|
| | 2024 | 2025 | 2026 | 2027 | 2028 |
| GAM | 5,267 | - | - | - | - |
| MUN | 4,351 | - | - | - | - |
| OPL | 3,356 | - | - | - | - |
| ISL | 308 | 4,706 | - | - | - |
| NWB | - | 3,801 | - | - | - |
| SMV | - | 4,132 | - | - | - |
| PHR | - | 336 | 5,136 | - | - |
| PJN | - | 163 | 2,491 | - | - |
| MISC | - | 1,375 | 1,575 | 1,650 | 1,700 |
| GPD | - | - | 2,259 | - | - |
| GFS | - | - | 625 | - | - |
| MOP | - | - | 1,872 | - | - |

| Table 1<br>Substation 5-Year Forecast<br>2024 to 2028<br>(Cont'd) | | | | | |
|---|---|---|---|---|---|
| Substation Designations | Cost Estimates ($000s) | | | | |
| | 2024 | 2025 | 2026 | 2027 | 2028 |
| GOU | - | - | 400 | 5,169 | - |
| FRN | - | - | 164 | 2,115 | - |
| LOK | - | - | 290 | 4,432 | - |
| LLK | - | - | - | 276 | 3,562 |
| BOY | - | - | - | 392 | 6,141 |
| LEW | - | - | - | 76 | 1,434 |
| TNS | - | - | - | - | 1,499 |
| SLA | - | - | - | - | 748 |
| HWD | - | - | - | - | 104† |
| BCV | - | - | - | - | 259† |
| HAR | - | - | - | - | 150† |
| TOTAL | $13,282 | $14,513 | $14,812 | $14,110 | $15,597 |

Note: SUB: See the Electrical System Handbook included with the *2006 Capital Budget Application* for three-letter substation designations.
MISC: Miscellaneous Substation Equipment Replacements
† Year one of multi-year projects in 2028 and 2029

Newfoundland Power's current plan includes the refurbishment and modernization of 22 substations over the next five years. The refurbishment and modernization plan reflects the age and condition of the Company's substation assets, as described below. Refurbishment and modernization projects will continue to focus on addressing obsolete and deteriorated equipment in individual substations.

## 2.2 Substation Asset Assessment

Substations include a combination of electrical system equipment, such as power transformers, reclosers and circuit breakers, and civil infrastructure, such as bus structures and buildings. The following section provides an update on the age and condition of substation equipment and infrastructure, including the strategy for addressing these assets during refurbishment and modernization projects.

Overall, the assessment shows that substation asset management practices have improved the age and risk profile of certain assets, such as reclosers and circuit breakers. The continued execution of the *Substation Refurbishment and Modernization Plan* is necessary to continue replacing obsolete and deteriorated substation equipment and infrastructure.

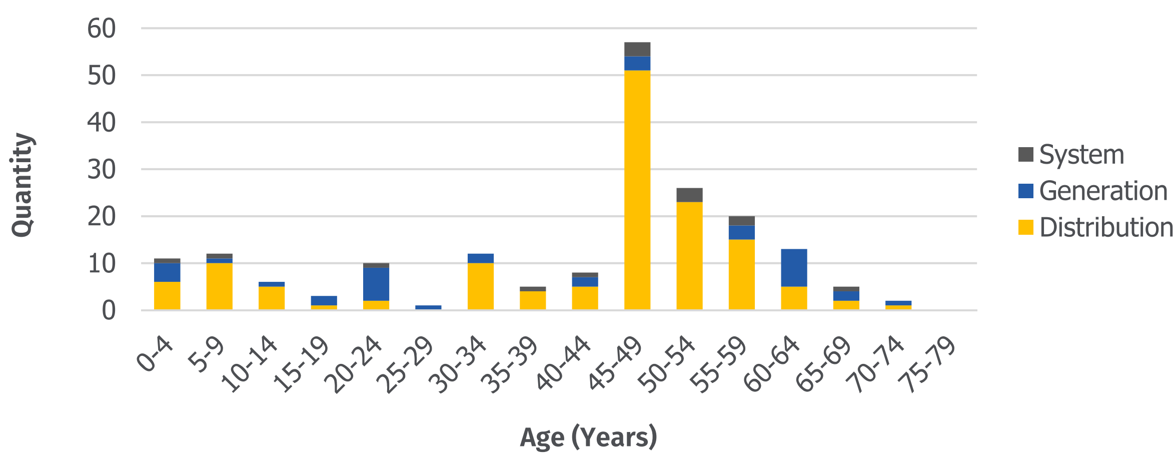
***Power Transformers***

Power transformers are the most critical assets in a substation and are used to change voltages for different applications. Newfoundland Power has 191 substation power transformers in service. The most common applications for power transformers include: (i) distribution power transformers which are used to change from transmission to distribution voltages, such as 66 kV to 12.5 kV; (ii) system power transformers which are used to change between transmission voltages, such as 138 kV to 66 kV; and (iii) generation transformers which are used to change generation voltages to transmission or distribution voltages.[4] Power transformer failures can lead to extended outages for a large number of customers.

According to industry experience, the expected life of a power transformer is between 30 and 50 years,[5] with a sharp decline for in-service power transformers past 70 years of age.[6] The load profile in Newfoundland and Labrador is favourable for transformer life expectancy, as the highest loads are experienced in the winter when ambient temperatures are the lowest.[7]

Figure 1 shows the age distribution of the Company's power transformers.

**Figure 1**
**Power Transformer Age Distribution**




---

4 Power transformers in hydro plants change from generation voltages from 2,400 volts and 6,900 volts to either distribution or transmission voltages.

5 Based on information published by the International Council on Large Electric Systems ("CIGRE"). CIGRE is an international association with an objective to develop and facilitate the exchange of engineering knowledge and information in the field of electric power systems. CIGRE published a report on asset management in 2013 titled *Asset Management Decision Making Using Different Risk Assessment Methodologies* (the "CIGRE Report"). Unless otherwise noted, information provided on industry experience regarding substation assets was based on the CIGRE Report.

6 Based on 2021 information available from the Electric Power Research Institute ("EPRI"). EPRI is an energy research and development organization. EPRI has a database of thousands of power transformers from its electric utility members, including Newfoundland Power.

7 The transformer temperature is influenced by the ambient temperature. The transformer temperature is one of the main factors affecting the winding insulation life of a transformer. Many transformer failures are a result of a breakdown of the winding insulation.

The useful service lives of Newfoundland Power's power transformers have historically exceeded what is typically seen in the industry, with 35% of the Company's transformer fleet at 50 years in service or older.

Given the age profile of the Company's transformer fleet, the probability of transformer failures will continue to increase as their condition degrades with age. The Company has had seven major power transformer failures in the past five years.[8]

Newfoundland Power will continue conducting regular inspections and oil sample analysis to gauge the internal health of transformers to determine when corrective maintenance is required.[9] Additionally, the Company will continue to monitor its spare power transformer inventory to manage risks associated with the increasing age of its transformer fleet and potential impacts on the provision of service to customers.[10] Power transformers will also be assessed and considered for replacement during refurbishment and modernization projects based on the estimated remaining useful life and timing of future replacement.

### *Circuit Breakers*

Circuit breakers are electrical system devices designed to safely protect, control, and isolate electrical equipment. Newfoundland Power has 362 high voltage circuit breakers in service.[11] Circuit breakers are critical components of the transmission and distribution system. The failure of a circuit breaker to operate when required increases the risk of damage to other assets, introduces safety concerns and increases the risk of customer outages.

The most common types of circuit breakers currently in service are the SF6 and vacuum types.[12] A majority of the SF6 type breakers were installed to replace older bulk-oil type breakers. There remains a number of older bulk-oil type breakers still in service.

Industry experience indicates the expected life of all types of circuit breakers is between 30 and 50 years. The Company's experience with vacuum and SF6 breakers is that they require replacement earlier than oil-filled breakers. Oil-filled breakers tended to remain in operation closer to 50 years, while it is anticipated that vacuum and SF6 breakers will likely have a useful life closer to 30 years.[13]

---

8 A major power transformer failure requires either transformer replacement, transportation off site for repairs, or removal from service for six months or longer. The seven major power transformers failures since 2018 include MUN-T2, BLK-T2, DUN-T1, SLA-T4, GBS-T1, BVA-T1, and PUL-T2.

9 Inspections also check for tank and cooler leaks, cooling fan and pump operation, operation of liquid and winding temperature equipment, oil level, tank pressure, breather operation and controls operation.

10 See the *2023 Capital Budget Application,* report *2.2 Substation Spare Transformer Inventory.*

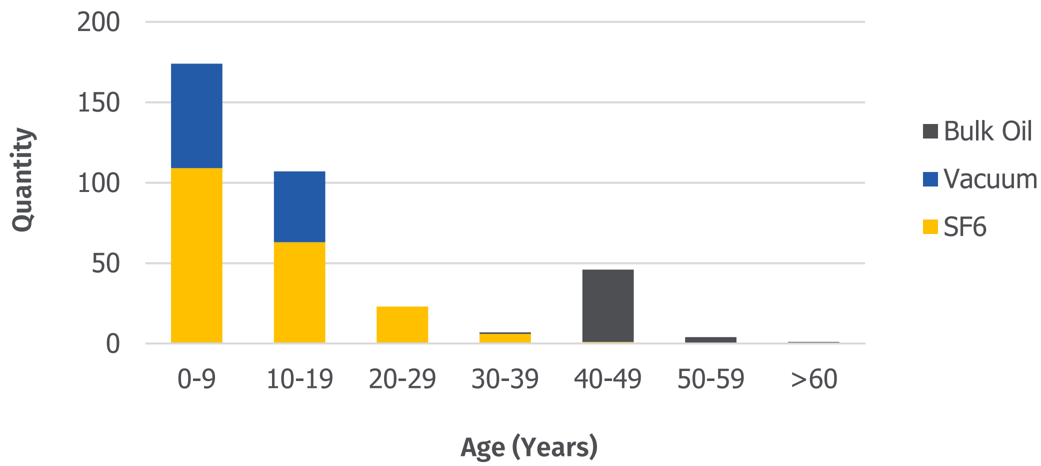
11 There are additional circuit breakers located in switchgear in the Company's substations and generation plants. This quantity of 362 breakers excludes switchgear circuit breakers.

12 Sulfur hexafluoride ("SF6") gas is used in high voltage circuit breaker design to extinguish the electrical arc created when opening energized breaker contacts.

13 The average age of failure for the Company's fleet of SF6 breakers is 25 years. The average age of failure for the Company's fleet of vacuum breakers is 18 years.

Figure 2 shows the age distribution of the Company's circuit breaker fleet.

**Figure 2**
**Circuit Breaker Age Distribution**




The age profile of Newfoundland Power's circuit breakers has been improved since 2007 as a result of the *Substation Refurbishment and Modernization*, *PCB Bushing Phase-out*, and *Replacements Due to In-Service Failures* projects and programs.

There are 202 SF6 type breakers in service. The majority of these breakers are less than 20 years old, with an average age of 11 years.

While the age of the Company's SF6 circuit breakers is generally favourable, certain models are experiencing operational issues. There were 44 Hyosung SF6 circuit breakers installed between 2008 and 2016.[14] These breakers have started to experience issues with excessive SF6 leaks, with nine of these units having gaskets replaced to address this issue.[15] These breakers are being monitored closely for further leakage issues and will be repaired as required. Additionally, there are two remaining Westinghouse and Siemens circuit breakers purchased in the 1980s that have historically been susceptible to SF6 leaks.[16] These breakers are replaced through *Substation Refurbishment and Modernization* projects and upon failure or imminent failure through *Replacements Due to In-Service Failures* projects.

---

14 There are 18 66 kV breakers and 26 138 kV breakers.

15 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.

16 Newfoundland Power installed 30 Westinghouse/Siemens SF6 circuit breakers between 1980 and 1990. A majority of these breakers have already been replaced. Repairs are often not possible with breakers of this vintage as spare parts are not available. The two remaining breakers are 34 and 42 years old and are at the end of their service life.

There are 51 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 47 years.

The bulk-oil type breakers that remain in service are approaching the end of their useful service life. GE KSO and GE FKP oil-filled breakers comprise 88% of those in service. GE KSO breakers were manufactured from 1976 to 1991, have an average age of 44 years and can no longer be economically maintained.[17] 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 250 and 12,500 liters of oil.

Currently, all new breakers being purchased are either SF6 or vacuum type, depending on the required voltage and fault interrupting capability.

### *Reclosers*

Reclosers are electrical safety devices designed to control, protect, and isolate electrical distribution equipment where low short circuit fault levels are present. Newfoundland Power has 177 substation reclosers in service.[18] Following the completion of the *Substation Feeder Automation* project in 2019, all in-service substation reclosers are either vacuum type or vacuum type insulated with SF6 gas manufactured by Nulec.[19]

Industry experience indicates the expected life of reclosers is between 30 and 50 years. This includes vintage hydraulic reclosers which tended to remain in operation in excess of 50 years. Based on the Company's experience, it is expected that the newer vintage reclosers will likely have a useful life more towards the lower end of this range.

---

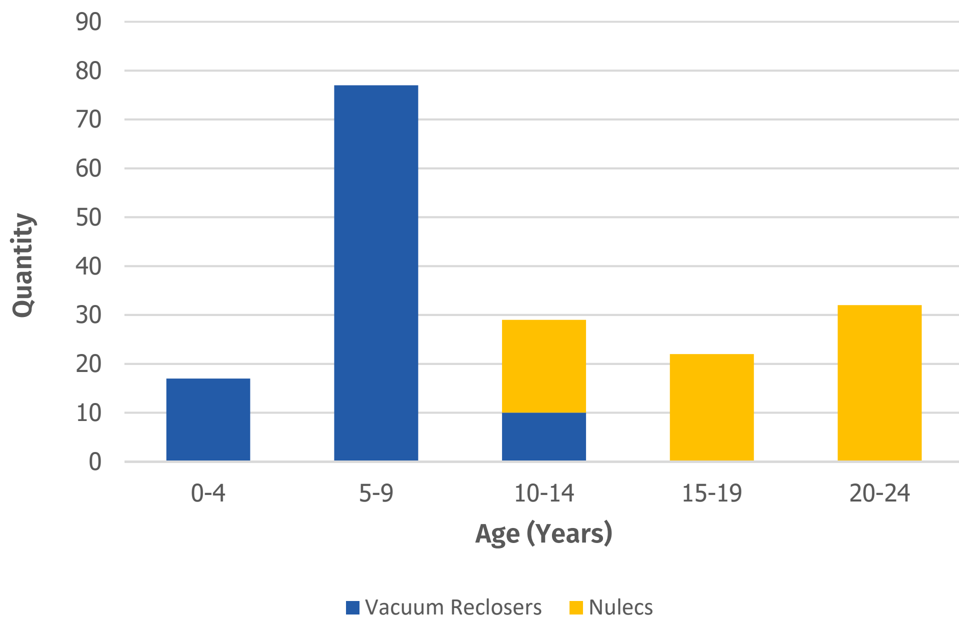
17 Newfoundland Power does not have adequate spare parts on hand and spare parts are not readily available. These circuit breakers are difficult to troubleshoot and the Company no longer has the expertise to maintain these units.

18 There are additional reclosers located on the Company's distribution feeders. This quantity of 177 reclosers excludes the downline reclosers installed on distribution feeders.

19 In 2015, as part of the *Substation Refurbishment and Modernization* project, the Company initiated a five-year *Substation Feeder Automation* program to modernize its substation reclosers by replacing vintage hydraulics reclosers with reclosers with automation capability.

Figure 3 shows the age distribution of the Company's substation recloser fleet.

**Figure 3**
**Recloser Age Distributon**




With the completion of the *Substation Feeder Automation* program in 2019, the age profile of the Company's substation reclosers is favourable.[20] All substation reclosers are currently less than 22 years old.

While the age profile of the Company's reclosers is favourable, some of the oldest reclosers in Newfoundland Power's system are no longer supported by the manufacturer and spare parts are no longer available. This includes 73 Nulec reclosers installed between 2001 to 2012 for distribution feeder protection.[21] Over the last five years, ten of these reclosers have required replacement. The failures experienced and the lack of manufacturer support of the Nulec reclosers indicate that they are reaching the end of their useful service life.[22]

---

20 Since the early 2000s, Newfoundland Power has been automating its distribution feeders to provide full remote monitoring and control from its Supervisory Control and Data Acquisition ("SCADA") system. In 2015, with approximately 60% of all distribution feeders already automated, the Company instituted a plan to complete the automation of substation reclosers and breakers on the remaining 40% of distribution feeders by the end of 2019.

21 Nulec was one of the first manufacturers of fully automated reclosers offering remote monitoring and control capability through utility SCADA systems. The remainder of the Company's reclosers were purchased since 2012 and were manufactured by either Thomas & Betts, G&W Viper, or Eaton Cooper.

22 The Nulec controller is the only digital relay for which Newfoundland Power cannot remotely access fault records using the Company's relay management system. Access to fault records is only available on site through the Nulec user interface.

### *Switchgear*

Switchgear is used in indoor applications and encloses circuit breakers which are electrical devices designed to safely control, protect, and isolate electrical equipment. Newfoundland Power has seven substations with ten distribution switchgear lineups.[23] The majority of this switchgear is operated at 12.5 kV distribution voltage; however, there are two locations with 4.16 kV switchgear.[24] The Company's substation switchgear consists of a total of 76 individual circuit breakers.[25]

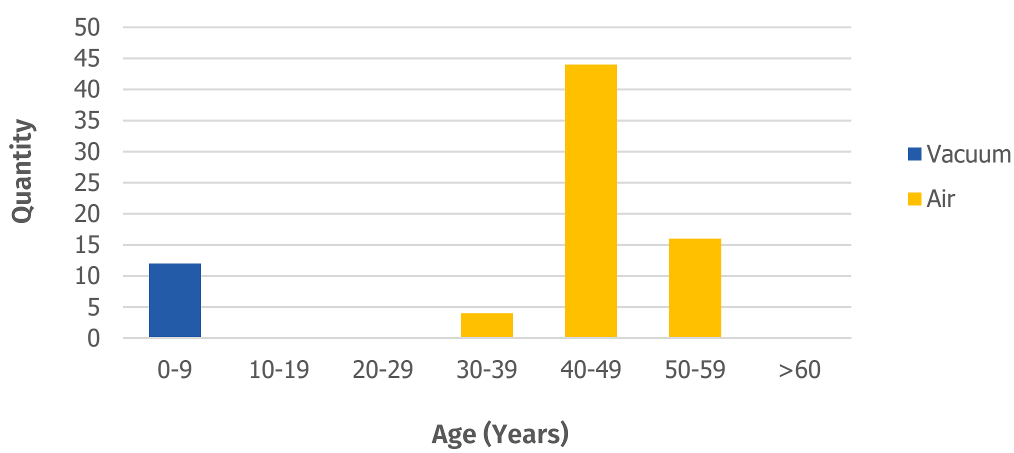
Switchgear circuit breakers are critical components of substation equipment. The failure of a circuit breaker to operate properly increases the risk of damage to other assets, introduces safety concerns, and increases the risk of customer outages.

Industry experience indicates the expected life of circuit breakers is 30 to 50 years.

The majority of Newfoundland Power's substation switchgear breakers were purchased in the 1960s and 1970s. Approximately 21% 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.

Figure 4 shows the age distribution of the Company's switchgear breakers.

**Figure 4**
**Substation Switchgear Breaker Age Distribution**




[23] There are also 27 switchgear lineups associated with the Company's generation plants.
[24] The only 4.16 kV distribution switchgear remaining in service are located at the Company's Grand Falls ("GFS") and Stamps Lane ("SLA") substations.
[25] The most common type of switchgear breakers currently in-service are air-blast circuit breakers.

All of the Company's 1960 and 1970 vintage substation switchgear is approaching the end of its service life. Support from the manufacturers has been discontinued and replacement parts are no longer available. This vintage of switchgear is not built to current standards necessary to mitigate arc flash hazards.[26] Arc flash technologies on newer switchgear mitigate the arc flash hazard to prevent injury to personnel and contain equipment damage.[27] Replacing end of life switchgear mitigates safety risks, equipment damage and supply interruptions impacting reliable service to customers.

### *Protection Relays*

Protective relaying in substations is used to protect transmission lines, substation equipment and distribution feeder circuits. Newfoundland Power currently uses electromechanical relays, digital relays and controllers to protect and control its substation equipment. Failure of protective relaying can result in widespread outages, cause significant equipment damage, and jeopardize the safe operation of the electrical system.

Vintage electromechanical relays were the original electrical protection used by Newfoundland Power. Electromechanical relays operate by using torque producing coils energized by current and voltage inputs, which open or close contacts based on mechanically calibrated thresholds. Electromechanical relays have moving parts that can fail as they age, wear, and accumulate dirt and dust. Electromechanical relays have become obsolete as digital relays have now become industry standard.

Starting in the early 2000s, Newfoundland Power began modernizing its protection devices by replacing electromechanical relays with digital relays and controllers.[28] Multiple electromechanical relays can be replaced by one digital relay as they can offer several protection elements in one device. This approach minimizes the number of active devices used to provide protection to substation assets. In addition, digital relays incorporate communications functionality to allow for remote interaction with the relay.[29]

Over the past 20 years, Newfoundland Power has upgraded most of the electromechanical protection devices. However, 9% of the protection devices currently in service are still electromechanical.

---

[26] Arc resistant switchgear relieves the pressure buildup from severe arcing and exhausts the rapidly expanding air away from operating personnel. Arc flash protective relays can detect the early stage of an arc's development and initiate instantaneous tripping of the associated breakers.

[27] The feeder protection and controls are typically installed on the front panel of the switchgear cubicles exposing personnel to potential arc flash hazards. The current standard is to install the protection and controls remote from the switchgear in a separate control room. This reduces the requirement for working in close physical proximity to the switchgear, which enhances safety for personnel in the event of an arc flash or other equipment failure.

[28] In its *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power,* December 17, 2014, The Liberty Consulting Group, examined Newfoundland Power's practice of replacing multiple obsolete electromechanical relays with a single modern microprocessor-controlled relay and concluded that the Company uses reasonable practices that conform to industry practice.

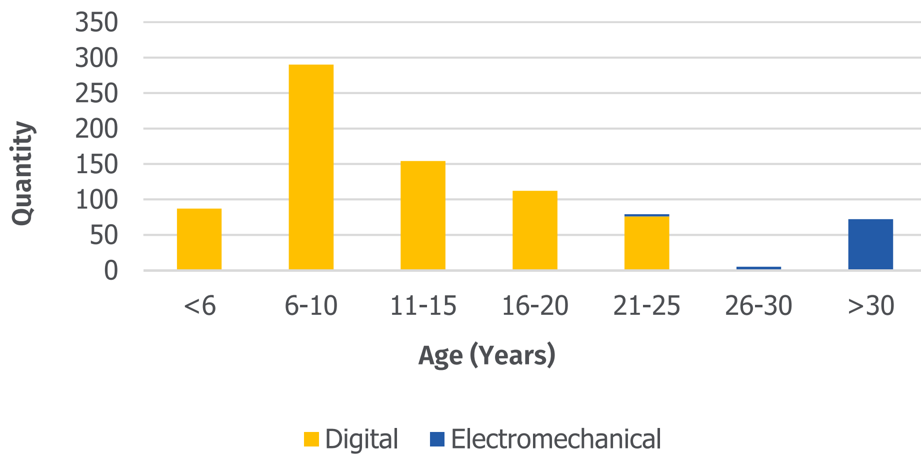
[29] Remote administration of upgraded devices allows protection relays to be interrogated and reconfigured remotely. This allows engineers to interrogate protection relays remotely, providing quicker diagnosis of system problems. Without this capability, engineers would have to travel to the substation to interrogate the relay on site, thereby increasing the time necessary to diagnose fault data and restore service to customers.

Industry experience indicates the expected useful service life is 20 to 30 years for electromechanical relays and 10 to 25 years for digital relays.

A majority of Newfoundland Power's electromechanical relays are over 30 years old, which is the upper limit of typical industry experience. The Company plans to continue replacing the remaining electromechanical relays with digital devices.

Figure 5 provides the age distribution of Newfoundland Power's electromechanical and digital relays.

**Figure 5**
**Electromechanical and Digital Relays Age Distribution**




Operating issues with the Company's older in-service digital relays have highlighted the need for asset replacement. For example, since 2015, 11 Micom P142 digital relays have failed in-service and required replacement.[30] There are a number of other in-service relays that will soon reach the end of the expected life for digital relays.[31]

### *High Voltage Switches*

Substation high voltage switches provide isolation for equipment such as power transformers, circuit breakers and reclosers.[32] Newfoundland Power has approximately 2,800 high voltage switches in service.

[30] There are currently 113 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 67% of the in-service Micom P142 devices.

[31] These include Micom P632, P442, P543, P941 and Schweitzer SEL-487B type relays.

[32] This includes switches of all high voltage classes including 12.5 kV, 25 kV, 66 kV, and 138 kV.

Switches that are operated infrequently tend to seize due to deterioration of bushings, corrosion in operating mechanisms or misalignment of blades. Substation switches such as transformer isolating and bus tie switches are operated infrequently. Consequently, they are susceptible to this form of failure.[33]

Over the life of a switch, its operation contributes to mechanical wear and tear experienced by items such as hinge bushings, Teflon bushing liners and springs used to assist movement. The result is typically misalignment of switch blades and contact surfaces, which causes heating, arcing and eventually switch failure. The Company's strategy for high voltage switches is to replace switches when they are more than 30 years old. Switches will also be assessed and considered for replacement during refurbishment and modernization projects if substation bus structure replacements or expansions are required.

### *High Voltage Fused Switches and High-Speed Ground Switches*

While digital protection relays are generally installed as today's industry standard for transformer protection, fuses are also used for transformer protection up to 10 MVA.[34] Fuses can economically protect small power transformers against primary and secondary faults; however, they provide limited protection against faults internal to the transformer. Generally, for transformers rated 10 MVA or higher, protection relays provide a higher degree of precision in the detection of internal faults.

Another method of providing transformer protection is to incorporate a high-speed ground switch for transformers up to 10 MVA.[35] The high-speed ground switch operates by providing a deliberate single-phase ground fault on the high voltage side of the power transformer.[36] This single-phase ground fault, in turn, is detected by the transmission line protection at the upstream substation. Relying on protection equipment at the upstream substation to detect faults at the downstream substation exposes the power transformer and low-voltage bus to increased fault levels for longer periods of time, which effectively reduces the life of the assets exposed to the fault.[37]

Newfoundland Power has 18 fuses installed for transformer protection on power transformers rated 10 MVA or higher, which is not industry standard. There are currently 11 high-speed ground switches in service being utilized for power transformer protection.[38]

[33] To help avoid switch issues resulting from infrequent use, the Company will operate and maintain these high voltage switches whenever opportunities and substation work permit.

[34] The IEEE Guide for Protecting Power Transformers ("IEEE C37.91") indicates that fuses can be used for protection on transformers rated less than 10 MVA.

[35] IEEE C37.91 also indicates that high-speed ground switches are generally used for protection on transformers operating at voltages less than 100 kV and on transformers rated less than 10 MVA.

[36] The operation of the switch is initiated by the transformer protection for a fault in the power transformer, on the low voltage bus, or on a distribution feeder where the fault is not cleared by the feeder recloser.

[37] The time for a high-speed ground switch to operate and the upstream circuit breaker to trip is slower than a standard circuit breaker operation.

[38] Eight of the 11 high-speed ground switches installed on the Company's transformers are operating at 138 kV or on transformers rated 10 MVA or higher, which does not conform with the recommendations of IEEE C37.91.

Proper transformer protection that conforms to current standards is required to safely and reliably operate the electrical system. Replacing fuses and high-speed ground switches with circuit breakers provides a standard form of transformer protection that conforms to current standards.[39] As part of *Substation Refurbishment and Modernization* projects, Newfoundland Power will replace fuses and high-speed ground switches with standard forms of protection for power transformers rated 10 MVA or higher.

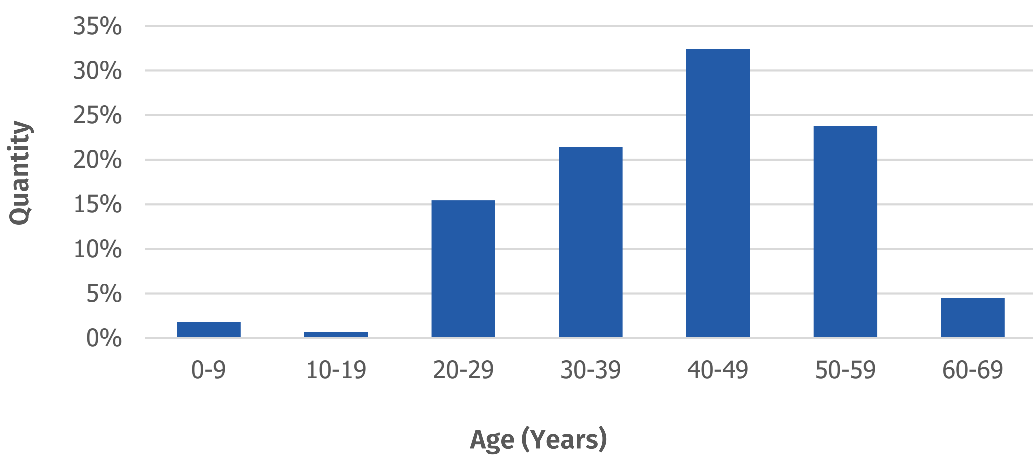
### *Bus Structures and Foundations*

Bus structures are galvanized steel or wood pole structures that support the switches, insulators, and conductors in a substation.[40]

Approximately 29% of the existing wooden bus structures are over 50 years of age. Wooden structures over 50 years of age show signs of deterioration such as decay, shell separation, splitting, checking, and cracking.[41] This deterioration compromises the strength of the wooden structures affecting their ability to support the weight of critical substation equipment and increasing the probability of failure. In addition, the deterioration leads to bending and movement in the wooden components affecting the alignment of equipment mounted on the bus structure. Depending on the degree of deterioration, the replacement of the bus structure may be required. Bus structures will also be assessed and considered for replacement during refurbishment and modernization projects based on the requirement to add additional equipment to the bus structure or substation reconfiguration requirements.

Figure 6 shows the age distribution of Newfoundland Power's Substation wooden poles that make up the bus structures.

**Figure 6**
**Bus Structure Wooden Poles Age Distribution**




---

39 Circuit breakers also provide the ability to remotely control the energization of the transformer through the Company's SCADA system.
40 Newfoundland Power has 113 wooden and 147 steel bus structures.
41 Deep splits and checks allow moisture and fungus to enter the pole past the treated outer layer and into the untreated center of the pole. Repeated freeze and thaw cycles exacerbate this problem by widening the split and checks, which can result in failure of the poles.

Steel structures are more physically stable than wood structures which move and twist over time. This makes steel structures better suited for mounting high voltage switches as they stay properly aligned, reducing maintenance, repair, and replacement of switches. Steel structures do not require guying. This decreases the overall dimensions of the substation compared to designs employing guyed wooden structures. The Company uses galvanized steel when replacing or installing new bus structures.[42]

Concrete foundations are used to support steel bus structures, breakers, and reclosers. Concrete foundations deteriorate over time. If left unchecked, the deterioration of concrete foundations and footings can jeopardize the structural stability of substation equipment. The Company repairs or replaces concrete foundations as required.

### *Spill Containments*

Spill containment structures are used to protect the environment from oil leaks and spills from oil filed substation equipment. IEEE Standard 980-2021 *Guide for Containment and Control of Oil Spills in Substations* recommends spill containment to prevent or mitigate the environmental impacts of an oil release or spill.[43] These impacts can range from the clean-up costs incidental to a spill, to the contamination of water supplies. Additionally, IEEE Standard 979-2012 *Guide for Substation Fire Protection* recommends spill containment to minimize the surface area of a spill, which provides fire protection benefits.[44]

Currently, 80 of the 191 in-service power transformers have spill containment installed. Newfoundland Power has 14 substations that contain voltage regulators and two of these currently have spill containment installed.

As part of *Substation Refurbishment and Modernization* projects, Newfoundland Power installs concrete containment foundations for power transformers and voltage regulators inside substations to manage the environmental risk from oil spills.[45]

### *Ground Grids*

A ground grid is a network of conductor and grounding electrodes embedded into the earth that connects to all major pieces of substation equipment. In accordance with *ANSI/IEEE Standard 80-2013 Guide for Safety in AC Substation Grounding*, the Company's substation ground grids are designed to:

(i) Provide a means to carry electric currents into the earth under normal and fault conditions without exceeding any operating and equipment limits or adversely affecting continuity of service.
(ii) Reduce the risk of a person in the vicinity of grounded facilities being exposed to the danger of electric shock or electrocution through step and touch potential.

---

42 See *Report 2.1 Substation Strategic Plan*, page 7, included with the *2007 Capital Budget Application*.
43 See https://standards.ieee.org/ieee/980/7038/.
44 See https://standards.ieee.org/ieee/979/3665/.
45 In February 2023, there was an incident where approximately 500L of oil was captured in a transformer spill containment, which prevented environmental contamination related to oil releasing from a power transformer.

Ground grid upgrades are completed in conjunction with *Substation Refurbishment and Modernization* projects and through the *Substation Ground Grid Upgrades* project.

Modifications include the addition of equipment bonding, grounding mats, below-grade copper wire, and ground wells as required to improve ground grid impedance. Grounding studies are necessary for each substation to design a proper ground grid that accounts for local site conditions. These studies include field testing and computer modeling to complete a step and touch potential analysis to identify the upgrades required.

### Control Buildings

Control buildings provide a weatherproof and temperature-controlled environment for auxiliary equipment such as protection relays, meters, battery systems, communication and control equipment, and AC and DC distribution panels for power substation equipment.

Small distribution substations with minimal auxiliary equipment may house the required auxiliary equipment in outdoor weatherproof cabinets.[46] Other substations that contain digital protection relays for circuit breakers and transformers require a control building to house the associated auxiliary equipment.[47]

Many of Newfoundland Power's existing control buildings are vintage pre-fabricated buildings which include metal roofs and exterior steel cladding. Maintenance and refurbishment of these pre-fabricated buildings is limited and would require adapting available construction materials to the pre-fabricated design. Newfoundland Power has standardized its control building design to wood frame construction on a concrete slab using standard construction materials such as metal siding and asphalt shingles. This design allows the control buildings to be easily built and maintained with materials readily available from local suppliers. Control buildings are assessed during refurbishment and modernization projects. Depending on the condition of the existing building and requirements to add additional auxiliary substation equipment, control buildings will be refurbished or replaced as required.

### Battery Banks and Chargers

Battery banks and chargers provide direct current ("DC") supply to protection and control devices inside substations. Battery banks are capacity tested every three years as part of a regular maintenance cycle. Battery banks that fail the capacity test are replaced the following year. Battery chargers are remotely monitored and trigger alarms when not operating properly. When an alarm investigation determines the charger has failed it is replaced immediately using a spare charger from inventory.

---

46 Small distribution substations may have a transformer protected by fuses, and feeder reclosers that have integrated protection cabinets. These substations would have minimal auxiliary equipment which could be housed in weatherproof cabinets.

47 Circuit breakers and power transformers will typically use digital protection relays to provide electric equipment protection at a substation. These substations would typically require a 125 VDC battery system, network and communication functionality, control switches, blocking switches, AC and DC distribution panels, and other auxiliary equipment. This amount of equipment is not feasible to be contained in outdoor enclosures. It is also difficult to operate and maintain devices in outdoor enclosures due to limited equipment accessibility and lack of protection from adverse weather conditions.

Batteries have a typical service life of between 10 and 20 years, and battery chargers have a typical service life of 20 years.

## 3.0 ASSESSMENT OF ALTERNATIVES

The age and condition of Newfoundland Power's substations shows that certain critical substation equipment and infrastructure is reaching the end of its useful service life and is prone to deterioration or obsolescence. Preventative and corrective maintenance continues to be required to address substation equipment and infrastructure that is deteriorated, obsolete and at imminent risk of failure.

There are generally two alternative approaches to addressing maintenance in substations:

**(i)** ***Alternative 1 – Component Replacement***

Alternative 1 focuses on the replacement of specific components at various substations throughout Newfoundland Power's service territory. This can include components that are identified as obsolete, failed or prone to failure based on operating experience. Under this alternative, work is prioritized based on the condition and criticality of a specific piece of equipment.

**(ii)** ***Alternative 2 – Refurbishment and Modernization***

Alternative 2 involves undertaking refurbishment and modernization projects at individual substations. This approach focuses on addressing a large number of deficiencies at individual substations that are identified as being in poor condition. Under this alternative, projects are prioritized based on the condition of individual substations where a large volume of work is required.

Both the component replacement and refurbishment and modernization approaches are viable alternatives to address maintenance requirements in substations.

In Newfoundland Power's experience, implementing a combination of these alternatives allows the Company to maintain the overall condition of its 131 substations.

For 2024, the Company has proposed five 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 during normal operations, which are generally not predictable. The *Substation Protection and Control Replacements* program replaces obsolete electromechanical protection relays with industry standard digital relays. This program allows the Company to focus on replacing a specific piece of equipment that is obsolete and poses a risk to the safe and reliable operation of the electrical system. The *Substation Ground Grid Upgrades* project ensures substation ground grids are compliant with industry standards. The *Oxen Pond Substation Switch Replacements* project will replace deteriorated switches at Oxen Pond Substation in coordination with bus conductor upgrades proposed in the *Oxen Pond Substation Bus Upgrade* project.

The *Substation Refurbishment and Modernization Plan* allows Newfoundland Power to focus on the condition of individual substations. Refurbishment and modernization projects are proposed when an individual substation contains a material amount of aged, deteriorated and obsolete equipment.

The continued implementation of the *Substation Refurbishment and Modernization Plan* provides productivity and service benefits for customers. Under this plan, individual refurbishment and modernization projects are coordinated with the maintenance cycle for major substation equipment. Coordinating a large volume of work required at a specific substation increases efficiency by reducing supervisory requirements, travel time, accommodation expenses and overhead expenses associated with job safety planning and environmental management planning. In addition, conducting work on critical equipment generally requires a substation to be removed from service. The approach outlined in this plan reduces requirements for customer outages and optimizes the deployment of portable substations required to maintain service to customers.

Newfoundland Power's substation asset management practices were reviewed by the Board of Commissioners of Public Utilities' (the "Board") consultant, The Liberty Consulting Group, in 2014 and were found to be consistent with good utility practice.[48]

## 4.0 PROJECT SCOPE AND COST

### 4.1 Gambo Substation Refurbishment and Modernization

GAM Substation was constructed in 1966 and serves approximately 1,370 customers in the Gambo area as a transmission and distribution substation. GAM Substation also serves approximately 3,500 customers from Hare Bay to Lumsden supplied by radial Transmission Line 115L from GAM Substation.

An engineering assessment of the substation shows that it contains a significant amount of deteriorated and obsolete equipment.

Appendix A provides the detailed engineering assessment and scope for the *Gambo Substation Refurbishment and Modernization* project.

48 Conclusion 3.6 of The Liberty Consulting Group's *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power,* December 17, 2014, stated that: *"Newfoundland Power's substation inspection, corrective maintenance, and preventive maintenance practices are consistent with good utility practices."*

Table 2 provides a detailed breakdown of the *Gambo Substation Refurbishment and Modernization* project for 2024.

Table 2
Gambo Substation
Refurbishment and Modernization Project
2024 Project Cost
($000s)

| Cost Category | ($000s) |
|---|---|
| Material | 3,754 |
| Labour – Internal | 299 |
| Labour – Contract | 0 |
| Engineering | 563 |
| Other | 651 |
| Total | $5,267 |

The project to refurbish and modernize GAM Substation is estimated to cost $5,267,000 in 2024.

### 4.2 Old Perlican Substation Refurbishment and Modernization

OPL Substation was constructed in 1975 as a transmission and distribution substation. The substation is supplied by Newfoundland Power 66 kV radial Transmission Line 65L from New Chelsea Substation. OPL Substation serves approximately 1,770 customers in the Old Perlican, Bay de Verde, and Lower Island Cove area.

An engineering assessment of the substation shows that it contains a significant amount of deteriorated and obsolete equipment.

Appendix B provides the detailed engineering assessment and scope for the *Old Perlican Substation Refurbishment and Modernization* project.

Table 3 provides a detailed breakdown of the *Old Perlican Substation Refurbishment and Modernization* project for 2024.

| Table 3<br>Old Perlican Substation<br>Refurbishment and Modernization Project<br>2024 Project Cost<br>($000s) | |
|---|---|
| Cost Category | ($000s) |
| Material | 2,143 |
| Labour – Internal | 190 |
| Labour – Contract | 0 |
| Engineering | 555 |
| Other | 468 |
| Total | $3,356 |

The project to refurbish and modernize OPL Substation is estimated to cost $3,356,000 in 2024.

### 4.3 Memorial Substation Refurbishment and Modernization

MUN Substation was constructed in 1966 and supplies the St. John's campus including the Health Science Centre, the Janeway Children's Health and Rehabilitation Centre, and other buildings on the north side of campus.

An engineering assessment has determined the substation contains a significant amount of deteriorated and obsolete equipment.

Appendix C provides the detailed engineering assessment and scope for the *Memorial Substation Refurbishment and Modernization* project.

Table 4 provides a detailed breakdown of the *Memorial Substation Refurbishment and Modernization* project for 2024.

| Table 4<br>MUN Substation<br>Refurbishment and Modernization Project<br>2024 Project Cost<br>($000s) | |
|---|---|
| Cost Category | ($000s) |
| Material | 2,879 |
| Labour – Internal | 169 |
| Labour – Contract | 0 |
| Engineering | 607 |
| Other | 696 |
| Total | $4,351 |

The project to refurbish and modernize MUN Substation is estimated to cost $4,351,000 in 2024.

## 4.4 Islington Substation Refurbishment and Modernization

ISL Substation was constructed in 1974 and serves approximately 1,060 distribution customers in the Islington area. ISL Substation is connected to New Harbour ("NHR") Substation through Transmission Line 80L. Outages on ISL Substation high voltage bus could also affect the approximately 1,760 distribution customers served by NHR Substation.

An engineering assessment of the substation shows that it contains a significant amount of deteriorated and obsolete equipment.

Appendix D provides the detailed condition assessment and scope for the *Islington Substation Refurbishment and Modernization* project.

Table 7 provides a detailed breakdown of the *Islington Substation Refurbishment and Modernization* multi-year project.

Table 7
Islington Substation Refurbishment and Modernization Project
Project Cost Estimate
($000s)

| Cost Category | 2024 | 2025 | Total |
|---|---|---|---|
| Material | 60 | 3,620 | 3,680 |
| Labour - Internal | - | 193 | 193 |
| Labour - Contract | - | - | - |
| Engineering | 241 | 350 | 591 |
| Other | 7 | 543 | 550 |
| Total | $308 | $4,706 | $5,014 |

The project to refurbish and modernize ISL Substation is estimated to cost $308,000 in 2024 and $4,706,000 in 2025 for a total project cost of $5,014,000.

## 5.0 CONCLUSION

The implementation of Newfoundland Power's *Substation Refurbishment and Modernization Plan* continues to be appropriate given the age and condition of the Company's substation assets. Implementing this plan allows the Company to maintain the overall condition of its substation assets in a manner that provides efficiency and service benefits for customers.

For 2024, Newfoundland Power is proposing to refurbish and modernize GAM, MUN, OPL and ISL substations.[49] These substations contain a significant amount of deteriorated and obsolete equipment. Refurbishing and modernizing these substations will ensure the continued provision of safe and reliable service to approximately 9,500 customers supplied by GAM, OPL and ISL substations, along with Memorial University's St. John's campus.

49 The refurbishment of ISL Substation is a two-year project commencing in 2024.

# APPENDIX A:

## Gambo Substation Refurbishment and Modernization

# TABLE OF CONTENTS

**Page**

## 1.0 GAMBO SUBSTATION

Gambo ("GAM") Substation was constructed in 1966 as a transmission and distribution substation. The substation is supplied by Newfoundland Power 138 kV Transmission Line 121L from Glovertown ("GLV") Substation and Transmission Line 146L from Gander ("GAN") Substation. One 6.67 MVA distribution power transformer, GAM-T1, supplies two 25 kV distribution feeders, serving approximately 1,370 customers in the Gambo area. One 41.6 MVA system power transformer, GAM-T2, converts 138 kV to 66 kV for Transmission Line 115L which feeds four substations including Hare Bay ("HBS"), Trinity ("TRN"), Greenspond ("GPD"), and Wesleyville ("WES") substations. There are approximately 3,500 customers fed from these substations which are supplied from radial Transmission Line 115L from GAM Substation.

Figure A-1 shows GAM Substation.

*Figure A-1 - GAM Substation*

## 2.0 ENGINEERING ASSESSMENT

### 2.1 138 kV Infrastructure

The 138 kV infrastructure comprises two bus structures, one constructed from wood and the other constructed using steel. The 138 kV wood pole structures are original to the substation and support various 138 kV equipment. A 138 kV steel structure was added to the substation in 1980 to support transmission line breakers and switches.

In 2022, an inspection and engineering assessment on the 138 kV wood pole structure was completed. The inspection identified that the wood poles and crossarms have deep splits and checks, decay, and woodpecker holes. The wood pole structure is deteriorated to the point where replacement is required.

Figures A-2 and A-3 show examples of the deteriorated wood structures.

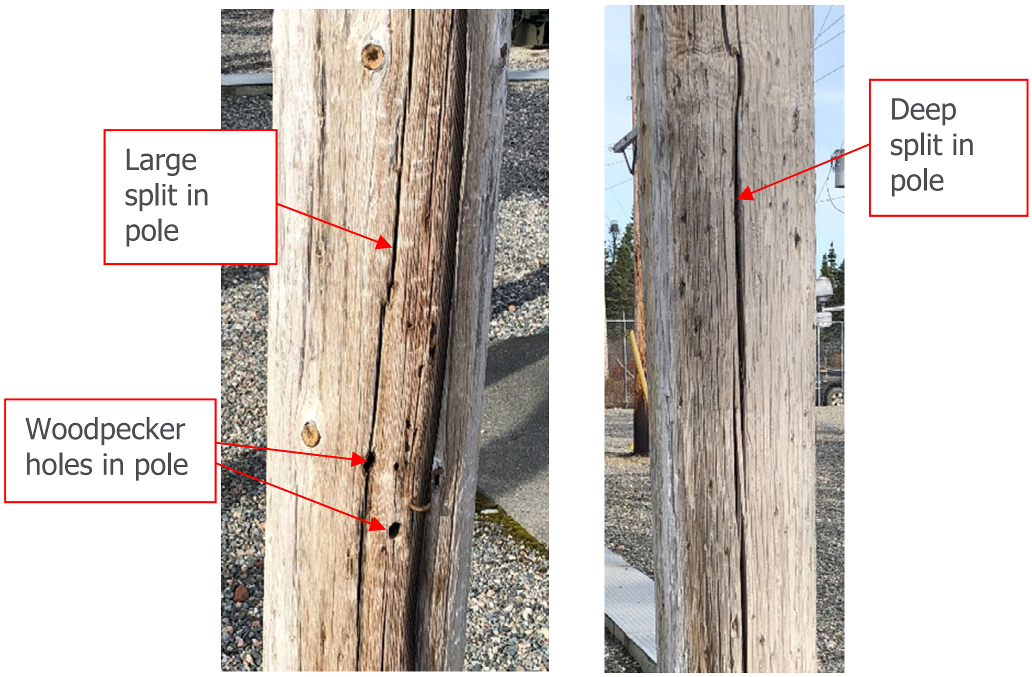



*Figure A-2 - Deteriorated Wood Poles*

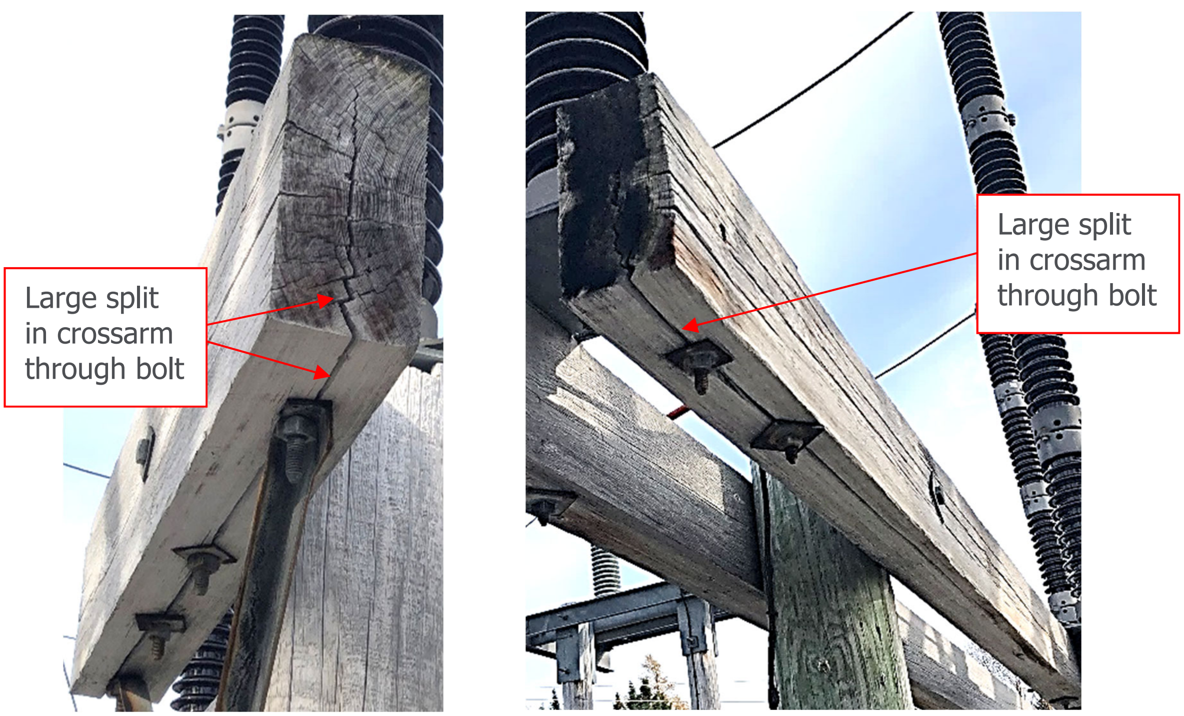



*Figure A-3 - Deteriorated Wood Crossarms*

The 138 kV wood pole structures will no longer be required since all 138 kV equipment can be installed on the existing 138 kV steel structures by adding two new steel girders.

The engineering assessment determined that the 138 kV steel structures and insulators are in good condition. Four of the six concrete pier foundations are deteriorated and require refurbishment.

Figure A-4 shows an example of a deteriorated 138 kV concrete pier foundation.

*Figure A-4 - Deteriorated 138 kV Concrete Pier Foundation*

The 138 kV switches are in excess of 45 years in service and are deteriorated. These switches require replacement as a result of their mechanical operating condition and corrosion. This includes four side break switches and four air break switches. The transformer air break switches are also deteriorated and will be replaced with new motorized air break switches.[1]

GAM Substation is designed such that, if a fault occurs in the substation, there will be an outage to approximately 1,370 customers in the Gambo area as well as approximately 3,500 customers from Hare Bay to Lumsden. The current protection scheme has an insufficient number of circuit breakers to isolate faults to minimize customer outages.

A new 138 kV circuit breaker with two side break switches will be installed as a tie-breaker between the 121L and 146L transmission line buses. The installation of a tie-breaker,

1 The motorized air break switches in conjunction with the upgraded protection relays will improve equipment protection. A motor operator allows the switch to be opened or closed remotely.

controlled by new bus and transformer protection relays, will improve automation and reduces substation and transmission outages for customers served by GAM Substation and radial Transmission Line 115L.[2]

A single-line diagram of the proposed 138 kV infrastructure including the installation of tie-breaker B1/B2-B is shown in Figure A-5.

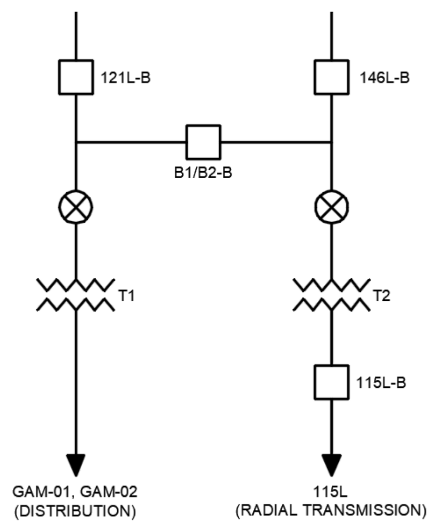



*Figure A-5 - GAM Conceptual Layout Diagram*

The 121L transmission line circuit breaker, GAM-121-B, is a 138 kV SF6 breaker that was installed in 2023 following the failure of the previously existing oil filled General Electric KSO breaker that was 45 years old at time of failure. The existing 146L transmission line circuit breaker, GAM-146L-B, is also a General Electric KSO breaker. This circuit breaker is currently 45 years old and is the same model as the GAM-121L-B breaker that recently failed.[3] These circuit breakers also present an environmental concern as they hold 12,500 liters of insulating oil. Adequate spare parts are not available for GAM-146L-B and it is at the end of its useful service life. The breaker will be replaced with a SF6 breaker which is the Company's standard for 138 kV breakers.

Two of the three existing 138 kV potential transformers mounted on the 138 kV bus structure are deteriorated and require replacement. An additional 138 kV potential transformer is required for the protection and control of the new 138 kV bus-tie breaker.

2 The installation of the tie-breaker allows GAM distribution customers to remain fed from GAM-T1 in the event of a fault on GAM-T2. Likewise, the tie-breaker allows radial Transmission Line 115L to remain fed from GAM-T2 in the event of a fault on GAM-T1.

3 The average service life prior to replacement for a 138 kV General Electric KSO oil filled breaker within the Company's fleet is 37 years.

## 2.2 66 kV Infrastructure

The 66 kV wood pole structure was installed in 1974. An inspection and engineering assessment was completed in 2022. The inspection determined that the wood poles are deteriorated to the point where replacement is required. The wood poles have splits and checks, decay, and shell separation. The crossarms are exhibiting various degrees of deterioration, including splits and decay. The deteriorated condition of the wood pole structure compromises its ability to support the weight of critical substation equipment such as switches and potential transformers, increasing the probability of failure. The wood pole structure will be removed and replaced with a new galvanized steel structure.

Figures A-6 and A-7 show the deteriorated wood structures.


*Figure A-6 - Deteriorated Wood Poles*

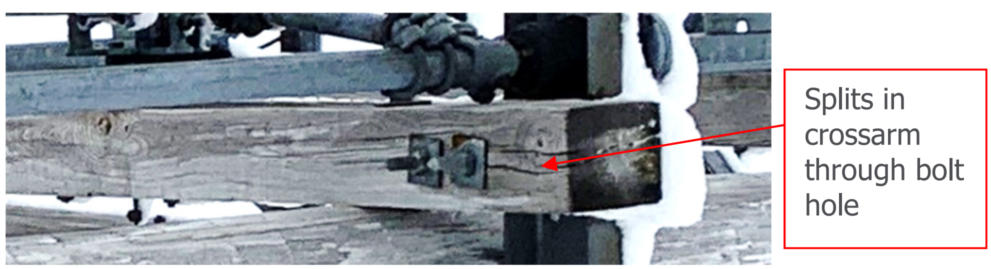



*Figure A-7 - Deteriorated Wood Crossarms*

The concrete foundation for the 66 kV breaker is deteriorated. The concrete is breaking apart on the sides of the foundation which has compromised its structural integrity. Figure A-8 shows the deteriorated 66 kV breaker concrete foundation.

*Figure A-8 - Deteriorated 66 kV Breaker Foundation*

The 66 kV switches are 49 years in service and are deteriorated. These switches, including two side break switches and one air break switch, require replacement as a result of their mechanical operating condition and corrosion.

The 115L transmission line circuit breaker is a 66 kV oil filled breaker. This breaker is currently 50 years old and is at the end of its service life.[4] The breaker will be replaced with a SF6 breaker which is the Company's standard for 66 kV breakers.

All three existing 66 kV potential transformers mounted on the 66 kV bus structure are deteriorated and require replacement.

## 2.3 25 kV Infrastructure

The 25 kV wood pole structures were installed in 1972. An inspection and engineering assessment was completed in 2022. The inspection determined that the wood poles and wooden crossarms are deteriorated to the point where replacement is required. The wood poles and crossarms have deep splits, checks, and decay. The deteriorated condition of the wood pole structure compromises its ability to support the weight of critical substation equipment such as switches and potential transformers, increasing the probability of failure. The wood pole structure will be removed and replaced with a new galvanized steel structure.

[4] 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. These breakers are also an environmental concern as they hold 1,340 liters of oil. Replacing this breaker will reduce the risk of the release of oil into the environment.

Figures A-9 and A-10 show examples of the deteriorated wood structures.

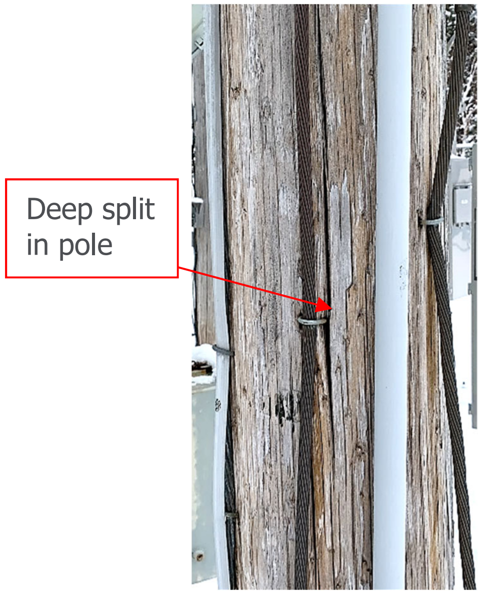



*Figure A-9 - Deteriorated Wood Poles*

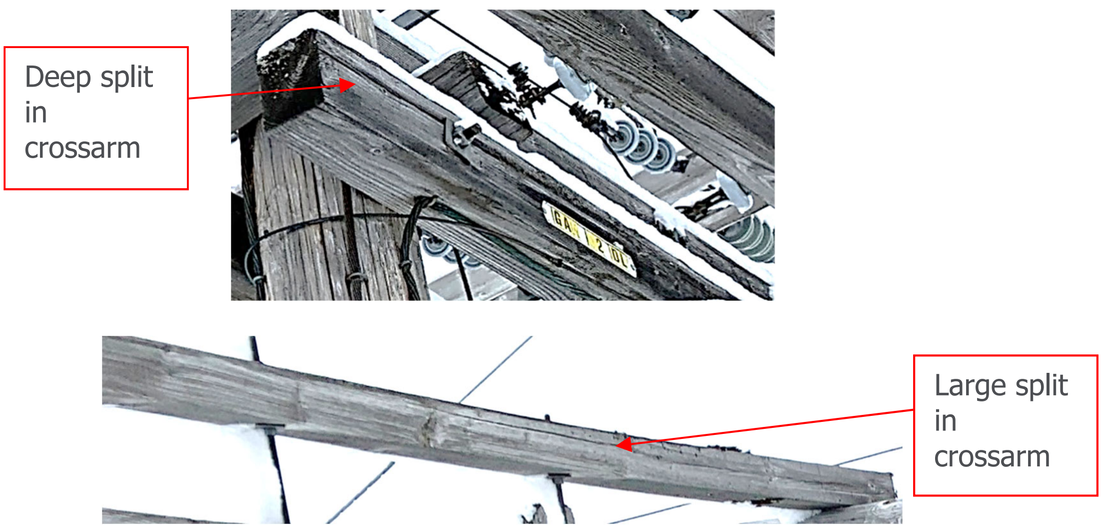



*Figure A-10 - Deteriorated Wood Crossarms*

The 25 kV switches are in excess of 40 years in service. These switches require replacement as a result of their mechanical operating condition and corrosion. This includes one air break switch and four sets of hook stick operated switches.

The GAM Substation voltage regulators manufactured by McGraw Edison in 1991 are in good condition and will remain in service. The oil-filled voltage regulators currently lack spill containment.[5] A spill containment foundation is required to protect against environmental damage in the event of an oil spill from either of the three units.

The oil-filled metering tank is currently 34 years old and is at the end of its service life. This will be replaced with a combined dry-type current and potential transformer.

The two 25 kV reclosers protecting distribution feeders GAM-01 and GAM-02 are in good condition and will be reinstalled to the new 25 kV steel bus structure.

## 2.4 Power Transformers

Distribution power transformer GAM-T1 is a 138 kV to 12.5/25 kV, 6.67 MVA rated unit that was manufactured by Moloney Electric in 1972. System power transformer GAM-T2 is a 138 kV to 66 kV, 41.6 MVA rated unit that was manufactured by Westinghouse in 1976.

Figures A-11 and A-12 show GAM-T1 and GAM-T2.

*Figure A-11 - GAM-T1*

*Figure A-12 - GAM-T2*

Both power transformers are in good overall condition and oil test results show no indication of abnormal internal conditions. As a result, both transformers are not identified for replacement at this time. The concrete foundation on GAM-T2 is deteriorated as shown in Figure A-13.

[5] The GAM Substation voltage regulator bank contains a total oil volume of approximately 1,500 liters.

*Figure A-13 - GAM-T2 Deteriorated Concrete Foundation*

Both transformers lack a spill containment foundation. New spill containment foundations are required for transformers GAM-T1 and GAM-T2 to protect against environmental damage in the event of an oil spill from the units.[6]

## 2.5 Protection and Control

The bus and transformer protection relays for GAM-T1 and GAM-T2 are vintage electromechanical type relays that were installed in 1977. The protection system for the 138 kV bus and transformers is comprised of 13 individual electromechanical relays installed in two separate protection panels inside the substation control building. These electromechanical relays are no longer industry standard and are at end of life.

[6] Power transformer GAM-T1 contains approximately 9,000 liters of oil and power transformer GAM-T2 contains 32,000 liters of oil.

Figure A-14 shows the protection equipment for the 138 kV bus and transformers GAM-T1 and GAM-T2.

*Figure A-14 - 138 kV Bus, GAM-T1 and GAM-T2 Protection Equipment*

The protection and control of the substation assets require modernization by replacing the obsolete electromechanical relays with microprocessor-based digital relays. This reduces the total protection relay device count for the 138 kV bus and both transformers from 13 individual electromechanical relays to two digital relays.[7]

[7] 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.

## 2.6 Control Building

The existing control building at GAM Substation was built in 1978. The control building currently houses the substation's communications, protection and control equipment.

The control building is a pre-fabricated building with a metal roof and siding. The roof leaked in 2022 which caused water damage to the building interior. The roof was repaired to temporarily stop the leak. However, the roof requires replacement. Asbestos is also present in some of the interior construction materials.

Figures A-15 and A-16 show the GAM Substation control building.

*Figure A-15 - GAM Substation Building*

*Figure A-16 - GAM Substation Building Water Damage*

Space is limited in the existing control building. The necessity of keeping the existing protection and control equipment in service during refurbishment will therefore add substantial engineering and construction complexity to the work.[8]

Due to the pre-fabricated design, the deteriorated condition and space limitations with the existing control building, it will be replaced with a new building.

[8] The protection of the substation equipment must be maintained while the substation is undergoing refurbishment and modernization. The new protection and control equipment will need to be installed in their permanent panels inside the existing control building. The existing protection and control equipment will have to be relocated to temporary panels that will be removed when the new equipment is installed. Transferring substation protection between the existing, temporary and new panels is a complicated process involving multiple commissioning sessions.

### 2.7 Site Condition

The substation yard will require an extension to accommodate the increased footprint requirements of the refurbishment and modernization project. A yard extension is necessary to allow the installation of a portable substation within the substation footprint while maintaining required clearances from energized equipment during construction activities. Minor improvements to the site such as addressing drainage requirements, removing unsuitable soils and vegetation, and laying structural fill will also be completed.

The existing ground grid at GAM Substation has deficiencies that pose a risk to the safe and reliable operation of the electric equipment in the substation. There are sections of the yard with insufficient grounding and there are also missing connections between the main ground grid and the substation fence. A grounding study is necessary and the ground grid for the substation requires an upgrade to align with current standards and to cover the expanded substation yard and new equipment.

## 3.0 RISK ASSESSMENT

The *Gambo Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to customers from the area of Gambo to Lumsden in the Bonavista-North area.

GAM Substation provides service to approximately 1,370 customers in the Gambo area. There are also approximately 3,500 customers from Hare Bay to Lumsden supplied from radial Transmission Line 115L from GAM Substation. Equipment failure in the substation exposes all customers supplied by GAM Substation to the risk of outages. The time to restore service to customers depends on the nature of the failure and could range from several hours up to 36 hours.

GAM Substation contains equipment that is deteriorated, obsolete, and at end of life which increases the probability of outages to customers. Two circuit breakers and a significant quantity of switches require replacement based on their age and mechanical condition. The electromechanical protection relays are obsolete and are no longer industry standard. The wood pole structures and crossarms in the substation are deteriorated and require replacement.

Both power transformers and the voltage regulators in GAM Substation contain large amounts of insulating oil and lack standard spill containment. Proper spill containment is required to mitigate the risk of an environment incident if an oil spill were to occur. Remediation costs associated with oil spills can be significant. In addition, spill containment will minimize the surface area of an oil spill and thus provides fire protection benefits.

There are deficiencies identified with the ground grid at GAM Substation that pose a risk to safe and reliable operation of the electric equipment. There are sections of the yard with insufficient grounding and there are also missing connections between the main ground grid and substation fence. The purpose of ground grid upgrades is to reduce the risk associated with step and touch potential hazards. An insufficient ground grid can also affect continuity of service if there is an inadequate ground path, which is required for proper equipment operation.

Overall, refurbishment and modernization of GAM Substation is necessary to ensure the continued delivery of reliable, safe and environmentally responsible service to customers in the area of Gambo to Lumsden in the Bonavista-North area.

## 4.0 ASSESSMENT OF ALTERNATIVES

In the case of GAM Substation, the number of components requiring preventative and corrective maintenance at this time justifies the refurbishment and modernization of the substation in 2024. One 138 kV oil filled breaker and one 66 kV oil filled breaker require replacement as they have reached the end of their useful service life. The existing electromechanical protection relays are obsolete and require replacement. The 138 kV, 66 kV and 25 kV wood pole structures are deteriorated and require replacement. The majority of the substation switches are deteriorated and have reached the end of their useful service life. The power transformers and voltage regulators do not have spill containment foundations. The ground grid requires upgrades and the metering tank is at the end of its service life.

Deferral of the *Gambo Substation Refurbishment and Modernization* project increases the risk that some components will be run to failure. Run to failure is not a viable alternative as it increases the risk to the delivery of safe and reliable service to approximately 1,370 customers in the Gambo area and approximately 3,500 customers from Hare Bay to Lumsden who rely on radial Transmission Line 115L from GAM Substation.

## 5.0 PROJECT SCOPE

The 2024 scope of work at GAM Substation includes the following:

(i) Complete a yard extension;
(ii) Construct a new control building to replace existing building;
(iii) Construct an extension to the 138 kV steel bus structure and remove deteriorated 138 kV wood pole structures;
(iv) Construct new 66 kV and 25 kV steel structures to replace deteriorated wood structures;
(v) Construct new concrete spill containment foundations for existing transformers and existing voltage regulators;
(vi) Install one new 138 kV breaker to replace existing end-of-life breaker and the addition of one new 138 kV tie-breaker;
(vii) Install new 66 kV breaker to replace existing end-of-life breaker;
(viii) Replace deteriorated 138 kV, 66 kV, and 25 kV switches;
(ix) Install 138 kV and 66 kV potential transformers;
(x) Install new 25 kV combined current and potential transformer to replace end-of-life metering tank;
(xi) Replace obsolete electromechanical relays with new digital relays; and
(xii) Upgrade and extend the ground grid.

Engineering design and procurement of long lead equipment will be completed in the first quarter of 2024. Construction will begin in the second quarter and will be completed early in the fourth quarter of 2024. Commissioning of the substation will be completed by the end of 2024.

Table A-1 summarizes the age and condition of the primary equipment planned to be replaced.

Table A-1
2024 Planned Equipment Replacements
Gambo Substation

| Equipment | Age (Years) | Condition |
|---|---|---|
| 138 kV Wood Pole Structures | 57 | Deteriorated |
| 138 kV Circuit Breaker | 45 | End of Life |
| 138 kV Air Break Switches | 26-45 | Deteriorated/End of Life |
| 138 kV Side Break Switches | 45 | Deteriorated/End of Life |
| 66 kV Wood Pole Structures | 49 | Deteriorated |
| 66 kV Circuit Breaker | 50 | End of Life |
| 66 kV Air Break Switches | 49 | Deteriorated/End of Life |
| 66 kV Side Break Switches | 49 | Deteriorated/End of Life |
| 25 kV Wood Pole Structure | 51 | Deteriorated |
| 25 kV Metering Tank | 34 | End of Life |
| 25 kV Air Break Switch | 32-51 | Deteriorated/End of Life |
| 25 kV Hook-Stick Operated Switches | 32-51 | Deteriorated/End of Life |
| Electromechanical Protection Relays | 46 | Obsolete |

## 6.0 PROJECT COST

Table A-2 provides the cost breakdown for the *Gambo Substation Refurbishment and Modernization* project.

Table A-2
Gambo Substation
Refurbishment and Modernization Project
2024 Project Cost
($000s)

| Cost Category | Total |
|---|---|
| Material | 3,754 |
| Labour - Internal | 299 |
| Labour - Contract | 0 |
| Engineering | 563 |
| Other | 651 |
| Total | $5,267 |

The total project cost for the *Gambo Substation Refurbishment and Modernization* project is $5,267,000 in 2024.

## 7.0 CONCLUSION

The *Gambo Substation Refurbishment and Modernization* project is required to provide reliable service to customers at the lowest possible cost. It will address the deteriorated and obsolete equipment identified through an engineering assessment in the GAM Substation. End of life 138 kV and 66 kV circuit breakers will be replaced, obsolete electromechanical protection relays will be replaced with digital relays, new 66 kV and 25 kV steel structures will replace the deteriorated wood structures, and deteriorated switches will be replaced. New transformer and voltage regulator spill containment foundations will be constructed to protect against environmental hazards. The total project cost for the *Gambo Substation Refurbishment and Modernization* project is $5,267,000 in 2024.

# APPENDIX B:

## Old Perlican Substation Refurbishment and Modernization

# TABLE OF CONTENTS

# 1.0 OLD PERLICAN SUBSTATION

Old Perlican ("OPL") Substation was constructed in 1975 as a distribution substation. The substation is supplied by Newfoundland Power 66 kV radial Transmission Line 65L from New Chelsea ("NCH") Substation. One 13.3 MVA distribution power transformer OPL-T1 supplies three 12.5 kV distribution feeders, serving approximately 1,800 customers in the Old Perlican, Bay de Verde, and Lower Island Cove area.

Figure B-1 shows OPL Substation.


*Figure B-1 - OPL Substation*

# 2.0 ENGINEERING ASSESSMENT

## 2.1 66 kV Infrastructure

The 66 kV wooden pole structures were installed in 1975 when the substation was first constructed. An inspection and engineering assessment was completed in 2022. The wood poles were found to have deep splits, shelling and decay. The deteriorated condition of the wood structures compromises their ability to support the weight of critical substation equipment such as switches and potential transformers, increasing the probability of failure.

Figure B-2 shows examples of the deterioration exhibited on the 66 kV wood bus structure.


*Figure B-2 - Deteriorated OPL 66 kV Wood Poles with pole shelling and large deep splits*

The 66 kV wood pole structure will be removed and replaced with a new galvanized steel bus structure.

The existing 66 kV switch is 48 years old and deteriorated necessitating its replacement. The installation of a new 66 kV circuit breaker requires the installation of new switches designed to mount properly on the new steel bus structure.[1]

## 2.2 12.5 kV Infrastructure

The 12.5 kV wood pole structures were installed in 1975 when the substation was first constructed. An inspection and engineering assessment were completed in 2022 and determined that the wood poles are deteriorated to the point where replacement is required. The wood poles have deep splits and the crossarms are showing varying degrees of deterioration, and are also experiencing splits and decay. The deteriorated condition of the wood structures compromises their ability to support the weight of critical substation equipment such as switches and potential transformers, increasing the probability of failure.

[1] The requirement for a new 66 kV circuit breaker is discussed in section 2.4 Protection and Control.

Figure B-3 shows examples of the deteriorated wood pole structures.


*Figure B-3 - Splitting of Wood Poles*

Figure B-4 shows an example of deteriorated wooden crossarms on the 25 kV structure.

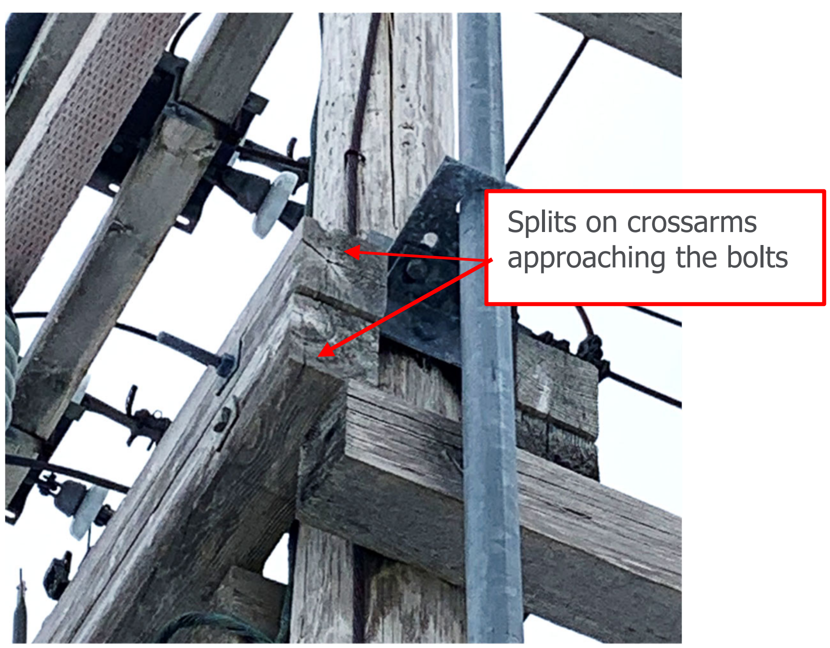



*Figure B-4 - Deterioration of Wooden Crossarm*

The wood pole structure will be removed and replaced with a new galvanized steel structure.

The switches on the 12.5 kV wooden structure are deteriorated and approaching end of life, with three of the air break switches being inoperable. Also, the installation of a new 25 kV steel structure requires the installation of new switches designed to mount properly on the new steel bus structure. Three air break switches, two sets of voltage regulator hook stick switches, and six sets of hook stick operated switches will be replaced.

The 12.5 kV feeder reclosers OPL-01-R, OPL-02-R, and OPL-03-R were manufactured by Thomas & Betts in 2014 and are in good condition and will be reconnected to the new bus structure. The OPL Substation voltage regulators were manufactured by Cooper Power Systems in 2016 and are also in good condition and will remain in service.

The oil-filled voltage regulators currently lack spill containment.[2] Figures B-5 shows the existing voltage regulators.

*Figure B-5 - OPL Voltage Regulators*

A spill containment foundation is required to protect against environmental damage in the event of an oil spill from the units.

[2] The OPL voltage regulators contain a total oil volume of 2,136 liters.

## 2.3 Power Transformer

OPL-T1 is a 54-year-old distribution power transformer that was manufactured by Moloney Electric in 1969. OPL-T1 is a 66 kV to 12.5 kV, 13.3 MVA rated unit. Based on the age and external physical condition, as well as oil test results showing no signs of abnormal internal conditions, the transformer will not be replaced at this time.

The transformer lacks standard spill containment. A new spill containment foundation is required for the transformer to protect against environmental damage in the event of an oil spill from the unit.[3]

Figure B-6 shows power transformer OPL-T1 and lack of spill containment.

*Figure B-6 - OPL-T1 Power Transformer*

## 2.4 Protection and Control

Protection of power transformer OPL-T1 is provided by a set of fuses, and the feeder protection is provided by microprocessor-based digital relays. Fuses can economically protect small power

[3] OPL-T1 contains a total oil volume of 6,455 liters.

transformers against primary and secondary faults; however, they provide limited protection against faults internal to the transformer. Digital protection relays are installed as industry standard protection for transformers rated 10 MVA or higher, as they provide a more precise means of protection from internal faults.[4] Replacing the fuses with a circuit breaker and a digital protection relay is recommended to provide a standard form of transformer protection that conforms to current standards.[5]

Modernization of the transformer protection requires upgrading the existing substation communication functionality, which currently only includes cellular modems inside the recloser cabinets. A communications gateway will provide remote control and monitoring of the new substation protection equipment from the Supervisory Control and Data Acquisition ("SCADA") system.[6] The communications gateway will provide a network connection to the SCADA system for all the substation devices that provide monitoring, protection and control of the transmission lines, distribution feeders, and substation power transformer. The modernization will also allow for remote administration of upgraded devices.[7]

The installation of new 12.5 kV current transformers are required for the operation of the new protection and control equipment and the installation of a new 12.5 kV combined potential and current transformer is required for metering.

### 2.5 Control Building

The OPL Substation does not have an existing control building as the limited number of protection and control devices in service are able to fit in small outdoor control cabinets. A new control building is required to permit the installation of a 125 VDC battery system, full network and communication functionality, multiple protection relays, control switches, blocking switches, and other miscellaneous equipment.[8]

### 2.6 Site Condition

The OPL Substation site requires an extension to accommodate the increased footprint required for the spill containment foundations, the 66 kV breaker, the new 66 kV and 12.5 kV steel structures, and a portable substation. Minor improvements to the site to address drainage requirements, removing unsuitable soils and vegetation, and laying structural fill will be completed during the proposed project.

---

4 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, but are not recommended for transformers rated above 10 MVA.

5 Circuit breakers also provide the ability to remotely control the energization of the transformer through the Company's SCADA system.

6 The enhanced capabilities provided by the microprocessor-based digital relays provide greater options for remote control and monitoring through the Company's SCADA system.

7 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 for customers. Without this capability, engineers have to travel to the substation to interrogate the relay on site, thereby greatly increasing the time necessary to assess fault data.

8 Protection and communication devices housed in panels are required to be kept in a dry environment with temperature control.

The existing ground grid at OPL Substation has deficiencies that pose a risk to the safe and reliable operation of the electric equipment in the substation. There are sections of the yard with insufficient grounding and there are also missing connections between the main ground grid and the substation fence. A grounding study is necessary and the ground grid for the substation requires an upgrade to align with current standards and to cover the expanded substation yard and new equipment.

## 3.0 RISK ASSESSMENT

The *Old Perlican Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to approximately 1,800 customers in the Old Perlican, Bay de Verde, and Lower Island Cove area.

Equipment failure in the substation exposes all customers supplied by OPL Substation to the risk of outages. The time to restore service to customers depends on the nature of the failure and could range from several hours up to 36 hours.[9]

OPL Substation contains equipment that is deteriorated and at end of life, which increases the probability of outages to customers. The wood pole structures in the substation are deteriorated and require replacement. The substation switches are aged and have deteriorated requiring replacement due to their mechanical condition. The power transformer is protected by fuses which does not provide industry standard protection.

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

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

Overall, refurbishment and modernization of OPL Substation is necessary to ensure the continued delivery of reliable, safe and environmentally responsible service to customers in the Old Perlican, Bay de Verde, and Lower Island Cove area.

9 In the event that OPL-T1 fails, a portable substation installation is required to restore service to customers. Typically, a portable substation can be installed within 24 to 36 hours, assuming one is available.

## 4.0 ASSESSMENT OF ALTERNATIVES

In the case of OPL Substation, the number of components requiring preventative and corrective maintenance at this time justifies the refurbishment and modernization of the substation in 2024. The 66 kV and 12.5 kV wood pole structures are deteriorated and require replacement. The 12.5 kV switches are experiencing failures and have reached the end of their useful life. The transformer protection does not conform to current industry standards. The power transformer and voltage regulators do not have a spill containment foundation.

Deferral of the *Old Perlican Substation Refurbishment and Modernization* project increases the risk that some components will be run to failure. Run to failure is not a viable alternative as it increases the risk to the delivery of safe and reliable service to approximately 1,800 customers in the Old Perlican, Bay de Verde, and Lower Island Cove area.

## 5.0 PROJECT SCOPE

The 2024 scope of work at OPL Substation includes the following:

- (i) Complete a yard extension;
- (ii) Construct a new control building;
- (iii) Construct new 66 kV and 12.5 kV steel structures to replace deteriorated wood structures;
- (iv) Construct new spill containment foundations for existing transformer and existing voltage regulators;
- (v) Install one new 66 kV breaker and one new 12.5 kV breaker;
- (vi) Replace deteriorated 66 kV and 12.5 kV switches;
- (vii) Install new 12.5 kV current transformer and 12.5 kV combined current and potential transformer;
- (viii) Install new digital relay and the associated communications equipment; and
- (ix) Upgrade and extend the ground grid.

Table B-1 summarizes the age and condition of the primary equipment planned to be replaced.

**Table B-1**
**2024 Planned Equipment Replacements**
**Old Perlican Substation**

| Equipment | Age (Years) | Condition |
|---|---|---|
| 66 kV Wood Pole Structure | 48 | Deteriorated |
| 66 kV Air Break Switch | 48 | Deteriorated/End of Life |
| 12.5 kV Wood Pole Structure | 48 | Deteriorated |
| 12.5 kV Air Break Switches | 24 | Deteriorated |
| 12.5 kV Hook-Stick Operated Switches | 24 | Deteriorated |

Engineering design and procurement of long lead equipment will be completed in the first quarter of 2024. Construction will begin in the second quarter and will be completed in the fourth quarter of 2024. Commissioning of the substation will be completed by the end of 2024.

## 6.0 PROJECT COST

Table B-2 provides the cost breakdown for the *Old Perlican Substation Refurbishment and Modernization* project.

**Table B-2**
**Old Perlican Substation**
**Refurbishment and Modernization Project**
**2024 Project Cost**
**($000s)**

| Cost Category | Total |
|---|---|
| Material | 2,143 |
| Labour - Internal | 190 |
| Labour - Contract | 0 |
| Engineering | 555 |
| Other | 468 |
| Total | $3,356 |

The total cost for the *Old Perlican Substation Refurbishment and Modernization* project is $3,356,000 in 2024.

## 7.0 CONCLUSION

The *Old Perlican Substation Refurbishment and Modernization* project is required to provide reliable service to customers at the lowest possible cost.  The project will address the deteriorated and obsolete equipment identified through an engineering assessment of OPL Substation.  New 66 kV and 12.5 kV steel structures will replace the deteriorated wood structures, deteriorated switches will be replaced, and existing transformer fuses will be replaced with a new breaker and digital relays.  New transformer and voltage regulator spill containment foundations will be constructed to protect against environmental hazards.  The total project cost to complete the *Old Perlican Substation Refurbishment and Modernization* project is estimated to be $3,356,000.

# APPENDIX C:

## Memorial Substation Refurbishment and Modernization

# TABLE OF CONTENTS

Page

## 1.0 MEMORIAL SUBSTATION

Memorial ("MUN") Substation is a 12.5 kV distribution substation located on Memorial University's St. John's campus (the "University" or "MUN"). The Substation was originally constructed in 1966 and includes equipment owned by the Company and the University.[1] MUN Substation is supplied by Newfoundland Power transmission lines 12L and 14L, which form a 66 kV looped transmission system between King's Bridge and Stamp's Lane substations.

Newfoundland Power owned equipment within MUN Substation includes two 66 kV transmission line termination structures, 66 kV infrastructure including a 66 kV bus structure, two 66 kV circuit breakers and side break switches, two power transformers, three 12.5 kV switchgear circuit breakers, and protection and control equipment.[2]

University owned equipment within the substation includes the 12.5 kV switchgear, switchgear building and distribution feeders.[3] There are ten 12.5 kV distribution feeder circuit breakers located in the customer owned switchgear, serving all St. John's campus buildings including the Health Sciences Centre, Janeway Children's Health and Rehabilitation Centre and other buildings on the north side of the campus.

Figure C-1 shows MUN Substation.

*Figure C-1 - MUN Substation*

1 A substation expansion took place in the mid-1970s. At this time, additions included a switchgear expansion, new protection and controls, a new power transformer, and new transmission line breakers.

2 The Newfoundland Power-owned 12.5 kV switchgear breakers include two main breakers fed from power transformers MUN-T1 and MUN-T2 along with a bus tie breaker. These breakers are located in MUN's 12.5 kV switchgear.

3 The switchgear building houses a switchgear lineup of breakers and associated protection and control equipment. This switchgear lineup is built into the side of the building providing outdoor rear access to the switchgear breakers.

## 2.0 ENGINEERING ASSESSMENT

### 2.1 Power Transformers

MUN-T1 power transformer was manufactured by Ferranti-Packard in 1966. MUN-T1 is a 66 kV to 12.5 kV, 11.125/14.83 MVA rated distribution power transformer. MUN-T2 power transformer was manufactured by Federal Pioneer in 1976. MUN-T2 is a 66 kV to 12.5 kV, 15/20 MVA power transformer.

The latest oil samples and maintenance reports indicate MUN-T1 power transformer does not require replacement at this time. MUN-T2 power transformer has failed and been removed from service, and will be replaced in 2024.[4] Both MUN-T1 and MUN-T2 power transformers are required to supply forecast load growth at the University.

Figures C-2 and C-3 show MUN-T1 and MUN-T2.


*Figure C-2 - MUN-T1*

*Figure C-3 - MUN-T2*

---

[4] Newfoundland Power filed a supplemental capital expenditure application, *2023 MUN Power Transformer Supplemental Application Supplemental Application,* on March 3, 2023. The replacement of MUN-T2 was approved by the Board in Order No. P.U. 14 (2023).

Both MUN-T1 and MUN-T2 lack standard spill containment. New spill containment foundations are required for transformers MUN-T1 and MUN-T2 to protect against environmental damage in the event of an oil spill from the units.[5]

Both power transformers are in close proximity to one another. A firewall between MUN-T1 and MUN-T2 will be installed to limit the damage and potential spread of fire in the event of a transformer failure on the adjacent transformer.

MUN Substation yard has a limited footprint. As a result, constructing spill containment and a firewall for the power transformers will require the substation layout to be reconfigured. The reconfiguration will also allow for a more standardized substation layout and delineation between Newfoundland Power and customer owned equipment.

## 2.2 12.5 kV Infrastructure

Newfoundland Power owns and maintains the circuit breakers on the low voltage side of power transformers MUN-T1 and MUN-T2 along with the bus tie breaker. These breakers are located within the existing customer-owned switchgear.

Figure C-4 shows the existing 12.5 kV switchgear cubicles.


*Figure C-4 - MUN Substation 12.5 kV Switchgear Front Layout and Protection and Controls*

5 Transformers MUN-T1 and MUN-T2 each contain an oil volume of approximately 10,000 litres.

Switchgear circuit breakers are critical components of substation equipment. The failure of a switchgear 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 switchgear circuit breakers is 30 to 50 years. These switchgear circuit breakers are 50 years old and are at the end of their useful service lives. 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.[6] Arc flash technologies on newer switchgear mitigate the hazard of injury to personnel and mitigate equipment damage.[7] Replacing end of life switchgear mitigates safety risks, equipment damage and supply interruptions impacting reliable service to customers.

The Company installs outdoor breakers where possible to reduce safety concerns with operating high voltage circuit breakers within enclosed switchgear.[8] In addition, outdoor circuit breakers allow for improved accessibility during maintenance and future refurbishment.

As part of the substation reconfiguration, the Newfoundland Power owned switchgear breakers will be replaced with two outdoor 12.5 kV circuit breakers and associated equipment. This will include steel bus structures and two new side-break switches which will provide an isolation point from the customer owned equipment.

### 2.3 66 kV Infrastructure

Circuit breakers for Transmission Line 12L and Transmission Line 14L are General Electric type FKP 66 kV oil filled breakers.[9] These breakers are 47 years old and are at the end of life.[10] The Company's standard for 66 kV breakers is SF6 type breakers. Replacing these circuit breakers with two new 66 kV SF6 circuit breakers will reduce the risk of releasing oil into the environment.

Five of the six switches on the 66 kV bus structures are in excess of 30 years in service and are in a deteriorated condition primarily as a result of corrosion and require replacement.

As part of the substation reconfiguration, the existing 66 kV circuit breakers, switches and steel bus structures will be replaced. The new 66 kV bus will be designed with two separate

---

6 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.

7 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.

8 In some cases, switchgear breakers are the only suitable option in a substation due to space constraints. At MUN Substation, the removal of the existing switchgear building would allow for the installation of standard outdoor breakers.

9 The 66 kV General Electric FKP breakers are an environmental concern as they hold approximately 1,100 liters of oil.

10 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.

sections, with one section connected to Transmission Line 12L and the other connected to Transmission Line 14L. A 66 kV bus tie switch will be installed between the two transmission line buses, which will provide additional operational and maintenance benefits.[11]

Both transmission lines 12L and 14L transition from aerial construction to buried cable just outside the University property, at Allandale Road near the Arts and Culture Centre and University Avenue respectively. The transmission lines enter MUN Substation as buried cables and transition above ground on transmission line termination structures. These transmission line termination structures are stand alone structures not requiring replacement at this time.

## 2.4 Protection and Control

The protection relays for the 66 kV bus and transformers MUN-T1 and MUN-T2 are vintage electromechanical type relays that were installed in 1974. At present, there are 17 electromechanical relays installed in three individual switchgear cubicles inside the existing customer owned switchgear. Electromechanical relays are not industry standard and are at the end of their useful service life.

Figure C-5 shows the vintage electromechanical relays.


*Figure C-5 - Electromechanical Relays*

11 The installation of the bus tie switch facilitates future equipment maintenance by allowing for the ability to isolate one side of the 66 kV bus from the other, eliminating an outage to the customer.

The protection and control of the substation assets require modernization by replacing the obsolete electromechanical relays with microprocessor-based digital relays. This approach minimizes the number of active devices used to provide protection of substation assets, consolidates the control and automation architecture, and reduces ongoing maintenance.

In addition, the existing communications equipment is located inside the existing customer owned switchgear building. The existing communication equipment includes obsolete devices that are no longer standard. The existing equipment provides inadequate redundant network reliability and reduced gateway performance.[12]

Figure C-6 shows the existing communications rack and equipment.

*Figure C-6 - Existing Communications Rack*

A communications gateway will provide remote control and monitoring of the new protection equipment from the Supervisory Control and Data Acquisition ("SCADA") system.[13] The

[12] The existing network switch is a single port device. A failure of the single switch would lose remote visibility of the substation. The existing gateway is limited to four serial ports for connecting remote devices and two copper ethernet ports. Newfoundland Power's standard gateway device provides up to 32 serial ports and ten ethernet ports that can be either copper or fibre. Upgrading this gateway device to modern standard would improve gateway performance.

[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.

communications gateway will provide a network connection to the SCADA system for all the substation devices that provide monitoring, protection and control of the transmission lines, distribution feeders, and substation power transformers.[14] The modernization will also allow for remote administration of upgraded devices.[15]

Upgrades to the existing communications equipment will allow for increased network reliability, the installation of remote monitoring devices on both power transformers, improved performance and scalability, and improved visibility and control of the substation. In addition, it will provide the ability to monitor the status of customer feeders and provide accurate timing among all network equipment.[16]

## 2.5 Control Building

The existing switchgear building is owned and maintained by the University having been built in 1966 as part of the original construction of the substation. This building houses the customer-owned 12.5 kV switchgear and associated protection and control equipment. Newfoundland Power does not have a control building in MUN Substation. The Company's equipment is located within the customer owned building.

Figures C-7 and C-8 show the MUN Substation switchgear building.


*Figure C-7 - MUN Switchgear Building Exterior*

---

[14] Newfoundland Power's SCADA system monitors the University's distribution feeder breakers only. The Company does not remotely control these distribution feeders.

[15] Remote administration of upgraded devices allows protection relays to be interrogated and reconfigured remotely. This allows engineers to interrogate protection relays from their office, providing quicker diagnosis of system problems and improved outage response times. Without this capability, engineers have to travel to the substation to interrogate the relay on site, thereby greatly increasing the time necessary to assess fault data.

[16] The installation of a satellite clock provides accurate timing of all network equipment. The existing satellite clock is discontinued and is not compatible with Newfoundland Power's standard digital protection and control relays. In order to modernize the substation's protection and control devices, a new satellite clock is required to provide accurate timing among all network devices.

*Figure C-8 - MUN Switchgear Building Interior*

The 57-year-old switchgear building is in poor condition. The University intends to remove the building in 2024 following the removal of Newfoundland Power's switchgear breakers and protection and control equipment from the building.

Newfoundland Power will construct a new control building to house the Company's protection and control equipment.[17] This will provide delineation between Newfoundland Power and customer owned equipment. The control building will accommodate the installation of a 125 VDC battery system, full network and communication functionality, multiple protection relays, control switches, blocking switches, and other miscellaneous equipment.[18]

## 2.6 Site Condition

There are operational limitations at MUN Substation. The current substation is surrounded by the University's Facilities Management building parking lot, and therefore has a limited footprint. There is a large amount of underground infrastructure for the customer-owned distribution feeders as well as the Company's transmission line cables. There are a number of pull pits and duct banks that accommodate this underground infrastructure. Significant underground infrastructure has also been added by the University in recent years in preparation for the switchgear replacement and relocation. Many of the recent installations are located at grade due to the limitations of installing equipment underground in the yard.

The planned scope of work will reduce the number of underground duct banks and pull pits allowing for a more standardized substation layout. The site reconfiguration will allow easy vehicle access to facilitate future maintenance and equipment replacements.

The existing ground grid at MUN Substation has deficiencies that pose a risk to the safe and reliable operation of the electrical equipment in the substation. There are sections of the yard with insufficient grounding. A grounding study is necessary and the ground grid for the

17 The building will be separate from the University owned switchgear building.

18 Protection and communication devices housed in panels are required to be kept in a dry environment with temperature control.

substation requires an upgrade to align with current standards and to cover the new equipment.

## 3.0 RISK ASSESSMENT

MUN Substation is relatively unique in that it is located in close proximity to MUN's Science Building and Facilities Management Building. A failure of aging equipment could result in damage to substation equipment, customer infrastructure, and public property.

The University is Newfoundland Power's largest customer and provides various public services. There are over 35 buildings with critical loads such as the Health Sciences Centre, Janeway Children's Hospital, student residences, apartment buildings, and a childcare centre. Approximately 15,000 students are currently enrolled at the University and almost 1,700 students are living in student residences on campus. Depending on the length of an outage, a loss of supply to the University could lead to the closure of the majority of campus buildings.

Both power transformers at MUN Substation lack standard spill containment to protect against environmental hazards. Power transformers contain large amounts of oil as an insulating fluid. Proper spill containment is required to mitigate the risk of an environment incident if an oil spill were to occur. If an oil spill were to occur, the oil would soak into the ground and significant efforts would be required for clean-up. These impacts can range from the clean-up costs associated with a spill to the contamination of a water supply. In addition, spill containment will minimize the surface area of an oil spill and thus provides fire protection benefits. The transformers also lack a firewall. Installation of a firewall between the transformers can limit the damage, and potential spread of fire, resulting from a transformer failure.

MUN Substation contains equipment that is deteriorated, obsolete, and at end of life. All the circuit breakers and a significant quantity of switches require replacement based on their age and mechanical condition. The electromechanical protection relays are obsolete and are not industry standard.

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

Overall, refurbishment and modernization of MUN Substation is necessary to ensure the continued delivery of reliable, safe and environmentally responsible service to customers. The refurbishment and modernization of MUN Substation in 2024 will mitigate these risks.

## 4.0 ASSESSMENT OF ALTERNATIVES

In the case of MUN Substation, the number of components requiring preventative and corrective maintenance at this time combined with the planned upgrades by the University on customer owned equipment and the replacement of MUN-T2 justifies the requirement to refurbish and modernize MUN Substation in 2024.

The refurbishment and modernization of MUN Substation was originally planned to be completed in 2023, but was deferred to align with the University's schedule for upgrades to the substation.[19] The *Memorial Substation Refurbishment and Modernization* project can no longer be deferred. The power transformers do not have spill containment foundations or a firewall.[20] The obsolete 12.5 kV switchgear breakers are an arc flash safety concern for the Company's employees and must be replaced. The 66 kV oil filled circuit breakers and switches are deteriorated and are at the end of their useful service life. The existing electromechanical protection relays are obsolete and must be replaced. The substation lacks a standard ground grid and requires upgrades.

The University is completing planned upgrades to its distribution equipment within MUN Substation in 2023 and 2024. This involves replacing obsolete customer-owned switchgear and rerouting the University's underground feeders from the existing switchgear to the new switchgear.[21] The existing switchgear building will remain in place until 2024, since Newfoundland Power's switchgear breakers and protection and controls equipment are located inside this building.

Continued deferral of the *Memorial Substation Refurbishment and Modernization* project will 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 the University.

## 5.0 PROJECT SCOPE

The 2024 scope of work at MUN Substation includes the following[22]:

(i) Construct new transformer spill containment foundations;
(ii) Install a new firewall between power transformers;
(iii) Replace the 66 kV bus structure;
(iv) Replace 66 kV equipment including circuit breakers, switches, and potential transformers;
(v) Install new 12.5 kV structures;
(vi) Replace 12.5 kV equipment including circuit breakers, switches, and potential transformers;
(vii) Replace obsolete electromechanical relays with new digital relays and install the associated communications equipment;
(viii) Construct a new control building; and
(ix) Install new ground grid.

---

19 The five-year capital plan filed with the *2022 Capital Budget Application* included the refurbishment and modernization of MUN Substation in 2023.

20 MUN-T2 is being replaced in 2024 as approved in Order No. P.U. 14 (2023).

21 The customer owned switchgear is 57 years old and is at end of life. This includes the switchgear building, switchgear breakers and protection and control devices. The new customer-owned switchgear and protection and controls will be installed within a new switchgear building owned and operated by the University. The customer-owned distribution feeders will be rerouted to the new building, which will be located at the opposite end of the substation yard.

22 The scope of work completed by MUN in 2024 includes the removal of the existing switchgear building.

Table C-1 summarizes the planned primary equipment replacements, including the age and condition of components.

| Table C-1<br>2024 Planned Equipment Replacements<br>MUN Substation | | |
|---|---|---|
| Equipment | Age (Years) | Condition |
| 66 kV Breakers | 47 | End of Life |
| 66 kV Side Break Switches | 49-57 | Deteriorated/End of Life |
| 12.5 kV Switchgear Breakers | 50 | End of Life |
| Electromechanical Protection Relays | 49 | Obsolete |

## 6.0 PROJECT COST

Table C-2 provides the cost breakdown for the *Memorial Substation Refurbishment and Modernization* project.

| Table C-2<br>Memorial Substation<br>Refurbishment and Modernization Project<br>2024 Project Cost<br>($000s) | |
|---|---|
| Cost Category | Total |
| Material | 2,879 |
| Labour - Internal | 169 |
| Labour - Contract | 0 |
| Engineering | 607 |
| Other | 696 |
| Total | $4,351 |

The total project cost for the *Memorial Substation Refurbishment and Modernization* project is $4,351,000 in 2024.

## 7.0 CONCLUSION

The *Memorial Substation Refurbishment and Modernization* project is required to provide reliable service to Memorial University. It will address the deteriorated and obsolete equipment identified through an engineering assessment of the MUN Substation. The total project cost for the *Memorial Substation Refurbishment and Modernization* project is $4,351,000 in 2024.

# APPENDIX D:

## Islington Substation Refurbishment and Modernization

# TABLE OF CONTENTS

# 1.0 ISLINGTON SUBSTATION

Islington ("ISL") Substation was constructed in 1974 as a distribution substation. The substation is supplied by Newfoundland Power 66 kV Transmission Line 80L from Heart's Content ("HCT") and New Harbour ("NHR") substations. One 4 MVA distribution power transformer ISL-T1 supplies a single 12.5 kV distribution feeder, serving approximately 1,100 customers in the Islington area.

Figure D-1 shows ISL Substation.

*Figure D-1 - ISL Substation*

# 2.0 ENGINEERING ASSESSMENT

## 2.1 Power Transformer

Power transformer ISL-T1 is a 65-year-old distribution power transformer that was manufactured by English Electric in 1958. ISL-T1 is a 69 kV to 13.8 kV, 4 MVA rated unit.

ISL-T1 is the Company's second oldest distribution power transformer and is approaching the end of its useful service life. According to industry experience, the expected life of a power transformer is between 30 and 50 years,[1] with a sharp decline for in-service power transformers past 70 years of age.[2] The risk of this power transformer failing is expected to increase as it

[1] From CIGRE's *Asset Management Decision Making Using Different Risk Assessment Methodologies* 2013 report on asset management.

[2] Based on 2021 information available from the Electric Power Research Institute ("EPRI"). EPRI is an energy research and development organization. EPRI has a database of thousands of power transformers from its electric utility members, including Newfoundland Power.

continues to age.[3] It is proposed that ISL-T1 be replaced due to the limited remaining expected life, the risk of an extended outage in the event of a failure,[4] and the long lead time associated with procuring new power transformers.[5]

Power transformer ISL-T1 will be 67 years old when replaced as part of the *Islington Refurbishment and Modernization* project in 2025. Given industry experience, there is a high risk that the transformer could fail in the near-term. The Company completed an analysis which showed that ISL-T1 would have to remain in service until approximately 75 years of age to offset the added costs of completing the transformer replacement as a separate project in the future. Given the customer risks and costs associated with a failure of ISL-T1, replacing the power transformer in 2025 is consistent with providing reliable service to customers at least cost.

The existing ISL-T1 transformer currently does not have a spill containment foundation. A new spill containment foundation is required to protect against environmental damage in the event of an oil spill from the unit.

## 2.2 66 kV Infrastructure

The wooden poles in the 66 kV bus structures range in age from 23 to 38 years old. An inspection and engineering assessment completed in 2022 determined that some of the older vintage poles were exhibiting deterioration including splits and checks.

---

[3] Insulation deterioration of the power transformer internal windings naturally occurs over time and is accelerated by exposure to high temperatures. Degraded insulation is a major indicator that a power transformer has reached end of life.

[4] In the event that ISL-T1 fails, a portable substation installation is required to restore service to customers. Typically, a portable substation can be installed within 24 to 36 hours, assuming one is available.

[5] Power transformer procurement lead times for manufacture and delivery have been increasing and can be as long as 24 months depending on the manufacturer.

Figure D-2 shows examples of wood splitting in 66 kV wood poles and crossarms.

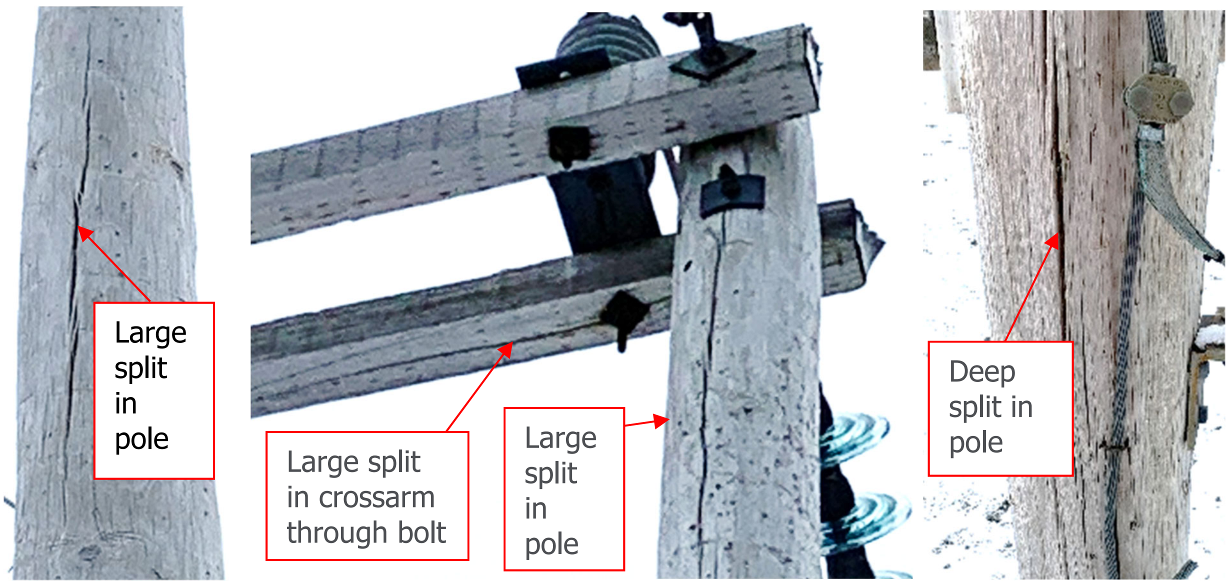



*Figure D-2 - Deteriorated ISL 66 kV Wood Poles with large deep splits*

There are currently no breakers on the 66 kV bus. A fault on Transmission Line 80L results in an outage to approximately 1,100 customers at ISL Substation and could also impact approximately 1,800 customers at NHR Substation. Two new 66 kV circuit breakers with two side break switches are recommended to split Transmission Line 80L into two sections.[6] These breakers will be controlled by new bus and transformer protection relays. Installing breakers will improve automation and reduce substation and transmission outages for customers served by both ISL and NHR substations. The existing 66 kV bus structure will require modifications to install the breakers and mount the associated switches.

In order to accommodate the new breakers and associated 66 kV switches the existing wood pole structures will be replaced with a standard 66 kV galvanized steel bus structure. The mechanical condition of the existing 66 kV switches will be assessed and those in working order will be stored and reused as spares for other wood pole applications where applicable. This includes three sets of air break switches. The new transformer air break switch will include a motor operator and ground switch.[7]

[6] The installation of these two breakers allows ISL and NHR substations to remain energized in the event of a fault on Transmission Line 80L between Islington and Heart's Content. It also allows ISL Substation to remain energized in the event of a fault on Transmission Line 80L between Islington and Blaketown, including on the NHR Substation high voltage bus. They also allow NHR Substation to remain energized in the event of a fault on the ISL high voltage bus.

[7] The motorized air break switches in conjunction with the upgraded protection relays will improve equipment protection.

## 2.3 12.5 kV Infrastructure

The 12.5 kV wood pole structures were installed in 1974 when the substation was first constructed. An inspection and engineering assessment completed in 2022 determined that the wood poles are deteriorated to the point where replacement is required. The wood poles have significant external decay, shell separation, deep splits and checks, and multiple large woodpecker holes.

Figure D-3 shows examples of the deteriorated wood structures.


*Figure D-3 - Deteriorated Wood Poles*

The crossarms are showing varying degrees of deterioration, and are experiencing splits and decay. Figure D-4 shows examples of the deteriorated wood crossarms.

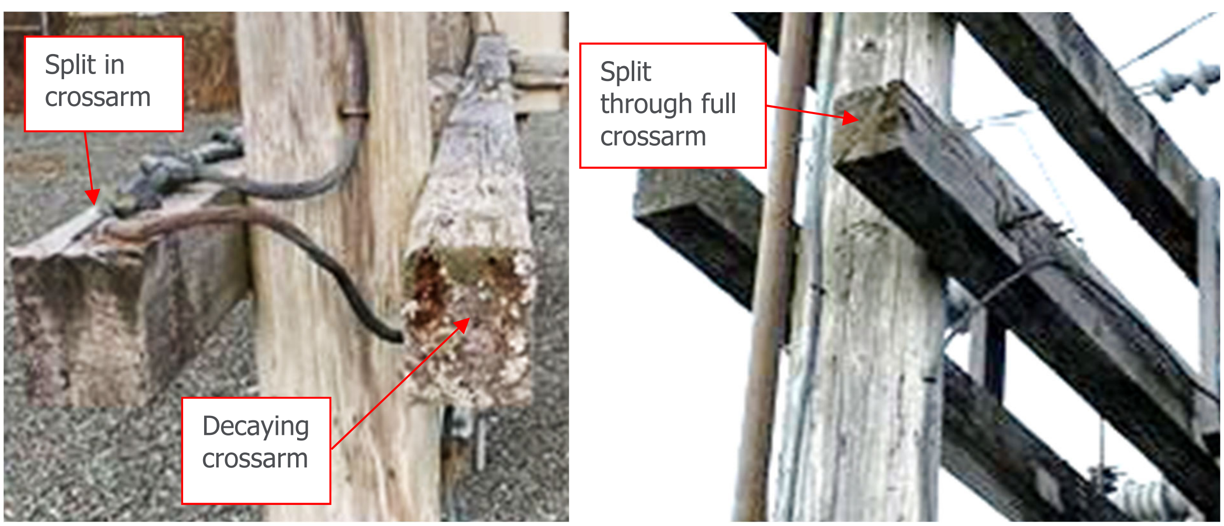



*Figure D-4 - Deteriorated Wood Crossarms*

The deteriorated condition of the wood structures compromises their ability to support the weight of critical substation equipment such as switches and potential transformers, increasing the probability of failure.

The switches on the 12.5 kV wooden structures are in excess of 30 years in service and are deteriorated. These switches, including two hook stick switches and one air break switch, require replacement as a result of their mechanical operating condition and corrosion.

The 12.5 kV feeder recloser, ISL-01-R, was manufactured by G&W in 2017. It is in good condition and will be reconnected to the new bus structure. The ISL Substation voltage regulators were manufactured by Cooper Power Systems in 2020.[8] They are in good condition and will be reconnected to the new bus structure. The oil-filled voltage regulators currently lack spill containment. A spill containment foundation is required to protect against environmental damage in the event of an oil spill from the units.

The oil-filled metering tank is currently 49 years old and is at the end of its service life. This will be replaced with a combined dry-type current and potential transformer.

## 2.4 Protection and Control

Power transformer ISL-T1 protection is provided by a set of fuses, and the feeder protection is provided by a microprocessor-based digital relay which will remain in service. The two new proposed 66 kV transmission line breakers with associated microprocessor-based digital relays will provide improved protection, automation, and outage response times for both ISL and NHR substations. Modernization of the transmission line protection requires upgrading the existing substation communication functionality, which currently only includes a cellular modem inside the recloser cabinet. A communications gateway will provide remote control and monitoring of the new substations protection equipment from the Supervisory Control and Data Acquisition ("SCADA") system.[9] The communications gateway will provide a network connection to the SCADA system for all the substation devices that provide monitoring, protection and control of the transmission lines, distribution feeders, and substation transformer. The modernization will also allow for remote administration of upgraded devices.[10]

## 2.5 Control Building

The ISL Substation does not have an existing control building as the limited number of protection and control devices in service are able to fit in small outdoor control cabinets. A new control building is required to permit the installation of a 125 VDC battery system, full network and communication functionality, multiple protection relays, control switches, blocking switches, and other miscellaneous equipment.[11]

8 The ISL Substation regulator bank contains a total oil volume of 1,875 litres.

9 The enhanced capabilities provided by the microprocessor-based digital relays provide greater options for remote control and monitoring through the Company's SCADA system.

10 Remote administration of upgraded devices allows protection relays to be interrogated and reconfigured remotely. This allows engineers to interrogate protection relays from their office, providing quicker diagnosis of system problems and improved outage response times. Without this capability, engineers have to travel to the substation to interrogate the relay on site, thereby greatly increasing the time necessary to assess fault data.

11 Protection and communication devices housed in panels are required to be kept in a dry environment with temperature control.

## 2.6 Site Condition

The ISL Substation yard requires an extension to accommodate the increased footprint of the steel structures, the spill containment foundations, and a portable substation. Minor improvements to the site such as addressing drainage requirements, removing unsuitable soils and vegetation, and laying structural fill will be completed during the project.

The existing ground grid at ISL Substation has deficiencies that pose a risk to the safe and reliable operation of the electric equipment in the substation. There are sections of the yard with insufficient grounding and there are also missing connections between the main ground grid and the substation fence. A grounding study is necessary and the ground grid for the substation requires an upgrade to align with current standards and to cover the expanded substation yard and new equipment.

# 3.0 RISK ASSESSMENT

The *Islington Substation Refurbishment and Modernization* project will mitigate risks to the delivery of reliable service to customers from the Islington and New Harbour areas.

ISL Substation provides service to approximately 1,100 customers in the Islington area. There are also approximately 1,800 customers served by NHR Substation that could be affected by faults at ISL Substation. Equipment failure in ISL Substation could expose up to approximately 2,900 customers to the risk of outages. The time to restore service to customers depends on the nature of the failure and could range from several hours up to 36 hours.

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

The existing 65-year-old power transformer is the second oldest distribution power transformer in the Company’s fleet and is approaching end of life. ISL-T1 and the voltage regulators contain large amounts of insulating oil and lack standard spill containment. Proper spill containment is required to mitigate the risk of an environmental incident if an oil spill were to occur. Remediation costs associated with oil spills can be significant. In addition, a spill containment will minimize the surface area of an oil spill and thus provides fire protection benefits.

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

Overall, refurbishment and modernization of ISL Substation is necessary to ensure the continued delivery of reliable, safe and environmentally responsible service to customers in the Islington and New Harbour areas.

## 4.0 ASSESSMENT OF ALTERNATIVES

In the case of ISL Substation, the number of components requiring preventative and corrective maintenance at this time justifies the refurbishment and modernization of the substation as a two-year project commencing in 2024. Power transformer ISL-T1 is the Company's second oldest distribution power transformer and is approaching the end of its useful service life. The 12.5 kV wood pole structures are deteriorated and require replacement. There are a number of deteriorated switches, which require replacement. The power transformer and voltage regulators do not have a spill containment foundation. The ground grid requires upgrades and the metering tank is at end of life.

Deferral of the *Islington Substation Refurbishment and Modernization* project increases the risk that some components will be run to failure. Run to failure is not a viable alternative as it increases risks to the delivery of safe and reliable service to approximately 1,100 customers in the Islington area and also could impact approximately 1,800 customers in the New Harbour area who rely on service provided by Transmission Line 80L.

## 5.0 PROJECT SCOPE

The 2024 and 2025 scope of work at ISL Substation includes the following:

- (i) Complete a yard extension;
- (ii) Construct a new control building;
- (iii) Construct new 66 kV and 12.5 kV steel structures;
- (iv) Install new power transformer with spill containment foundation to replace ISL-T1;
- (v) Install two new 66 kV transmission line breakers and associated switches;
- (vi) Construct new spill containment foundation and connect existing voltage regulators;
- (vii) Replace all deteriorated 66 kV and 12.5 kV switches;
- (viii) Install new 66 kV potential transformers;
- (ix) Install new 12.5 kV combined current and potential transformer to replace end-of-life metering tank;
- (x) Install new digital relays and the associated communications equipment; and
- (xi) Upgrade and extend the ground grid.

Engineering design and procurement of long lead equipment will be completed in 2024. Construction will begin in the second quarter of 2025 and will be completed early in the fourth quarter of 2025. Commissioning of the substation will be completed during the fourth quarter of 2025.

Table D-1 summarizes the age and condition of the primary equipment planned to be replaced.

| Table D-1<br>2024 Planned Equipment Replacements<br>Islington Substation | | |
|---|---|---|
| Equipment | Age (Years) | Condition |
| ISL-T1 Power Transformer | 65 | End of Life |
| 66 kV Wood Pole Structures | 38 | Deteriorated |
| 12.5 kV Wood Pole Structure | 49 | Deteriorated |
| 12.5 kV Metering Tank | 49 | Deteriorated/End of Life |
| 12.5 kV Air Break Switches | 49 | Deteriorated/End of Life |
| 12.5 kV Hook Operated Switches | 49 | Deteriorated/End of Life |

## 6.0 PROJECT COST

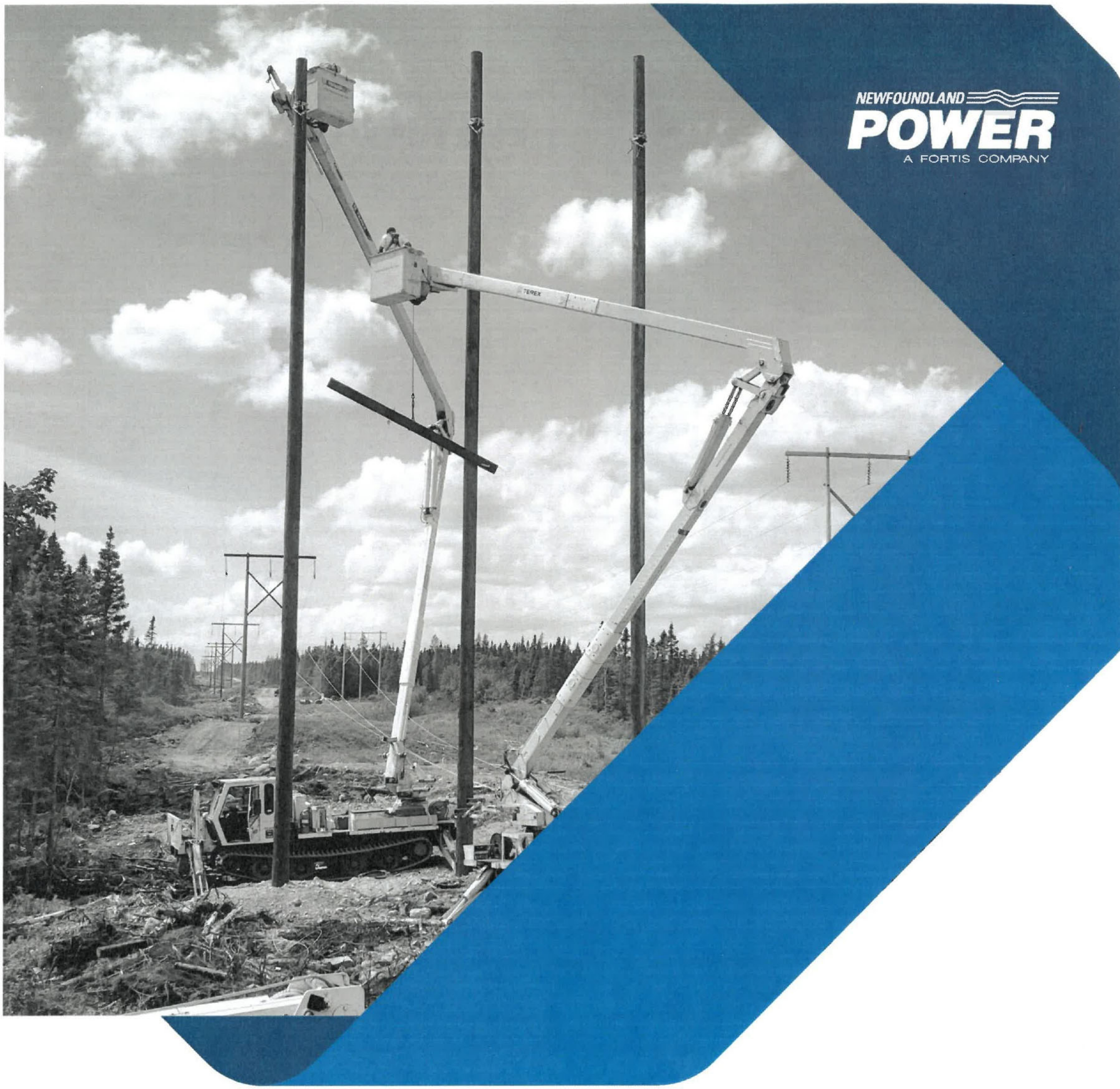
Table D-2 provides the cost breakdown for the *Islington Substation Refurbishment and Modernization* project.

| Table D-2<br>Project Cost Estimate<br>($000s) | | | |
|---|---|---|---|
| Cost Category | 2024 | 2025 | Total |
| Material | 60 | 3,620 | 3,680 |
| Labour - Internal | - | 193 | 193 |
| Labour - Contract | - | - | - |
| Engineering | 241 | 350 | 591 |
| Other | 7 | 543 | 550 |
| Total | $308 | $4,706 | $5,014 |

Proposed expenditures for the *Islington Substation Refurbishment and Modernization* project are $308,000 in 2024 and $4,706,000 in 2025 for a total project cost of $5,014,000.

## 7.0 CONCLUSION

The *Islington Substation Refurbishment and Modernization* project is required to provide reliable service to customers at the lowest possible cost. It will address the deteriorated and obsolete equipment identified through an engineering assessment of ISL Substation. A new power transformer will replace the existing unit that is approaching the end of life. New 12.5 kV steel structures will replace the deteriorated wood structures, new 66 kV steel structures will be installed to accommodate two new breakers and new digital relays that will provide improved automation and protection. The deteriorated wood mounted switches will be replaced. New spill containment foundations will be installed for the voltage regulators and new power transformer to protect against environmental hazards. The total project cost to complete the *Islington Substation Refurbishment and Modernization* project in 2024 and 2025 is estimated to be $5,014,000.




# 3.1 2024 Transmission Line Rebuild

## June 2023

Prepared by: Jonathan O'Reilly, P. Tech.
Approved by: Adam Scott, P. Eng.

LICENSED PROFESSIONAL ENGINEER
10579
ADAM D.G. SCOTT
A Scott
SIGNATURE
13/06/23
DATE
NEWFOUNDLAND & LABRADOR

# TABLE OF CONTENTS

Page

## 1.0 INTRODUCTION

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") transmission lines are the backbone of the electricity system providing service to customers. The Company maintains approximately 2,100 kilometres of transmission lines that operate at 66 kV or 138 kV.

Transmission line failures typically result in outages to a significant number of customers at once. Maintaining transmission lines is therefore critical to the delivery of reliable service to customers.

The 2024 *Transmission Line Rebuild* project includes a new multi-year project to rebuild Transmission Line 146L in 2024 and 2025.

## 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 27 transmission lines have been rebuilt under the strategy since 2006. With transmission lines 94L and 55L currently being rebuilt, approximately 85% of the strategy will be executed by the end of 2024.[1] Newfoundland Power plans to continue implementation of the *Transmission Line Rebuild Strategy* in 2024 and 2025 by rebuilding Transmission Line 146L.

## 3.0 TRANSMISSION LINE 146L

### 3.1 General

Transmission Line 146L is a 138 kV line running between Gander ("GAN") Substation and Gambo ("GAM") Substation. The transmission line serves as a critical element of the Central Newfoundland 138 kV looped transmission system which is supplied primarily from Sunnyside ("SUN") and Stony Brook ("STY") infeed supply points from

[1] Three transmission lines have been removed from the strategy since 2006. Transmission lines 101L and 102L have been addressed as part of the Central Newfoundland System Planning Study. Transmission Line 53L is no longer in service. This brings the total number of transmission lines encompassed by the strategy to 34. Transmission lines 94L and 55L are scheduled for completion in 2024, which will bring the total number of lines rebuilt as part of the strategy to 29 (29 / 34 = 0.85, or 85%). Three of the five remaining transmission line 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 2029.

Newfoundland and Labrador Hydro's ("Hydro") bulk power system. The SUN-STY loop is a key transmission supply network providing power to 35 Newfoundland Power substations.

Figure 1 is a diagram of the Central Newfoundland 138 kV looped transmission network.

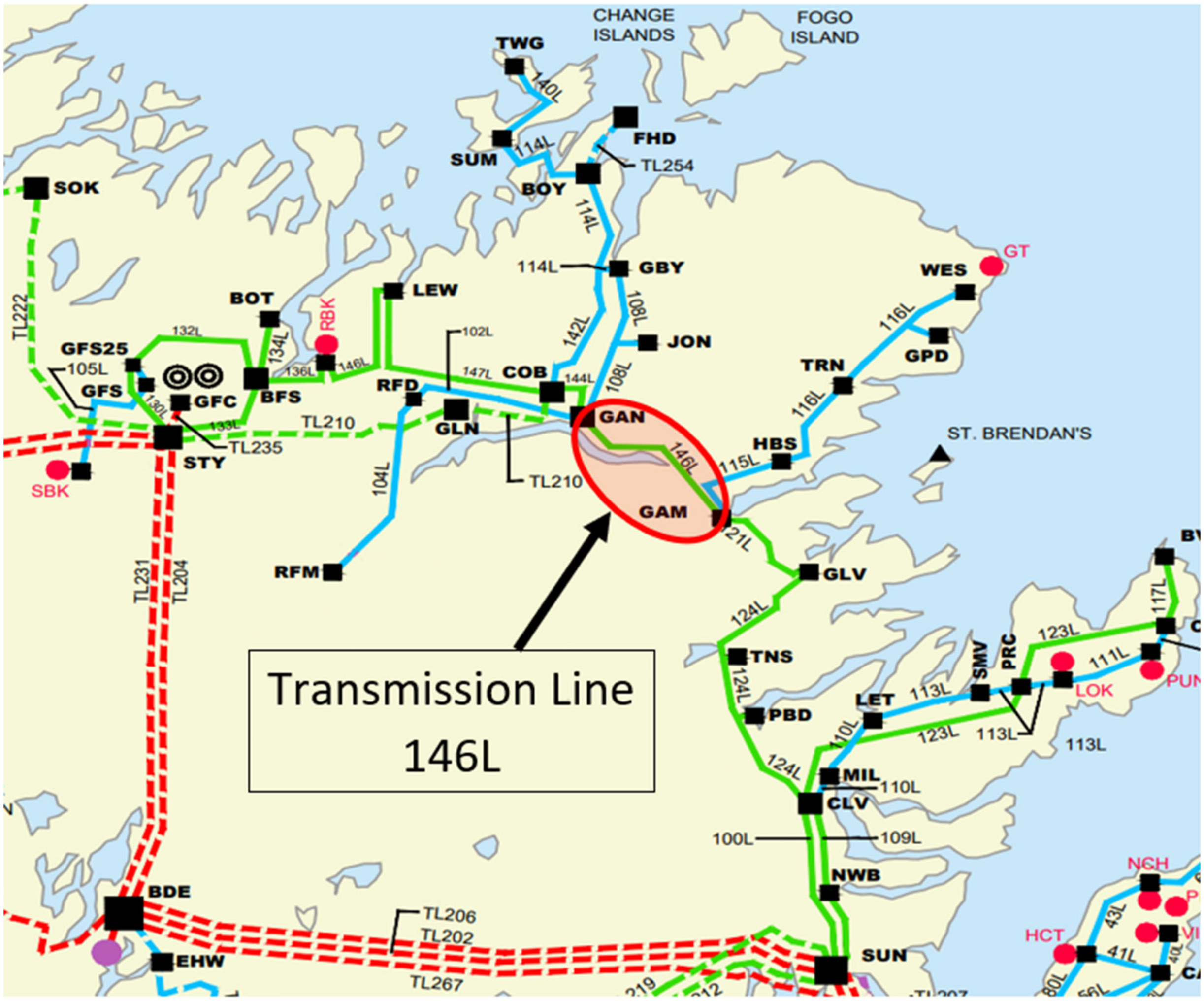


*Figure 1 - Central Newfoundland 138 kV Loop*

## 3.2 Condition Assessment

Transmission Line 146L was originally constructed in 1964 and is 40.7 kilometres in length. The line consists of approximately 160 H-Frame structures with a combination of 244.4 ACSR and 397.5 ACSR conductor.[2] Having been in service for almost 60 years the

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

conductor is approaching the end of the typical useful service life for transmission line conductor.[3]

Transmission Line 146L does not meet current standards for the construction of overhead lines.[4] The Canadian Standards Association ("CSA") establishes standards for the construction of overhead systems based on local climatic conditions. At the time of construction in 1964, Transmission Line 146L was designed to withstand sustained winds of 90 km/hour. CSA standards require that overhead lines be constructed based on actual historical climate data. Based on this parameter and actual historical wind speed data provided in the standard, Transmission Line 146L should be designed to withstand winds of upwards of 120 km/hour, which is over 33% higher than its current design.[5] The substandard design of this line means it is not built to withstand local climatic conditions, which increases its probability of failure.

Transmission Line 146L has been inspected annually over the last decade. Annual inspections are conducted by experienced Planners following the Company's *Transmission Line Inspection and Maintenance Practices*. In conducting annual inspections, Planners create work requests to correct identified deficiencies. Work requests are categorized as Emergency, TD1, TD2 or TD4.[6] TD4 work requests represent deficiencies to be addressed as part of Newfoundland Power's longer-term capital planning process. The Company monitors these work requests to inform its future capital investment priorities.

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

4 As noted in Newfoundland Power's 2006 *Transmission Line Rebuild Strategy*, 37 of Newfoundland Power's transmission lines constructed between the 1940s and 1960s were not built to adequate design and construction standards by present day criteria. For example, the current version of CSA standard C22.3 – Overhead Systems includes design criteria for maximum wind load conditions which were not considered in the original design of 146L.

5 CSA Standard C22.3 – Overhead Systems states *"it is mandatory in the standard to consider a maximum wind-only weather load case in the design of overhead lines. The magnitude of this wind is required, as a minimum value, to be that which can be predicted to occur at least once in every 50-year period."*

6 The highest priority for Planners inspecting transmission lines is to identify deficiencies categorized as Emergencies, TD1 or TD2. These deficiencies require action over the near term to address or avoid failure of transmission assets. Work requests for Emergency deficiencies must be addressed immediately. Work Requests for TD1 deficiencies must be addressed within seven days and those for TD2 deficiencies must be addressed within one month.

Table 1 provides the number of TD4 work requests created following annual inspections of Transmission Line 146L over the last 10 years.

Table 1
Transmission Line 146L
TD4 Work Requests

| Year | Annual |
|---|---|
| 2014 | 12 |
| 2015 | 14 |
| 2016 | 12 |
| 2017 | 14 |
| 2018 | 10 |
| 2019 | 14 |
| 2020 | 22 |
| 2021 | 44 |
| 2022 | 84 |
| 2023 | 156 |

The number of TD4 work requests created for Transmission Line 146L has increased over the last decade, with additional deficiencies identified annually. This shows the line's condition has deteriorated considerably over time.

Newfoundland Power initiated an engineering assessment of Transmission Line 146L in response to the line's deteriorating condition. A detailed inspection of the line was completed in 2023 to quantify its overall condition. The inspection determined that 104 of 160 H-Frame structures have deficiencies.

A total of 94 of 160 H-Frame structures have deteriorated poles, with the majority of these structures having both poles deteriorated. In total, there are 192 poles that require replacement.[7] The deteriorated condition of these poles is to be expected given they have exceeded the typical useful service life of a transmission line wood pole.[8]

Many of the poles on Transmission Line 146L have significant shell separation, as shown in Figure 2. Shell separation occurs when the pole shrinks over time and the outer shell separates from the core of the pole. This creates a safety risk for employees climbing the poles to

7 An additional 98 poles were inspected and found to be in moderate condition. These poles are original 1964 vintage and are exhibiting splits and cracks.

8 Transmission Line 146L has been in service for 59 years. Industry experience indicates the typical useful service life of a transmission wood pole is 58 years. See Newfoundland Power's *2024-2028 Capital Plan, page 10.*

perform maintenance as the deteriorated shell is unable to support the weight of the climber and the climber's spikes can tear out of the pole. It also leaves the core of a pole exposed to moisture and fungus, which accelerates wood rot, compromising its strength over time and increasing the probability of failure.


*Figure 2 – Shell Separation on 146L*

The poles comprising Transmission Line 146L are also experiencing severe splits and woodpecker holes as shown in Figure 3. Similar to shell separation, deep splits and woodpecker holes can undermine the strength of a pole and introduce avenues for internal decay. Sounding tests also determined that many of these poles are exhibiting hollowness, meaning their strength has already been compromised.[9]

*Figure 3 –Split Poles with Numerous Woodpecker Holes on 146L*

Numerous hardware deficiencies were observed on the H-Frame structures comprising Transmission Line 146L. This includes 90 worn ball link eye bolts used to connect insulators to cross arms, failure of which can result in the energized conductor falling free from the cross arm.[10] It also includes 42 porcelain Canadian Ohio Brass ("COB") insulators, which are non-standard and prone to failure due to cement growth.[11] Figure 4 shows an example of the worn ball link eye bolts on 146L.

9 A sounding test is conducted using a flat faced hammer to sound the pole surface at regular intervals. If a hollow sound is detected, it indicates that decay is present. Poles that have been in service more than 35 years require a sounding test during each inspection. If a sounding test indicates a potential problem, a core sampling test can be completed by drilling through the centerline of the pole to observe the decay.

10 The ball link eye bolts are designed to allow for movement between components to provide flexible support for suspension insulators. This movement causes friction between the components, and over time can result in the pieces wearing. If the eyebolt is completely worn through the insulator can separate from the crossarm and fall free of the structure. This can cause a phase to ground fault that results in an outage and a serious safety hazard including forest fire risks.

11 Cement growth is the expansion of the material that holds in place the pin supporting the connection of the insulator to the pole and conductor. Cement growth causes hairline cracks in the porcelain, weakening the insulator leading to electrical and mechanical failure. The Company's new standard insulator is a toughened glass insulator.

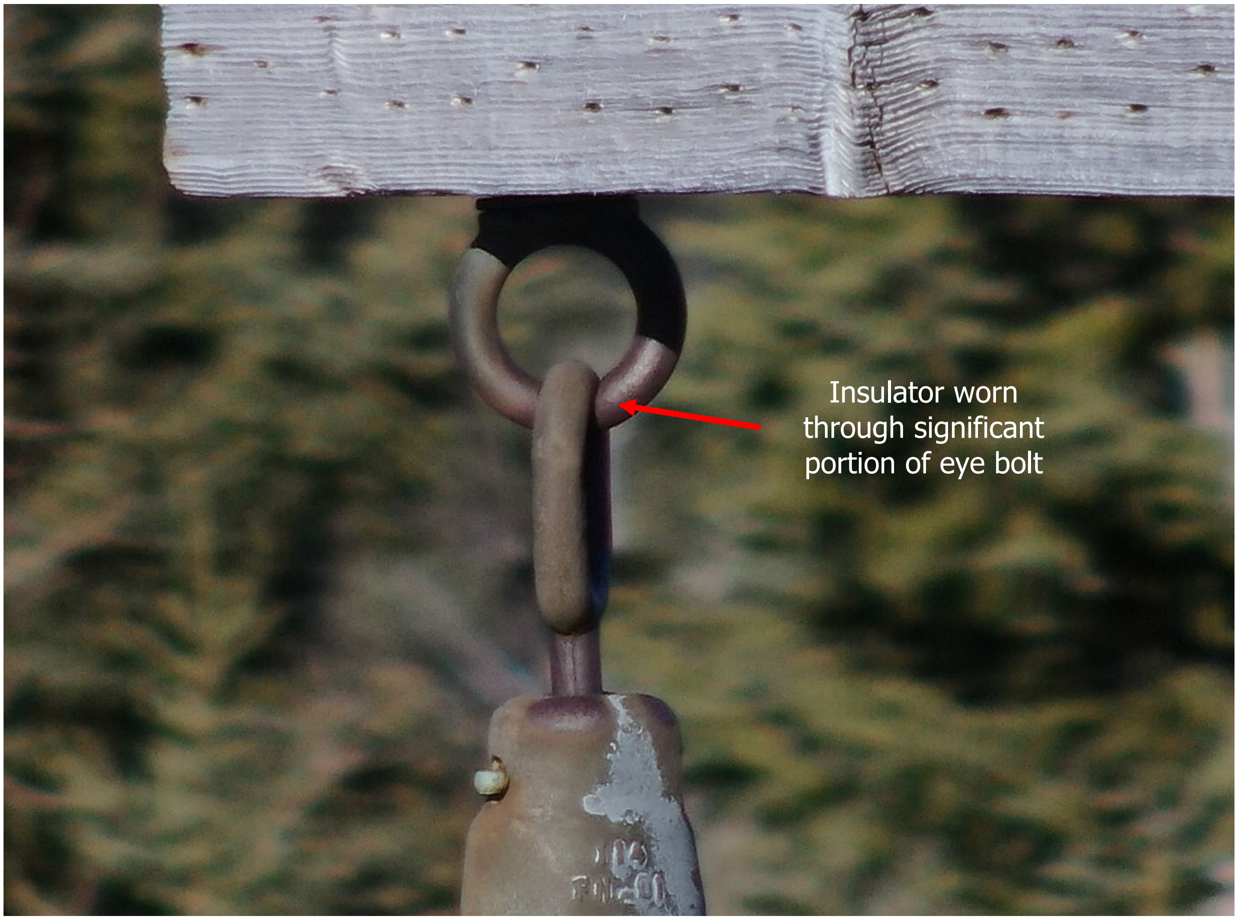



*Figure 4 –Worn Ball Link Eye Bolt on 146L*

Appendix B provides additional photos of the deterioration present on Transmission Line 146L.

### 3.3 Risk Assessment

Due to their criticality in serving customers, Newfoundland Power's transmission lines must be maintained to operate to a high standard of reliability.[12] All transmission lines, including Transmission Line 146L, are maintained in accordance with the Company's *Transmission Inspection and Maintenance Practices*.[13]

The historical reliability performance of Transmission Line 146L has been reasonable. There have been three outage events over the last five years due to requirements to undertake preventative and corrective maintenance.

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

13 Over the last 10 years, approximately $247,000 has been spent on completing corrective and preventative maintenance of Transmission Line 146L.

Table 2 provides the list of all planned and unplanned outages for Transmission Line 146L from 2018 to 2022.

Table 2
146L Outage Events and Durations
(2018-2022)

| Date | Planned/ Unplanned | Outage Cause | Duration (Hours) |
|---|---|---|---|
| November 2018 | Unplanned | Severe Weather | 3.5 |
| December 2019 | Planned | Preventative Maintenance | 29.8 |
| July 2022 | Unplanned | Equipment Failure | 44.2 |

While the historical reliability performance of Transmission Line 146L has been reasonable, the line's sub-standard design and deteriorated condition exposes it to an increased probability of failure going forward.[14]

Failures on Transmission Line 146L can leave the line out of service for long periods of time. The potential consequences for customers of prolonged outages to Transmission Line 146L are significant from two perspectives.

First, Transmission Line 146L plays a critical role in the Central Newfoundland 138 kV transmission system. An outage to Transmission Line 146L results in two sections of the Central Newfoundland 138 kV transmission system becoming radial. Following an outage, all substations in the Eastern half of the system from Port Blandford to Wesleyville would be radially supplied from the series of transmission lines originating from SUN Substation. When radially supplied, any single failure on one of these transmission lines could result in outages to between 4,900 and 8,700 customers downstream of the affected line. Similarly, on the Western portion of the system, Gander Substation would be radially supplied by Transmission Line 144L from Cobbs Pond Substation, increasing the risk of an outage to approximately 1,700 customers.

Second, Transmission Line 146L is required to maintain normal operating voltages on the transmission system under peak load scenarios. Recent analyses showed that a loss of Transmission Line 146L during peak load conditions would result in voltage levels within the looped transmission system dropping into the emergency range, increasing the risk of load shedding and customer outages.[15] The analysis also showed that Transmission Line 146L is essential to operating procedures required to avoid emergency voltage levels and overload

---

[14] For example, the Board stated in relation to the *Transmission Line 55L Rebuild* project included in Newfoundland Power's *2023 Capital Budget Application*, that it "does not take past reliability performance as evidence of future reliability performance, especially in light of the evidence showing the deteriorated condition of the line." See Board Order P.U. No. 38 (2022).

[15] Transmission Line 146L is subjected to annual reliability contingency analyses due to the criticality of the STY-SUN loop.

conditions in the event of other failures on the looped system.[16] Without Transmission Line 146L, such failures would likely lead to customer outages.

Overall, the criticality of Transmission Line 146L and its increased probability of failure create a high risk to the delivery of reliable service to a significant number of Newfoundland Power's customers. Transmission Line 146L was originally scheduled for rebuild in 2008 as part of the 2006 *Transmission Line Rebuild Strategy*. The rebuild of this line has been deferred for 15 years as a result of regular maintenance. Due it its deteriorated condition and increased risks to customers, a capital project is required to address the deficiencies present on the line.

## 4.0 ASSESSMENT OF ALTERNATIVES

### 4.1 General

Newfoundland Power evaluated two alternatives to address the deteriorated condition of Transmission Line 146L to mitigate risks to the delivery of reliable service to customers. These are: (i) address all deficiencies identified through inspection and defer the rebuild of the remainder of the line; and (ii) rebuild the existing line in a new, parallel right-of-way. These alternatives are discussed below.

### 4.2 Alternative 1 – Address Existing Deficiencies and Defer Rebuild

Alternative 1 involves addressing the identified deficiencies on Transmission Line 146L by performing required preventative maintenance in 2025. To facilitate the execution of this work, 2024 would be used as a planning year to complete required engineering, secure applicable approvals and permits, and complete the required brush clearing to enable access during construction. The focus of this maintenance work would be deteriorated poles and hardware which presently require replacement. Some temporary conductor replacement would be required to address changes in pole height for the new poles and the transition to the existing poles which will not be as high. This conductor would be spliced to the existing 60-year-old conductor.[17]

Under this alternative, the rebuild of the rest of Transmission Line 146L would be completed in 2028 and 2029.[18] At that point, the remaining line components would be in service for 65 years. Because the remaining components have exceeded their expected useful service life, an increased risk of equipment failure is expected.

---

16 The analysis encompassed five different reliability contingency scenarios, including the loss of transmission lines 124L, 144L, 137L and TL210, and the loss of power transformer SUN-T1 at Sunnyside Substation. For all five of these scenarios, the operating procedures that are in place require Transmission Line 146L to be available in order to mitigate the low voltage and overload conditions.

17 After all of the replacement poles and temporary splices have been installed the entire length of transmission line would need to be tensioned to ensure the proper sagging is in place.

18 An additional planning year would be required in 2027 to allow for the completion of engineering and permitting activities in advance of the restart of construction.

Table 3 provides the capital costs associated with Alternative 1.

Table 3
Alternative 1 Capital Costs
($000)

| Year | Item | Cost |
|---|---|---|
| 2024 | Engineering, permitting and brush clearing | 1,715 |
| 2025 | Address Existing Deficiencies | 4,103 |
| 2027 | Engineering, permitting and brush clearing | 477 |
| 2028 | Rebuild 20km of Transmission Line 146L | 3,652 |
| 2029 | Rebuild 20km of Transmission Line 146L | 3,673 |
| | Total | 13,620 |

Alternative 1 introduces a number of inefficiencies to the rebuild of Transmission Line 146L. The deteriorated structures identified for replacement in the initial scope of work are located across the entire 40.7 kilometre length of the line. As a result, additional time will be required to access selected structures as construction crews move along the line, increasing the difficulty of moving resources and materials during the work. Additionally, in order to ensure future rebuild of this line adheres to current design standards, the new poles being installed may need to be higher than the existing poles that are being replaced. Installing a large number of poles of greater height will require additional conductor to be spliced onto the existing conductor.[19] The conductor will also have to be re-sagged when all of the poles are replaced.

Similar issues will exist when the remaining structures are replaced in 2028 and 2029. During the completion of this scope, the remaining structures will be replaced and additional structures will have to be added to the line to again ensure the design meets present day standards. This work will also be spread across the entire length of the line, and will cause inefficiencies in construction. Finally, the existing conductor will have to be removed and replaced.

Alternative 1 presents additional reliability risks to the Central Newfoundland 138 kV looped transmission system. To complete this alternative, Transmission Line 146L will have to be taken out of service for approximately four months in each year that construction will be taking place. During this planned work, customers would be exposed to an increased risk of outages as a number of transmission lines would become radially supplied for prolonged periods of time. An outage on any of these lines during the construction activities will result in outages to customers. The rough terrain and routing of the transmission lines in Central Newfoundland can result in lengthy restoration times for outages. To complete Alternative 1, up to 10,400

[19] The additional conductor will be required at the transition from the shorter poles to the taller poles, and from the taller poles to the shorter poles.

customers would be put at an increased risk of an outage while Transmission Line 146L is out of service for construction.

Overall, Alternative 1 causes unnecessary inefficiencies and duplication of work throughout the execution of the project. It also exposes customers to increased risks of outages during the completion of the work due to the existing line being offline for prolonged periods each year.

### 4.3 Alternative 2 – Rebuild in a Parallel Right-of-Way

Alternative 2 involves rebuilding Transmission Line 146L in a new, parallel right-of-way. Under this alternative, the existing line would remain energized throughout the project while a new line is constructed in a transmission right-of-way parallel to the existing line. Once completed, the original line would be de-energized and removed.

Table 4 includes the capital costs associated with Alternative 2.

Table 4
Alternative 2 Capital Costs
($000)

| Year | Item | Cost |
|---|---|---|
| 2024 | Engineering, permitting and brush clearing | 2,152 |
| 2025 | Rebuild 40km of Transmission Line 146L | 9,209 |
| | Total | 11,361 |

Alternative 2 ensures the continued reliability of the Central Newfoundland 138 kV looped transmission system during the execution of the project. Since the existing line is able to stay in service during the construction of the new line, it would avoid exposing thousands of customers to the increased risk of outages associated with transmission lines being radially supplied for prolonged periods of time.

Additionally, rebuilding the entire line in a single construction season allows for the efficient execution of the project with no duplication of work during construction.

Overall, this alternative would avoid exposing customers to increased risks of outages while the scope of work is being completed and would provide the greatest value in terms of construction efficiencies.[20]

[20] During construction the existing 146L will remain in service. After the new line is constructed the existing 146L will be taken out of service and the new line will be connected to the Central Newfoundland 138 kV transmission system. There will be no customer outages required to transition from the existing line to the new line.

## 4.4 Net Present Value Analysis of Alternatives

A net present value ("NPV") calculation of customer revenue requirement was completed for both alternatives. Capital costs from all years were converted to the customer revenue requirement and an NPV was calculated using the Company's weighted average incremental cost of capital.

Table 5 includes the results of the NPV analysis for the two alternatives.

Table 5
Net Present Value Analysis
($000)

| Alternative | NPV |
|---|---|
| 1 – Address Existing Deficiencies and Defer Rebuild | 13,830 |
| 2 – Rebuild in a Parallel Right-of-Way | 12,615 |

The NPV analysis determined that Alternative 2, which involves rebuilding Transmission Line 146L in a new right-of-way, is the lowest cost alternative.

A sensitivity analysis was completed of Alternative 1, which involves addressing existing deficiencies in 2025 and deferring the rebuild of the remainder of the line until 2028 and 2029. The sensitivity analysis evaluated the impact of advancing and deferring the rebuild of the remaining structures not addressed in 2025.

Table 6 provides the sensitivity analysis of Alternative 1 based on the NPV of customer revenue requirement.

Table 6
Sensitivity Analysis of Alternative 1
($000)

| Base Case NPV | Advanced Replacement NPV | Deferred Replacement NPV |
|---|---|---|
| 13,830 | 13,945 | 12,663 |

The Base Case NPV is described in section 4.2 and summarized in Table 5. In the Base Case, the remaining structures not addressed in 2025 would be addressed in 2027 through 2029. In the Advanced Replacement sensitivity case, the remaining structures not addressed in 2025 would be addressed in 2026 and 2027. In the Deferred Replacement sensitivity case, the remaining structures not addressed in 2025 would be addressed in 2033 and 2034.

The sensitivity analysis of Alternative 1 determined that advancing the future replacements to 2028 and 2029 increased the NPV to $13.9 million. Further deferral of the remaining rebuild of the line to 2033 and 2034 results in an NPV of $12.7 million. In both cases, Alternative 2 remains the least-cost alternative to address the deterioration identified on Transmission Line 146L.

Based on the NPV and associated sensitivity analysis, Alternative 2 is the least-cost alternative to address the deficiencies on Transmission Line 146L.

## 5.0 PROJECT SCOPE AND COST

Transmission Line 146L is proposed to be rebuilt as a multi-year project. In 2024, the work consists of engineering and pre-construction activities, including securing environmental and development permits and approvals, acquiring property rights, completing brush clearing of the new right-of-way, collecting topographic data, finalizing the engineering design, and ordering materials. In 2025, the work consists of establishing construction contracts and completing construction of the new line.

Appendix C shows the proposed routing of Transmission Line 146L once rebuilt and the location of the existing line.

Table 7 provides a breakdown of the cost to rebuild Transmission Line 146L.

Table 7
Transmission Line 146L Rebuild Project Cost
($000s)

| Description | 2024 | 2025 | Total |
|---|---|---|---|
| Engineering | 161 | 173 | 334 |
| Labour - Contract | - | 4,645 | 4,645 |
| Labour - Internal | - | 167 | 167 |
| Material | - | 3,884 | 3,884 |
| Other | 1,991 | 340 | 2,331 |
| Total | $2,152 | $9,209 | $11,361 |

The cost of rebuilding Transmission Line 146L is estimated at $11,361,000, including $2,152,000 in 2024 and $9,209,000 in 2025.

## 6.0 CONCLUSION

Transmission Line 146L forms an integral part of the Central Newfoundland 138 kV transmission system that is critical to the delivery of reliable service to customers in Central Newfoundland. The line was constructed in 1964, is not built to current engineering standards, and has become deteriorated. The line's sub-standard design and deteriorated condition increase the probability of failure. This, in turn, increases the risk of customer outages.

The rebuilding of Transmission Line 146L has been deferred by over 15 years. An assessment of alternatives determined that rebuilding Transmission Line 146L in a parallel right-of-way is the least-cost alternative to mitigate risks to the delivery of reliable service to customers. The proposed project will address deficiencies identified during inspection, eliminate non-standard equipment and ensure Transmission Line 146L is constructed to meet current engineering standards. This will enable the continued delivery of reliable service to customers served by the Central Newfoundland 138 kV transmission system.

# APPENDIX A:

## Transmission Line Rebuild Schedule: 2024-2028

| Table A-1<br>Transmission Line Rebuild Schedule<br>2024-2028<br>($000s) | | | | | | |
|---|---|---|---|---|---|---|
| Line | Year Built | 2024 | 2025 | 2026 | 2027 | 2028 |
| 55L BLK-CLK | 1971 | 5,284 | | | | |
| 94L BLK-RVH | 1969 | 4,276 | | | | |
| 146L GAN-GAM | 1964 | 2,152 | 9,209 | | | |
| 108L GAN-GBY | 1965 | | 1,584 | 10,340 | 5,642 | |
| 35L OXP-APT | 1965 | | | 546 | | |
| 48L BRB-BLK | 1967 | | | 1,480 | 5,842 | |
| 86L WAV-BLK | 1969 | | | | 972 | 3,489 |
| 95L RVH-TRP | 1969 | | | | 1,735 | 8,635 |
| 100L SUN-CLV | 1964 | | | | | 1,889 |
| 105L SBK-GFS | 1969 | | | | | 654 |
| TOTAL | | 11,712 | 10,793 | 12,366 | 14,191 | 14,667 |

# APPENDIX B:

## Photographs of Transmission Line 146L

*Figure B-1 – Void in Pole Top, Hollow Pole*

*Figure B-2 – Deep Splits in Pole*

*Figure B-3 – Severe Splits in Pole through Cross Arm Bolt Locations*

*Figure B-4 – Large Crack through Cross Brace*

*Figure B-5 – Large Split in Pole, Hollow*

*Figure B-6 – Split through Pole Top, Woodpecker Holes*

*Figure B-7 – Pole Top Damage, Splits, Woodpecker Holes*

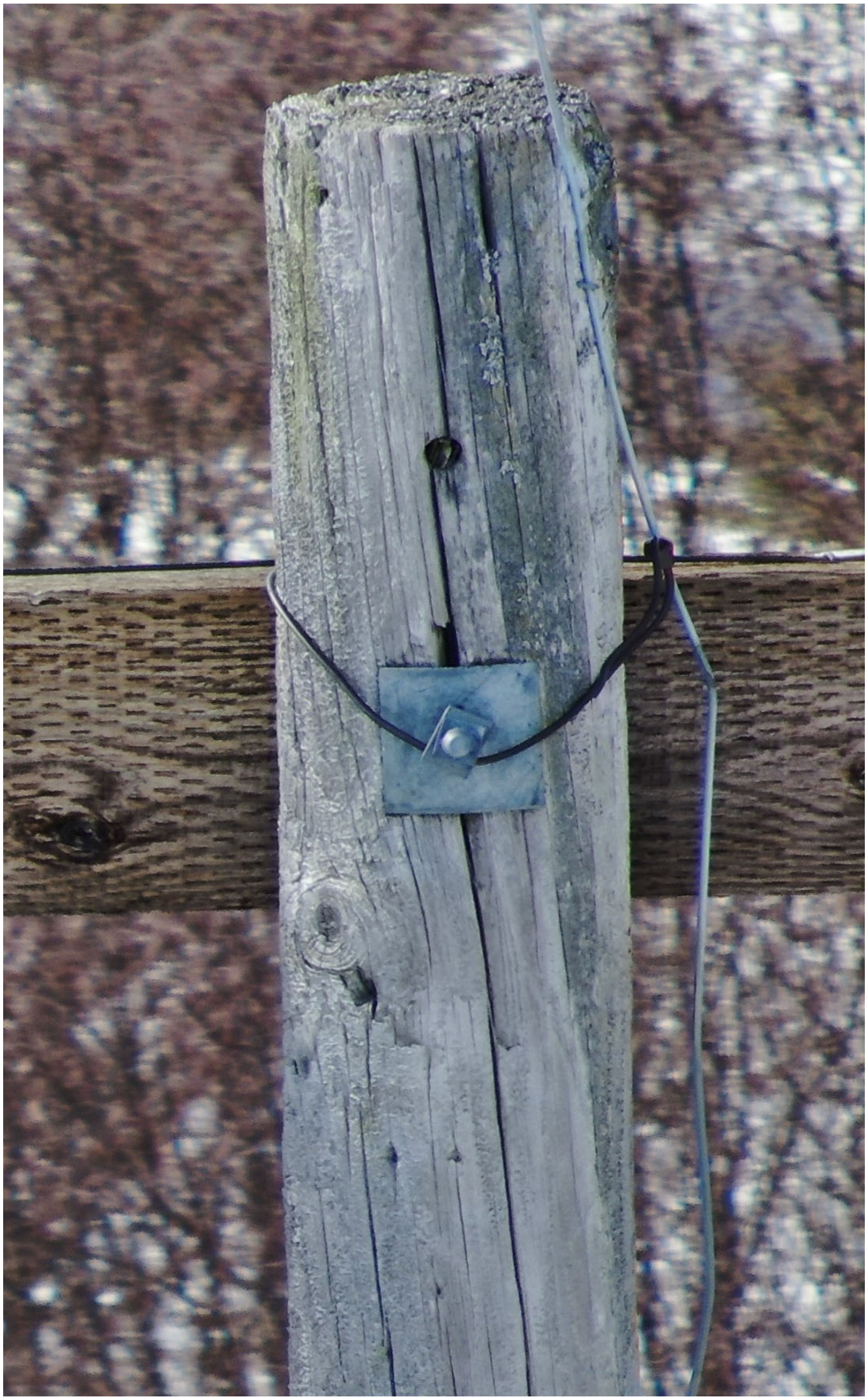


*Figure B-8 – Deep Splits and Void in Pole through Cross Arm Bolt*

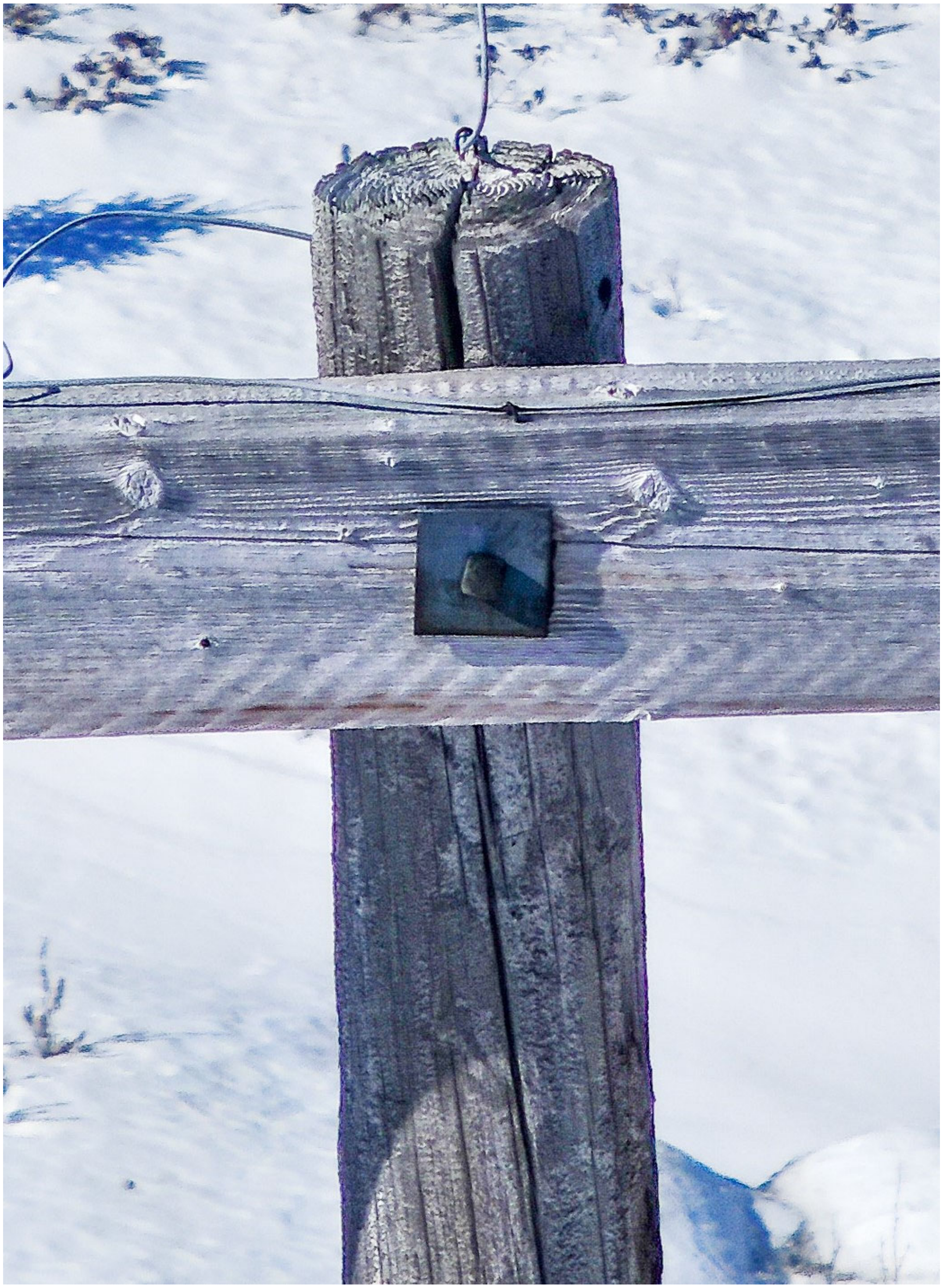


*Figure B-9 – Deep Splits in Pole Top and Pole through Cross Arm Bolt*

Figure B-10 – Shell Separation and Missing Crib

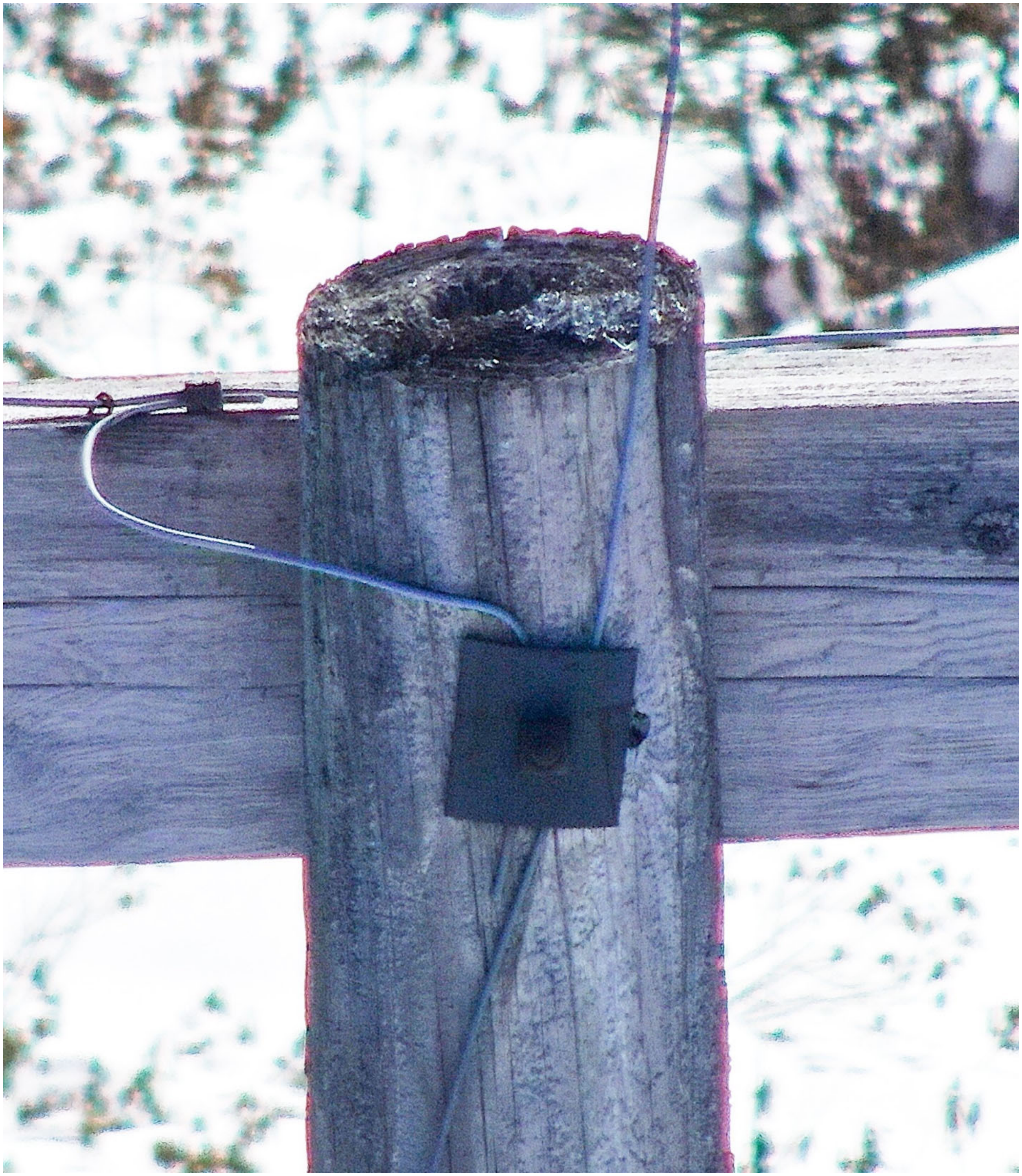


*Figure B-11 – Hole in Top of Pole, Hollow*

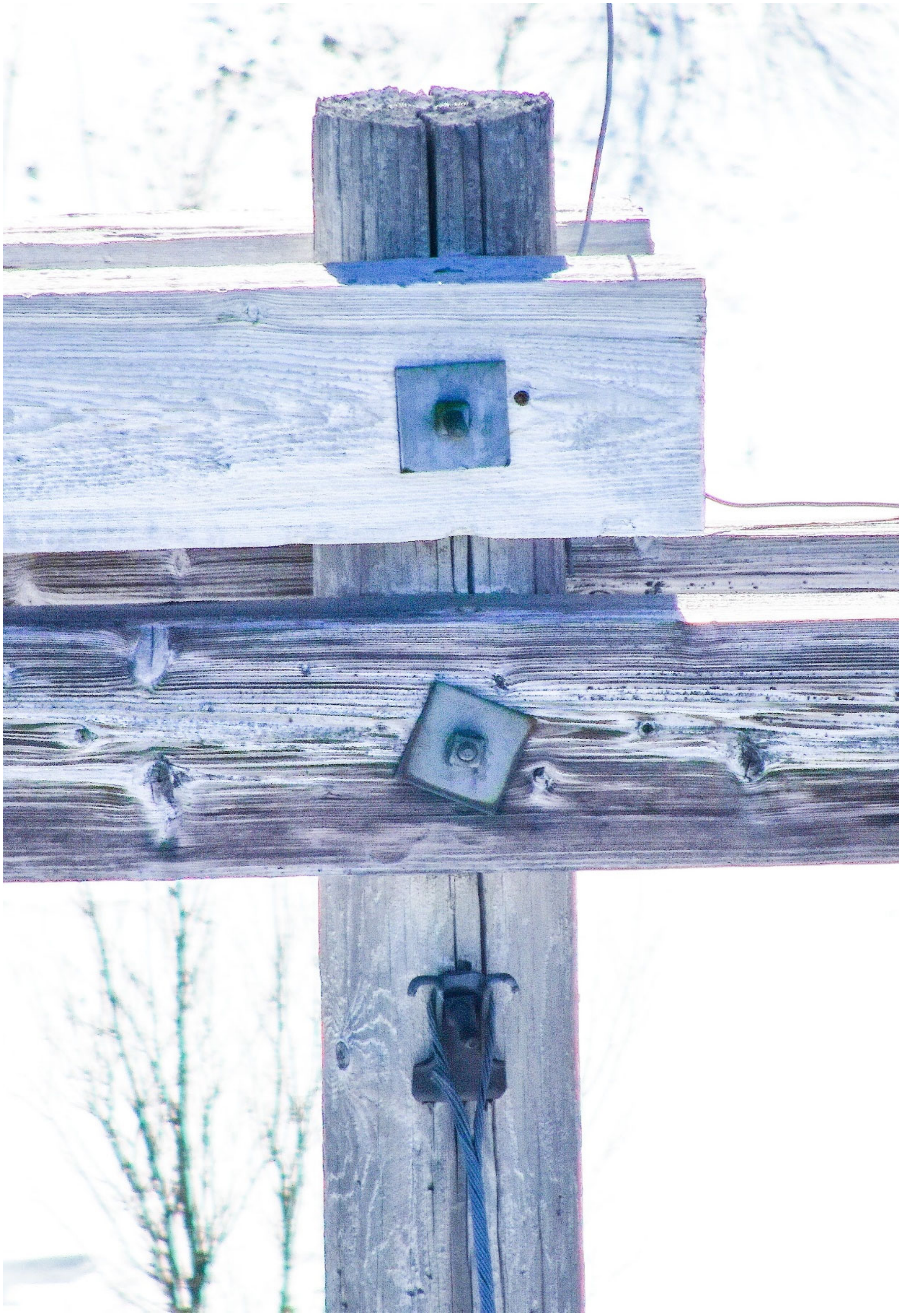


*Figure B-12 – Severe Pole Splits through Cross Arm Bolts, Extra Arm Installed for Temporary Support*

*Figure B-13 – Pole Damage and Horizontal Crack*

Figure B-15 - Pole Rot

# APPENDIX C:

## Map of Transmission Line 146L

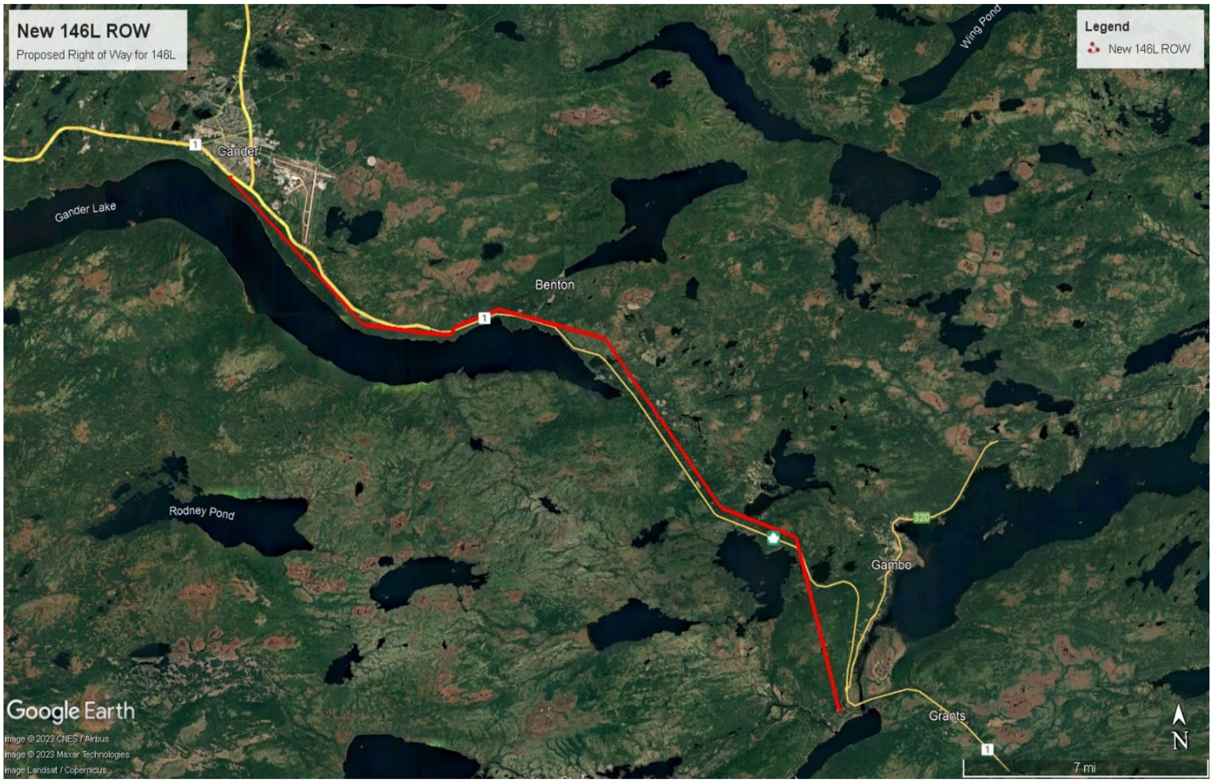
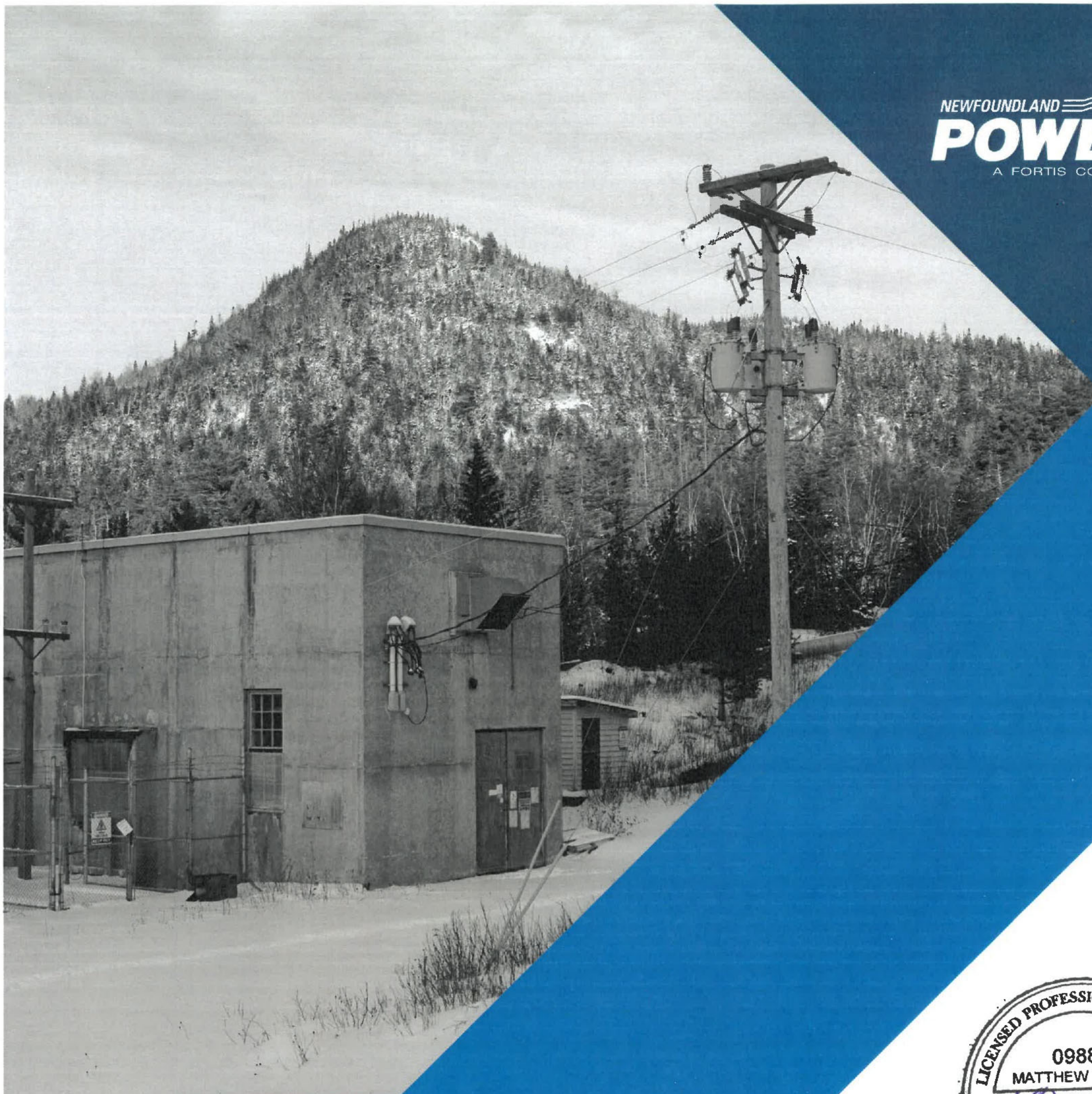



*Figure C-1 - Map of Transmission Line 146L*

NEWFOUNDLAND
POWER
A FORTIS COMPANY



LICENSED PROFESSIONAL ENGINEER
09888
MATTHEW J. DAVIS
SIGNATURE
16-Jun-2023
DATE
NEWFOUNDLAND & LABRADOR

# 4.1 Lookout Brook Hydro Plant Refurbishment

## June 2023

Prepared by: William Casey, E.I.T.
Approved by: Matthew Davis, P. Eng.

# TABLE OF CONTENTS

Page

## 1.0 INTRODUCTION

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") Lookout Brook hydroelectric generating plant (the "Lookout Brook Plant" or the "Plant") is located in western Newfoundland near the community of St. George's.

Newfoundland Power is proposing a multi-year project to refurbish the Plant to address deficiencies identified through inspections. The project includes: (i) rewinding and reinsulating a generator rotor, stator, and exciter; (ii) addressing deficiencies in the building envelope and crane; and (iii) replacing a main inlet valve.

The *Lookout Brook Hydro Plant Refurbishment* project is estimated to cost $1,935,000, including $362,000 in 2024 and $1,573,000 in 2025.

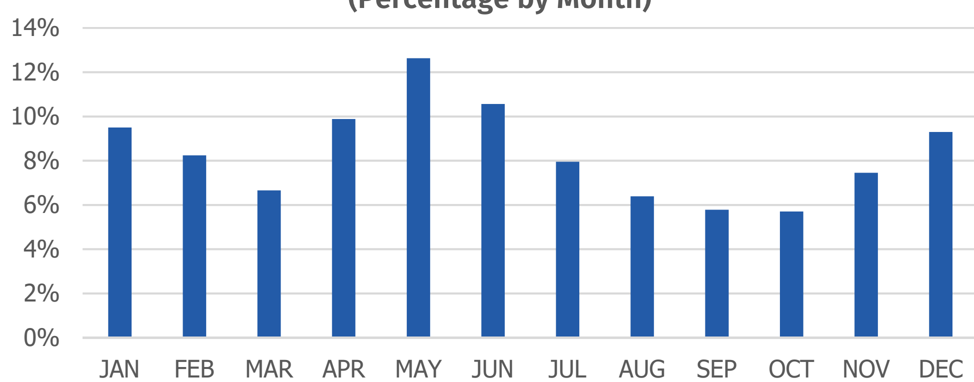
## 2.0 BACKGROUND

The Lookout Brook Plant was originally commissioned in 1946 with two generating units, G1 and G2. The Plant was upgraded in 1958 with a third generating unit, G3. Units G1 and G2 were replaced with a single larger generating unit, G4, in 1984. The Plant's current configuration includes units G3 and G4.

The Plant is a source of renewable hydroelectric generation on the Island Interconnected System. It has an operating capacity of 5.6 MW under a net head of 154.6 metres. Annual production from the Plant is 31.51 GWh, or approximately 7% of Newfoundland Power's annual hydroelectric production.[1] The Plant normally operates during all 12 months of the year.

Figure 1 shows the average production of the Lookout Brook Plant by month based on the most recent five-year average.

**Figure 1**
**Lookout Brook Average Annual Production**
**(Percentage by Month)**




[1] 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 Lookout Brook Plant at 31.51 GWh. This review placed Newfoundland Power's normal annual production at 438.4 GWh.

The Lookout Brook 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").[2] These requests are most often received during the winter peak period, although non-peak operation is also requested.

Table 1 lists the upgrades completed at the Lookout Brook Plant over the last 25 years.

Table 1
Lookout Brook Plant Upgrades

| Year | Upgrade |
|---|---|
| 1998 | G3 and G4 Main Valve Replacement |
| 1999 | G3 and G4 Turbine Overhauls and Runner Replacements |
| 2000 | Partial Penstock Replacement |
| 2005 | Vibration Monitoring System Upgrade for G3 and G4 |
| 2010 | Control Room Extension |
| 2010 | Governor Upgrades |
| 2010 | Plant Control Upgrades |
| 2010 | Switchgear Replacement |
| 2010 | AC Distribution, DC Distribution and Battery Bank Upgrades |
| 2013 | Sheep Brook Bridge Refurbishment |
| 2019 | Generator Bearing Replacement and Alignment |
| 2022 | Exciter and Commutator Emergency Repair |

The Plant has undergone two large-scale refurbishments in the last 25 years. Both generating units received a major mechanical refurbishment and turbine runner replacement in 1999. A subsequent refurbishment in 2010 addressed major plant systems, including governor systems, protection and control systems, switchgear, AC and DC distribution systems, and the addition of a new control room. Apart from these refurbishments, the Plant has received minor upgrades in response to in-service failures.

[2] From 2018 through 2022, Hydro requested generation 513 times. These requests are divided into Avalon hydro, island-wide hydro, and all-island generation requests. The Lookout Brook Plant is placed into service in response to island-wide hydro requests and all-island generation requests. Island-wide hydro requests and all-island generation requests accounted for 389 of the 513 requests made by Hydro since 2018.

# 3.0 CONDITION ASSESSMENT

## 3.1 General

Newfoundland Power conducted a detailed condition assessment of the Lookout Brook Plant in 2023 to identify deteriorated, obsolete and non-standard equipment. This included assessments of: (i) building systems; (ii) turbine and generator equipment; (iii) the G3 inlet valve; and (iv) ancillary equipment.

## 3.2 Building Systems

### *Powerhouse*

The powerhouse building consists of an original building from 1946 with additions of various vintages.[3] The building houses equipment critical to the operation of the Lookout Brook Plant, including the generators, turbines, governors, protection and control systems, and switchgear.

Figure 2 shows the powerhouse building with the 1958 addition in the foreground and the 2010 addition at the extreme left of the figure.

*Figure 2 – Powerhouse Building*

[3] The original powerhouse building was constructed in 1946 and an addition was added to accommodate G3 in 1958. A further addition was made in 2010 to relocate the control room and accommodate new protection and control panels installed at that time.

The condition assessment of the powerhouse building identified multiple deficiencies and significant deterioration. Deterioration was identified with the building's roof, windows and loading door.

A significant leak is present in the Plant building envelope. Water is penetrating the roofing structure through a large crack located in the seam between the original building and the 1958 addition. The seam is shown in Figure 3.[4] Figure 4 shows further detail of the crack in the powerhouse building's roof between the original building and the addition.

*Figure 3 – Seam Between Original Building and Addition*

*Figure 4 – Roof Crack Between Original Building and Addition*

4 This seam is circumferential to the building, continuing across the roof and down the other side of the building.

Multiple repair attempts have been made to address this leak, with the most recent being in 2022. These repair attempts have been unsuccessful. Water from the leak is currently landing on the powerhouse crane rails and switchgear. Left unmitigated, this leak will damage the equipment located inside the Plant.

As shown in Figure 5, water damage is seen in the roof itself and water trails are visible on the adjacent wall. Corrosion is visible on the crane rails below the leak, with corrosion products being washed down the crane rail.

*Figure 5 – Signs of Water Entry and Corrosion on Crane Rail*

A further issue identified in the building envelope is the deterioration of the powerhouse windows as they are no longer weather tight, allowing further water ingress into the building. Windows no longer properly close and sealing membranes are displaced. The windows are single glazed with mould and rot visible on the frame.

Figure 6 shows an example of a deteriorated powerhouse window.

*Figure 6 – Example of Deteriorated Powerhouse Window*

The condition of the powerhouse loading door poses an additional risk of water ingress and impaired building security. The powerhouse loading door was installed in 1958 and is a two-piece wooden carriage style door, as shown in Figure 7. The wood comprising the main structure of the door is weathered and degraded. The bottom edge of the door has begun to splinter and has lost its structural integrity. The door has settled and is no longer sealed at the top edge. Daylight is visible from inside the powerhouse, as shown in Figure 8, indicating the door is no longer weather tight.

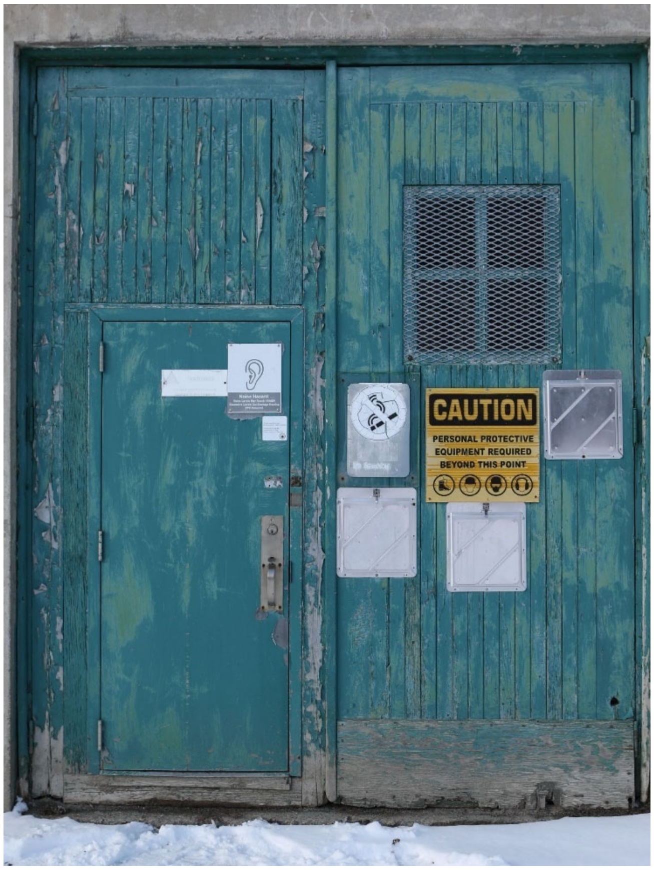



*Figure 7 - Powerhouse Loading Door External View*


*Figure 8 - Powerhouse Loading Door Internal View*

### Powerhouse Crane

Newfoundland Power use cranes in its hydro plants to lift major components when completing overhauls, maintenance activities, and other operational tasks. The Lookout Brook Plant powerhouse crane is original to the Plant's 1946 construction and no upgrades have been completed other than regular maintenance. Safe operation of the crane is necessary to enable the refurbishment of major plant components, such as the generators, and for any future planned or emergency work that may become necessary.[5]

---

[5] For example, refurbishing the generator rotor would require its removal from the generator assembly. This would approach the 7.5 ton capacity of the crane. 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.

Figures 9 and 10 show the powerhouse crane.

*Figure 9 – Powerhouse Crane*

*Figure 10 – Crane Mechanical Operators*

The Lookout Brook Plant crane failed its inspection in 2020 due to worn brakes, which require replacement.[6] The Company's crane contractor is unable to locate replacement brake components or an off-the-shelf replacement brake. The crane cannot be certified in its current condition and modifications to reuse the current bridge and trolley are not viable.

### 3.3 Turbine Generator

#### *Turbine*

The Lookout Brook Plant generating unit G3 was installed as an addition to the Plant in 1958. G3 consists of a 3,600-horsepower Francis turbine and Giljet impeller originally supplied by Gilbert Gilkes and Gordon Ltd. of Kendal England. In 1999, after 41 years in service, the runner and wicket gates were replaced with new stainless-steel components and the stationary runner seals were also replaced. Wicket gate bushings were replaced with a greaseless design and a damaged middle bearing pedestal was replaced. The generator bearing was replaced in 2019 and the alignment was verified at that time.[7]

[6] The powerhouse crane was used extensively during the 1998 and 2010 refurbishments with several lifts approaching its rated load. The crane was used for lighter weight lifts multiple times per year in support of maintenance and operations tasks until the defective brake was identified. The crane has been removed from service following the identification of the brake defect in 2020.

[7] In 2019, an excessive loss of oil was observed emanating from this bearing. This was determined to be a result of excessive play in the bearing allowing oil to migrate. A spare bearing liner was installed at this time and an adjustment was made to the alignment to reduce the risk of a re-occurrence.

Figure 11 shows the turbine headcover.

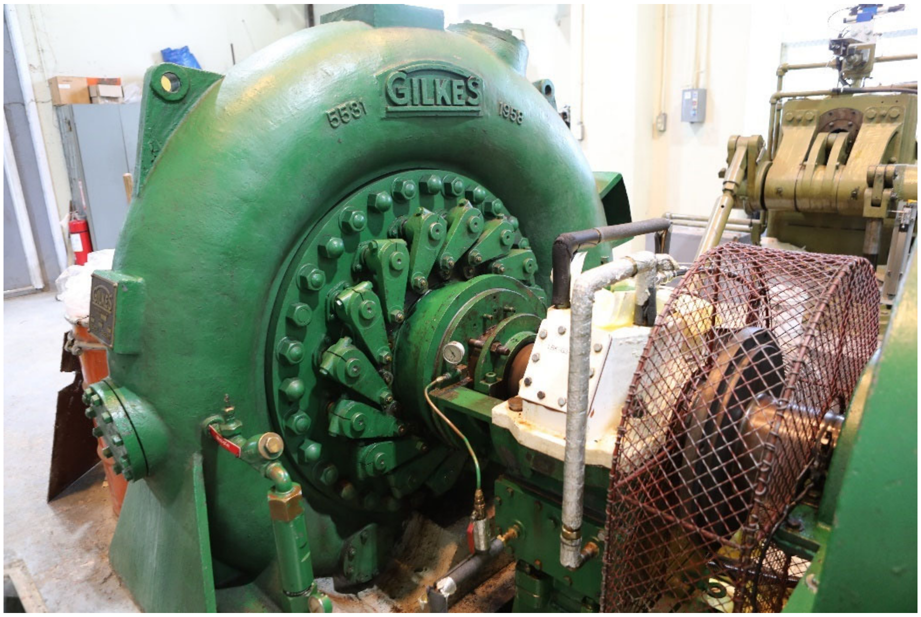



*Figure 11 – Turbine Headcover*

A detailed turbine inspection was completed in 2020, which found that the runner and wicket gate components installed in 1999 remain in good condition with no work required. 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.

Turbine disassembly is required to assess other wicket gate components, such as the stems, linkages and operating ring bushings. These components have been in place since the runner replacement and turbine overhaul in 1999. Due to the continuous movement of the wicket gates and shafts during operation, these parts wear over time and are typically replaced when a turbine is overhauled. These components will undergo a detailed inspection and assessment when the unit is out of service for refurbishment.

***G3 Main Inlet Valve***

The Plant is designed such that a single penstock leaves the intake structure and remains a single pipe for a significant portion of the penstock length. As the penstock nears the powerhouse, a bifurcation creates separate penstock sections for each unit. The separate sections enter the powerhouse towards the generating units. Each unit has a main inlet valve providing isolation from the upstream water column.

The G3 main inlet valve, as shown in Figure 12, was installed in 1998 and is a butterfly type valve with a valve disc in the water passage.[8] The valve is located in a valve pit below floor level in the Plant. Due to the elevation of the Plant's forebay, inlet valves for G3 and G4

[8] The main inlet valve isolates a turbine from the attached penstock. The Company's practice is to close the main inlet valve whenever the unit is taken offline and then open the valve during unit start-up.

experience the highest penstock pressures of the Company's 23 generating plants at 250 pounds per square inch.

*Figure 12 – Main Inlet Valve*

The G3 main inlet valve has become degraded and can no longer effectively isolate G3 from the penstock. During a maintenance inspection in early 2023, work crews were unable to seal the main inlet and observed pressurized water coming from the downstream drain line. In addition, the valve lacks a disassembly joint making removal and replacement of the valve difficult.

In order to prevent water from entering G3 during maintenance or a refurbishment, the main inlet valve must be closed or the penstock must be dewatered. Dewatering the penstock would result in a full loss of production from the Plant. Closing the inlet valve isolates the unit and allows G4 to remain in service, limiting lost production from the Plant. Replacing the main inlet valve at the outset of a refurbishment of G3 would enable G4 to stay in service with only a brief interruption to replace the valve.

### *G3 Generator and Exciter*

The Lookout Brook Plant G3 generator is comprised of three major components: the stator, rotor and exciter. The Plant's stator windings, rotor poles and exciter are original to the 65-year-old generator. The stator is the stationary component of the generator containing a series of insulated copper coils or windings fixed into a laminated steel core.[9] The insulation is rated for a maximum temperature rise of 60˚C over a reference ambient temperature of 40˚C with a maximum allowable hot spot temperature of 130˚C.

[9] 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.

Figure 13 shows the generator and exciter.

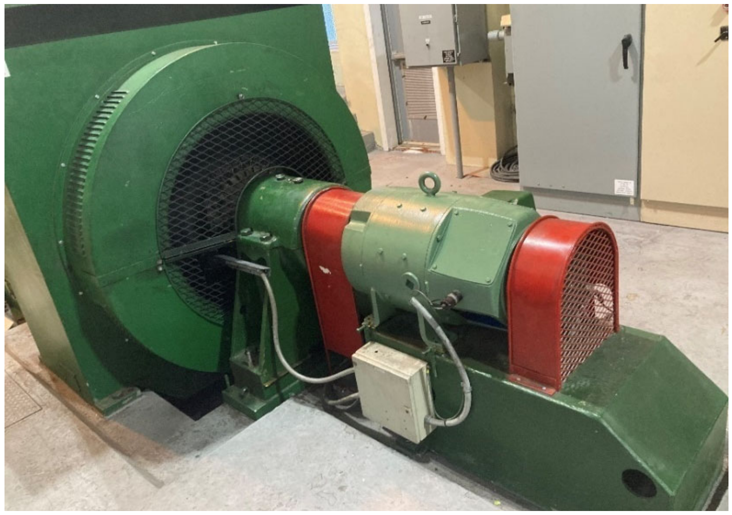


*Figure 13 – Generator and Exciter*

An in-service failure of the exciter and commutator system occurred in the fall of 2022.[10] The the exciter repair is temporary and a full rewind of the exciter is required.

A visual inspection of the stator and rotor show contamination of both components with oil mist from the bearings. This oil has been impregnated with carbon dust from the 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 2010.

Figure 14 shows the rotor poles contamination.

*Figure 14 – Contaminated Rotor Poles*

[10] During this event, a failure in the carbon brush holders caused damage to the commutator bars, physically damaging the commutator. New brush holders were procured and the exciter and commutator assembly were sent to a local shop where insulation damage was found. An insulation repair kit was applied as a temporary repair to the exciter. The unit was returned to service in December 2022.

Table 2 details the electrical parameters of generator LBK-G3.

Table 2
Generator LBK-G3 Electrical Parameters

| | | | |
|---|---|---|---|
| Rating: | 3,000 KVA | Speed: | 900 RPM |
| Voltage: | 2,400 VAC | Exciter Voltage: | 60 VDC |
| Current: | 723 Amperes | Exciter Current: | 320 Amperes |
| Power Factor: | 0.80 % | Phases: | 3 |
| Frequency: | 60 Hz | Serial No.: | 663828 |

The generator was disassembled during the 2010 refurbishment project and found to be in serviceable condition. Instrumentation upgrades were made to the generator at that time, but the windings themselves were not upgraded. At that time, a generator rewind for G3 was scheduled for 2018.[11] The planned 2018 rewind of G3 has been deferred by seven years to 2025.

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 an insulation system.

Stator coils and rotor poles 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.[12] In that instance, the core may have to be replaced along with the windings.

The 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.[13] Over time, the insulation on the poles deteriorates.

A review of the on/off cycling of the Plant during the period 2018 to 2022 shows that the Plant has experienced 789 cycles for an average of 158 per year.[14] The Plant's on/off cycling is based on water levels and responses to Hydro's requests to maximize generation. The cycling nature

11 See Newfoundland Power's *2010 Capital Budget Application*, report *1.2 Lookout Brook Hydro Plant Refurbishment,* page 3.
12 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.
13 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.
14 Unit G3 experienced 416 cycles and unit G4 experienced 373 cycles.

of the operation leads to thermal cycling and vibration which can lead to deterioration of the insulating components of the generator.

## 4.0 RISK ASSESSMENT

Newfoundland Power has achieved service lives for generators beyond the typically accepted 40-year lifespan for stator windings and rotor poles. This can be attributed to preventative maintenance and regular monitoring. Stator rewinding and rotor reinsulating have historically been done proactively based on age, as condition warranted or correctively, upon imminent failure during operation. Historically, 10 units have been rewound/reinsulated by the Company at an average age of 51 years. This experience demonstrates that proactive maintenance activities successfully extend the service lives of generators beyond the generally accepted lifespan of 40 years.

The Lookout Brook Plant G3 generator stator windings and rotor pole insulation are original and will be 67 years old in 2025. The generator was last dismantled in 1998 and is due for an overhaul.

A statistical analysis of the lifetime of stator windings published by the Institute of Electrical and Electronics Engineers ("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.[15]

Figure 15 shows the probability of failure over the lifetime of stator windings.[16]

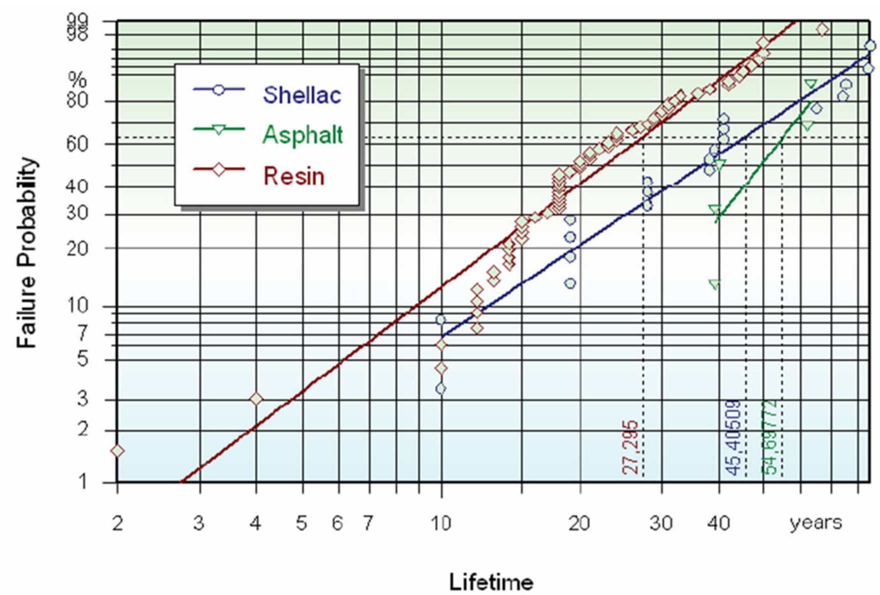



*Figure 15 – Statistical Lifetime of Hydro Generators by Insulation System*

15 See C. Sumereder, *Statistical Lifetime of Hydro Generators and Failure Analysis*, *IEEE Transactions on Dielectrics and Electrical Insulation*, Vol. 15, No. 3, June 2008.

16 Ibid.

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.

## 5.0 LIFECYCLE COST ANALYSIS

A lifecycle cost analysis has determined that continued operation of the Lookout Brook Plant will provide an economic benefit to customers over the longer term and that the risk of the Plant becoming stranded is very low. The analysis compared the cost of continued operation of the Plant to the cost of replacement production. The results are presented on a levelized cost of energy basis and are therefore expressed in terms of cents per kWh of production.

Table 3 summarizes the results of the lifecycle cost analysis of the Lookout Brook Plant.

Table 3
Lookout Brook Plant Lifecycle Cost Analysis Results

| | 50 Year Levelized Value | Net benefit |
|---|---|---|
| Lifecycle Cost of the Plant | 3.52 ¢/kWh | - |
| Cost of Replacement Production (Run-of-River) | 5.63 ¢/kWh | 2.11 ¢/kWh |
| Cost of Replacement Production (Fully Dispatchable) | 6.49 ¢/kWh | 2.97 ¢/kWh |

The analysis shows the Plant's production provides a net benefit for customers of between 2.11 ¢/kWh and 2.97 ¢/kWh. The cost of replacement production would need to be reduced by between 37% and 46% to be less than the cost of operating the Plant. The large differences between costs and benefits suggest any reasonable variance in the cost estimates will support the continued operation of the Plant. Various sensitivity analyses related to the marginal cost of replacement energy and capacity have confirmed the economic benefit of the Plant's production.

The present value of the cost of continued operation of the Plant is $17.2 million. This compares to the cost of replacing the Plant's production of between $27.4 and $31.6 million.[17]

[17] The proposed project cost of $1.935 million to maintain 5.6 MW of capacity compares favourably to Hydro's proposed alternatives for additional generation in the *Reliability and Resource Adequacy Study*, Volume III, November 2018, Tables 7 and 8, pages 37 and 43. Hydro's alternatives range in capital cost from a low of $2.4 million/MW to a high of $13.8 million/MW. The *Lookout Brook Hydro Plant Refurbishment* project will have a capital cost of approximately $346,000/MW.

Appendix A to this report provides the detailed lifecycle cost analysis, including the sensitivity analyses.

## 6.0 ASSESSMENT OF ALTERNATIVES

### 6.1 General

A condition assessment and corresponding risk assessment determined that the Lookout Brook Plant contains deteriorated, obsolete and non-standard equipment that needs to 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 Lookout Brook Plant: (i) refurbish the Plant in 2024 and 2025; and (ii) defer refurbishment of the Plant to a future year. The assessment of each alternative is detailed below.

### 6.2 Alternative 1: Refurbish Plant in 2024/2025

Alternative 1 involves refurbishing the Lookout Brook Plant in 2024 and 2025. Refurbishment would include the building envelope, crane, main inlet valve and generator.

The work required for 2024 would include replacing the crane and procurement and design work, which would be completed without a Plant outage. A full Plant outage of approximately 32 weeks would be necessary in 2025 to complete the generator refurbishment and other elements of the scope of work. A 32-week outage would result in a production loss of approximately 2.4 GWh, which in 2025 equates to approximately $60,000.[18]

### 6.3 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 $64,000 per year.[19] There are no other potential benefits associated with deferring the refurbishment.

Based on the age and condition of the Plant, the probability of failure is high. Deferring the proposed refurbishment to a future year would increase the risk of failure of a major Plant component.[20]

Completing the necessary repairs in response to an in-service failure would add additional costs in comparison to a planned refurbishment. While under planned conditions design and procurement can be undertaken in advance of a Plant outage, responding to an in-service

---

18 Based on a 2025 marginal energy cost estimate during the non-winter period of $24,800 per GWh.

19 Difference between the net present value of completing the work in 2025 and completing the work in a future year. For example, deferring the project execution by one year to 2026 will provide a potential savings of approximately $80,000.

20 The failed powerhouse crane and G3 main inlet valve must be rectified to enable the proposed work scopes and enable the continued operation of the Plant.

failure would require this work to be undertaken while the Plant is out of service, increasing lost production. Failure of the turbine generator system components could result in loss of production for a year or more. A year's worth of lost production from Lookout Brook G3 is estimated to cost approximately $909,000.[21]

There would likely be additional costs associated with undertaking repairs in emergency conditions. For example, there would be additional engineering and administrative work necessary to ensure the site remains safe and that there is no additional damage to the environment. The cost could be significantly higher 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, given the probability of failure of the generator, any minimal benefit of deferring the Lookout Brook Plant refurbishment is outweighed by the potential costs associated with responding to an in-service failure. Deferring the project is therefore not recommended.

## 7.0 PROJECT SCOPE

The assessment of alternatives determined that refurbishing the Lookout Brook Plant in 2024 and 2025 is necessary to address the deteriorated condition of the Plant and ensure the continued delivery of low-cost energy to customers.

The *Lookout Brook Hydro Plant Refurbishment* project includes upgrades or refurbishment of four components within the Plant, which are:

**(i)** ***Crane Replacement***

The crane in the powerhouse will be replaced in 2024 in advance of the required generator refurbishment.[22] This will require replacing the existing manually operated crane with a modern, electrically driven traverse and hoist system along with a wireless type crane control. The existing crane bridge is incompatible with standard size crane trolleys of modern manufacture and will be replaced during the crane refurbishment. A new electrical supply will be installed with a retractable cable reel or festoon system. The crane will undergo a certified load test before being placed into service.

**(ii)** ***Powerhouse Building Upgrade***

The powerhouse roof will be replaced and new building windows will be installed in 2025. A new loading door and siding system will also be installed at this time.

**(iii)** ***G3 Main Inlet Valve Replacement***

A replacement main inlet valve for G3 will be engineered and procured in 2024 for installation in 2025 prior to commencing the G3 generator refurbishment. A

---

21 The loss of 15.65 GWh of production at the current marginal energy cost estimate of $58.10 per MWh in 2024 and $27.50 in 2032 ranges from approximately $909,000 and $430,000 respectively.

22 The crane hoist, trolley and bridge will be replaced with a modern equivalent. The crane rails are integral to the building and will be retained with only minor changes such as addressing the corrosion noted in Figure 5.

dismantling joint will be added to enable disassembly of the main inlet valve for future maintenance or repairs.

**(iv)** ***G3 Generator Refurbishment***

The generator stator windings will be designed and ordered in early 2024. Disassembly of the unit will begin in 2025 following completion of the crane replacement in 2024. Following lead and asbestos testing of the rotor and stator components, the existing stator windings will be removed from the stator core while any necessary precautions are taken to address hazardous materials.[23] Once the generator has been disassembled, the generator rotor and exciter will be removed and shipped offsite for rewinding and reinsulating. Reassembly will consist of installing the stator, rotor and exciter, installing the turbine and impeller, realignment of the rotor and turbine, reconnecting the required wiring and instrumentation, followed by testing and commissioning of the reassembled unit.

The design and procurement of replacement components will be completed in 2024. The Plant will be taken out of service in May 2025, at which point components to be replaced or refurbished will be removed. G3 will be out of service for approximately 32 weeks while the new components are installed and commissioned.

## 8.0 PROJECT COST

Table 4 provides a breakdown by category of the cost of the *Lookout Brook Hydro Plant Refurbishment* project.

Table 4
Lookout Brook Plant Refurbishment Project
Project Cost
($000s)

| Cost Category | 2024 | 2025 | Total Cost |
|---|---|---|---|
| Material | 184 | 1,083 | 1,267 |
| Labour - Internal | 64 | 127 | 191 |
| Labour - Contract | - | - | - |
| Engineering | 30 | 60 | 90 |
| Other | 84 | 303 | 387 |
| Total | 362 | 1,573 | 1,935 |

23 When the turbine is disassembled an assessment of the wicket gate components including the stems, linkages and operating ring bushings will be completed. Work on these components will be completed as required.

The *Lookout Brook Hydro Plant Refurbishment* project is estimated to cost $1,935,000, including $362,000 in 2024 and $1,573,000 in 2025.

## 9.0 CONCLUSION

Many critical components in the Lookout Brook Plant are original and have been in service approaching 77 years. Due to their age, condition and operating experience, 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 *Lookout Brook Hydro Plant Refurbishment* project includes upgrading the powerhouse building, replacing the powerhouse crane, replacing the main inlet valve for generating unit G3 and rewinding and reinsulating rotor, stator, and exciter of unit G3. An assessment of alternatives determined that completing this work in 2024 and 2025 is necessary to ensure the safe and reliable operation of the Plant at the continued delivery of low-cost energy to customers.

# APPENDIX A:

## Lifecycle Cost Analysis of the Lookout Brook Hydro Plant

# TABLE OF CONTENTS

**Page**

# 1.0 INTRODUCTION

This lifecycle evaluation examines the future viability of generation at Newfoundland Power's Lookout Brook hydroelectric generating plant (the "Lookout Brook Plant" or the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2024 and 2025 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 expected service life of the generator, and expresses the results in terms of the levelized cost of energy. It also provides sensitivity analyses that examine the sensitivity of the results to changes in assumptions.

# 2.0 LIFECYCLE COSTS

## 2.1 Capital Costs

Table A-1 provides all significant capital expenditures for the Lookout Brook Plant over the next 25 years.

Table A-1
Lookout Brook Plant
Capital Expenditures
($000s)

| Year | Expenditure |
|---|---|
| 2024 | 362 |
| 2025 | 1,573 |
| 2031 | 2,264 |
| 2032 | 2,879 |
| 2033 | 1,171 |
| 2035 | 788 |
| 2036 | 617 |
| 2040 | 1,323 |
| 2047 | 2,245 |
| 2050 | 1,578 |
| Total | $14,800 |

The estimated capital expenditure for the Plant is $14,800,000 over the next 25 years.[1] These capital expenditures include the expenditures proposed for 2024 and 2025 and future capital expenditures commencing in 2031.

Attachment A provides a breakdown of capital costs.

## 2.2 Operating Costs

Annual operating costs for the Plant, including water rental fees, are estimated to be approximately $307,000 per year.[2] The operating cost represents both direct charges for operations and maintenance at the Plant, as well as indirect costs such as those related to managing the environment, safety, dam safety inspections, and staff training. The annual water rental fee is approximately $96,000 for 2023.[3] This fee, adjusted for inflation, will be paid annually to the Provincial Government based on the Plant's production.

Attachment B provides a summary of operating costs.

## 2.3 Cost of Spill During Construction

Included in the lifecycle cost is the cost of reduced production from the Plant during the refurbishment project. During construction, the Plant will be out of service for a period of time. This will result in the spillage of water from its reservoirs and reduced Plant production. In 2025, it is expected that approximately 2.4 GWh of reduced production will occur, which will result in additional costs to replace lost production of approximately $60,000.

# 3.0 COST OF PLANT DOWNTIME

## 3.1 General

If the refurbishment project does not proceed as proposed, there is risk that the Plant will be out of service for a prolonged period due to equipment failure and potential safety hazards. Taking the Plant out of service will result in replacing its production with additional power from Newfoundland and Labrador Hydro ("Hydro"). The cost to replace the production from the Plant consists primarily of: (i) marginal energy costs; and (ii) the potential need to add generation capacity.

[1] Capital expenditures beyond the initial 25 years are included in the analysis and are broadly indicative of the expenditures anticipated.

[2] Reflects 2023 dollars.

[3] The water rental rate is the Provincial Government legislated water power rental charge. The charge in 2022 was $2.81/MWh and is increased annually by the Consumer Price Index (CPI) All Items for Canada. The additional cost is added to the annual operating cost.

Table A-2 provides a breakdown of the normal production of the Plant.

Table A-2
Normal Production from Lookout Brook Plant

| Marginal Cost Period | Normal Production (GWh) | Production (%) | Average Normal Production (MW) |
|---|---|---|---|
| Non-Winter Period (All hours) | 20.80 | 66 | 3.22 |
| Winter Period | | | |
| On-Peak | 5.04 | 16 | 3.66 |
| Off-Peak | 5.67 | 18 | 3.75 |
| Annual Production | 31.51 | 100 | 3.60 |

The average normal production during the on-peak winter period is 3.66 MW. This is 65% of the maximum winter capacity of 5.6 MW.[4]

When Newfoundland Power receives a request from Hydro to maximize hydro plant production, the Lookout Brook Plant produces on average 3.40 MW.[5] It is during the on-peak winter period in which the benefits of electricity production are highest.[6]

### 3.2 Marginal Energy Cost

The Island Interconnected System is connected to the North American power grid through the Labrador Island Link and the Maritime Link. An updated marginal cost study (the "Marginal Cost Update") completed by Hydro in 2022 provides estimates of the marginal energy cost as the opportunity cost of selling energy to other jurisdictions.[7] The marginal energy cost estimates vary by time of day and by season. To recognize these time-varying characteristics, the costs are summarized by winter on-peak, winter off-peak and non-winter peak periods.

Attachment C to this report provides the forecast marginal energy costs for the period 2023 to 2040.

4 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. During the winter peak period on February 4, 2023 the Plant was on line producing approximately 5 MW.

5 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.

6 See Attachment C.

7 The most recent marginal cost study results are found in Hydro's Marginal Cost Update, dated December 2022. The marginal cost study covers the period from 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. Removing the Plant from service would reduce the capacity available to supply customers and increase the need for new generation sources.[8]

The Marginal Cost Update provides estimates of the marginal cost of generation capacity for the Island Interconnected System in terms of cost per MWh and cost per kW of peak demand.

The Plant can provide 5.6 MW of capacity during the winter. The cost of replacement capacity is dependent on the extent to which this capacity is available to meet peak load conditions. This is impacted by the amount of storage, the timing of rainfall, how the Plant is dispatched, the volume of requests by Hydro to maximize generation and the potential that the Plant is out of service when required to meet increased customer demand.

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.[9] The capacity from a run-of-river plant is dependent on the extent to which timing of the river flow will correspond to periods when the cost of capacity is the greatest. Evaluation of a run-of-river plant is completed by applying the production for each marginal cost time period to the appropriate marginal generation capacity cost.

*Fully dispatchable* generation, on the other hand, has sufficient storage to allow it to produce at its full rated capacity for all potential periods of need. This would be similar to a gas turbine, which can be dispatched at any time to provide its rated capacity to support customer demand. The capacity of a fully dispatchable plant is primarily reflective of its rated capacity and the likelihood it is not available for service.

Newfoundland Power's hydro generation facilities operate between being run-of-river and fully dispatchable generation plants. The Plant has total available storage of approximately 4.1 GWh. This level of storage represents approximately 30 days of production at a production rate of 5.6 MW. However, storage levels are often not full, and there are practical limitations to managing the flow of water from storage to the forebay. These practical considerations limit

---

8 In its *Reliability and Resource Adequacy Study – 2022 Update* Hydro stated that "Regardless of the assumptions made for the Island Interconnected System load growth, the LIL capacity and bipole forced outage rate, the Island Interconnected System will be significantly capacity constrained once the Holyrood TGS and the Hardwoods Gas Turbine are retired." See *Reliability and Resource Adequacy Study – 2022 Update, Volume III, Long Term Resource Plan*, Page 51, lines 25-27.

9 As examples, periods of greatest value for production include during generation shortages and peak demand periods.

the Company's ability to maintain continuous production at rated capacity for extended periods of time.[10]

## 4.0 LIFECYCLE ANALYSIS RESULTS

### 4.1 Base Case Analysis

An analysis has been completed comparing the lifecycle costs of the Plant to the cost of replacement production over a 50-year study period to match the anticipated lifecycle for the Plant. The Marginal Cost Update covers the period from 2023 to 2040. As a result, there is no forecast of marginal costs beyond this period. For the purposes of the 50-year study period, the Company has used the GDP Deflator to escalate marginal cost for the remaining years of the 50-year study period. To deal with the uncertainty of future marginal costs, the Company has prepared five sensitivity analyses with different approaches to estimate future marginal cost to confirm the robustness of the lifecycle cost analysis.

The costs are presented on a levelized cost of energy approach. The levelized cost of energy expresses the costs and benefits in terms of a ¢/kWh of production.

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[11] | Net benefit |
|---|---|---|
| Lifecycle Cost of the Plant | 3.52 ¢/kWh | |
| Cost of Replacement Production (Run-of-River) | | |
| Energy Costs | 2.10 ¢/kWh | |
| Capacity Costs | 3.53 ¢/kWh | |
| Total | 5.63 ¢/kWh | 2.11 ¢/kWh |
| Cost of Replacement Production (Fully Dispatchable) | | |
| Energy Cost | 2.10 ¢/kWh | |
| Capacity Cost | 4.39 ¢/kWh | |
| Total | 6.49¢/kWh | 2.97 ¢/kWh |

[10] 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.

[11] See Attachment D.

The cost to replace the Plant's production will exceed the Plant's cost by between 2.11¢/kWh and 2.97 ¢/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 37% and 46% based on the run-of-river and fully dispatchable assumptions, respectively. The large differences between costs and benefits suggest any reasonable variance in the estimates of the costs and benefits will support the continued operation of the Plant.

This evaluation compares the cost of continued operation of the Plant to the cost of replacing Plant production. If the life extension of the Plant was determined to be costlier than the cost of replacing Plant production, then further analysis would be required to assess the cost of decommissioning through mothballing or dismantling the Plant and associated development. The present value of these costs would be incremental to the cost of replacement production.

Attachment D provides the detailed results of the calculated levelized costs and benefits.[12]

## 4.2 Sensitivity Analysis

To illustrate the robustness of the conclusion that continued operation is in the economic best interest of customers, the following scenarios were included in a sensitivity analysis:

(i) *Scenario 1A: Uncertainty with marginal costs beyond 2040*
Assumes the Plant ceases production in 2041 in consideration of the expiration of the Churchill Falls contract in 2041.[13]

(ii) *Scenario 1B: Uncertainty with marginal costs beyond 2040*
Assumes the marginal energy and capacity costs for the years after 2040 will remain at the same amount as the 2040 forecast with no escalation.

(iii) *Scenario 1C: Uncertainty with marginal costs beyond 2040*
Assumes the marginal energy for the years after 2040 will remain at the same amount as the 2040 forecast with no escalation, and capacity costs for the years after 2040 escalated using the GDP Deflator.

(iv) *Scenario 2: Uncertain accuracy of Hydro's marginal capacity cost*
Assumes Hydro's marginal capacity costs decrease by 25%.

(v) *Scenario 3: Uncertain accuracy of Hydro's marginal energy cost*
Assumes Hydro's marginal energy costs decrease by 25%.

---

12 The financial assumptions used in the economic evaluation are provided in Attachment E.

13 This scenario tests whether the Lookout Brook Hydro Plant Refurbishment Project remains economic if the Plant ceases production in 2041.

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
Present Value Sensitivity Analysis Results
($2024)

| Scenario | Cost of Continued Operation ($M) | Cost of Replacement Production: Run-of-River ($M) | Cost of Replacement Production: Fully Dispatchable ($M) | Net Savings ($M) |
|---|---|---|---|---|
| Base Case[14] | 17.2 | 27.4 | 31.6 | 10.2 – 14.4 |
| Scenario 1A | 8.7 | 17.4 | 19.7 | 8.7 –11.0 |
| Scenario 1B | 17.2 | 25.3 | 29.0 | 8.1 – 11.8 |
| Scenario 1C | 17.2 | 25.0 | 29.2 | 7.8 –12.0 |
| Scenario 2 | 17.2 | 23.1 | 26.3 | 5.9 – 9.1 |
| Scenario 3 | 17.2 | 24.9 | 29.1 | 7.7 – 11.9 |

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 Lookout Brook 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.

[14] The base case provides the results of the levelized costs provided in Table A-3 expressed as present value of costs as opposed to the levelized cost per kWh.

# Attachment A:

## Summary of Capital Costs

| Lookout Brook Plant Economic Analysis<br>Summary of Capital Costs (2024-2050)<br>($000s) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Description | 2024 | 2025 | 2031 | 2032 | 2033 | 2035 | 2036 | 2040 | 2047 | 2050 |
| Civil | | | | | | | | | | |
| Dam, Spillways and Gates | - | - | 2,264 | - | - | - | 617 | - | - | - |
| Penstock | - | - | - | - | 1,171 | - | - | - | - | - |
| Access Road and Bridges | | | | | | | | 1,323 | | |
| Powerhouse | 362 | 428 | - | - | - | - | - | | - | - |
| Mechanical | | | | | | | | | | |
| Turbine | - | - | - | - | - | 606 | - | - | - | 395 |
| Powerhouse Systems | - | 225 | - | - | - | - | - | - | - | - |
| Electrical | | | | | | | | | | |
| Generator Refurbishment | - | 920 | - | - | - | - | - | - | 1,497 | - |
| Control Systems | - | - | - | - | - | - | - | - | 748 | - |
| Switchgear | - | - | - | - | - | - | - | - | - | 1,183 |
| Protection and Control Systems | - | - | - | - | - | 182 | - | - | - | - |
| Other | | | | | | | | | | |
| Substation Refurbishment | - | - | - | 2,879 | - | - | - | - | - | - |
| Total ($2023) | 362 | 1,573 | 2,264 | 2,879 | 1,171 | 788 | 617 | 1,323 | 2,245 | 1,578 |

# Attachment B:

## Summary of Operating Costs

| Lookout Brook Plant<br>Economic Evaluation<br>Summary of Operating Costs<br>($2024) | |
|---|---|
| | Amount |
| 2018 | $179,768 |
| 2019 | $241,409 |
| 2020 | $226,414 |
| 2021 | $208,873 |
| 2022 | $196,301 |
| Average[1] | $210,553 |
| Water Power Rental[2] | $96,421 |
| Total Average Operating Cost | $306,973 |

1 Cost excludes the water power rental rate.
2 Calculated using the Provincial Government's current water rental rate ($2.81/MWh in 2022 escalated using CPI All Items for Canada) 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 $/MWh | Off-Peak $/MWh | All hours $/MWh | On-Peak $/MWh | Off-Peak $/MWh | All hours $/MWh | Annual $/kW·yr |
| 2023 | 172.24 | 139.98 | 40.46 | 151.45 | 58.94 | 2.61 | 307.14 |
| 2024 | 124.58 | 101.21 | 30.20 | 167.79 | 65.34 | 2.90 | 340.42 |
| 2025 | 97.81 | 79.71 | 24.80 | 112.65 | 43.66 | 1.90 | 227.95 |
| 2026 | 58.14 | 49.33 | 23.22 | 99.30 | 38.41 | 1.66 | 200.70 |
| 2027 | 47.15 | 40.03 | 19.20 | 107.24 | 41.51 | 1.80 | 216.85 |
| 2028 | 47.98 | 41.33 | 21.81 | 115.85 | 44.88 | 1.95 | 234.37 |
| 2029 | 50.45 | 42.22 | 22.06 | 125.20 | 48.54 | 2.11 | 253.39 |
| 2030 | 43.98 | 36.82 | 21.43 | 135.01 | 52.38 | 2.29 | 273.35 |
| 2031 | 42.10 | 37.84 | 19.19 | 149.26 | 57.97 | 2.54 | 302.36 |
| 2032 | 44.82 | 37.85 | 20.47 | 165.09 | 64.18 | 2.83 | 334.61 |
| 2033 | 48.76 | 40.55 | 19.89 | 100.77 | 38.89 | 1.66 | 203.41 |
| 2034 | 44.80 | 35.88 | 20.84 | 106.63 | 41.17 | 1.76 | 215.31 |
| 2035 | 38.94 | 33.01 | 20.59 | 112.85 | 43.60 | 1.87 | 227.95 |
| 2036 | 34.83 | 29.90 | 17.90 | 119.45 | 46.18 | 1.99 | 241.37 |
| 2037 | 30.01 | 26.13 | 13.47 | 126.46 | 48.92 | 2.11 | 255.61 |
| 2038 | 24.66 | 21.99 | 12.87 | 132.79 | 51.39 | 2.22 | 268.48 |
| 2039 | 22.06 | 19.64 | 9.88 | 139.45 | 53.99 | 2.34 | 282.01 |
| 2040 | 14.44 | 14.80 | 8.22 | 146.46 | 56.73 | 2.46 | 296.25 |

**Notes:**
1. 2023-2040 based on the marginal cost projections provided by Hydro in the summary report Marginal Cost Update, dated December 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 | 17,180.6 | 1,110.4 | 31.51 | 3.52 |
| Cost of Replacement Production (Run-of-River) | | | | |
| Energy Cost | 10,221.8 | 660.7 | 31.51 | 2.10 |
| Capacity Cost | 17,215.2 | 1,112.7 | 31.51 | 3.53 |
| **Total** | **27,437.0** | **1,773.4** | | **5.63** |
| Cost of Replacement Production (Fully Dispatchable) | | | | |
| Energy Cost | 10,221.8 | 660.7 | 31.51 | 2.10 |
| Capacity Cost | 21,415.7 | 1,384.2 | 31.51 | 4.39 |
| **Total** | **31,637.5** | **2,044.9** | | **6.49** |

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

| Production Year | Year | Generation Hydro 65.7yrs 8% CCA | Generation Hydro 65.7yrs 100% CCA | Transmission 51.9 yrs 8% CCA | Substation 48.5 yrs 8% CCA | Capital Revenue Requirement | Operating Costs | Spillage Cost | Net Benefit | Present Worth Benefit | Cumulative Present Value Benefit |
|---|---|---|---|---|---|---|---|---|---|---|---|
| -1 | 2024 | 362,000 | 0 | 0 | 0 | 31,246 | 0 | 0 | -31,246 | -33,163 | -33,163 |
| 0 | 2025 | 1,573,000 | 0 | 0 | 0 | 169,645 | 0 | 59,520 | -229,165 | -229,165 | -262,328 |
| 1 | 2026 | 0 | 0 | 0 | 0 | 180,062 | 315,922 | 0 | -495,984 | -467,319 | -729,647 |
| 2 | 2027 | 0 | 0 | 0 | 0 | 174,853 | 321,327 | 0 | -496,180 | -440,485 | -1,170,132 |
| 3 | 2028 | 0 | 0 | 0 | 0 | 169,895 | 327,239 | 0 | -497,134 | -415,826 | -1,585,958 |
| 4 | 2029 | 0 | 0 | 0 | 0 | 165,169 | 335,339 | 0 | -500,507 | -394,452 | -1,980,410 |
| 5 | 2030 | 0 | 0 | 0 | 0 | 160,655 | 341,429 | 0 | -502,084 | -372,825 | -2,353,235 |
| 6 | 2031 | 2,263,807 | 0 | 0 | 0 | 352,794 | 347,464 | 0 | -700,258 | -489,929 | -2,843,164 |
| 7 | 2032 | 0 | 0 | 0 | 2,878,752 | 622,946 | 353,480 | 0 | -976,426 | -643,666 | -3,486,830 |
| 8 | 2033 | 1,171,337 | 0 | 0 | 0 | 743,103 | 359,569 | 0 | -1,102,673 | -684,879 | -4,171,709 |
| 9 | 2034 | 0 | 0 | 0 | 0 | 733,454 | 365,771 | 0 | -1,099,225 | -643,279 | -4,814,988 |
| 10 | 2035 | 787,911 | 0 | 0 | 0 | 780,747 | 372,104 | 0 | -1,152,851 | -635,670 | -5,450,659 |
| 11 | 2036 | 616,682 | 0 | 0 | 0 | 820,145 | 378,610 | 0 | -1,198,755 | -622,781 | -6,073,439 |
| 12 | 2037 | 0 | 0 | 0 | 0 | 803,358 | 385,267 | 0 | -1,188,625 | -581,829 | -6,655,268 |
| 13 | 2038 | 0 | 0 | 0 | 0 | 781,004 | 392,050 | 0 | -1,173,054 | -541,021 | -7,196,290 |
| 14 | 2039 | 0 | 0 | 0 | 0 | 759,548 | 398,982 | 0 | -1,158,529 | -503,442 | -7,699,731 |
| 15 | 2040 | 1,322,848 | 0 | 0 | 0 | 853,718 | 406,079 | 0 | -1,259,797 | -515,809 | -8,215,540 |
| 16 | 2041 | 0 | 0 | 0 | 0 | 844,004 | 413,259 | 0 | -1,257,262 | -485,020 | -8,700,561 |
| 17 | 2042 | 0 | 0 | 0 | 0 | 821,146 | 420,573 | 0 | -1,241,719 | -451,340 | -9,151,900 |
| 18 | 2043 | 0 | 0 | 0 | 0 | 799,115 | 428,068 | 0 | -1,227,183 | -420,276 | -9,572,177 |
| 19 | 2044 | 0 | 0 | 0 | 0 | 777,843 | 435,715 | 0 | -1,213,557 | -391,590 | -9,963,767 |
| 20 | 2045 | 0 | 0 | 0 | 0 | 757,269 | 443,492 | 0 | -1,200,762 | -365,069 | -10,328,835 |
| 21 | 2046 | 0 | 0 | 0 | 0 | 737,339 | 451,379 | 0 | -1,188,718 | -340,520 | -10,669,355 |
| 22 | 2047 | 2,244,848 | 0 | 0 | 0 | 912,813 | 459,406 | 0 | -1,372,218 | -370,367 | -11,039,722 |
| 23 | 2048 | 0 | 0 | 0 | 0 | 911,250 | 467,575 | 0 | -1,378,825 | -350,642 | -11,390,365 |
| 24 | 2049 | 0 | 0 | 0 | 0 | 886,696 | 475,890 | 0 | -1,362,587 | -326,486 | -11,716,851 |
| 25 | 2050 | 1,577,834 | 0 | 0 | 0 | 999,840 | 484,353 | 0 | -1,484,193 | -335,071 | -12,051,923 |
| 26 | 2051 | 0 | 0 | 0 | 0 | 988,875 | 492,966 | 0 | -1,481,842 | -315,206 | -12,367,129 |
| 27 | 2052 | 0 | 0 | 0 | 0 | 962,051 | 501,733 | 0 | -1,463,784 | -293,370 | -12,660,499 |
| 28 | 2053 | 1,663,515 | 0 | 0 | 0 | 1,080,405 | 510,655 | 0 | -1,591,060 | -300,449 | -12,960,948 |
| 29 | 2054 | 1,015,859 | 0 | 0 | 0 | 1,156,075 | 519,736 | 0 | -1,675,811 | -298,164 | -13,259,112 |
| 30 | 2055 | 0 | 0 | 0 | 0 | 1,134,667 | 528,979 | 0 | -1,663,645 | -278,893 | -13,538,005 |
| 31 | 2056 | 0 | 0 | 0 | 0 | 1,103,492 | 538,385 | 0 | -1,641,878 | -259,336 | -13,797,341 |
| 32 | 2057 | 0 | 0 | 0 | 0 | 1,073,252 | 547,959 | 0 | -1,621,212 | -241,272 | -14,038,613 |
| 33 | 2058 | 0 | 0 | 0 | 0 | 1,043,872 | 557,704 | 0 | -1,601,576 | -224,575 | -14,263,188 |
| 34 | 2059 | 0 | 0 | 0 | 0 | 1,015,282 | 567,621 | 0 | -1,582,904 | -209,129 | -14,472,317 |
| 35 | 2060 | 0 | 0 | 0 | 0 | 987,420 | 577,716 | 0 | -1,565,136 | -194,831 | -14,667,148 |
| 36 | 2061 | 957,720 | 0 | 5,746,318 | 0 | 1,560,841 | 587,989 | 0 | -2,148,830 | -252,031 | -14,919,179 |
| 37 | 2062 | 0 | 0 | 0 | 0 | 1,603,496 | 598,445 | 0 | -2,201,941 | -243,334 | -15,162,513 |
| 38 | 2063 | 0 | 0 | 0 | 0 | 1,556,690 | 609,087 | 0 | -2,165,777 | -225,505 | -15,388,019 |
| 39 | 2064 | 0 | 0 | 0 | 0 | 1,511,327 | 619,919 | 0 | -2,131,246 | -209,085 | -15,597,103 |
| 40 | 2065 | 1,027,683 | 0 | 0 | 0 | 1,556,476 | 630,943 | 0 | -2,187,418 | -202,193 | -15,799,297 |
| 41 | 2066 | 0 | 0 | 0 | 0 | 1,521,550 | 642,163 | 0 | -2,163,712 | -188,443 | -15,987,740 |
| 42 | 2067 | 0 | 0 | 0 | 0 | 1,476,993 | 653,582 | 0 | -2,130,575 | -174,833 | -16,162,573 |
| 43 | 2068 | 0 | 0 | 0 | 0 | 1,433,611 | 665,205 | 0 | -2,098,816 | -162,273 | -16,324,847 |
| 44 | 2069 | 0 | 0 | 0 | 0 | 1,391,310 | 677,034 | 0 | -2,068,345 | -150,675 | -16,475,522 |
| 45 | 2070 | 0 | 0 | 0 | 0 | 1,350,004 | 689,074 | 0 | -2,039,078 | -139,958 | -16,615,480 |
| 46 | 2071 | 0 | 0 | 0 | 0 | 1,309,612 | 701,328 | 0 | -2,010,940 | -130,050 | -16,745,529 |
| 47 | 2072 | 0 | 0 | 0 | 0 | 1,270,061 | 713,800 | 0 | -1,983,861 | -120,884 | -16,866,413 |
| 48 | 2073 | 2,366,632 | 0 | 0 | 0 | 1,231,285 | 726,493 | 0 | -1,957,779 | -112,400 | -16,978,813 |
| 49 | 2074 | 0 | 0 | 0 | 0 | 1,193,222 | 739,412 | 0 | -1,932,634 | -104,544 | -17,083,357 |
| 50 | 2075 | 1,838,664 | 0 | 0 | 0 | 1,155,813 | 752,561 | 0 | -1,908,375 | -97,265 | -17,180,622 |

## Present Value of the Cost of Replacement Energy (Reduced Exports)

| Production Year | Year | Marginal Energy Costs | Total Present Worth | Cumulative Present Worth | Export Sales (¢/kWhr) |
|---|---|---|---|---|---|
| | | $ | $ | $ | |
| -1 | 2024 | - | - | - | - |
| 0 | 2025 | - | - | - | - |
| 1 | 2026 | 1,055,806 | 994,786 | 994,786 | 3.35 |
| 2 | 2027 | 864,048 | 767,061 | 1,761,847 | 2.74 |
| 3 | 2028 | 929,885 | 777,798 | 2,539,646 | 2.95 |
| 4 | 2029 | 952,585 | 750,736 | 3,290,382 | 3.02 |
| 5 | 2030 | 876,236 | 650,655 | 3,941,036 | 2.78 |
| 6 | 2031 | 825,959 | 577,875 | 4,518,911 | 2.62 |
| 7 | 2032 | 866,349 | 571,102 | 5,090,013 | 2.75 |
| 8 | 2033 | 889,464 | 552,453 | 5,642,467 | 2.82 |
| 9 | 2034 | 862,769 | 504,902 | 6,147,369 | 2.74 |
| 10 | 2035 | 811,748 | 447,590 | 6,594,959 | 2.58 |
| 11 | 2036 | 717,445 | 372,729 | 6,967,688 | 2.28 |
| 12 | 2037 | 579,633 | 283,729 | 7,251,416 | 1.84 |
| 13 | 2038 | 516,701 | 238,306 | 7,489,723 | 1.64 |
| 14 | 2039 | 428,082 | 186,024 | 7,675,747 | 1.36 |
| 15 | 2040 | 327,691 | 134,169 | 7,809,916 | 1.04 |
| 16 | 2041 | 333,485 | 128,650 | 7,938,566 | 1.06 |
| 17 | 2042 | 339,387 | 123,360 | 8,061,927 | 1.08 |
| 18 | 2043 | 345,435 | 118,302 | 8,180,229 | 1.10 |
| 19 | 2044 | 351,606 | 113,456 | 8,293,685 | 1.12 |
| 20 | 2045 | 357,882 | 108,807 | 8,402,492 | 1.14 |
| 21 | 2046 | 364,247 | 104,342 | 8,506,834 | 1.16 |
| 22 | 2047 | 370,724 | 100,060 | 8,606,894 | 1.18 |
| 23 | 2048 | 377,317 | 95,954 | 8,702,848 | 1.20 |
| 24 | 2049 | 384,026 | 92,016 | 8,794,863 | 1.22 |
| 25 | 2050 | 390,856 | 88,240 | 8,883,103 | 1.24 |
| 26 | 2051 | 397,806 | 84,618 | 8,967,721 | 1.26 |
| 27 | 2052 | 404,880 | 81,146 | 9,048,867 | 1.28 |
| 28 | 2053 | 412,080 | 77,816 | 9,126,682 | 1.31 |
| 29 | 2054 | 419,408 | 74,622 | 9,201,305 | 1.33 |
| 30 | 2055 | 426,867 | 71,560 | 9,272,864 | 1.35 |
| 31 | 2056 | 434,458 | 68,623 | 9,341,487 | 1.38 |
| 32 | 2057 | 442,184 | 65,807 | 9,407,294 | 1.40 |
| 33 | 2058 | 450,047 | 63,106 | 9,470,400 | 1.43 |
| 34 | 2059 | 458,050 | 60,516 | 9,530,916 | 1.45 |
| 35 | 2060 | 466,196 | 58,033 | 9,588,949 | 1.48 |
| 36 | 2061 | 474,486 | 55,651 | 9,644,601 | 1.51 |
| 37 | 2062 | 482,924 | 53,367 | 9,697,968 | 1.53 |
| 38 | 2063 | 491,512 | 51,177 | 9,749,145 | 1.56 |
| 39 | 2064 | 500,252 | 49,077 | 9,798,222 | 1.59 |
| 40 | 2065 | 509,148 | 47,063 | 9,845,285 | 1.62 |
| 41 | 2066 | 518,202 | 45,132 | 9,890,417 | 1.64 |
| 42 | 2067 | 527,417 | 43,279 | 9,933,696 | 1.67 |
| 43 | 2068 | 536,797 | 41,503 | 9,975,199 | 1.70 |
| 44 | 2069 | 546,342 | 39,800 | 10,014,999 | 1.73 |
| 45 | 2070 | 556,058 | 38,167 | 10,053,166 | 1.76 |
| 46 | 2071 | 565,946 | 36,600 | 10,089,767 | 1.80 |
| 47 | 2072 | 576,011 | 35,098 | 10,124,865 | 1.83 |
| 48 | 2073 | 586,254 | 33,658 | 10,158,523 | 1.86 |
| 49 | 2074 | 596,679 | 32,277 | 10,190,800 | 1.89 |
| 50 | 2075 | 607,290 | 30,952 | 10,221,752 | 1.93 |

## Present Value of the Cost of Replacement Capacity (Run-of-River Assumption)

| Production Year | Year | Marginal Capacity Cost $ | Total Present Worth $ | Cumulative present Worth $ | Avoided Generation Capacity (¢/kWhr) |
|---|---|---|---|---|---|
| -1 | 2024 | - | - | - | - |
| 0 | 2025 | - | - | - | - |
| 1 | 2026 | 752,926 | 709,412 | 709,412 | 2.39 |
| 2 | 2027 | 813,488 | 722,176 | 1,431,587 | 2.58 |
| 3 | 2028 | 879,201 | 735,404 | 2,166,991 | 2.79 |
| 4 | 2029 | 950,510 | 749,100 | 2,916,092 | 3.02 |
| 5 | 2030 | 1,025,372 | 761,397 | 3,677,488 | 3.25 |
| 6 | 2031 | 1,134,153 | 793,500 | 4,470,988 | 3.60 |
| 7 | 2032 | 1,255,088 | 827,361 | 5,298,350 | 3.98 |
| 8 | 2033 | 763,126 | 473,983 | 5,772,333 | 2.42 |
| 9 | 2034 | 807,786 | 472,725 | 6,245,059 | 2.56 |
| 10 | 2035 | 855,187 | 471,542 | 6,716,600 | 2.71 |
| 11 | 2036 | 905,501 | 470,429 | 7,187,029 | 2.87 |
| 12 | 2037 | 958,910 | 469,384 | 7,656,413 | 3.04 |
| 13 | 2038 | 1,007,165 | 464,512 | 8,120,925 | 3.20 |
| 14 | 2039 | 1,057,929 | 459,726 | 8,580,651 | 3.36 |
| 15 | 2040 | 1,111,334 | 455,022 | 9,035,673 | 3.53 |
| 16 | 2041 | 1,130,982 | 436,304 | 9,471,978 | 3.59 |
| 17 | 2042 | 1,150,999 | 418,365 | 9,890,342 | 3.65 |
| 18 | 2043 | 1,171,511 | 401,210 | 10,291,553 | 3.72 |
| 19 | 2044 | 1,192,438 | 384,776 | 10,676,328 | 3.78 |
| 20 | 2045 | 1,213,724 | 369,009 | 11,045,338 | 3.85 |
| 21 | 2046 | 1,235,307 | 353,866 | 11,399,203 | 3.92 |
| 22 | 2047 | 1,257,275 | 339,343 | 11,738,547 | 3.99 |
| 23 | 2048 | 1,279,633 | 325,417 | 12,063,964 | 4.06 |
| 24 | 2049 | 1,302,389 | 312,063 | 12,376,027 | 4.13 |
| 25 | 2050 | 1,325,549 | 299,256 | 12,675,282 | 4.21 |
| 26 | 2051 | 1,349,121 | 286,975 | 12,962,257 | 4.28 |
| 27 | 2052 | 1,373,113 | 275,198 | 13,237,455 | 4.36 |
| 28 | 2053 | 1,397,531 | 263,904 | 13,501,359 | 4.44 |
| 29 | 2054 | 1,422,383 | 253,074 | 13,754,433 | 4.51 |
| 30 | 2055 | 1,447,677 | 242,688 | 13,997,120 | 4.59 |
| 31 | 2056 | 1,473,421 | 232,728 | 14,229,849 | 4.68 |
| 32 | 2057 | 1,499,623 | 223,177 | 14,453,026 | 4.76 |
| 33 | 2058 | 1,526,291 | 214,018 | 14,667,044 | 4.84 |
| 34 | 2059 | 1,553,433 | 205,235 | 14,872,280 | 4.93 |
| 35 | 2060 | 1,581,058 | 196,813 | 15,069,093 | 5.02 |
| 36 | 2061 | 1,609,173 | 188,736 | 15,257,829 | 5.11 |
| 37 | 2062 | 1,637,789 | 180,990 | 15,438,819 | 5.20 |
| 38 | 2063 | 1,666,914 | 173,563 | 15,612,382 | 5.29 |
| 39 | 2064 | 1,696,557 | 166,440 | 15,778,822 | 5.38 |
| 40 | 2065 | 1,726,727 | 159,609 | 15,938,431 | 5.48 |
| 41 | 2066 | 1,757,433 | 153,059 | 16,091,491 | 5.58 |
| 42 | 2067 | 1,788,686 | 146,778 | 16,238,268 | 5.68 |
| 43 | 2068 | 1,820,494 | 140,754 | 16,379,023 | 5.78 |
| 44 | 2069 | 1,852,868 | 134,978 | 16,514,001 | 5.88 |
| 45 | 2070 | 1,885,817 | 129,439 | 16,643,440 | 5.98 |
| 46 | 2071 | 1,919,353 | 124,127 | 16,767,566 | 6.09 |
| 47 | 2072 | 1,953,485 | 119,033 | 16,886,599 | 6.20 |
| 48 | 2073 | 1,988,223 | 114,148 | 17,000,747 | 6.31 |
| 49 | 2074 | 2,023,580 | 109,463 | 17,110,210 | 6.42 |
| 50 | 2075 | 2,059,565 | 104,971 | 17,215,181 | 6.54 |

## Present Value of the Cost of Replacement Capacity (Fully Dispatchable Assumption)

| Production Year | Year | Effective Capacity MW | Marginal Capacity Cost $ | Total Present Worth $ | Cumulative Present Worth $ | Avoided Generation Capacity (¢/kWhr) |
|---|---|---|---|---|---|---|
| -1 | 2024 | - | - | - | - | - |
| 0 | 2025 | - | - | - | - | - |
| 1 | 2026 | 4.67 | 936,600 | 882,470 | 882,470 | 2.97 |
| 2 | 2027 | 4.67 | 1,011,967 | 898,376 | 1,780,846 | 3.21 |
| 3 | 2028 | 4.67 | 1,093,727 | 914,843 | 2,695,688 | 3.47 |
| 4 | 2029 | 4.67 | 1,182,487 | 931,922 | 3,627,611 | 3.75 |
| 5 | 2030 | 4.67 | 1,275,633 | 947,230 | 4,574,840 | 4.05 |
| 6 | 2031 | 4.67 | 1,411,013 | 987,203 | 5,562,043 | 4.48 |
| 7 | 2032 | 4.67 | 1,561,513 | 1,029,359 | 6,591,402 | 4.96 |
| 8 | 2033 | 4.67 | 949,247 | 589,585 | 7,180,987 | 3.01 |
| 9 | 2034 | 4.67 | 1,004,780 | 588,009 | 7,768,996 | 3.19 |
| 10 | 2035 | 4.67 | 1,063,767 | 586,550 | 8,355,546 | 3.38 |
| 11 | 2036 | 4.67 | 1,126,393 | 585,187 | 8,940,733 | 3.57 |
| 12 | 2037 | 4.67 | 1,192,847 | 583,896 | 9,524,628 | 3.79 |
| 13 | 2038 | 4.67 | 1,252,907 | 577,850 | 10,102,478 | 3.98 |
| 14 | 2039 | 4.67 | 1,316,047 | 571,891 | 10,674,370 | 4.18 |
| 15 | 2040 | 4.67 | 1,382,500 | 566,048 | 11,240,418 | 4.39 |
| 16 | 2041 | 4.67 | 1,406,942 | 542,763 | 11,783,181 | 4.47 |
| 17 | 2042 | 4.67 | 1,431,844 | 520,446 | 12,303,627 | 4.54 |
| 18 | 2043 | 4.67 | 1,457,360 | 499,106 | 12,802,732 | 4.63 |
| 19 | 2044 | 4.67 | 1,483,394 | 478,661 | 13,281,394 | 4.71 |
| 20 | 2045 | 4.67 | 1,509,873 | 459,048 | 13,740,441 | 4.79 |
| 21 | 2046 | 4.67 | 1,536,723 | 440,209 | 14,180,650 | 4.88 |
| 22 | 2047 | 4.67 | 1,564,050 | 422,143 | 14,602,794 | 4.96 |
| 23 | 2048 | 4.67 | 1,591,864 | 404,819 | 15,007,613 | 5.05 |
| 24 | 2049 | 4.67 | 1,620,172 | 388,206 | 15,395,819 | 5.14 |
| 25 | 2050 | 4.67 | 1,648,984 | 372,274 | 15,768,094 | 5.23 |
| 26 | 2051 | 4.67 | 1,678,307 | 356,997 | 16,125,090 | 5.33 |
| 27 | 2052 | 4.67 | 1,708,153 | 342,346 | 16,467,436 | 5.42 |
| 28 | 2053 | 4.67 | 1,738,529 | 328,297 | 16,795,733 | 5.52 |
| 29 | 2054 | 4.67 | 1,769,445 | 314,824 | 17,110,557 | 5.62 |
| 30 | 2055 | 4.67 | 1,800,911 | 301,904 | 17,412,461 | 5.72 |
| 31 | 2056 | 4.67 | 1,832,937 | 289,514 | 17,701,975 | 5.82 |
| 32 | 2057 | 4.67 | 1,865,532 | 277,633 | 17,979,608 | 5.92 |
| 33 | 2058 | 4.67 | 1,898,707 | 266,239 | 18,245,847 | 6.03 |
| 34 | 2059 | 4.67 | 1,932,471 | 255,313 | 18,501,160 | 6.13 |
| 35 | 2060 | 4.67 | 1,966,837 | 244,835 | 18,745,995 | 6.24 |
| 36 | 2061 | 4.67 | 2,001,813 | 234,788 | 18,980,782 | 6.35 |
| 37 | 2062 | 4.67 | 2,037,411 | 225,152 | 19,205,935 | 6.47 |
| 38 | 2063 | 4.67 | 2,073,642 | 215,912 | 19,421,847 | 6.58 |
| 39 | 2064 | 4.67 | 2,110,518 | 207,051 | 19,628,898 | 6.70 |
| 40 | 2065 | 4.67 | 2,148,049 | 198,554 | 19,827,452 | 6.82 |
| 41 | 2066 | 4.67 | 2,186,248 | 190,406 | 20,017,858 | 6.94 |
| 42 | 2067 | 4.67 | 2,225,126 | 182,592 | 20,200,450 | 7.06 |
| 43 | 2068 | 4.67 | 2,264,695 | 175,099 | 20,375,549 | 7.19 |
| 44 | 2069 | 4.67 | 2,304,968 | 167,913 | 20,543,461 | 7.32 |
| 45 | 2070 | 4.67 | 2,345,958 | 161,022 | 20,704,483 | 7.45 |
| 46 | 2071 | 4.67 | 2,387,676 | 154,414 | 20,858,897 | 7.58 |
| 47 | 2072 | 4.67 | 2,430,136 | 148,077 | 21,006,974 | 7.71 |
| 48 | 2073 | 4.67 | 2,473,351 | 142,000 | 21,148,974 | 7.85 |
| 49 | 2074 | 4.67 | 2,517,335 | 136,172 | 21,285,146 | 7.99 |
| 50 | 2075 | 4.67 | 2,562,100 | 130,584 | 21,415,730 | 8.13 |

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%.

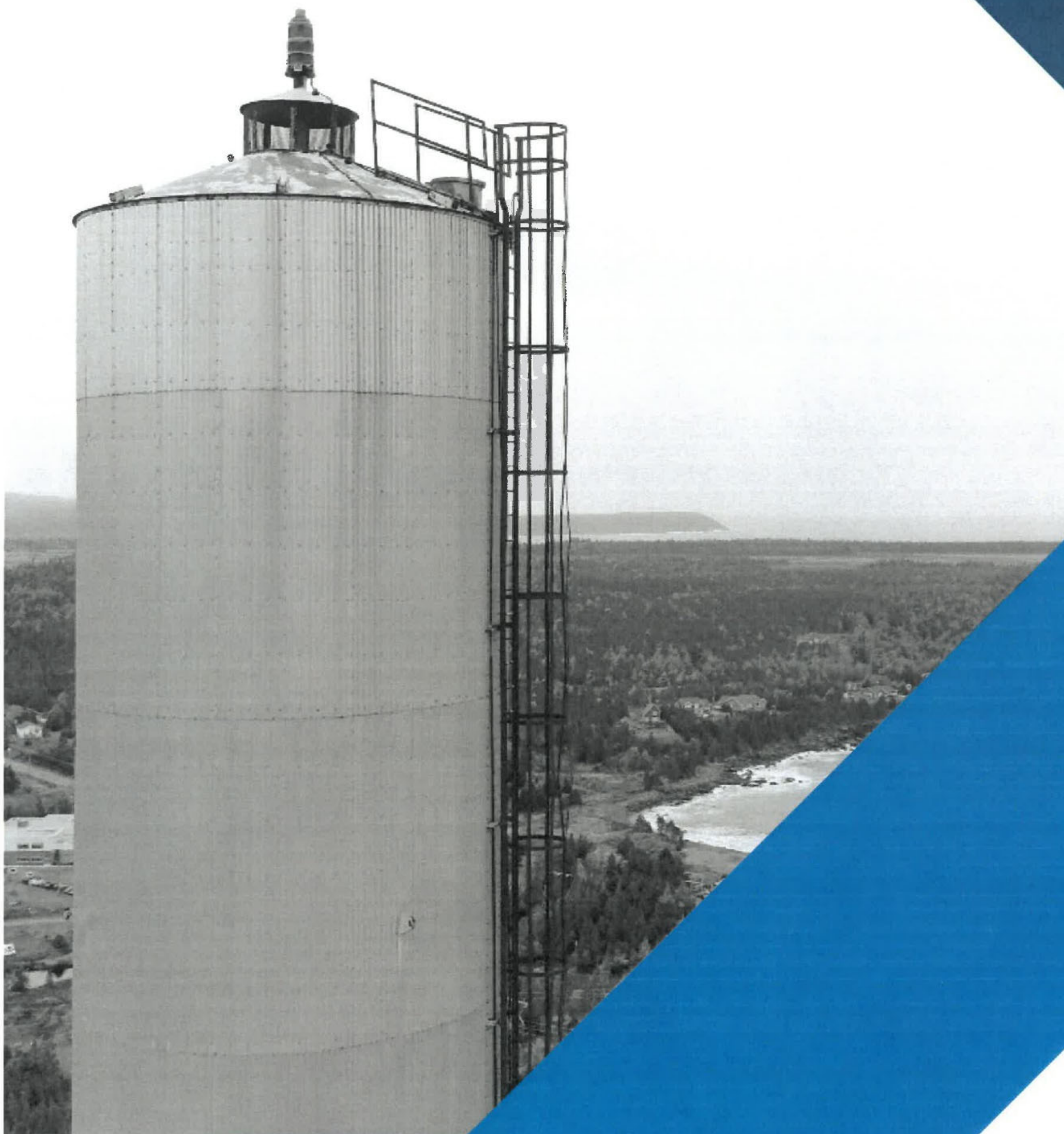
***Operating Costs:*** Operating costs were assumed to be in 2023 dollars escalated yearly using the GDP Deflator for Canada.

| *Average Incremental Cost of Capital:* | | Capital Structure | Return | Weighted Cost |
|---|---|---|---|---|
| | Debt | 55.00% | 4.198% | 2.31% |
| | Common Equity | 45.00% | 8.500% | 3.83% |
| | Total | 100.00% | | 6.13% |

| *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, medium term forecast dated February 6, 2023, and long term forecast dated December 16, 2022.

***Supporting Documents:*** Newfoundland and Labrador Hydro's Marginal Cost Update, dated December 2022.



NEWFOUNDLAND POWER
A FORTIS COMPANY

LICENSED PROFESSIONAL ENGINEER
08900
ALEX C. HAWCO
SIGNATURE
06/15/23
DATE
NEWFOUNDLAND & LABRADOR

# 4.2 Mobile Hydro Plant Surge Tank Refurbishment

## June 2023

Prepared by: Alex Hawco, P. Eng.

# TABLE OF CONTENTS

## 1.0 INTRODUCTION

Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") Mobile hydroelectric generating plant (the "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.[2] The Plant is connected to the Island Interconnected System at Mobile Substation and has provided 72 years of reliable energy production.

The Mobile Plant is the second largest of Newfoundland Power's 23 hydro plants by both installed capacity and annual energy production.[3]

In 2024, the Company is proposing to refurbish deteriorated structural components of the surge tank.[4] The surge tank is approaching the half way point of its expected service life and addressing the deterioration related to rust and corrosion now will ensure it provides reliable service for the remainder of its service life. The project includes: (i) replacement of the surge tank exterior protective coating system; (ii) installation of surge tank cross bracing wear plates[5]; (iii) replacement of the surge tank access system's protective coating; and (iv) rehabilitation of the surge tank interior protective coating system.

The project is estimated to cost $977,000 in 2024.

The proposed project in 2024 is in addition to the previously approved refurbishment work to be completed in 2023 and 2024 at the Plant as detailed in Newfoundland Power's *2023 Capital Budget Application,* report *4.2 Mobile Hydro Plant Refurbishment*. The previously approved multi-year project included: (i) replacing and upgrading building systems, (ii) upgrading protection and control systems, including switchgear; and (iii) refurbishing the turbine and generator.[6]

---

1 The Mobile Plant operates in series with the Morris hydroelectric generating plant (the "Morris Plant"). Water is first utilized for electricity generation at the Morris Plant before flowing downstream to the Mobile Plant.

2 A turbine converts potential energy from pressurized water into rotational mechanical energy. A generator converts rotational mechanical energy into electrical energy.

3 Only Newfoundland Power's Rattling Brook hydroelectric generating plant, with two generators at 7.5 MVA and 8.25 MVA, is larger in capacity and annual energy production than the Mobile Plant.

4 Surge tanks are vertical pipelines normally located near the Plant, that extend to the height of the head pond and are open to the environment. Surge tanks are used to mitigate water pressure variations or surges during normal operation and emergency shut down events.

5 Wear plates are sometimes referred to as rub plates.

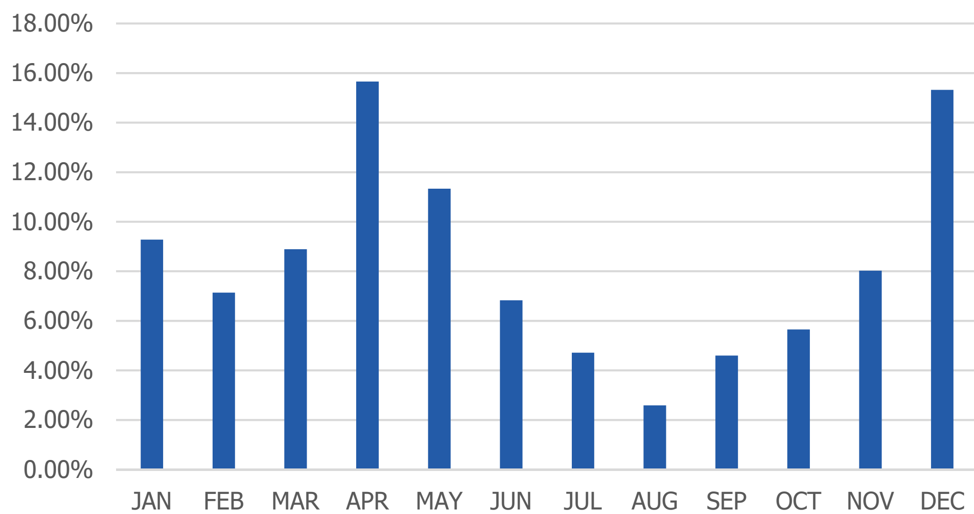
6 See Board Order No. P.U. 38 (2022).

## 2.0 BACKGROUND

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.[7] 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 Average 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").[8] 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 May. This corresponds to when customer load and capacity constraints are greatest on the Island Interconnected System.

In addition to these 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

7 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.

8 From 2018 through 2022, Hydro requested generation 389 times for the Avalon Peninsula hydro plants, and 513 total times for all Island hydro plants.

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 de-energized, the Mobile Plant is the largest of seven hydro plants on the Southern Shore that operates as an isolated system to supply customers in the area.[9]

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 |
| 2023 & 2024 | Hydro Plant Refurbishment (ongoing) |

[9] Since February 2020, there have been six occasions where 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 lead generator to set frequency for the other isolated generators to follow.

The Mobile surge tank was constructed in 1999 to replace the original surge tank installed in 1951.[10] The surge tank supporting structure is constructed of hollow structural steel with bar type steel cross bracing. The surge tank is 61.1-metre tall with a 1.83-metre diameter steel pipe riser and a 5.17-metre diameter steel surge bowl. The main structural steel system has a protective coating system for corrosion resistance while the pipe riser and surge tank bowl have external cladding and internal protective coating system for corrosion resistance. The surge tank has been in service for 24 years.

Figure 2 shows the Mobile Plant surge tank.

*Figure 2 - Mobile Plant Surge Tank*

[10] The original surge tank required replacement after 48 years in service as a result of structural steel material loss due to failure of the protective coating system.

## 3.0 CONDITION ASSESSMENT

### 3.1 General

Newfoundland Power commissioned Kleinschmidt Canada Inc. ("Kleinschmidt") to conduct an internal and external condition assessment of the surge tank to identify and document deterioration. The following sections contain a summary of the Kleinschmidt inspection.[11]

### 3.2 Surge Tank

#### *External Protective Coating System*

The surge tank external protective coating system provides protection to the main structural system, access ladders, handrails and platforms and the surge tank roof. The protective coating system has failed to varying degrees, from slight degradation up to complete coating loss, throughout the surge tank structure. The external structural system has complete protective coating loss in the vicinity of the structural connections with distributed areas of coating loss on the remaining structural members. The access ladders, handrails and platforms also have total protective coating loss.

Figure 3 shows exterior protective coating loss in the vicinity of a structural connection. This is consistent with coating loss on other structural connections throughout the surge tank structure.

*Figure 3 - Protective Coating Loss*

[11] The detailed inspection report can be found in Appendix B, *Surge Tank Inspection Report – Mobile Development*.

### *Structural Support System*

The surge tank structural support system provides the main structural support to resist the applied loading from the weight of the water column as well as environmental loading (wind, ice, etc.). Without a stable structural support system, the surge tank structure would incur large lateral deflections, inducing stress in the structural system that could result in component failure. The structural support system is comprised of column legs, horizontal struts, and cross bracing with bolted and welded connections.

There are no concerns for the structural integrity of the column legs, horizontal struts or connections at this time. The cross-bracing members are also not showing significant material loss at this time. However, signs of wear are present where the members are in contact which will eventually lead to material loss over time.

At Newfoundland Power's Rattling Brook Hydro Plant, the surge tank cross bracing is of similar construction. The cross-bracing members in Rattling Brook were also contacting in a similar way and over time led to cross sectional loss of the members. Welding of additional steel was required to mitigate damage caused by the rubbing and wear plates were installed to prevent the reoccurrence of material loss.[12] If the wear plates are inspected and replaced at regular intervals, no cross-sectional material loss of structural members will occur.

Figure 4 shows an example of protective coating loss and cross-bracing contact.

*Figure 4 - Cross Bracing Contact*

[12] Wear plates act as a sacrificial rubbing surface such that the wear plates will suffer material loss over time and require replacement. See Newfoundland Power's *2021 Capital Budget Application*, report *1.1 2021 Facility Rehabilitation* for an example of what occurred at Rattling Brook Hydro Plant where cross bracing contact persisted for many years.

### *Exterior Cladding*

The exterior cladding system consists of corrugated metal siding with screw type fasteners. The fasteners are in good condition with no elongation of screw holes visible.[13] The metal siding is showing no signs of significant corrosion.

Exterior cladding is used to both protect the structural steel of the surge tank and surge tank riser, and also to securely fasten and protect surge tank insulation. Surge tank insulation is required to ensure the water column does not freeze. If the water column in the surge tank were frozen prior to an emergency shutdown situation, the frozen water column would not allow the surge pressure to be released. The surge pressure would be directed back into the penstock and travel towards the Plant and reservoir. This surge pressure would cause damage to Plant equipment.

Figure 5 shows the condition of the external surge tank riser and bowl cladding.

*Figure 5 - Exterior Cladding*

### *Surge Tank Access System*

The surge tank access system provides a safe means of access for personnel to complete inspection and maintenance activities. The surge tank access system includes ladders, ladder cages, platforms and handrails.

The ladders, ladder cages, platforms and handrails do not show any signs of structural degradation but corrosion and coating loss are evident throughout.

[13] Elongation of the screw holes is a precursor to failure of screw type fastening systems.

Figure 6 shows total loss of protective coating on a portion of the surge tank access system.

*Figure 6 - Tank Access System Protective Coating Loss*

### *Internal Protective Coating System*

The internal protective coating system provides similar protection of the structural steel as does the external protective coating system. Without an internal protective coating system, the surge tank's life expectancy would be reduced. Areas of the surge tank system that are not often in contact with water or are normally fully submerged typically have less degradation than areas where water levels fluctuate inside the tank. For normally submerged areas, the lack of oxygen inhibits corrosion of the structure. For normally dry areas, the lack of a conductive electrolyte also inhibits corrosion of the structure.[14] The interior protective coating system protects the surge tank riser as well as the inside of the surge tank bowl.[15]

The interior protective coating system is generally in good condition with localized protective coating loss near the operational water level as well as along weld seams.

[14] For corrosion to occur metal, oxygen, and an electrolyte are required. Removing any of these components greatly reduces the potential for corrosion.

[15] The surge tank riser extends into the surge tank bowl.

Figure 7 shows interior protective coating loss in the surge tank bowl near the operational water level elevation.

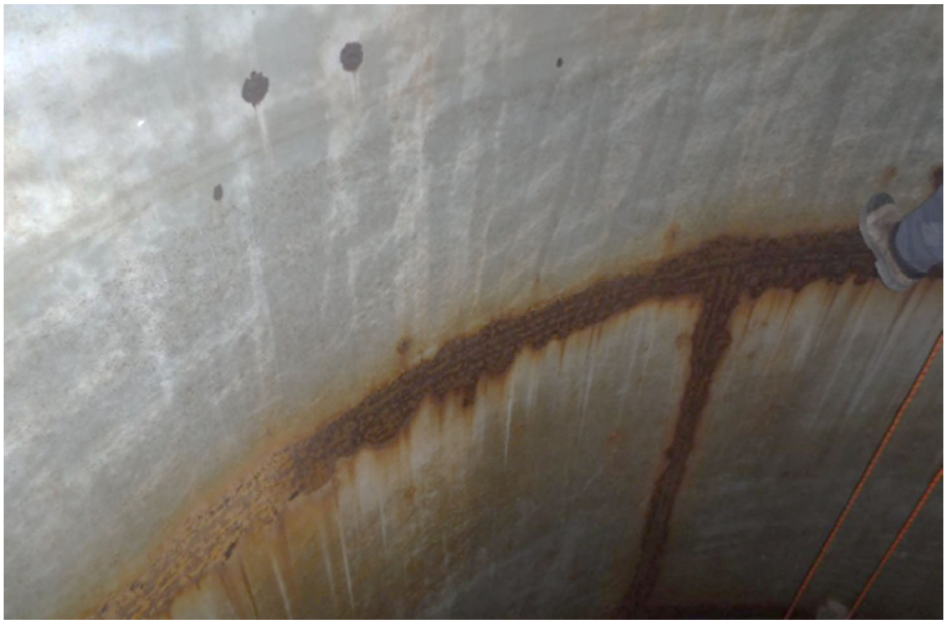


*Figure 7 - Interior Protective Coating System Loss*

### *Surge Tank Foundation*

The surge tank foundations provide a stable base for which the surge tank structural systems are attached. The surge tank foundation is designed to resist the loads applied by the weight of the water column in the tank, as well as the environmental loading from wind and ice. Without an adequate foundation, the surge tank would become unstable and fail. The surge tank foundations consist of steel base plates, anchor bolts, concrete foundations and structural granular fill.

The steel base plates and anchor bolts do not show signs of significant corrosion. The concrete foundations are in good condition with no significant cracking or material loss visible and the structural granular fill is not exposed in any locations. Rehabilitation of the surge tank foundations is not required at this time.

Figure 8 shows typical surge tank foundation.


*Figure 8 - Typical Foundation*

## 4.0 RISK ASSESSMENT

Protective coating systems are an integral part of surge tank structural systems. The Mobile Plant surge tank is constructed of steel. A specified material thickness of steel is required to resist the applied loads on the structure. The applied loads on the surge tank are predominantly from the weight of water and wind loads acting on the structure. If left exposed to environmental conditions (wind, rain, salt spray and temperature changes), corrosion will occur and material thickness will be lost. Over time this material loss will degrade the capability of the surge tank to resist wind loading that occurs naturally.

Protective coatings are designed to protect steel systems from corrosion. In areas subject to salt spray, such as coastal environments, the expected life is shorter than in less corrosive environments. Protective coating systems require replacement to ensure continued protection of the structural steel elements. If protective coating systems are not replaced, bare steel will be exposed, and corrosion will occur resulting in material loss. The ability of the structural steel to resist the applied loads will be reduced as material loss occurs. In the case of surge tanks, steel loss will result in decreased resistance to loading conditions and ultimately surge tank collapse.

If protective coating systems are not replaced, the surge tank life expectancy will be reduced. Unprotected structural steel will experience progressive material loss until failure occurs. By replacing the protective coating system prior to material loss, the service life of the surge tank will be increased. A properly protected steel surge tank can have a service life exceeding 80 years.[16]

Surge tank cross bracing forms part of the main structural system of a surge tank to resist the applied wind loading. Surge tank cross bracing wear plates were not originally installed on surge tanks of this vintage. Operational experience has shown that without wear plates, the structural cross bracing members will rub together resulting in cross sectional material loss. This has previously occurred on the Rattling Brook Hydro Plant surge tank.[17] Once material loss has occurred, the surge tank's ability to resist the applied loads will be reduced. If left unmitigated, the material loss will advance until surge tank collapse occurs. The installation of wear plates acts as a sacrificial material to protect the main structural cross bracing. The wear plates will also suffer material loss, but this loss will not affect the ability of the structural members to resist the applied loads. Wear plate installation will extend the life of the cross-bracing elements, which will in turn extend the life of the surge tank.

## 5.0 Lifecycle Cost Analysis

A condition assessment and corresponding risk assessment determined that the Mobile Plant surge tank is deteriorated and requires refurbishment. An updated lifecycle cost analysis has been completed and confirms that continued operation of the Plant will provide an economic benefit for Newfoundland Power's customers over the longer term.

Since the filing of the *2023 Capital Budget Application*, the capital expenditure plan for the Mobile Plant has changed.[18] In addition, there have been changes in marginal cost and escalation rates. The lifecycle cost analysis submitted as part of Newfoundland Power's *2023 Capital Budget Application* has been updated to reflect these changes.[19]

16 To achieve a service life exceeding 80 years, routine inspections and protective coating replacements are required.

17 See Newfoundland Power's *2021 Capital Budget Application*, report *1.1 2021 Facility Rehabilitation*.

18 These capital expenditure plan changes include a revised budget estimate for the surge tank recoating, deferring required work on the penstock to 2025, deferring the substation work to 2026-2027 and deferring work on the dams, spillways and gates until 2029. Details on these capital expenditure plan changes can be found in *Appendix A: Updated Lifecycle Cost Analysis of the Mobile Plant, Attachment A: Summary of Capital Costs*.

19 *Appendix A: Updated Lifecycle Cost Analysis of the Mobile Plant*, includes an updated analysis completed using the same methodology as previously submitted in Newfoundland Power's *2023 Capital Budget Application* with an updated capital plan, escalation rates and marginal costs of energy and capacity.

Table 2 summarizes the results of the updated lifecycle cost analysis of the Mobile Plant.

Table 2
Mobile Plant Updated Lifecycle Cost Analysis Results

| | 50 Year Levelized Value | Net benefit |
|---|---|---|
| Lifecycle Cost of the Plant | 2.72 ¢/kWh[20] | - |
| Cost of Replacement Production (Run-of-River) | 7.24 ¢/kWh | 4.52¢/kWh |
| Cost of Replacement Production (Fully Dispatchable) | 8.77 ¢/kWh | 6.05 ¢/kWh |

The updated analysis shows the Plant's production provides a net benefit for customers of between 4.52 ¢/kWh and 6.05 ¢/kWh.[21] The cost of replacement production would need to be reduced by between 62% and 69% to be less than the cost of operating the Plant. The differences between costs and benefits suggest any reasonable variance in the estimates will support the continued operation of the Mobile Plant.[22] Various sensitivity analyses have confirmed the economic benefit of the Plant's production.[23]

The present value of the cost of continued operation of the Plant is $17.8 million. This compares to the cost of replacing the Plant's production of between $47.3 and $57.3 million.[24]

## 6.0 PROJECT SCOPE

The refurbishment of the Mobile Plant surge tank in 2024 is necessary to address the deteriorated condition of the asset and ensure continued safe and reliable operation at the lowest possible cost.

20 The 2024 budget estimates included in Newfoundland Power's *2023 Capital Budget Application* have been changed to reflect the plan outlined in this report. In addition, the substation, transmission, penstock and dam work has also been deferred to future years as detailed in *Appendix A: Updated Lifecycle Cost Analysis of the Mobile Plant, Attachment A: Summary of Capital Costs*. These modifications result in a change from 2.70 ¢/kWh to 2.72¢/kWh for the 50 year levelized value.

21 In the *2023 Capital Budget Application*, report *4.2 Mobile Plant refurbishment* the net benefit for customers was between 5.14 ¢/kWh and 6.79 ¢/kWh.

22 This analysis does not incorporate any cost associated with decommissioning the Plant, either through mothballing or dismantling, if the cost of life extension was determined to not be least cost.

23 See *Appendix A: Updated Lifecycle Cost Analysis of the Mobile Plant,* Table A-4.

24 The proposed project cost of $977,000 to maintain 11.0 MW of capacity compares favourably to Hydro's proposed alternatives for additional generation in the *Reliability and Resource Adequacy Study*, Volume III tables 7 and 8. Hydro's alternatives range in capital cost from a low of $2.4 million/MW to a high of $13.8 million/MW. The *Mobile Hydro Plant Surge Tank Refurbishment* project will have a capital cost of $89,000/MW. Including the previously approved multi-year project to refurbish the Mobile Plant, the work will have a capital cost of $466,000/MW.

The *Mobile Hydro Plant Surge Tank Refurbishment* project includes:

(i) Refurbishing the surge tank including the removal and replacement of the exterior protective coating system;
(ii) Installing cross bracing wear plates;
(iii) Replacing the surge tank access system protective coating system; and
(iv) Rehabilitating the interior protective coating system.[25]

The engineering and procurement for the project will be completed in the first quarter of 2024. The Plant is being taken out of service starting in June 2024 for the capital project previously approved in the *2023 Capital Budget Application.* The completion of the surge tank scope of work listed above will utilize the same plant outage. The Plant will be out of service for approximately 26 weeks while all work is completed and commissioned as previously submitted.

## 7.0 PROJECT COST

Table 3 provides a breakdown by category of the cost of the *Mobile Hydro Plant Surge Tank Refurbishment* project.

Table 3
Mobile Hydro Plant Surge Tank Refurbishment Project
2024 Budget
($000s)

| Cost Category | 2024 |
|---|---|
| Material | 903 |
| Labour – Internal | 7 |
| Labour – Contract | - |
| Engineering | 40 |
| Other | 27 |
| Total | $977 |

The *Mobile Hydro Plant Surge Tank Refurbishment* project is estimated to cost $977,000 in 2024.

25 Work on the surge tank requires utilizing specialized work methods which will include articulating lifts, rope access and confined space work.

## 8.0 CONCLUSION

Condition assessments have determined that the Mobile Plant surge tank and supporting structure is in fair condition overall with no significant structural defects noted, but the protective coating systems are in poor condition with several areas of coating loss and early corrosion. Removal of the internal and external protective coating system and their replacement is necessary in 2024 to prevent the corrosion from progressing further and compromising the structure. The lack of surge tank cross bracing wear plates will result in material loss to the cross braces and must be addressed in 2024.

The surge tank is a critical asset to the operation of the Plant. An updated lifecycle cost analysis confirms that continued operation of the Plant, including the cost of the surge tank refurbishment, will provide an economic benefit for customers over the longer term.

# APPENDIX A:

## Updated Lifecycle Cost Analysis of the Mobile Plant

# TABLE OF CONTENTS

**Page**

## 1.0 INTRODUCTION

The lifecycle evaluation previously submitted for the *Mobile Hydro Plant Refurbishment* as part of Newfoundland Power's *2023 Capital Budget Application* has been updated to reflect the changes to marginal costs, escalation and the capital expenditures plan that have occurred since the 2023 submission. The following sections are a summary of the financial analysis that have been affected by these changes.

## 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 | 3,457 |
| 2025 | 639 |
| 2027 | 1,910 |
| 2029 | 695 |
| 2037 | 353 |
| 2039 | 201 |
| 2042 | 2,103 |
| Total | $11,024 |

The estimated capital expenditure for the Plant is $11,024,000 over the next 25 years.[1]

Attachment A provides a comprehensive breakdown of capital costs.

1 Capital expenditures beyond the initial 25 years are included in the analysis and are broadly indicative of the expenditures anticipated.

### 2.2 Operating Costs

Operating costs remain unchanged from the original analysis. 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 $422,800.[2]

## 3.0 COST OF PLANT DOWNTIME

### 3.1 General

Taking the Plant out of service will result in replacing its production with additional supply from Newfoundland and Labrador Hydro ("Hydro"). The cost to replace the production from the Plant consists primarily of: (i) marginal energy costs; and (ii) the potential need to add generation capacity.

Normal hydro production remains unchanged since the original submission.

### 3.2 Marginal Energy Cost

An updated marginal cost study completed by Hydro in December 2022 provides estimates of the opportunity cost of selling energy to other jurisdictions (the "Marginal Cost Update").[3] The marginal energy cost estimates vary by time of day and by season. To recognize these time-varying characteristics, the costs are summarized by winter on-peak, winter off-peak and non-winter periods.

Attachment C to this report provides the forecast marginal energy costs for the period 2023 to 2040.

### 3.3 Cost of Replacement Capacity

Replacement capacity analysis remains unchanged from the previous submission with the exception being the difference in forecast capacity costs over the 2023 to 2040 period as provided in Hydro's December 2022 update.

---

[2] Energy costs related to the spillage of water have increased to $422,800 from $220,000 in the *2023 Capital Budget Application*. The increased cost is related to the 2024 marginal cost of energy during the non-winter period increasing from $15,750 per GWh to $30,200 per GWh over the past year.

[3] The most recent marginal cost study results are found in Hydro's *Marginal Cost Update*, dated December 2022.

## 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-2 compares the estimated levelized costs of the Plant's production and the cost of replacement production.

Table A-2
Lifecycle Analysis Results

| | 50 Year Levelized Value[4] | Net benefit |
|---|---|---|
| Lifecycle Cost of the Plant | 2.72 ¢/kWh | |
| Cost of Replacement Production (Run-of-River) | | |
| Energy Costs | 2.50 ¢/kWh | |
| Capacity Costs | 4.74 ¢/kWh | |
| Total | 7.24 ¢/kWh | 4.52¢/kWh |
| Cost of Replacement Production (Fully Dispatchable) | | |
| Energy Cost | 2.50 ¢/kWh | |
| Capacity Cost | 6.27 ¢/kWh | |
| Total | 8.77 ¢/kWh | 6.05 ¢/kWh |

The cost to replace the Plant's production will exceed the Plant's cost of production by between 4.52 ¢/kWh and 6.05 ¢/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 62% and 69% based on the run-of-river and fully dispatchable assumptions, respectively. The large differences between costs and benefits suggest any reasonable variance in the estimates of the costs and benefits will support the continued operation of the Plant.

Attachment D provides the detailed results of the calculated levelized costs and benefits.[5]

4 See Attachment D.
5 The financial assumptions used in the economic evaluation are provided in Attachment E.

## 4.2 Sensitivity Analysis

To illustrate the robustness of the conclusion that continued operation is 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 contract in 2041 will result in there being no cost of electricity to replace the Plant's production beyond 2041.[6]

***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-3 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-3
Sensitivity Analysis Results
(Present Value in $2023)

| Scenario | Cost of Continued Operation ($M) | Cost of Replacement Production | | Net Savings ($M) |
|---|---|---|---|---|
| | | Run-of-River ($M) | Fully Dispatchable ($M) | |
| Base Case[7] | 17.8 | 47.3 | 57.3 | 29.5 – 39.5 |
| Scenario 1 | 13.3 | 30.3 | 35.9 | 17.0 – 22.6 |
| Scenario 2 | 17.8 | 39.5 | 47.0 | 21.7 – 29.2 |
| Scenario 3 | 17.8 | 47.2 | 57.3 | 29.4 – 39.5 |

The sensitivity analysis shows that the cost of continuing to operate the Plant will provide an economic benefit under all scenarios.

6 This scenario is to simulate a situation whereby once the Churchill Falls contract ends in 2041, future production from Churchill Falls will be in excess of available internal and export markets and can fully address capacity constraints on the Island of Newfoundland.

7 The base case provides the results of the levelized costs provided in Table A-2 expressed as present value of costs as opposed to the levelized cost per kWh.

## 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. In addition, sensitivity analyses were completed to verify the continued operation of the Plant 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)[1]

| Description | 2023 | 2024 | 2025 | 2027 | 2029 | 2037 | 2039 | 2042 | 2049 | 2050 | 2054 | 2067 | 2069 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Civil | | | | | | | | | | | | | |
| Dam, Spillways and Gates | - | - | - | - | 647 | 353 | - | 2,103 | - | - | - | 629 | - |
| Penstock | - | - | 639 | - | - | - | - | - | - | 1,008 | - | - | - |
| Surge Tank | - | 977 | - | - | - | - | - | - | 1,515 | - | - | - | - |
| Powerhouse | 928 | - | - | - | - | - | - | - | 309 | - | - | - | - |
| Mechanical | | | | | | | | | | | | | |
| Turbine | - | 346 | - | - | - | - | - | - | - | - | - | - | - |
| Governor | 45 | 125 | - | - | - | - | - | - | - | - | - | - | 110 |
| Powerhouse Systems | - | - | - | - | - | - | - | - | 78 | - | - | - | - |
| Electrical | | | | | | | | | | | | | |
| Generator Refurbishment | 260 | 1,136 | - | - | - | - | - | - | - | - | - | - | - |
| Control Systems | 138 | 362 | - | - | - | - | 156 | - | - | - | 203 | - | 265 |
| Switchgear | 175 | 511 | - | - | - | - | - | - | - | - | - | - | - |
| AC/DC Systems | 120 | - | - | - | - | - | - | - | 39 | - | - | - | - |
| Battery/Charger | - | - | - | - | - | - | 45 | - | - | - | 59 | - | 77 |
| Other | | | | | | | | | | | | | |
| Substation Refurbishment | - | - | - | 1,910 | - | - | - | - | - | - | - | - | - |
| TML Refurbishment | - | - | - | - | 48 | - | - | - | - | - | - | - | - |
| Total ($2023) | 1,666 | 3,457 | 639 | 1,910 | 695 | 353 | 201 | 2,103 | 1,941 | 1,008 | 262 | 639 | 452 |

[1] Changes from the previously submitted Summary of Capital Costs as filed as part of Newfoundland Power *2023 Capital Budget Application* are noted above in bold and underline text. Estimates for the years beyond 2027 are escalated to match the lifecycle cost analysis on page D-2.

# Attachment B:

## Summary of Operating Costs

Operating costs remain unchanged from the previous submission.

| Mobile Hydro Plant<br>Economic Evaluation<br>Summary of Operating Costs<br>($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 escalated using CPI All Items for Canada) 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 $/MWh | Off-Peak $/MWh | All hours $/MWh | On-Peak $/MWh | Off-Peak $/MWh | All hours $/MWh | Annual $/kW·yr |
| 2023 | 172.24 | 139.98 | 40.46 | 151.45 | 58.94 | 2.61 | 307.14 |
| 2024 | 124.58 | 101.21 | 30.20 | 167.79 | 65.34 | 2.90 | 340.42 |
| 2025 | 97.81 | 79.71 | 24.80 | 112.65 | 43.66 | 1.90 | 227.95 |
| 2026 | 58.14 | 49.33 | 23.22 | 99.30 | 38.41 | 1.66 | 200.70 |
| 2027 | 47.15 | 40.03 | 19.20 | 107.24 | 41.51 | 1.80 | 216.85 |
| 2028 | 47.98 | 41.33 | 21.81 | 115.85 | 44.88 | 1.95 | 234.37 |
| 2029 | 50.45 | 42.22 | 22.06 | 125.20 | 48.54 | 2.11 | 253.39 |
| 2030 | 43.98 | 36.82 | 21.43 | 135.01 | 52.38 | 2.29 | 273.35 |
| 2031 | 42.10 | 37.84 | 19.19 | 149.26 | 57.97 | 2.54 | 302.36 |
| 2032 | 44.82 | 37.85 | 20.47 | 165.09 | 64.18 | 2.83 | 334.61 |
| 2033 | 48.76 | 40.55 | 19.89 | 100.77 | 38.89 | 1.66 | 203.41 |
| 2034 | 44.80 | 35.88 | 20.84 | 106.63 | 41.17 | 1.76 | 215.31 |
| 2035 | 38.94 | 33.01 | 20.59 | 112.85 | 43.60 | 1.87 | 227.95 |
| 2036 | 34.83 | 29.90 | 17.90 | 119.45 | 46.18 | 1.99 | 241.37 |
| 2037 | 30.01 | 26.13 | 13.47 | 126.46 | 48.92 | 2.11 | 255.61 |
| 2038 | 24.66 | 21.99 | 12.87 | 132.79 | 51.39 | 2.22 | 268.48 |
| 2039 | 22.06 | 19.64 | 9.88 | 139.45 | 53.99 | 2.34 | 282.01 |
| 2040 | 14.44 | 14.80 | 8.22 | 146.46 | 56.73 | 2.46 | 296.25 |

**Notes:**

1. 2023-2040 based on the marginal cost projections provided by Hydro in the summary report Marginal Cost Update, dated December, 2022.
2. Beyond 2040, marginal cost projections are held constant.

# 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 | 17,762.1 | 1,097.1 | 40.32 | 2.72 |
| Cost of Replacement Production (Run-of-River) | | | | |
| Energy Cost | 16,297.1 | 1,006.6 | 40.32 | 2.50 |
| Capacity Cost | 30,965.3 | 1,912.7 | 40.32 | 4.74 |
| **Total** | **47,262.4** | **2,919.3** | | **7.24** |
| Cost of Replacement Production (Fully Dispatchable) | | | | |
| Energy Cost | 16,297.1 | 1,006.6 | 40.32 | 2.50 |
| Capacity Cost | 40,960.1 | 2,530.0 | 40.32 | 6.27 |
| **Total** | **57,257.2** | **3,536.6** | | **8.77** |

[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 Cumnulative 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 | 4,195,000 | 0 | 0 | 432,182 | 0 | 422,800 | 854,982 | 854,982 | 936,223 | 5,423,435 | 6,359,658 |
| 1 | 2025 | 639,000 | 0 | 0 | 513,831 | 286,452 | 0 | 800,283 | 756,339 | 1,692,563 | 5,631,146 | 7,323,708 |
| 2 | 2026 | 0 | 0 | 0 | 505,359 | 290,725 | 0 | 796,084 | 711,058 | 2,403,621 | 5,179,762 | 7,583,382 |
| 3 | 2027 | 0 | 0 | 1,910,000 | 654,748 | 295,698 | 0 | 950,446 | 802,319 | 3,205,940 | 6,496,864 | 9,702,804 |
| 4 | 2028 | 0 | 0 | 0 | 659,711 | 301,139 | 0 | 960,850 | 766,564 | 3,972,504 | 5,970,548 | 9,943,052 |
| 5 | 2029 | 646,702 | 48,066 | 0 | 699,563 | 308,593 | 0 | 1,008,156 | 760,141 | 4,732,645 | 6,048,788 | 10,781,433 |
| 6 | 2030 | 0 | 0 | 0 | 687,500 | 314,197 | 0 | 1,001,697 | 713,799 | 5,446,445 | 5,558,883 | 11,005,327 |
| 7 | 2031 | 0 | 0 | 0 | 668,756 | 319,751 | 0 | 988,508 | 665,722 | 6,112,167 | 5,108,501 | 11,220,668 |
| 8 | 2032 | 0 | 0 | 0 | 650,784 | 325,287 | 0 | 976,071 | 621,252 | 6,733,419 | 4,694,288 | 11,427,707 |
| 9 | 2033 | 0 | 0 | 0 | 633,521 | 330,891 | 0 | 964,412 | 580,126 | 7,313,545 | 4,313,205 | 11,626,749 |
| 10 | 2034 | 0 | 0 | 0 | 616,910 | 336,598 | 0 | 953,508 | 542,072 | 7,855,617 | 3,962,489 | 11,818,106 |
| 11 | 2035 | 0 | 0 | 0 | 600,900 | 342,426 | 0 | 943,326 | 506,836 | 8,362,453 | 3,639,634 | 12,002,087 |
| 12 | 2036 | 0 | 0 | 0 | 585,441 | 348,413 | 0 | 933,855 | 474,197 | 8,836,650 | 3,342,356 | 12,179,006 |
| 13 | 2037 | 352,669 | 0 | 0 | 599,985 | 354,539 | 0 | 954,524 | 458,078 | 9,294,728 | 3,249,854 | 12,544,582 |
| 14 | 2038 | 0 | 0 | 0 | 588,241 | 360,781 | 0 | 949,022 | 430,430 | 9,725,158 | 2,983,056 | 12,708,214 |
| 15 | 2039 | 201,458 | 0 | 0 | 590,094 | 367,160 | 0 | 957,253 | 410,323 | 10,135,481 | 2,829,694 | 12,965,175 |
| 16 | 2040 | 0 | 0 | 0 | 577,105 | 373,691 | 0 | 950,796 | 385,177 | 10,520,658 | 2,595,903 | 13,116,561 |
| 17 | 2041 | 0 | 0 | 0 | 562,419 | 380,298 | 0 | 942,717 | 360,934 | 10,881,591 | 2,380,572 | 13,262,164 |
| 18 | 2042 | 2,103,047 | 0 | 0 | 724,015 | 387,029 | 0 | 1,111,044 | 402,023 | 11,283,614 | 2,995,626 | 14,279,240 |
| 19 | 2043 | 0 | 0 | 0 | 726,429 | 393,926 | 0 | 1,120,355 | 383,132 | 11,666,746 | 2,747,206 | 14,413,952 |
| 20 | 2044 | 0 | 0 | 0 | 707,229 | 400,963 | 0 | 1,108,192 | 358,163 | 12,024,909 | 2,518,633 | 14,543,542 |
| 21 | 2045 | 0 | 0 | 0 | 688,618 | 408,120 | 0 | 1,096,738 | 334,998 | 12,359,906 | 2,308,295 | 14,668,202 |
| 22 | 2046 | 0 | 0 | 0 | 670,549 | 415,378 | 0 | 1,085,927 | 313,482 | 12,673,389 | 2,114,723 | 14,788,112 |
| 23 | 2047 | 0 | 0 | 0 | 652,979 | 422,765 | 0 | 1,075,744 | 293,491 | 12,966,880 | 1,936,573 | 14,903,453 |
| 24 | 2048 | 0 | 0 | 0 | 635,868 | 430,283 | 0 | 1,066,151 | 274,902 | 13,241,781 | 1,772,618 | 15,014,399 |
| 25 | 2049 | 1,940,932 | 0 | 0 | 781,502 | 437,934 | 0 | 1,219,437 | 297,161 | 13,538,942 | 2,125,692 | 15,664,634 |
| 26 | 2050 | 1,008,236 | 0 | 0 | 864,593 | 445,722 | 0 | 1,310,315 | 301,774 | 13,840,716 | 2,193,219 | 16,033,934 |
| 27 | 2051 | 0 | 0 | 0 | 851,289 | 453,648 | 0 | 1,304,937 | 284,033 | 14,124,748 | 2,007,927 | 16,132,676 |
| 28 | 2052 | 0 | 0 | 0 | 828,044 | 461,716 | 0 | 1,289,760 | 265,314 | 14,390,063 | 1,837,592 | 16,227,654 |
| 29 | 2053 | 0 | 0 | 0 | 805,471 | 469,926 | 0 | 1,275,397 | 247,954 | 14,638,016 | 1,680,998 | 16,319,014 |
| 30 | 2054 | 262,430 | 0 | 0 | 805,461 | 478,283 | 0 | 1,283,744 | 235,872 | 14,873,889 | 1,588,171 | 16,462,060 |
| 31 | 2055 | 0 | 0 | 0 | 786,110 | 486,788 | 0 | 1,272,898 | 221,037 | 15,094,926 | 1,451,664 | 16,546,590 |
| 32 | 2056 | 0 | 0 | 0 | 764,542 | 495,445 | 0 | 1,259,987 | 206,781 | 15,301,707 | 1,326,192 | 16,627,899 |
| 33 | 2057 | 0 | 0 | 0 | 743,488 | 504,255 | 0 | 1,247,744 | 193,528 | 15,495,235 | 1,210,875 | 16,706,111 |
| 34 | 2058 | 0 | 0 | 0 | 722,909 | 513,223 | 0 | 1,236,132 | 181,199 | 15,676,435 | 1,104,907 | 16,781,342 |
| 35 | 2059 | 0 | 0 | 0 | 702,766 | 522,349 | 0 | 1,225,115 | 169,723 | 15,846,158 | 1,007,548 | 16,853,706 |
| 36 | 2060 | 0 | 0 | 0 | 683,023 | 531,638 | 0 | 1,214,662 | 159,035 | 16,005,193 | 918,120 | 16,923,314 |
| 37 | 2061 | 0 | 0 | 0 | 663,650 | 541,092 | 0 | 1,204,742 | 149,075 | 16,154,269 | 836,000 | 16,990,269 |
| 38 | 2062 | 0 | 0 | 0 | 644,616 | 550,715 | 0 | 1,195,331 | 139,789 | 16,294,058 | 760,615 | 17,054,672 |
| 39 | 2063 | 0 | 0 | 0 | 625,895 | 560,508 | 0 | 1,186,403 | 131,126 | 16,425,184 | 691,438 | 17,116,622 |
| 40 | 2064 | 0 | 0 | 0 | 607,461 | 570,475 | 0 | 1,177,936 | 123,042 | 16,548,226 | 627,985 | 17,176,211 |
| 41 | 2065 | 0 | 0 | 0 | 589,291 | 580,620 | 0 | 1,169,911 | 115,493 | 16,663,720 | 569,811 | 17,233,530 |
| 42 | 2066 | 0 | 0 | 0 | 571,364 | 590,945 | 0 | 1,162,310 | 108,443 | 16,772,162 | 516,503 | 17,288,665 |
| 43 | 2067 | 638,735 | 0 | 0 | 607,080 | 601,454 | 0 | 1,208,534 | 106,564 | 16,878,726 | 525,483 | 17,404,209 |
| 44 | 2068 | 0 | 0 | 0 | 594,542 | 612,150 | 0 | 1,206,692 | 100,559 | 16,979,285 | 475,937 | 17,455,222 |
| 45 | 2069 | 452,130 | 0 | 0 | 613,339 | 623,036 | 0 | 1,236,375 | 97,375 | 17,076,660 | 466,803 | 17,543,463 |
| 46 | 2070 | 0 | 0 | 0 | 598,093 | 634,115 | 0 | 1,232,208 | 91,718 | 17,168,378 | 422,284 | 17,590,663 |
| 47 | 2071 | 0 | 0 | 0 | 578,364 | 645,392 | 0 | 1,223,756 | 86,087 | 17,254,466 | 381,598 | 17,636,064 |
| 48 | 2072 | 0 | 0 | 0 | 558,914 | 656,869 | 0 | 1,215,783 | 80,830 | 17,335,296 | 344,439 | 17,679,735 |
| 49 | 2073 | 0 | 0 | 0 | 539,721 | 668,550 | 0 | 1,208,270 | 75,920 | 17,411,216 | 310,527 | 17,721,742 |
| 50 | 2074 | 2,353,317 | 0 | 0 | 520,762 | 680,438 | 0 | 1,201,201 | 71,331 | 17,482,547 | 279,602 | 17,762,149 |

**Present Value of the Cost of Replacement Energy (Reduced Exports)**

| | Year | Marginal Energy Costs | Present Value $ | Cumulative Present $ |
|---|---|---|---|---|
| -1 | 2023 | - | - | - |
| 0 | 2024 | - | - | - |
| 1 | 2025 | 2,252,634 | 2,128,942 | 2,128,942 |
| 2 | 2026 | 1,533,781 | 1,369,966 | 3,498,909 |
| 3 | 2027 | 1,251,706 | 1,056,628 | 4,555,537 |
| 4 | 2028 | 1,326,701 | 1,058,440 | 5,613,977 |
| 5 | 2029 | 1,364,078 | 1,028,503 | 6,642,480 |
| 6 | 2030 | 1,234,514 | 879,702 | 7,522,183 |
| 7 | 2031 | 1,181,711 | 795,837 | 8,318,020 |
| 8 | 2032 | 1,233,361 | 785,012 | 9,103,032 |
| 9 | 2033 | 1,286,277 | 773,738 | 9,876,770 |
| 10 | 2034 | 1,220,132 | 693,649 | 10,570,418 |
| 11 | 2035 | 1,130,561 | 607,435 | 11,177,854 |
| 12 | 2036 | 1,004,528 | 510,084 | 11,687,938 |
| 13 | 2037 | 829,213 | 397,941 | 12,085,879 |
| 14 | 2038 | 723,861 | 328,308 | 12,414,187 |
| 15 | 2039 | 613,630 | 263,030 | 12,677,217 |
| 16 | 2040 | 458,092 | 185,577 | 12,862,794 |
| 17 | 2041 | 466,190 | 178,488 | 13,041,282 |
| 18 | 2042 | 474,442 | 171,673 | 13,212,955 |
| 19 | 2043 | 482,897 | 165,138 | 13,378,093 |
| 20 | 2044 | 491,523 | 158,858 | 13,536,951 |
| 21 | 2045 | 500,297 | 152,815 | 13,689,767 |
| 22 | 2046 | 509,193 | 146,992 | 13,836,759 |
| 23 | 2047 | 518,248 | 141,392 | 13,978,151 |
| 24 | 2048 | 527,464 | 136,004 | 14,114,155 |
| 25 | 2049 | 536,844 | 130,822 | 14,244,977 |
| 26 | 2050 | 546,391 | 125,837 | 14,370,814 |
| 27 | 2051 | 556,108 | 121,042 | 14,491,856 |
| 28 | 2052 | 565,997 | 116,430 | 14,608,286 |
| 29 | 2053 | 576,062 | 111,994 | 14,720,280 |
| 30 | 2054 | 586,306 | 107,727 | 14,828,007 |
| 31 | 2055 | 596,732 | 103,622 | 14,931,629 |
| 32 | 2056 | 607,344 | 99,674 | 15,031,302 |
| 33 | 2057 | 618,144 | 95,876 | 15,127,178 |
| 34 | 2058 | 629,137 | 92,222 | 15,219,401 |
| 35 | 2059 | 640,325 | 88,709 | 15,308,109 |
| 36 | 2060 | 651,712 | 85,328 | 15,393,437 |
| 37 | 2061 | 663,301 | 82,077 | 15,475,515 |
| 38 | 2062 | 675,097 | 78,950 | 15,554,464 |
| 39 | 2063 | 687,102 | 75,942 | 15,630,406 |
| 40 | 2064 | 699,321 | 73,048 | 15,703,454 |
| 41 | 2065 | 711,757 | 70,265 | 15,773,718 |
| 42 | 2066 | 724,414 | 67,587 | 15,841,306 |
| 43 | 2067 | 737,296 | 65,012 | 15,906,317 |
| 44 | 2068 | 750,407 | 62,535 | 15,968,852 |
| 45 | 2069 | 763,752 | 60,152 | 16,029,004 |
| 46 | 2070 | 777,334 | 57,860 | 16,086,864 |
| 47 | 2071 | 791,157 | 55,655 | 16,142,520 |
| 48 | 2072 | 805,226 | 53,535 | 16,196,054 |
| 49 | 2073 | 819,545 | 51,495 | 16,247,549 |
| 50 | 2074 | 834,119 | 49,533 | 16,297,082 |

**Present Value of the Cost of Replacement Capacity (Run-of-River Assumption)**

| | Year | Marginal Capacity Cost $ | Present Value $ | Cumulative Present $ |
|---|---|---|---|---|
| -1 | 2023 | - | - | - |
| 0 | 2024 | - | - | - |
| 1 | 2025 | 1,357,584 | 1,212,588 | 1,212,588 |
| 2 | 2026 | 1,466,655 | 1,238,077 | 2,450,665 |
| 3 | 2027 | 1,585,000 | 1,264,510 | 3,715,175 |
| 4 | 2028 | 1,713,419 | 1,291,903 | 5,007,079 |
| 5 | 2029 | 1,848,238 | 1,317,036 | 6,324,114 |
| 6 | 2030 | 2,044,118 | 1,376,635 | 7,700,750 |
| 7 | 2031 | 2,261,879 | 1,439,646 | 9,140,396 |
| 8 | 2032 | 1,376,281 | 827,878 | 9,968,274 |
| 9 | 2033 | 1,456,731 | 828,156 | 10,796,430 |
| 10 | 2034 | 1,542,118 | 828,560 | 11,624,990 |
| 11 | 2035 | 1,632,750 | 829,085 | 12,454,075 |
| 12 | 2036 | 1,728,954 | 829,729 | 13,283,804 |
| 13 | 2037 | 1,815,882 | 823,595 | 14,107,399 |
| 14 | 2038 | 1,907,327 | 817,569 | 14,924,968 |
| 15 | 2039 | 2,003,527 | 811,648 | 15,736,616 |
| 16 | 2040 | 2,038,948 | 780,642 | 16,517,258 |
| 17 | 2041 | 2,075,036 | 750,836 | 17,268,094 |
| 18 | 2042 | 2,112,015 | 722,253 | 17,990,347 |
| 19 | 2043 | 2,149,743 | 694,788 | 18,685,135 |
| 20 | 2044 | 2,188,116 | 668,358 | 19,353,493 |
| 21 | 2045 | 2,227,028 | 642,892 | 19,996,385 |
| 22 | 2046 | 2,266,631 | 618,396 | 20,614,781 |
| 23 | 2047 | 2,306,938 | 594,833 | 21,209,613 |
| 24 | 2048 | 2,347,963 | 572,168 | 21,781,781 |
| 25 | 2049 | 2,389,716 | 550,366 | 22,332,147 |
| 26 | 2050 | 2,432,213 | 529,396 | 22,861,543 |
| 27 | 2051 | 2,475,465 | 509,224 | 23,370,767 |
| 28 | 2052 | 2,519,486 | 489,821 | 23,860,588 |
| 29 | 2053 | 2,564,290 | 471,157 | 24,331,745 |
| 30 | 2054 | 2,609,891 | 453,204 | 24,784,949 |
| 31 | 2055 | 2,656,303 | 435,936 | 25,220,885 |
| 32 | 2056 | 2,703,540 | 419,325 | 25,640,210 |
| 33 | 2057 | 2,751,617 | 403,348 | 26,043,558 |
| 34 | 2058 | 2,800,549 | 387,979 | 26,431,537 |
| 35 | 2059 | 2,850,351 | 373,196 | 26,804,733 |
| 36 | 2060 | 2,901,039 | 358,976 | 27,163,708 |
| 37 | 2061 | 2,952,628 | 345,298 | 27,509,006 |
| 38 | 2062 | 3,005,134 | 332,141 | 27,841,147 |
| 39 | 2063 | 3,058,575 | 319,485 | 28,160,632 |
| 40 | 2064 | 3,112,965 | 307,312 | 28,467,943 |
| 41 | 2065 | 3,168,323 | 295,602 | 28,763,545 |
| 42 | 2066 | 3,224,665 | 284,339 | 29,047,884 |
| 43 | 2067 | 3,282,010 | 273,504 | 29,321,388 |
| 44 | 2068 | 3,340,374 | 263,083 | 29,584,472 |
| 45 | 2069 | 3,399,775 | 253,059 | 29,837,530 |
| 46 | 2070 | 3,460,234 | 243,416 | 30,080,947 |
| 47 | 2071 | 3,521,767 | 234,141 | 30,315,088 |
| 48 | 2072 | 3,584,395 | 225,220 | 30,540,308 |
| 49 | 2073 | 3,648,136 | 216,638 | 30,756,946 |
| 50 | 2074 | 3,713,011 | 208,384 | 30,965,330 |

## 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 | 1,960,173 | 1,852,541 | 1,852,541 |
| 2 | 2026 | 8.60 | 1,725,847 | 1,541,519 | 3,394,060 |
| 3 | 2027 | 8.60 | 1,864,723 | 1,574,107 | 4,968,167 |
| 4 | 2028 | 8.60 | 2,015,380 | 1,607,867 | 6,576,033 |
| 5 | 2029 | 8.60 | 2,178,936 | 1,642,899 | 8,218,932 |
| 6 | 2030 | 8.60 | 2,350,574 | 1,674,996 | 9,893,928 |
| 7 | 2031 | 8.60 | 2,600,035 | 1,751,025 | 11,644,953 |
| 8 | 2032 | 8.60 | 2,877,358 | 1,831,387 | 13,476,340 |
| 9 | 2033 | 8.60 | 1,749,151 | 1,052,172 | 14,528,512 |
| 10 | 2034 | 8.60 | 1,851,480 | 1,052,572 | 15,581,084 |
| 11 | 2035 | 8.60 | 1,960,173 | 1,053,175 | 16,634,259 |
| 12 | 2036 | 8.60 | 2,075,574 | 1,053,944 | 17,688,204 |
| 13 | 2037 | 8.60 | 2,198,026 | 1,054,837 | 18,743,041 |
| 14 | 2038 | 8.60 | 2,308,697 | 1,047,111 | 19,790,152 |
| 15 | 2039 | 8.60 | 2,425,043 | 1,039,486 | 20,829,638 |
| 16 | 2040 | 8.60 | 2,547,495 | 1,032,015 | 21,861,653 |
| 17 | 2041 | 8.60 | 2,592,533 | 992,591 | 22,854,244 |
| 18 | 2042 | 8.60 | 2,638,419 | 954,691 | 23,808,935 |
| 19 | 2043 | 8.60 | 2,685,437 | 918,348 | 24,727,283 |
| 20 | 2044 | 8.60 | 2,733,409 | 883,426 | 25,610,709 |
| 21 | 2045 | 8.60 | 2,782,201 | 849,821 | 26,460,531 |
| 22 | 2046 | 8.60 | 2,831,677 | 817,440 | 27,277,971 |
| 23 | 2047 | 8.60 | 2,882,033 | 786,293 | 28,064,264 |
| 24 | 2048 | 8.60 | 2,933,284 | 756,333 | 28,820,597 |
| 25 | 2049 | 8.60 | 2,985,446 | 727,514 | 29,548,111 |
| 26 | 2050 | 8.60 | 3,038,537 | 699,793 | 30,247,904 |
| 27 | 2051 | 8.60 | 3,092,571 | 673,129 | 30,921,033 |
| 28 | 2052 | 8.60 | 3,147,566 | 647,481 | 31,568,514 |
| 29 | 2053 | 8.60 | 3,203,539 | 622,810 | 32,191,324 |
| 30 | 2054 | 8.60 | 3,260,508 | 599,079 | 32,790,402 |
| 31 | 2055 | 8.60 | 3,318,489 | 576,252 | 33,366,654 |
| 32 | 2056 | 8.60 | 3,377,502 | 554,295 | 33,920,949 |
| 33 | 2057 | 8.60 | 3,437,564 | 533,174 | 34,454,123 |
| 34 | 2058 | 8.60 | 3,498,694 | 512,859 | 34,966,982 |
| 35 | 2059 | 8.60 | 3,560,912 | 493,317 | 35,460,299 |
| 36 | 2060 | 8.60 | 3,624,235 | 474,520 | 35,934,819 |
| 37 | 2061 | 8.60 | 3,688,685 | 456,439 | 36,391,259 |
| 38 | 2062 | 8.60 | 3,754,281 | 439,048 | 36,830,306 |
| 39 | 2063 | 8.60 | 3,821,043 | 422,319 | 37,252,625 |
| 40 | 2064 | 8.60 | 3,888,993 | 406,227 | 37,658,852 |
| 41 | 2065 | 8.60 | 3,958,151 | 390,748 | 38,049,600 |
| 42 | 2066 | 8.60 | 4,028,539 | 375,860 | 38,425,459 |
| 43 | 2067 | 8.60 | 4,100,178 | 361,538 | 38,786,997 |
| 44 | 2068 | 8.60 | 4,173,092 | 347,762 | 39,134,760 |
| 45 | 2069 | 8.60 | 4,247,302 | 334,511 | 39,469,271 |
| 46 | 2070 | 8.60 | 4,322,832 | 321,765 | 39,791,037 |
| 47 | 2071 | 8.60 | 4,399,705 | 309,505 | 40,100,542 |
| 48 | 2072 | 8.60 | 4,477,944 | 297,712 | 40,398,254 |
| 49 | 2073 | 8.60 | 4,557,576 | 286,368 | 40,684,622 |
| 50 | 2074 | 8.60 | 4,638,623 | 275,457 | 40,960,079 |

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, medium term forecast dated February 6, 2023 and long term forecast dated December 16, 2022.

***Supporting Documents:*** Newfoundland and Labrador Hydro's Marginal Cost Update, dated December 2022.

# APPENDIX B:

## Surge Tank Inspection Report – Mobile Development

# SURGE TANK INSPECTION REPORT

## MOBILE DEVELOPMENT

***Prepared for:***

**Newfoundland Power Inc.**
**St. John's, Newfoundland and Labrador**

***Prepared by:***

Kleinschmidt

Dartmouth, Nova Scotia
www.KleinschmidtGroup.com

2061014.01
May 2023

# SURGE TANK INSPECTION REPORT

## MOBILE DEVELOPMENT

*Prepared for:*

Newfoundland Power Inc.
St. John's, Newfoundland and Labrador

*Prepared by:*

Kleinschmidt

Dartmouth, Nova Scotia
www.KleinschmidtGroup.com

2061014.01
May 2023

**SURGE TANK INSPECTION REPORT**

**MOBILE DEVELOPMENT**

**TABLE OF CONTENTS**



**LIST OF TABLES**



**APPENDICES**

**SURGE TANK INSPECTION REPORT**

**MOBILE DEVELOPMENT**

# 1.0 INTRODUCTION

## 1.1 PROJECT DESCRIPTION

Newfoundland Power Inc. (Newfoundland Power)’s Mobile Hydroelectric Development (the Project) is located in the town of Mobile, Newfoundland and Labrador, and was constructed in 1951. Original construction included a diversion dam, woodstave penstock, steel penstock, surge tank, and powerhouse. The original penstock sections and surge tank were constructed in 1951, along with the diversion works and canals. The wooden portion of the penstock from the intake to the surge tank was replaced with a fiberglass reinforced plastic (FRP) pipe in 1990 and the surge tank was replaced in 1999. No other significant changes or replacements have occurred over the history of the Project and the original design head of the plant remains unaltered (refer to Appendix B for drawings).

The surge tank is a differential type tank with restricted orifice, welded steel structure 61.1 m (200.5 feet) tall. There is a 1.83-m (6.0-foot) diameter steel pipe riser to the bowl which continues as an internal riser inside. The surge tank bowl has a diameter of 5.17 m (17.0 feet) and is supported on four legs.

## 1.2 INSPECTION SCOPE

Kleinschmidt Associates Canada Inc. (Kleinschmidt) inspected the interior and exterior of the steel surge tank utilizing rope access methods. The interior of the penstock was not part of the inspection scope. The purpose of the inspection was to assess the condition of the steel surge tank for continued safe operation and identify any remediation required to ensure continued safe operation or extend the life of the structure. The inspection consisted of a visual inspection of the steel plate, welded joints, tower support legs and connections, and steel thickness readings.

## 1.3 INSPECTION TEAM

Chris Vella, P.Eng., senior structural engineer with Kleinschmidt, and Nick Townsend, E.I.T., performed the inspection. Kleinschmidt was assisted by Technical Rope and Rescue (TRR) personnel including Todd LeGrow as the SPRAT Level 3 rope access supervisor and rescue team leader, Steve Foley as a member of the rope access and rescue team, and Blake Abbott as the confined space attendant. Shane Cole of Newfoundland Power was on site during the inspection.

### 1.4 INSPECTION PROCEDURES

Kleinschmidt inspected the surge tank on October 19 and 20, 2022. The inspection team completed a safety orientation prior to arriving on site and went through safety tailboard, access plans, and rescue plans on site prior to commencing inspection. Shane Cole of Newfoundland Power attended the safety discussions. Weather was partly cloudy with very light wind and with an approximate high temperature of 14 degrees C.

**PHOTO A SURGE TANK ROOF**

The inspection started at the bottom with items visible without climbing the tank. The inspection progressed as the inspectors climbed the access ladder on Leg 4 and took pictures of the members from each level. At the top of Level 4 the inspectors were able to walk around the tank and inspect close-up the tops of the tower legs and support structure. The inspectors descended to the lower access deck under Level 5 and were able to see close-up the top connections for the bracing. The inspection progressed to the top of the surge tank, top of Level 5, and the inspectors entered the surge tank from the top access hatch to complete the internal inspection.

TRR provided rigging for rope access, confined space monitoring, and rescue services during the inspection. TRR arrived the day before Kleinschmidt to setup rigging and anchorage sites for ropes. Ropes were used for backup while climbing the exterior ladder and for descending through the interior. For the interior inspection two ropes were rigged for each inspector (four ropes total). Interior access to the surge tank was through the access hole on the roof. The inspection team descended in the surge tank and exited the access hatch at the bottom of the surge tank. The inspection team then went back to the top of the tank and descended the riser and exited through the access hole in the penstock immediately upstream of the surge tank. The interior of the surge tank inspection included the interior of the tank shell and interior of the riser. The exterior inspection consisted of visual observations of the insulating shell, observations of the upper platform and structural elements and support connections, and the access ladder and fall restraint systems.

During the interior inspection Kleinschmidt measured shell thickness readings with an Olympus Model 45MG Plus Ultrasonic gauge. A dual element transducer, Panametrics Model D790, was used and the readings were taken in the “standard” mode. In “standard” mode the paint thickness does not affect the steel thickness readings if the paint thickness is below 0.4 mm. The gauge was calibrated before the field measurements to an accuracy of 0.25mm. Thickness readings were taken with the thickness gauge at approximately the 3 o’clock position below the top access hole. Clock positions are noted looking down with 12 o’clock pointing downstream toward the powerhouse. The interior coating of the penstock was in good condition and readings were taken at each level or section of the surge tank, with the circumferential welds separating the levels. The riser was a spiral wound pipe and readings were taken approximately every 4 meters.

Photographs taken during the surge tank inspection can be found in Appendix A.

The inspection used the standard nomenclature of left/right position and clockwise position relative to a view looking downstream.

# 2.0 INSPECTION FINDINGS

The surge tank and supporting structure is in fair condition overall with no significant structural defects noted but the coating system is in poor condition with several areas of coating loss and early corrosion. The coating system should be removed and replaced to prevent the corrosion from progressing.

Definitions for qualitative terminology such as fair and good are in Table 2-1.

**TABLE 2-1 DEFINITIONS FOR CONDITION ASSESSMENT**

| TERM | DEFINITION |
|---|---|
| Excellent | New or near new condition. No visible deterioration present and remedial action is not required |
| Good | General or light deterioration where performance is not affected, and remedial action is not expected to be required in the next 10 years |
| Fair | Medium deterioration or defects are visible that do not require maintenance in the next 12 months but may require preventative maintenance in the next 5 to 10 years |
| Poor | Significant deterioration is visible, and remediation is required in the next 1 to 5 years |
| Very Poor | Severe deterioration or defect is visible, and remediation is required within 1 year |

## 2.1 SURGE TANK EXTERIOR

For purposes of this report, Kleinschmidt has labelled the tower legs to help describe location of observations:

- Upstream left tower leg and footing – Leg 1 and Footing 1
- Downstream left tower leg and footing – Leg 2 and Footing 2
- Downstream right tower leg and footing – Leg 3 and Footing 3
- Upstream right tower leg and footing – Leg 4 and Footing 4

Kleinschmidt has also labelled the sections between horizontal struts as levels with Level 1 starting at the ground. Figure 1 in Appendix B shows the labelling of the levels to help understand location descriptions. Note that the access ladder is located on Leg 4.

An external surge tank inspection was started on October 18, 2022, and completed the morning of October 19th. Kleinschmidt observed the surge tank for condition of the wall (shell), support legs, struts, and bracing, and connection to the foundation. Corrosion, deformation, or other damage was noted when observed.

The footings all appeared to be in good condition with Footing 2 representative of the general condition of the footings (Photo 2). There does not appear to be any significant cracks in the concrete footings but there is some light efflorescence and minor surface cracks that do not require repair.

The steel base plates, and anchor rods appear in good condition with no signs of stress, deformation, bending, or cracking of the plate or welds (Photo 3). The paint coating is in fair condition for the plate. The bolts have some light surface corrosion and should be cleaned and coated when the rest of the structure coating is replaced.

The diagonal bracing connection plates for the entire structure have near complete coating loss (Photos 4 to 8). The rust is light to moderate at this point with no significant pitting. These connection plates should be cleaned and coated to maintain good condition of these critical components.

The tower legs and intermediate struts at higher levels were viewed from the ground, from the ladder on the side of Leg 4, from the deck at the bottom of Level 5, and from rope hung on the left side of the tower. The tower legs were generally in good structural condition with no signs of excessive stress, bending, warping, or cracking (Photos 9 to 11, 26). The paint coating was in poor condition with several spots of flaking and missing paint and light to moderate corrosion observed most notably around the connection points of the horizontal bracing (Photos 8 and 14).

The diagonal bracing (or cross-bracing) coating is in poor condition with significant paint loss and some surface corrosion (Photos 15 to 18). All of the bracing are in contact where they cross but no significant wear or material loss was observed. Wear can occur during windy days and the crossing bracing rubs as happened at Rattling Brook. It is recommended that rub plates be installed at Mobile to mitigate the possibility of wear.

The structural steel support structure at the top of level 4 (base of the tank) was in fair structural condition. There were no signs of excessive stress, bending, warping, displacement, or cracking; however, the coating is in poor condition and there was several areas of paint loss and light corrosion mostly around the connections (Photos 19 to 22). The coating system on structural members should be replaced.

The handrails show near complete loss of coating (Photos 23 and 24). These should be cleaned and coated to mitigate section loss and extend their life.

The roof of the tank was in good structural condition but has some paint loss and areas of corrosion (Photo 25). The roof and anchor points should be cleaned and coated when the rest of the structure coating is replaced.

The tank cladding was in good condition (Photo 27). No missing bolts or lose panels were observed.

The ladders and cages going up the side of the tower leg and tank have near complete loss of paint and should be cleaned and painted to ensure future safe use. Replacement should be considered as it may be more cost effective due to the labour involved in cleaning and painting ladders this height. During access on the Mobile surge tank, we reviewed the existing ladder safety system (vertical Cable lifeline) with TRR. Overall, the system seems to be in fair condition for the age. This is not a certification for the system but our opinion as a detailed review and certification of the safety system was not included. There is some corrosion on some key components, but most items are stainless steel and in good condition. Placement of the top brackets is not ideal. As pictured (Photo 29), the bracket is a bit short at the top and would likely require the user to disconnect during the transition from ladder-deck and deck-ladder which is arguably the riskiest part of the climb. Some systems have a taller top bracket available and can be installed to one side of the ladder rather than the center, allowing transition to the safe platform while remaining connected.

Ladder safety systems have many benefits over other fall protection systems in this application. One of the main benefits of a cable ladder safety system would be, in most applications, eliminating the traditional ladder cage. It seems the existing ladder cages would likely require some extensive maintenance. Cost of maintaining the current cage would probably cover the cost of a new cable system and install.

## 2.2 Surge Tank and Riser Interior

Kleinschmidt began the interior of the steel surge tank inspection around 2:00 pm on October 18, 2022, following the exterior inspection of the tank and support structure.

The interior surfaces on the steel plating were in fair to good condition with spot corrosion in a few locations (Photos 31 to 41) and corrosion around the weld seems. The corrosion was more pronounced around the normal water line and below (Photo 37, 39, 41). This is the area where water levels typically fluctuate with pond level changes and surge events. The steel in this area of the shell was originally 6 mm thick with corresponding steel plate thickness in the interior riser of 6 mm, and 8 mm. Less corrosion was noted above the normal water level where the steel is generally dry (Photo 32) and below where the shell is typically continually submerged (Photo 41). Table 2-2 lists thickness readings and calculations for Normal Pond hoop tensile stresses at different elevations using measured plate thickness readings is in Appendix C.

Overall, the internal surface varies in condition from good for the internal riser above the normal water line (Photo 45) and most of the tank outer shell above the water line, to poor for weld seams and specifically the weld seams at or below normal water levels (Photo 41). The interior of the lower riser was in good condition (Photos 47, 48) with only a few spots (less than 10) of rust (Photo 49) that should be cleaned and painted. The weld seams and rust spots should be cleaned and painted. A full refurbishment of the coating system is not viewed to be necessary at this time.

***Steel Shell Thickness Review***

As part of Kleinschmidt's inspection, surge tank shell plate thickness measurements were taken using a UT gauge as noted in Section 1.4.  Readings were taken at each plate section going down the tank, and at roughly 4-meter intervals going down the riser. Refer to Table 2-2 for the measurements and a comparison to the design thickness per the drawings in Appendix B.

**TABLE 2-2 SURGE TANK SHELL THICKNESS READINGS**

| LOCATION | AVERAGE THICKNESS (mm) | DESIGN THICKNESS (mm) | DIFFERENCE (mm) |
|---|---|---|---|
| Surge Tank Roof | 4.53 | 5.00 | -0.47 |
| Surge Tank Plate 1 | 6.07 | 6.00 | 0.07 |
| Surge Tank Plate 2 | 7.00 | 6.00 | 1.00 |
| Surge Tank Plate 3 | 6.86 | 6.00 | 0.86 |
| Surge Tank Plate 4 | 7.34 | 6.00 | 1.34 |

| LOCATION | AVERAGE THICKNESS (mm) | DESIGN THICKNESS (mm) | DIFFERENCE (mm) |
|---|---|---|---|
| Surge Tank Plate 5 | 7.02 | 6.00 | 1.02 |
| Surge Tank Plate 6 | 7.09 | 6.00 | 1.09 |
| Top of Internal Riser | 6.28 | 6.00 | 0.28 |
| Spot of deterioration/organics | 9.18 | 10.00 | -0.82 |
| Internal Riser Above Expansion Joint 1 | 8.91 | 10.00 | -1.09 |
| Internal Riser Above Expansion Joint 2 | 8.91 | 10.00 | -1.09 |
| Internal Riser Below Expansion Joint | 6.14 | 6.00 | 0.14 |
| | 6.05 | 6.00 | 0.05 |

The surge tank shell thickness measurements show that the readings have some spread with some readings closely matching and some exceeding the design values. There are a few spots where readings are below design and these spots are at locations where the coating was missing and the spot was actively rusting. These are relatively small spots (hand size) and readings in other locations are good. Based on the stress analysis discussed in the following section and the relative good condition of the coating, further analysis is not warranted. It is recommended the interior coating be restored in the few spots and welds where the coating has been lost and corrosion has started.

# 3.0 EVALUATION

A structural evaluation was completed looking at hoop stresses in the surge tank shell, internal riser, and lower riser. The configuration and operational conditions were based on existing drawings in Appendix B. The data collected during the inspection was combined with existing drawings and available data to complete the evaluation following the guidelines of AWWA-D100, *Welded Carbon Steel Tanks for Water Storage* (2011). A structural analysis of the tower legs and bracing was not included in the scope.

Based on our inspection and evaluation, we conclude that the existing steel surge tank is currently sufficient to carry the loads described in the evaluation.

## 3.1 LOADING CONDITIONS AND ALLOWABLE STRESSES

The loading conditions and allowable stresses followed AWWA D-100. It was assumed that the riser steel was spiral pipe A139 Grade C as per Figure 1, and the surge tank shell is CSA G40.21 300W per Figure 7. An allowable stress of 15,000 pounds per square inch (psi), equal to 103.4 megapascals (MPa), was used for the surge tank based on a yield strength of the steel plate greater than 27,000 psi (186.16 MPa) per AWWA D-100.

The welded seams are not as strong as the original base material; these reductions are designated as “joint efficiency, E” and are defined as 75 percent per AWWA D-100 for all welded joints.

The two load cases presented in Tables 1 and 2 in Appendix C include:

- Maximum static pond water levels in the surge tank at El. 494 feet or 150.6 m.
- Maximum static pond multiplied by 1.3 to account for transient pressures. Note that this represents an elevation of 642.2 feet (195.7 m) which is higher than the top of the surge tank.

## 3.2 SHELL AND RISER STRESSES INDUCED BY INTERNAL PRESSURE

Tables 1 and 2 in Appendix C summarize the analysis of the steel shell thickness data and internal pressure analysis.

Stresses presented are based on the average thickness reading for the steel thicknesses measured.

The maximum hoop stress in the surge tank riser and shell is due to internal static and dynamic water pressures. The stress ratio is the maximum hoop stress divided by the allowable steel stress. A hoop stress less than 1.0 indicates that the surge tank meets industry-standard factors of safety as designated in *ASCE Engineering Practice No. 79, Steel Penstocks* (2012).

The calculated stress ratios for both loading conditions are all less than 1.0 including the reduced joint efficiency. The peak stress ratios for the maximum pond level and dynamic surge level are 0.49 and 0.64, respectively, occurring at the joints. No further analysis is recommended at this time.

# 4.0 RECOMMENDATIONS

There were no potential safety-related issues noted during the inspection. The recommendations presented here are based on the inspection observations and are intended to help provide continued reliable and safe operation of the surge tank.

Overall, the surge tank appears to be structurally in fair to good condition. Well maintained surge tanks will typically have a service life of 80 years (ASCE 2012). With the proper repairs and maintenance, Kleinschmidt's judgment is that the Mobile surge tank should have a reliable service life for at least another 50 years or more.

The surge tank is 23 years old and coatings have a typical life span of 20 to 25 years. The coating system is in poor condition and replacement is required to extend the life of the surge tank.

## 4.1 SHORT TERM

Kleinschmidt has the following short-term recommendations to be completed in the next 1 to 5 years:

1. Clean and repaint the access ladders, cages, and connection tabs. Due to the labour-intensive nature of cleaning and painting ladders, we recommend NL Power price the option of a full replacement.
2. Clean and repaint the handrails on both decks around the base of the surge tank.
3. Clean and paint the tower structural steel.
4. Rub plates should be installed at the intersection of the cross-bracing to prevent wear.
5. The roof of the surge tank should be painted along with the roof vent components.
6. The interior coating of the surge tank shell should be touched up. Specifically at the weld seams and about a dozen hand sized spot repairs on the plating.
7. The interior coating of the riser has a dozen hand sized spots that should be cleaned and painted. The exterior of the riser requires no repairs.
8. The interior platform at the top of the surge tank should be cleaned and painted around its connection points.

We recommend performing visual inspection of the surge tank interior every 5 years to monitor the condition of the coating. These do not have to be full rope access inspections. The surge tank can be entered at the top and a camera lowered to record the condition of the coating on the shell and riser sections.

## 4.2 LONG TERM (10+ YEARS)

We recommend that the interior of the surge tank bowl and risers be recoated when inspection shows significant degradation. Total interior coating is not necessary based on the current condition of the steel. Kleinschmidt recommends waiting until either the coating all over the tank interior begins to fail or significant material loss is found during inspections. Coating the interior of the tank includes surface preparation to SPCC-SP-10 and then a coating of choice, such as the three-part epoxy system similar to Carboline 134. This acrylicpolyurethane coating or similar products will adhere well and protect the interior surface of the steel riser.

We recommend that thickness readings be taken within the next 10 years in the water-fluctuation zone. This will be the area where significant deterioration is first noticed. A detailed inspection of the entire surge tank, interior, exterior, and support structure, should be performed within the next 15 to 20 years. We recommend that this inspection, when the tank is 40 to 50 years old, include removal of the cladding in large areas to verify the condition of the shell and lower riser exterior.

## 5.0 REFERENCES

1. American Society of Civil Engineers (ASCE). 2012. Steel Penstocks – ASCE Manuals and Reports on Engineering Practice No. 79. 2nd Edition. American Society of Civil Engineers. Reston, Virginia.
2. Guidelines for Evaluating Aging Penstocks, American Society of Civil Engineers (ASCE), 1995
3. Guidelines for Inspection and Monitoring of In-Service Penstocks, ASCE, 1998

## REPORT SIGNATURE PAGE

**KLEINSCHMIDT ASSOCIATES CANADA INC.**

Chris M. Vella, P.Eng.
Senior Structural Engineer

CMV:SCB

# APPENDIX A

# PHOTOGRAPHS

**Photo 1: Looking up at the Surge Tank near Upstream Right Leg**


**Photo 2: Footing 2**

**Photo 3: Steel Base plate Connection Footing 1**

**Photo 4: Diagonal bracing connection plate, Leg 2 Level 1**

**Photo 5: Diagonal bracing connection plate, Leg 2 top of Level 4**

**Photo 6: Diagonal bracing connection plate Leg 2 Level 3**

Photo 7: Diagonal Bracing Connections, Leg 3, level 2

Photo 8: Paint loss at connection points, Leg 4, top of level 2. Typical Condition

**Photo 9: Looking from Leg 4 at Leg 2 at the top of level 2**

**Photo 10: Leg 1 viewed from Leg 2**

**Photo 11: Leg 1 at top of level 2**

**Photo 12: Leg 2 splice**

**Photo 13: Leg 4 splice**

**Photo 14: Paint loss at connection points, Leg 2, top of level 1. Typical Condition**

**Photo 15: Level 2 cross bracing between Legs 1 and 2**

**Photo 16: Level 3 cross bracing between Legs 4 and 1**

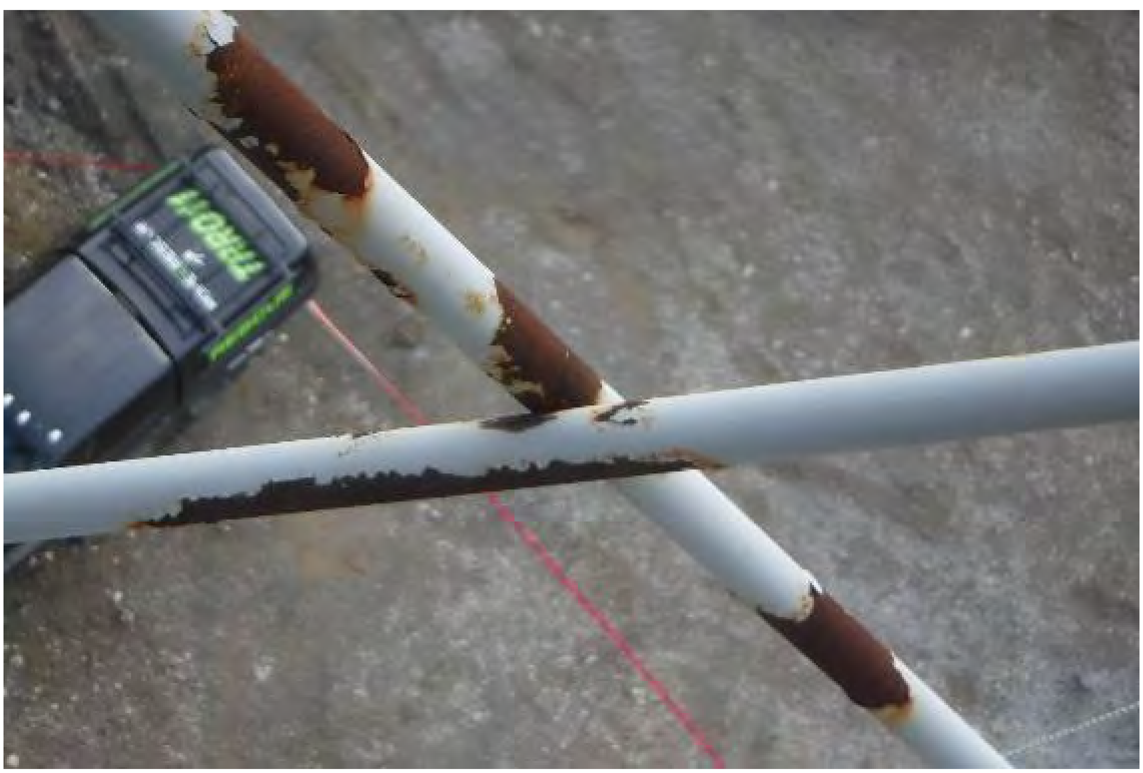


**Photo 17: Level 2 cross bracing between Legs 3 and 4**

**Photo 18: Level 3 cross bracing between Legs 2 and 3**

**Photo 19: Top of Leg 2**

**Photo 20: Horizontal Support beams connecting to Leg 2**

**Photo 21: Horizontal Intermediate Support Beam Between Leg 2 and 3**

**Photo 22: Horizontal Deck support. Note paint loss and corrosion at connections**

**Photo 23: Lower Deck near top of level 4.**

**Photo 24: Typical handrails around Upper Deck.**

**Photo 25: Roof vent**

**Photo 26: Access ladder on Leg 4**

**Photo 27: Tank Cladding adjacent ladder**

**Photo 28: Top of Leg 4 ladder.**

**Photo 29: Top of Leg 4 ladder.**

**Photo 30: Surge tank ladder cage.**

**Photo 31: Inside Surge Tank at top platform.**

**Photo 32: Inside Surge Tank looking down from top platform.**

**Photo 33: Roof structure Inside Surge Tank**

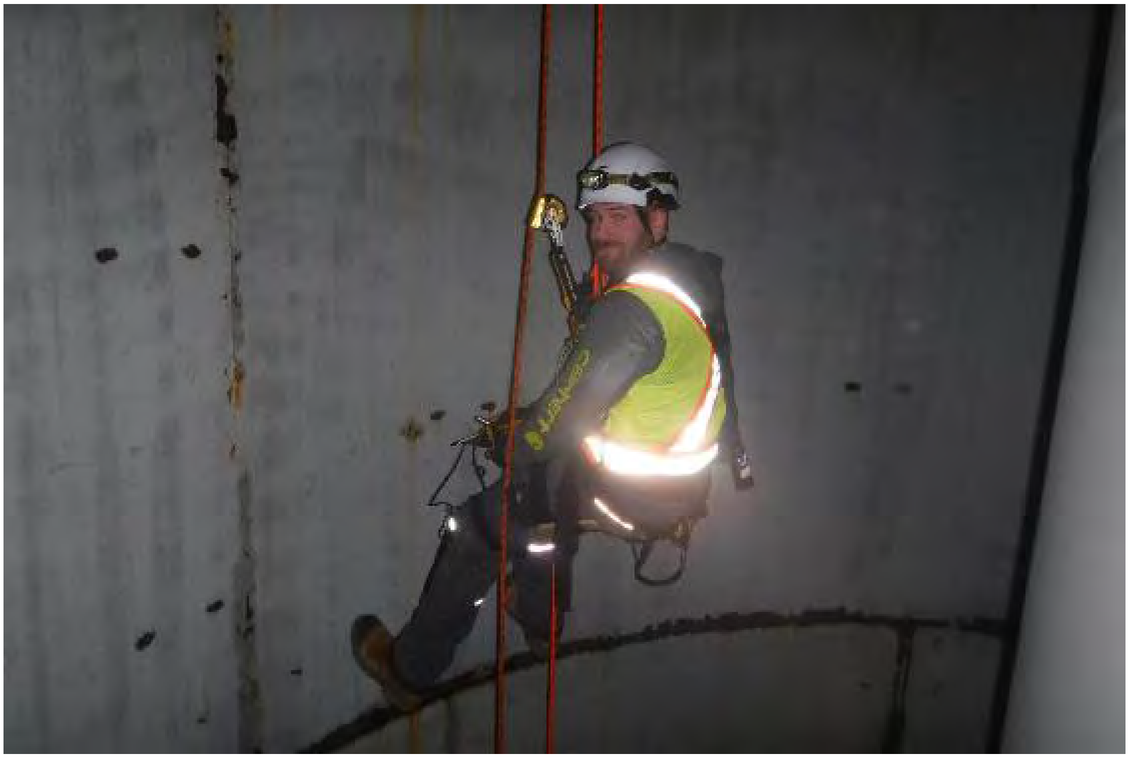


**Photo 34: Rope access decent inside of tank. Note minor spots of corrosion**

**Photo 35: Weld seam just below top platform.**

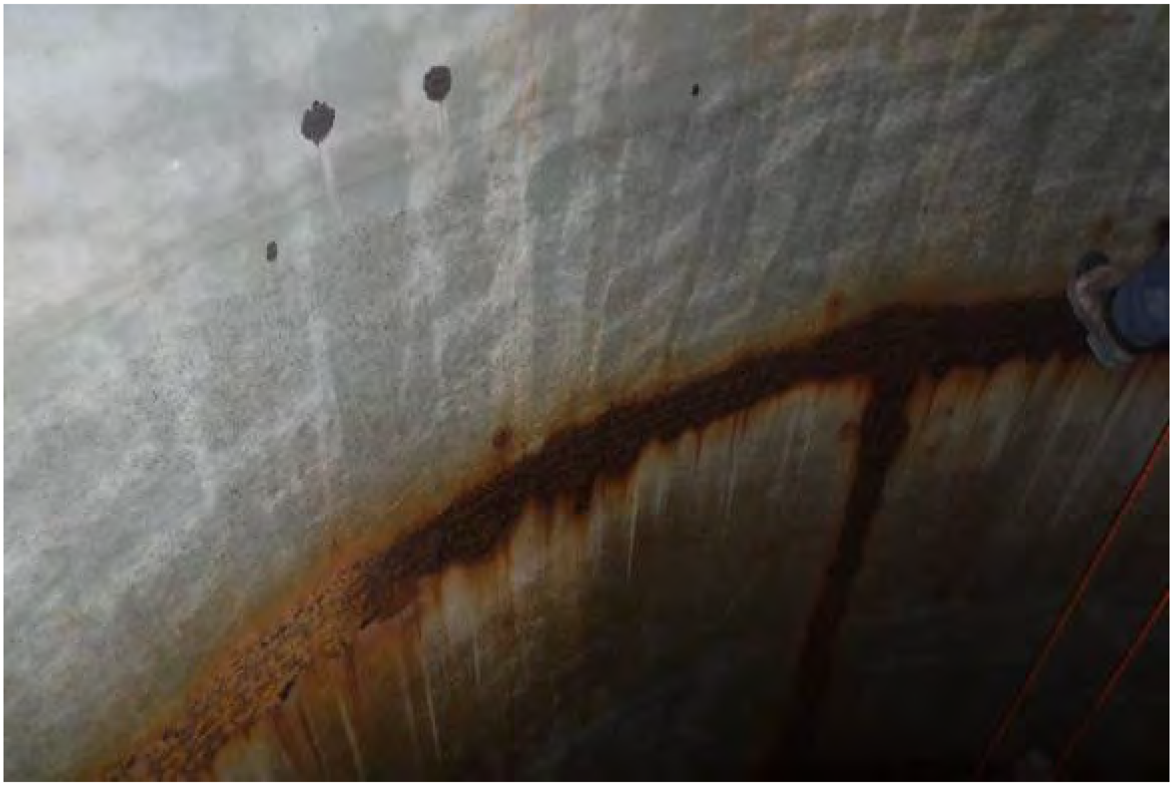


**Photo 36: Weld seam near normal operating water level.**

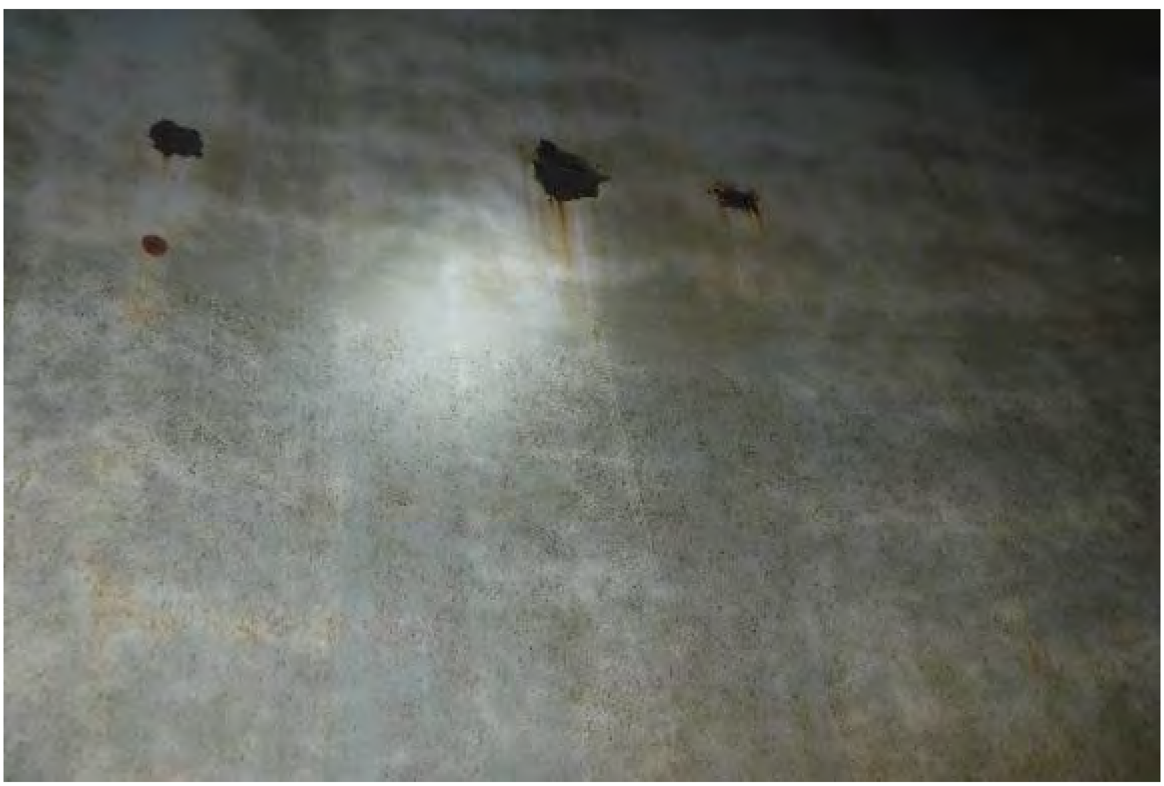


**Photo 37: Inside Surge Tank spot corrosion.**

**Photo 38: Looking up inside Surge Tank from below normal water level.**

**Photo 39: Looking down inside Surge Tank. Not riser in center of tank**

**Photo 40: Bottom of surge tank.**

**Photo 41: Weld seam near normal water elevation.**

**Photo 42: Transition from lower riser to upper inner riser. Note discolouration is organics and dirt not corrosion**

**Photo 43: Bottom bowl of surge tank. Note discolouration is organics and dirt not corrosion**

Photo 44: Internal stiffener ring near bottom of surge tank. Note spot of corrosion.

Photo 45: Internal riser above normal water.

**Photo 46: Expansion joint in riser**

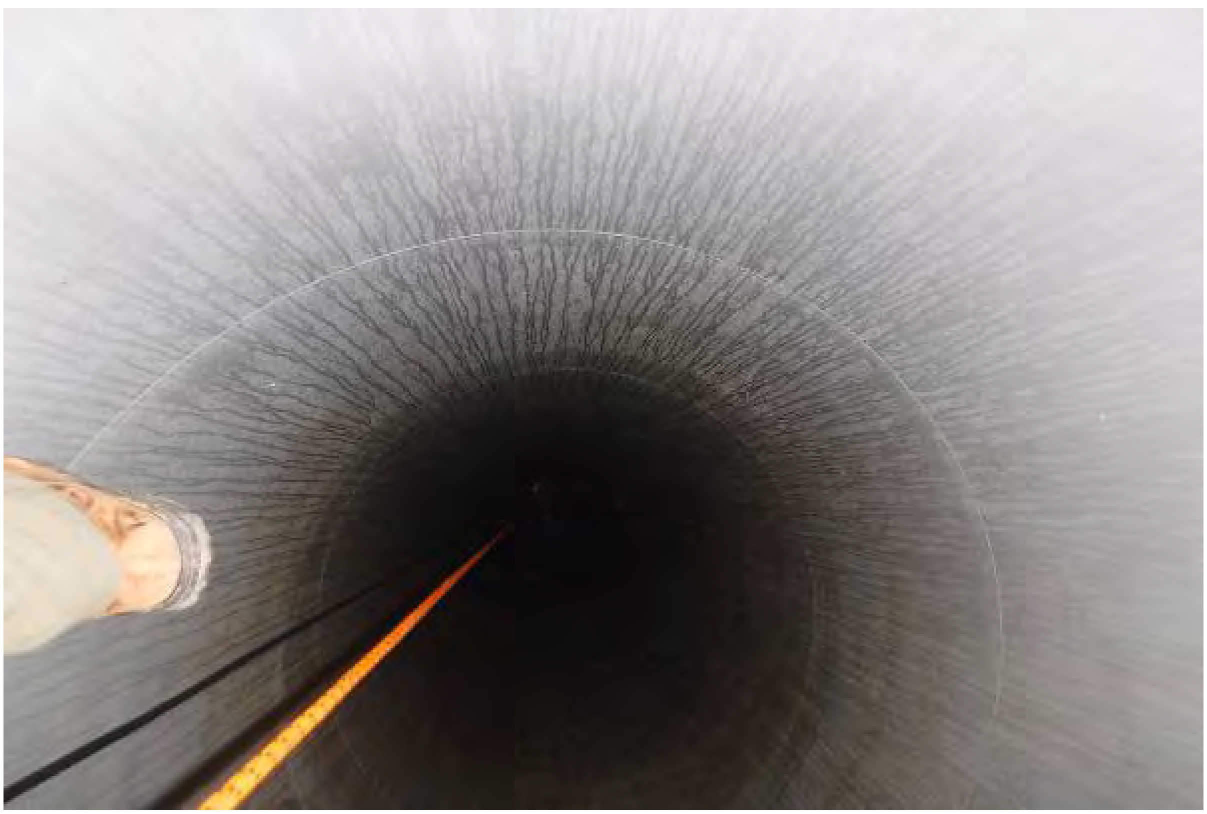


**Photo 47: looking down inside rider**

**Photo 48: Inside riser below water line**

**Photo 49: Spot of rust inside riser below water line**

**Photo 50: Inside penstock looking downstream**

**Photo 51:Weld seam at riser to penstock transition**

# APPENDIX B

# DRAWINGS

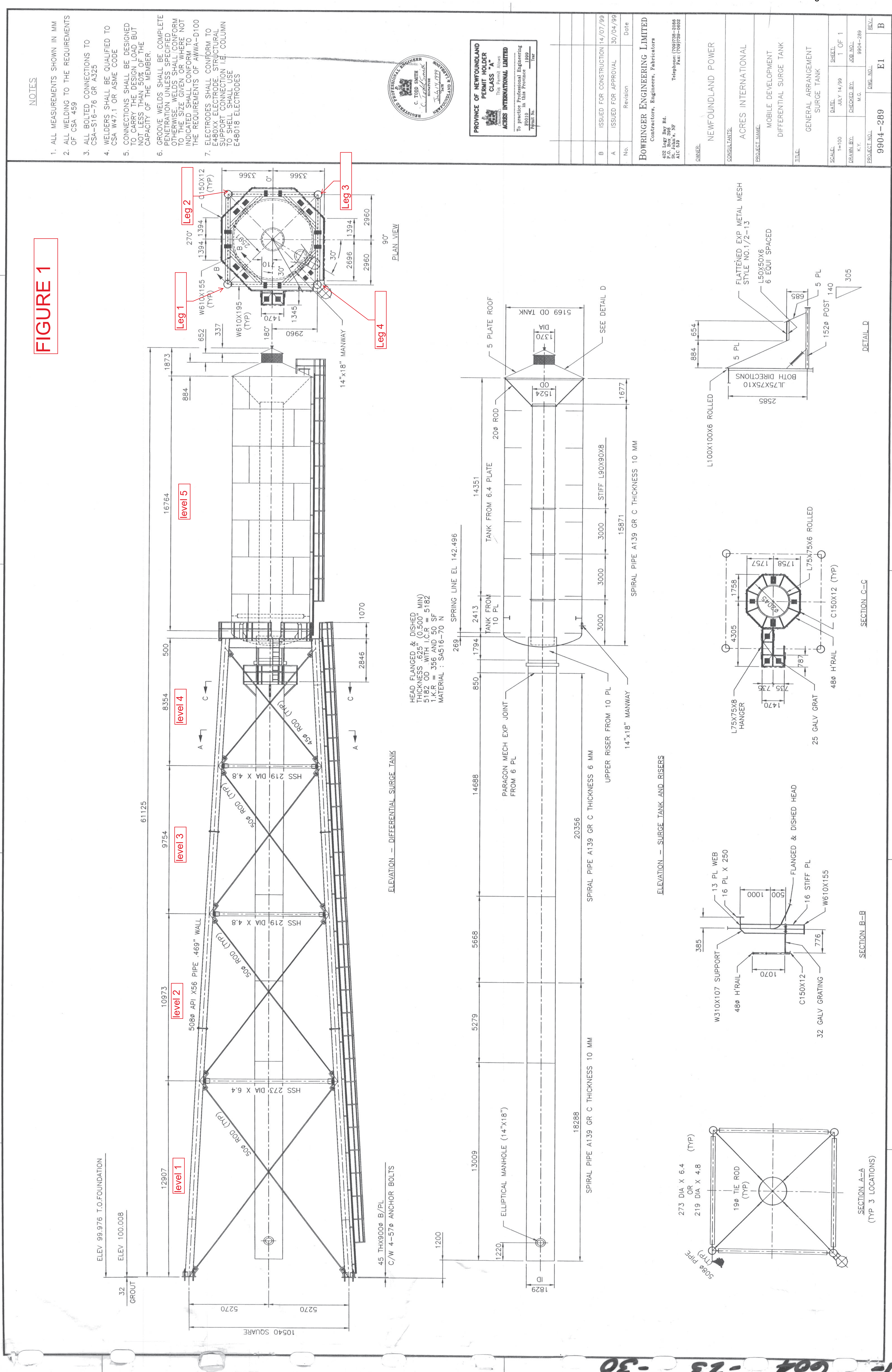
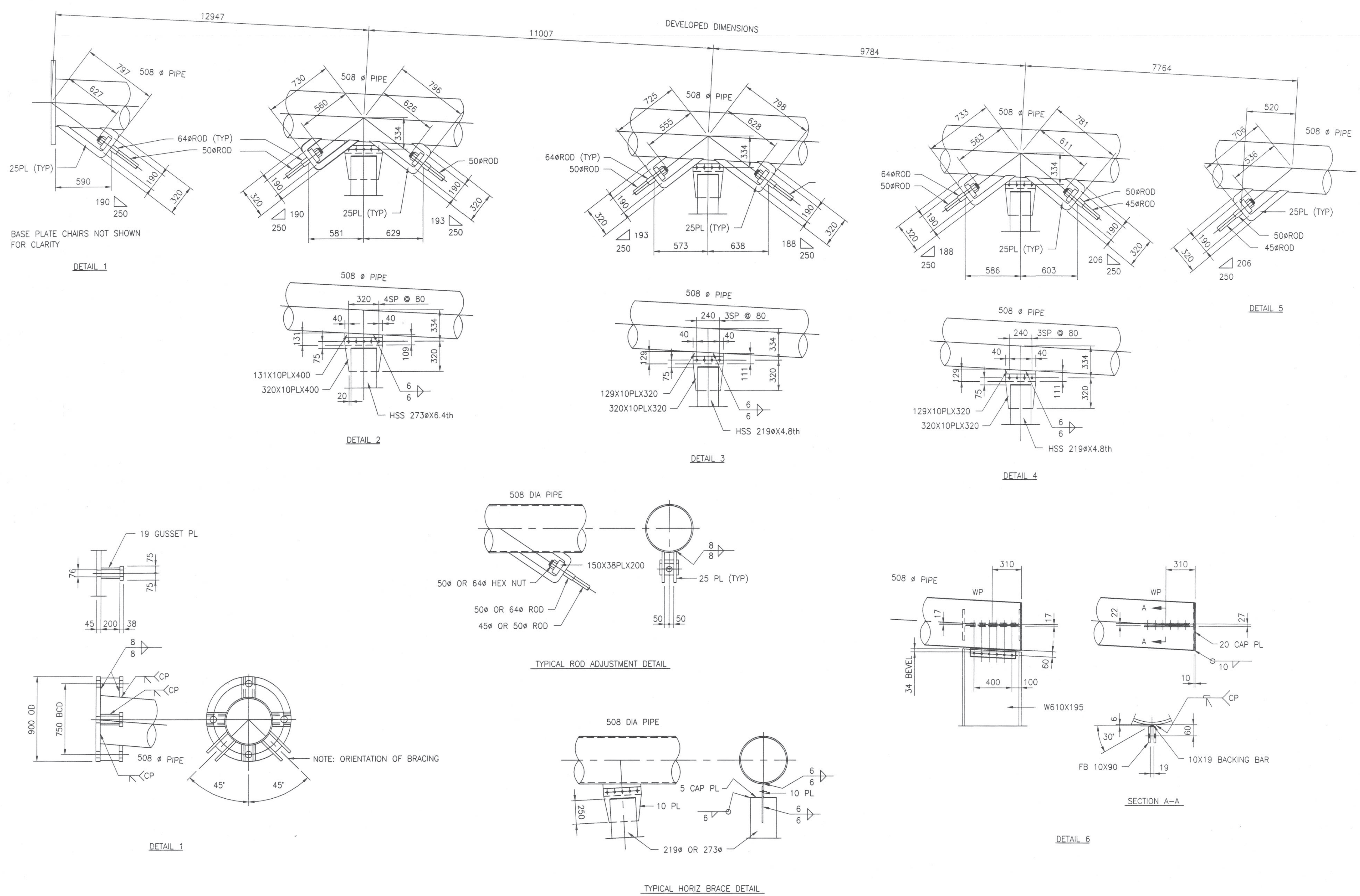


FIGURE 1
NOTES
1. ALL MEASUREMENTS SHOWN IN MM
2. ALL WELDING TO THE REQUIREMENTS OF CSA 459
3. ALL BOLTED CONNECTIONS TO CSA-S16-76 GR A325
4. WELDERS SHALL BE QUALIFIED TO CSA W47.1 OR ASME CODE
5. CONNECTIONS SHALL BE DESIGNED TO CARRY THE DESIGN LOAD BUT NOT LESS THAN 50% OF THE CAPACITY OF THE MEMBER.
6. GROOVE WELDS SHALL BE COMPLETE PENETRATION UNLESS SPECIFIED OTHERWISE. WELDS SHALL CONFORM TO THE SIZE GIVEN OR WHERE NOT INDICATED SHALL CONFORM TO THE REQUIREMENTS OF AWWA-D100
7. ELECTRODES SHALL CONFORM TO E480XX ELECTRODE. STRUCTURAL SUPPORT CONNECTION I.E. COLUMN TO SHELL SHALL USE E48018 ELECTRODES
PROVINCE OF NEWFOUNDLAND PERMIT HOLDER CLASS "A"
ACRES INTERNATIONAL LIMITED
B ISSUED FOR CONSTRUCTION 14/07/99
A ISSUED FOR APPROVAL 30/04/99
No. Revision Date
BOWRINGER ENGINEERING LIMITED
Contractors, Engineers, Fabricators
OWNER: NEWFOUNDLAND POWER
CONSULTANTS: ACRES INTERNATIONAL
PROJECT NAME: MOBILE DEVELOPMENT DIFFERENTIAL SURGE TANK
TITLE: GENERAL ARRANGEMENT SURGE TANK
SCALE: 1=100
DATE: JULY 14/99
SHEET: 1 OF 1
DRAWN BY: K.Y.
CHECKED BY: M.G.
JOB NO.: 9904-289
PROJECT NO.: 9904-289
DWG. NO.: E1
REV.: B
PLAN VIEW
Leg 1
Leg 2
Leg 3
Leg 4
level 1
level 2
level 3
level 4
level 5
ELEVATION – DIFFERENTIAL SURGE TANK
ELEVATION – SURGE TANK AND RISERS
SECTION A-A (TYP 3 LOCATIONS)
SECTION B-B
SECTION C-C
DETAIL D
SPRING LINE EL 142.496
ELEV 99.976 T.O.FOUNDATION
ELEV 100.008
10540 SQUARE
61125
508ø API X56 PIPE .469" WALL
HSS 273 DIA X 6.4
HSS 219 DIA X 4.8
SPIRAL PIPE A139 GR C THICKNESS 10 MM
SPIRAL PIPE A139 GR C THICKNESS 6 MM
TANK FROM 6.4 PLATE
5169 OD TANK
14"x18" MANWAY
ELLIPTICAL MANHOLE (14"x18")
45 THX900ø B/PL C/W 4-57ø ANCHOR BOLTS
1-604-23-30

FIGURE 2

## NOTES

1. ALL MEASUREMENTS SHOWN IN MM
2. MATERIAL: CSA G40.21 300W FOR ROLLED SECTIONS OR 350W FOR HSS
3. WELDING TO CSA W47.1 AND W59
4. ELECTRODES TO BE E480XX SERIES




| | | |
|---|---|---|
| A | ISSUED FOR INFORMATION | 14/07/99 |
| No. | Revision | Date |

BOWRINGER ENGINEERING LIMITED
Contractors, Engineers, Fabricators

422 Logo Bay Rd.
P.O. Box 398
St. John's, NF
A1C 5J9
Telephone: (709)738-2086
Fax: (709)739-0602

CUSTOMER: NEWFOUNDLAND POWER

CONSULTANTS: ACRES INTERNATIONAL

PROJECT NAME: MOBILE DEVELOPMENT DIFFERENTIAL SURGE TANK

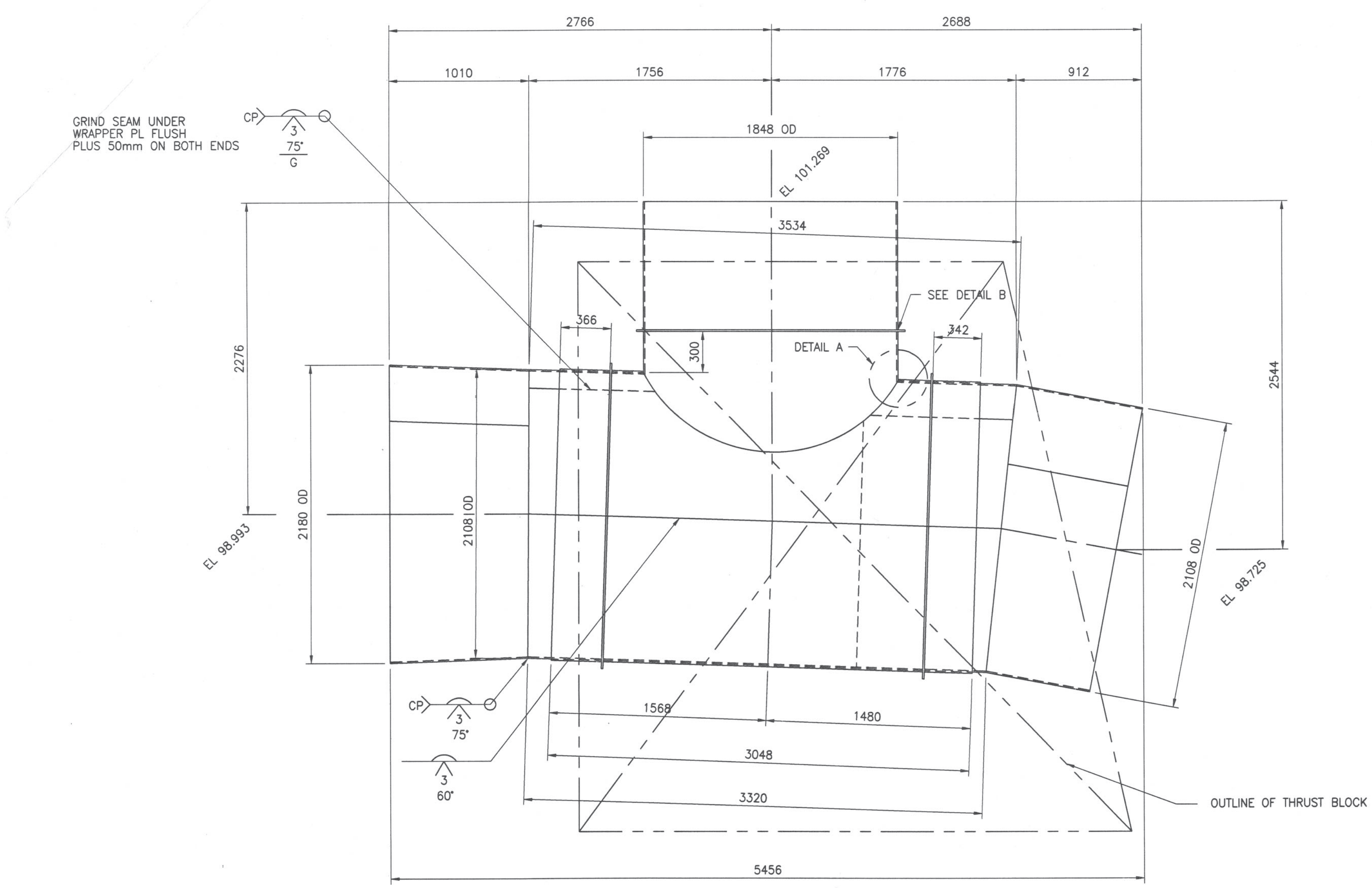
TITLE: FABRICATION DETAILS

| SCALE: | DATE: | SHEET: |
|---|---|---|
| 1:20 | JULY 14/99 | 1 OF 1 |
| DRAWN BY: K.Y. | CHECKED BY: M.G. | JOB NO.: 9904-289 |
| PROJECT NO.: 9904-289 | DWG. NO.: E11 | REV.: A |

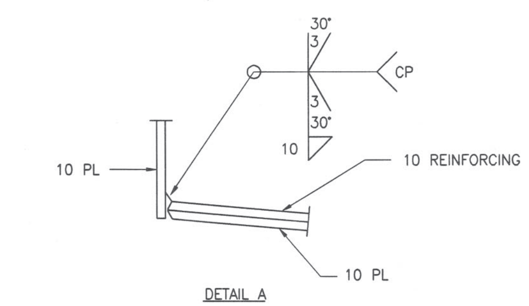
1-604-23-26

1-604-23-26

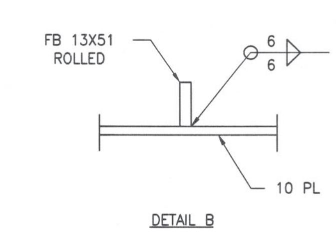
FIGURE 3




ELEVATION – SURGE TANK TEE




DETAIL A




DETAIL B

ALL MATERIAL 3/8" ASTM A516 GR 70
OR G40-21 350 WT

## NOTES

1. ALL MEASUREMENTS SHOWN IN MM
2. MATERIAL: ASTM A516 GR 70
3. WELDING TO CSA W59-M1989
4. ELECTRODES TO BE E480 XX SERIES
5. LONGITUDINAL SEAMS TO BE STAGGERED A MINIMUM OF 300mm

| No. | Revision | Date |
|---|---|---|
| B | ISSUED FOR CONST | 22/06/99 |
| A | ISSUED FOR APPROVAL | 03/06/99 |

**BOWRINGER ENGINEERING LIMITED**
Contractors, Engineers, Fabricators
422 Logo Bay Rd.
P.O. Box 396
St. John's, NF
A1C 5J9
Telephone: (709)738-2086
Fax: (709)739-0602

CUSTOMER
NEWFOUNDLAND POWER

CONSULTANTS
ACRES INTERNATIONAL

PROJECT NAME:
MOBILE DEVELOPMENT
DIFFERENTIAL SURGE TANK

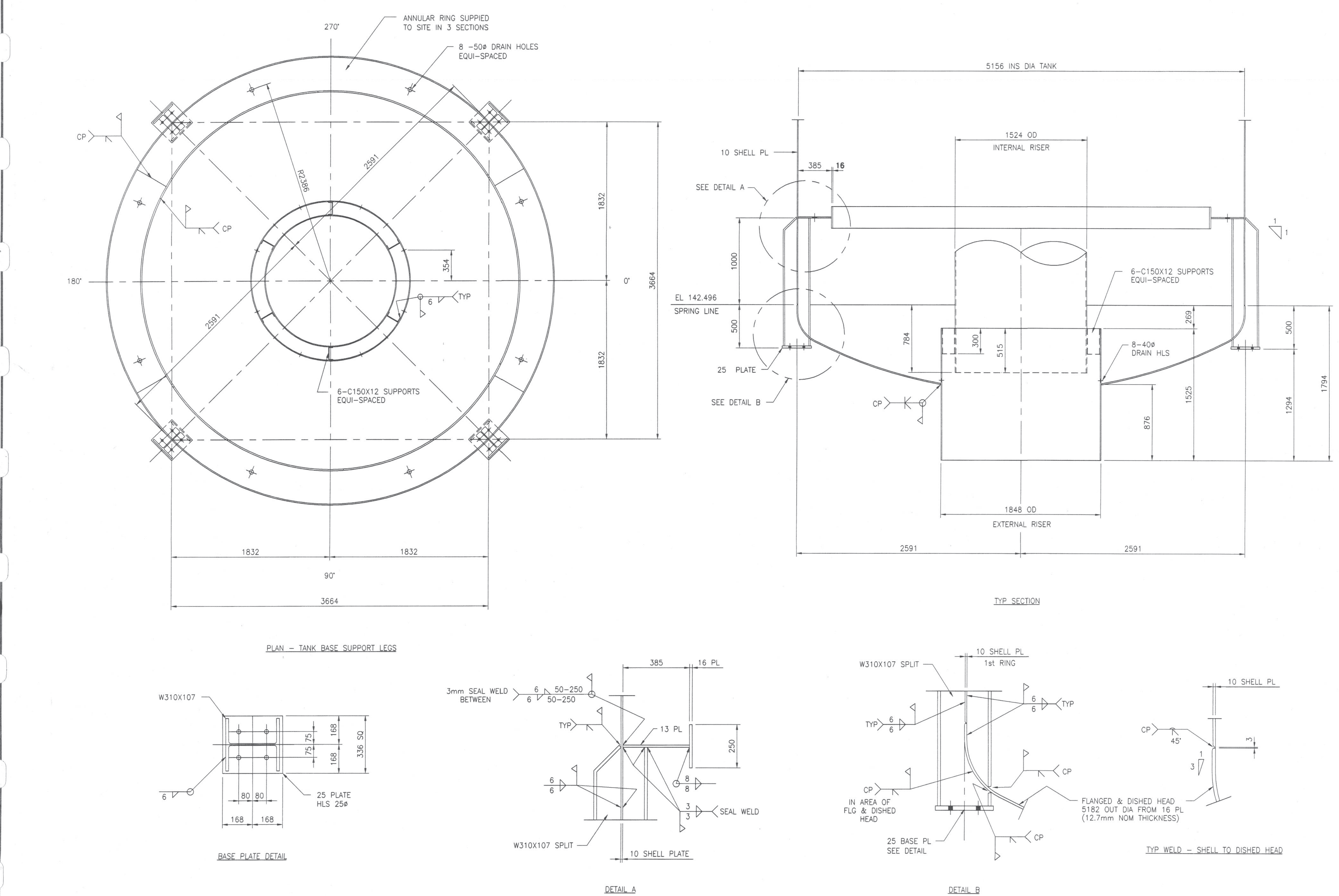
TITLE:
SURGE TANK TEE

| SCALE: 1:20 | DATE: JUNE 3/99 | SHEET: 1 OF 1 |
|---|---|---|
| DRAWN BY: K.Y. | CHECKED BY: M.G. | JOB NO.: 9904-289 |
| PROJECT NO.: 9904-289 | DWG. NO.: E12 | REV.: B |

1-604-23-27

1-604-23-27

FIGURE 4




## NOTES

1. ALL MEASUREMENTS SHOWN IN MM
2. MATERIAL: CSA G40.21 300W
3. WELDING TO CSA W47.1 AND W59
4. ELECTRODES TO BE E480XX SERIES

REGISTERED PROFESSIONAL ENGINEER
C. TODD SMITH
C. Todd Smith
SIGNATURE
July 14, 1999
DATE
NEWFOUNDLAND & LABRADOR

PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
CLASS "A"
This Permit Allows
ACRES INTERNATIONAL LIMITED
To practice Professional Engineering in this Province
F0010 Permit No.
1999 Year

| No. | Revision | Date |
|---|---|---|
| B | ISSUED FOR CONSTRUCTION | 14/07/99 |
| A | ISSUED FOR APPROVAL | 03/06/99 |

BOWRINGER ENGINEERING LIMITED
Contractors, Engineers, Fabricators
422 Logo Bay Rd.
P.O. Box 398
St. John's, NF
A1C 5J9
Telephone: (709)738-2086
Fax: (709)739-0602

CUSTOMER: NEWFOUNDLAND POWER

CONSULTANTS: ACRES INTERNATIONAL

PROJECT NAME: MOBILE DEVELOPMENT DIFFERENTIAL SURGE TANK

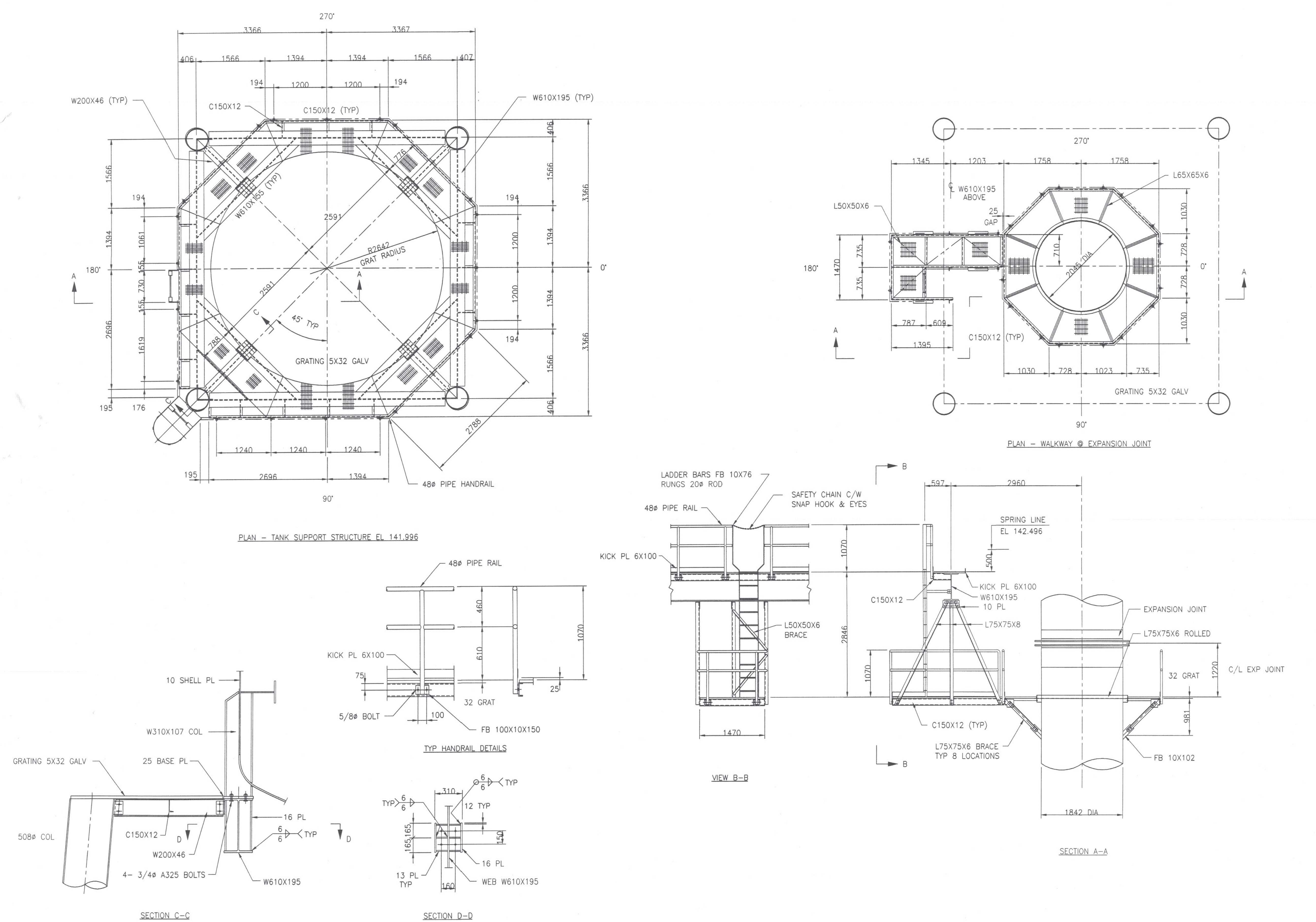
TITLE: TANK BASE SUPPORT LEGS

| SCALE: 1:20 | DATE: JULY 14/99 | SHEET: 1 OF 1 |
|---|---|---|
| DRAWN BY: K.Y. | CHECKED BY: M.G. | JOB NO.: 9904-239 |
| PROJECT NO: 9904-289 | DWG. NO.: E5 | REV.: B |

1-604-23-28

1-604-23-28

FIGURE 5




## NOTES

1. ALL MEASUREMENTS SHOWN IN MM
2. MATERIAL: CSA G40.21 300W
3. WELDING TO CSA W47.1 AND W59
4. ELECTRODES TO BE E480XX SERIES
4. ALL BOLTS 3/4 DIA A325 ASS. U/N

REGISTERED PROFESSIONAL ENGINEER
C. TODD SMITH
SIGNATURE
July 14, 1999
DATE
NEWFOUNDLAND & LABRADOR

PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
CLASS "A"
This Permit Allows
ACRES INTERNATIONAL LIMITED
To practice Professional Engineering in this Province
F0010 Permit No. 1999 Year

| No. | Revision | Date |
|---|---|---|
| B | ISSUED FOR CONSTRUCTION | 14/07/99 |
| A | ISSUED FOR APPROVAL | 17/05/99 |

**BOWRINGER ENGINEERING LIMITED**
Contractors, Engineers, Fabricators
422 Logo Bay Rd.
P.O. Box 398
St. John's, NF
A1C 5J9
Telephone: (709)738-2086
Fax: (709)739-0602

CUSTOMER: NEWFOUNDLAND POWER

CONSULTANTS: ACRES INTERNATIONAL

PROJECT NAME: MOBILE DEVELOPMENT DIFFERENTIAL SURGE TANK

TITLE: TANK SUPPORT STRUCTURE EXPANSION JOINT PLATFORM

| SCALE: | DATE: | SHEET: |
|---|---|---|
| 1:40 | JULY 14/99 | 1 OF 1 |
| DRAWN BY: K.Y. | CHECKED BY: M.G. | JOB NO.: 9704-289 |
| PROJECT NO.: 9704-289 | DWG. NO.: E3 | REV.: B |

1-604-23-29

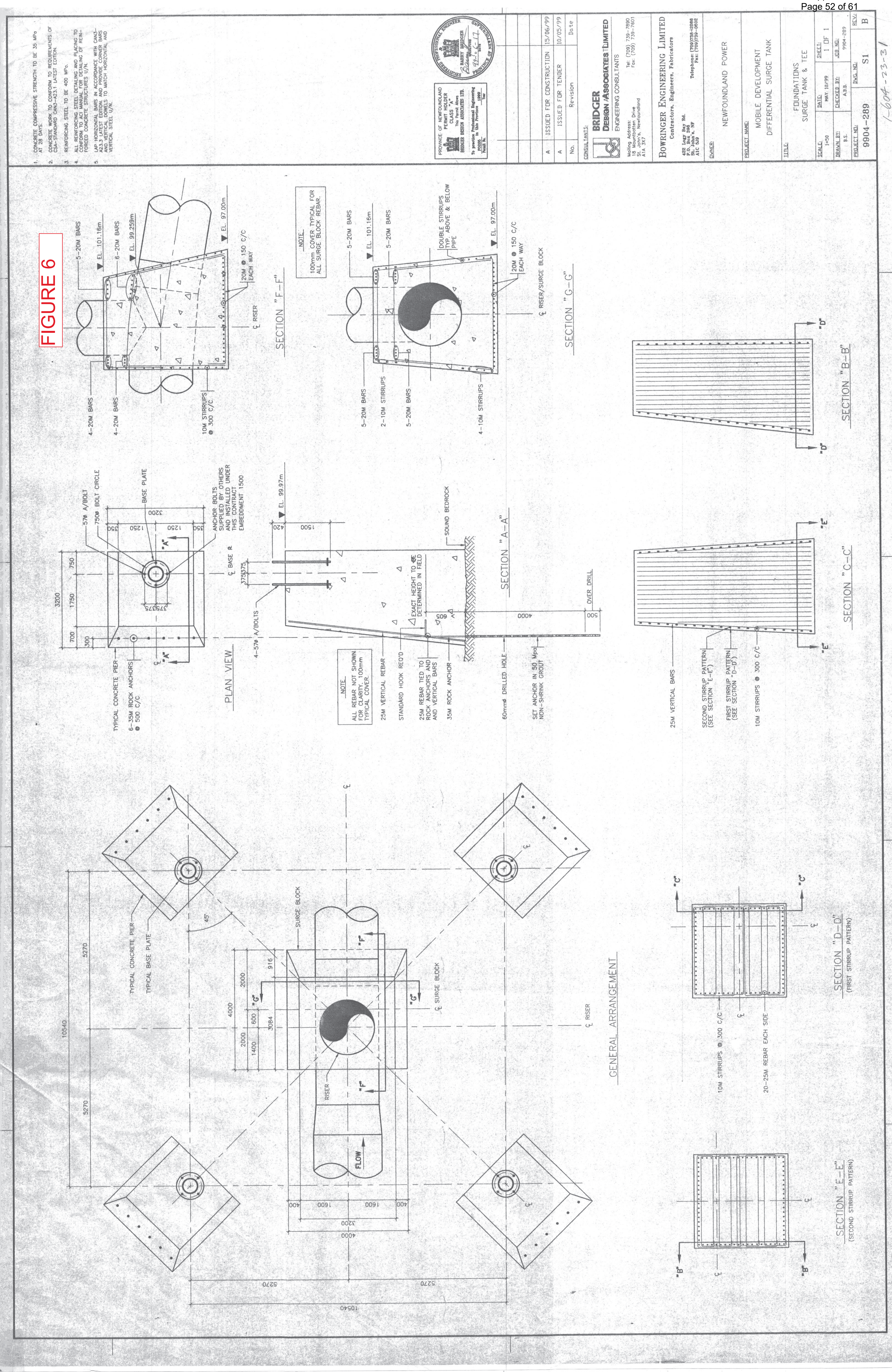
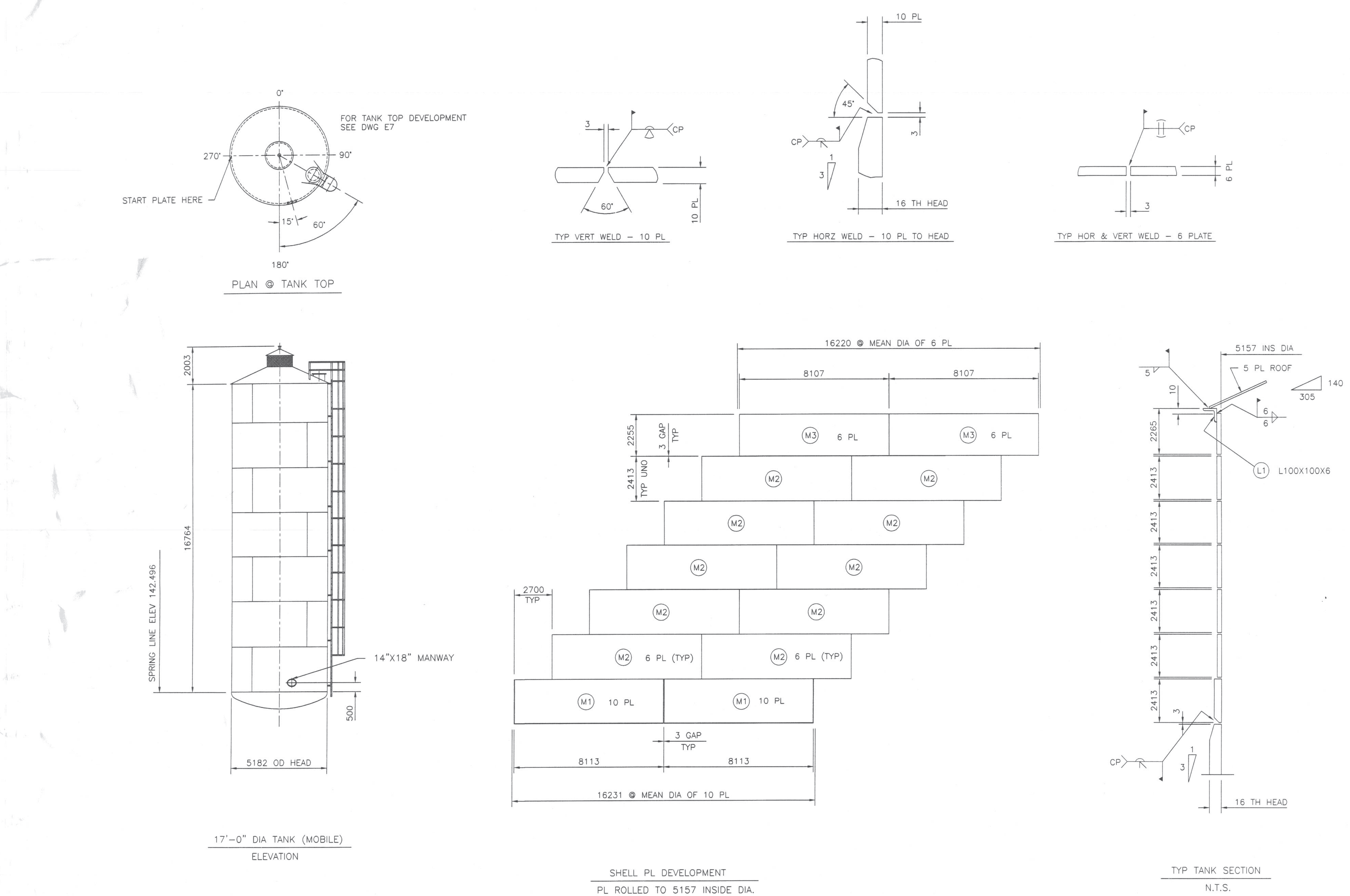


FIGURE 6
1. CONCRETE COMPRESSIVE STRENGTH TO BE 35 MPa AT 28 DAYS.
2. CONCRETE WORK TO CONFORM TO REQUIREMENTS OF CSA-STANDARD CAN3-A23.1 LATEST EDITION.
3. REINFORCING STEEL TO BE 400 MPa.
4. ALL REINFORCING STEEL DETAILING AND PLACING TO CONFORM TO ACI MANUAL FOR DETAILING OF REINFORCED CONCRETE STRUCTURES U/N.
5. LAP HORIZONTAL BARS IN ACCORDANCE WITH CAN3-A23.3 LATEST EDITION. AND PROVIDE CORNER BARS AND VERTICAL DOWELS TO MATCH HORIZONTAL AND VERTICAL STEEL U/N.
SECTION "F-F"
SECTION "G-G"
SECTION "A-A"
SECTION "B-B"
SECTION "C-C"
SECTION "D-D"
(FIRST STIRRUP PATTERN)
SECTION "E-E"
(SECOND STIRRUP PATTERN)
PLAN VIEW
GENERAL ARRANGEMENT
NOTE
100mm COVER TYPICAL FOR ALL SURGE BLOCK REBAR.
NOTE
ALL REBAR NOT SHOWN FOR CLARITY. 100mm TYPICAL COVER.
TYPICAL CONCRETE PIER
TYPICAL BASE PLATE
SURGE BLOCK
RISER
FLOW
ANCHOR BOLTS SUPPLIED BY OTHERS AND INSTALLED UNDER THIS CONTRACT EMBEDMENT 1500
SOUND BEDROCK
60mmØ DRILLED HOLE
SET ANCHOR IN 50 Mpa NON-SHRINK GROUT
25M VERTICAL REBAR
STANDARD HOOK REQ'D
25M REBAR TIED TO ROCK ANCHORS AND AND VERTICAL BARS
35M ROCK ANCHOR
EXACT HEIGHT TO BE DETERMINED IN FIELD
OVER DRILL
25M VERTICAL BARS
SECOND STIRRUP PATTERN (SEE SECTION "E-E")
FIRST STIRRUP PATTERN (SEE SECTION "D-D")
10M STIRRUPS @ 300 C/C
20-25M REBAR EACH SIDE
DOUBLE STIRRUPS TYP. ABOVE & BELOW PIPE
20M @ 150 C/C EACH WAY
EL. 101.16m
EL. 99.259m
EL. 97.00m
EL. 99.97m
A ISSUED FOR CONSTRUCTION 15/06/99
A ISSUED FOR TENDER 10/05/99
No. Revision Date
CONSULTANTS:
BRIDGER DESIGN ASSOCIATES LIMITED
ENGINEERING CONSULTANTS
Mailing Address: 18 Mountbatten Drive St. John's, Newfoundland A1A 3X7
Tel: (709) 739-7890 Fax: (709) 739-7601
BOWRINGER ENGINEERING LIMITED
Contractors, Engineers, Fabricators
422 Logy Bay Rd. P.O. Box 398 St. John's, NF A1C 5J9
Telephone: (709)738-12086 Fax: (709)739-0602
OWNER: NEWFOUNDLAND POWER
PROJECT NAME: MOBILE DEVELOPMENT DIFFERENTIAL SURGE TANK
TITLE: FOUNDATIONS SURGE TANK & TEE
SCALE: 1=50
DATE: MAY 10/99
SHEET: 1 OF 1
DRAWN BY: B.S.
CHECKED BY: A.B.B.
JOB NO: 9904-289
PROJECT NO: 9904-289
DWG. NO: S1
REV: B
1-604-23-31

FIGURE 7




NOTES

1. ALL MEASUREMENTS SHOWN IN MM
2. MATERIAL: CSA G40.21 300W
3. WELDING TO CSA W47.1 AND W59
4. ELECTRODES TO BE E480XX SERIES

REGISTERED PROFESSIONAL ENGINEER
C. TODD SMITH
SIGNATURE
July 14/1999
DATE
NEWFOUNDLAND & LABRADOR

PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
CLASS "A"
This Permit Allows
ACRES INTERNATIONAL LIMITED
To practice Professional Engineering in this Province
F0010 Permit No.
1999 Year

| No. | Revision | Date |
|---|---|---|
| B | ISSUED FOR CONSTRUCTION | 14/07/99 |
| A | ISSUED FOR APPROVAL | 07/06/99 |

BOWRINGER ENGINEERING LIMITED
Contractors, Engineers, Fabricators
422 Logy Bay Rd.
P.O. Box 398
St. John's, NF
A1C 5J9
Telephone: (709)738-2086
Fax: (709)739-0602

OWNER:
NEWFOUNDLAND POWER

CONSULTANTS:
ACRES INTERNATIONAL

PROJECT NAME:
MOBILE SITE
DIFFERENTIAL SURGE TANK

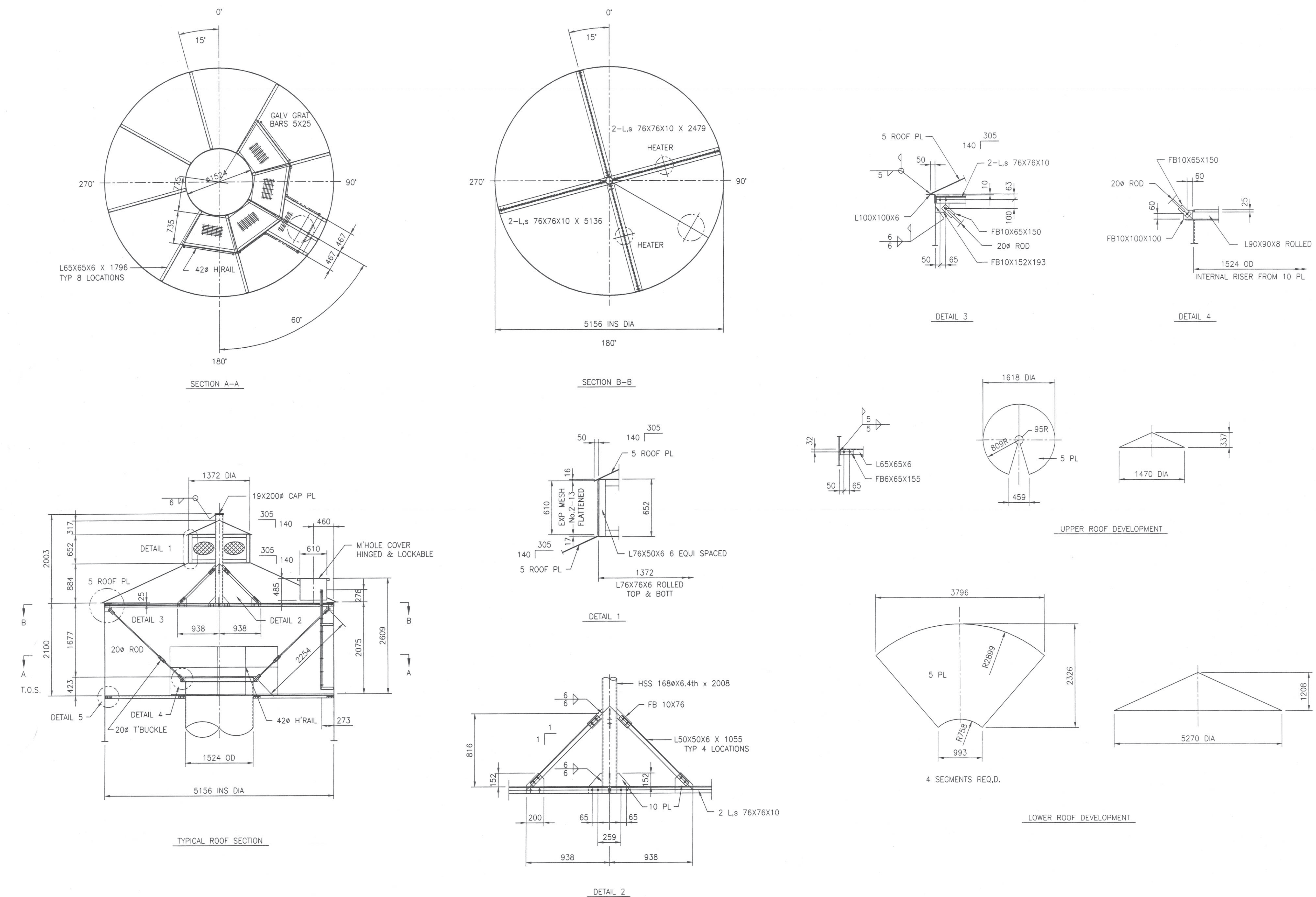
TITLE:
17'–0" OVERFLOW TANK
SHELL PLATE DEVELOPMENT

| SCALE: NTS | DATE: JULY 14/99 | SHEET: 1 OF 1 |
|---|---|---|
| DRAWN BY: K.Y. | CHECKED BY: M.G. | JOB NO.: 9904-289 |
| PROJECT NO.: 9904-289 | DWG. NO.: E9 | REV.: B |

1-604-23-32

1-604-23-32

FIGURE 14




## NOTES

1. ALL MEASUREMENTS SHOWN IN MM
2. MATERIAL: CSA G40.21 300W
3. WELDING TO CSA W47.1 AND W59
4. ELECTRODES TO BE E480XX SERIES
4. ALL BOLTS 3/4 DIA A325 ASS U/N

REGISTERED PROFESSIONAL ENGINEER
C. TODD SMITH
NEWFOUNDLAND & LABRADOR
July 14, 1999

PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
CLASS "A"
This Permit Allows
ACRES INTERNATIONAL LIMITED
To practice Professional Engineering in this Province
P0010 — Permit No.
1999 — Year

| No. | Revision | Date |
|---|---|---|
| B | ISSUED FOR CONSTRUCTION | 14/07/99 |
| A | ISSUED FOR APPROVAL | 18/06/99 |

BOWRINGER ENGINEERING LIMITED
Contractors, Engineers, Fabricators
422 Logy Bay Rd.
P.O. Box 398
St. John's, NF
A1C 5J9
Telephone: (709)738-2086
Fax: (709)739-0602

CUSTOMER: NEWFOUNDLAND POWER

CONSULTANTS: ACRES INTERNATIONAL

PROJECT NAME: MOBILE DEVELOPMENT DIFFERENTIAL SURGE TANK

TITLE: ROOF DEVELOPMENT INTERNAL WALKWAY

| SCALE: 1:40 | DATE: JULY 14/99 | SHEET: 1 OF 1 |
|---|---|---|
| DRAWN BY: K.Y. | CHECKED BY: M.G. | JOB NO.: 9704-289 |
| PROJECT NO.: 9704-289 | DWG. NO.: E7 | REV.: B |

1-604-23-33

1-604-23-33

# APPENDIX C

# CALCULATIONS

Kleinschmidt

| | | | |
|---|---|---|---|
| **PROJECT TITLE:** | Mobile Development Differential Surge Tank | **CLIENT:** | Newfoundland Power |
| **KLEINSCHMIDT PROJECT NO:** | 2061014 | **LOCATION:** | Mobile, Newfoundland |
| **SUBJECT:** | Mobile Surge Tank Structural Analysis | | |
| | | | |
| **PROJECT MANAGER:** | Chris Vella | | |
| **TECHNICAL LEAD/ADVISOR:** | Chris Vella | | |
| **ENGINEER:** | **OMAR MOHAMED** | | |

| REV. | NAME | | DATE | COMMENTS |
|---|---|---|---|---|
| | Performed By: | OGM | 12/13/2022 | |
| | Checked By: | NT | 12/17/2022 | |
| | TA Approval: | CMV | 1/25/2023 | |
| | Performed By: | | | |
| | Checked By: | | | |
| | TA Approval: | | | |
| | Performed By: | | | |
| | Checked By: | | | |
| | TA Approval: | | | |
| | Performed By: | | | |
| | Checked By: | | | |
| | TA Approval: | | | |
| | Performed By: | | | |
| | Checked By: | | | |
| | TA Approval: | | | |
| | Performed By: | | | |
| | Checked By: | | | |
| | TA Approval: | | | |
| | Performed By: | | | |
| | Checked By: | | | |
| | TA Approval: | | | |

[Insert PE Stamp]

**OBJECTIVE:**
Determine the structural integrity of Mobile Development Differential Surge Tank.

**ANALYSIS ASSUMPTIONS AND INPUTS**
1. Average thickness readings vary by plate and are included in Tables 1 and 2.
2. Top of tank before plate roof is at EL. 522.51' (159.26 m). Top of tank to plate roof is at EL. 525.41' (160.144 m). Tank Total height = 200.54ft (61.125 m), (*Ref.* 5).
3. Max Normal Pond is at EL. 494'.

**REFERENCES:**
*1- CISC Steel Design Handbook 12th Edition - 2021.*
*2- AWWA D100-11 - Welded Steel Tanks for Water Storage.*
*3- ASTM A139/A139M-22.*
*4. Hydroelectric Handbook Justin & Creager 1950.*
*5. Existing Drawings: Mobile Development Differential Surge Tank 1999.*

**MATERIAL PROPERTIES:**

**CSA G40.21 300W Steel for the Surge Tank**

| | | | |
|---|---|---|---|
| $F_y$ = | 43500 | psi | *Ref. 1* |
| $F_u$ = | 65267 | psi | *Ref. 1* |
| Class 2 shell plate | | | *Ref. 2 - Table 4* |
| $\sigma_{allow}$ = | 15000 | psi | *Ref. 2 - Allowable tensile stress in shell (Table 5)* |

**A139 Grade C Steel for the Riser**

| | | | |
|---|---|---|---|
| $F_y$ = | 42000 | psi | *Ref. 3* |
| $F_u$ = | 60000 | psi | *Ref. 3* |
| Class 2 shell plate | | | *Ref. 2 - Table 4* |
| $\sigma_{allow}$ = | 15000 | psi | *Ref. 2 - Allowable tensile stress in shell (Table 5)* |

**JOINT EFFICIENCY:**

Joint efficiency (welded joints - assumed lap with fillet weld on each edge without knowing details of obvious butt joint welds) *Ref. 2*

E = joint efficiency = 0.75

$$Base\ material\ stress = \frac{(\mathrm{NP} - \mathrm{Elevation})\,\gamma_{water}\,R_{shell}}{t_{shell}}$$

$$Joint\ stress = \frac{Base\ material\ stress}{Joint\ efficiency}$$

## Table 1: Surge Tank Thickness Measurements and Stresses (Normal Pond)

**References**

*1- CISC Steel Design Handbook 12th Edition - 2021*
*2- AWWA D100-11 - Welded Steel Tanks for Water Storage*
*3- ASTM A139/A139M-22*

**TABLE 1 - SURGE TANK THICKNESS MEASUREMENTS AND STRESSES (NORMAL POND)**

| Elevation (m) | Elevation (ft) | Location[1] | Reading No.[3,4] | Thickness Reading (in) | Avg. Thickness (in) | Original Plate Thickness (mm) | at Joints Stress (psi)[6] | at Joints Stress Ratio[7] | Base Material Stress (psi)[6] | Base Material Stress Ratio[7] | Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 159.70 | 523.96 | Shell | 001 | 0.178 | 0.178 | 5 | 0 | 0.00 | 0 | 0.00 | Roof |
| 159.70 | 523.96 | Shell | 002 | 0.178 | | 5 | 0 | 0.00 | 0 | 0.00 | |
| 159.70 | 523.96 | Shell | 003 | 0.178 | | 5 | 0 | 0.00 | 0 | 0.00 | |
| 158.12 | 518.77 | Shell | 001 | 0.239 | 0.239 | 6 | 0 | 0.00 | 0 | 0.00 | PL1 Top |
| 158.12 | 518.77 | Shell | 002 | 0.239 | | 6 | 0 | 0.00 | 0 | 0.00 | |
| 158.12 | 518.77 | Shell | 003 | 0.238 | | 6 | 0 | 0.00 | 0 | 0.00 | |
| 155.86 | 511.34 | Shell | 001 | 0.274 | 0.276 | 6 | 0 | 0.00 | 0 | 0.00 | PL2 |
| 155.86 | 511.35 | Shell | 002 | 0.278 | | 6 | 0 | 0.00 | 0 | 0.00 | |
| 155.86 | 511.35 | Shell | 003 | 0.276 | | 6 | 0 | 0.00 | 0 | 0.00 | |
| 153.45 | 503.44 | Shell | 001 | 0.272 | 0.270 | 6 | 0 | 0.00 | 0 | 0.00 | PL3 |
| 153.45 | 503.44 | Shell | 002 | 0.269 | | 6 | 0 | 0.00 | 0 | 0.00 | |
| 153.45 | 503.44 | Shell | 003 | 0.269 | | 6 | 0 | 0.00 | 0 | 0.00 | |
| 151.04 | 495.53 | Shell | 001 | 0.289 | 0.289 | 6 | 0 | 0.00 | 0 | 0.00 | PL4 |
| 151.04 | 495.54 | Shell | 002 | 0.292 | | 6 | 0 | 0.00 | 0 | 0.00 | |
| 151.04 | 495.54 | Shell | 003 | 0.285 | | 6 | 0 | 0.00 | 0 | 0.00 | |
| 148.63 | 487.62 | Shell | 001 | 0.269 | 0.276 | 6 | 1,354 | 0.09 | 1,016 | 0.07 | PL5 |
| 148.63 | 487.63 | Shell | 002 | 0.286 | | 6 | 1,352 | 0.09 | 1,014 | 0.07 | |
| 148.63 | 487.63 | Shell | 003 | 0.274 | | 6 | 1,352 | 0.09 | 1,014 | 0.07 | |
| 146.22 | 479.71 | Shell | 001 | 0.282 | 0.279 | 6 | 3,000 | 0.20 | 2,250 | 0.15 | PL6 |
| 146.22 | 479.72 | Shell | 002 | 0.272 | | 6 | 2,998 | 0.20 | 2,249 | 0.15 | |
| 146.22 | 479.72 | Shell | 003 | 0.284 | | 6 | 2,998 | 0.20 | 2,249 | 0.15 | |
| 139.56 | 457.87 | Int Riser | 001 | 0.250 | 0.247 | 6 | 2,531 | 0.17 | 1,898 | 0.13 | Top - Horizontal |
| 139.56 | 457.87 | Int Riser | 002 | 0.247 | | 6 | 2,531 | 0.17 | 1,898 | 0.13 | Top - Joint |
| 139.56 | 457.87 | Int Riser | 003 | 0.245 | | 6 | 2,531 | 0.17 | 1,898 | 0.13 | Top - 40' Above hatch |
| 140.70 | 461.62 | Int Riser | 001 | 0.350 | 0.351 | 8 | 1,601 | 0.11 | 1,200 | 0.08 | At First Organic Material |
| 140.70 | 461.62 | Int Riser | 002 | 0.351 | | 8 | 1,601 | 0.11 | 1,200 | 0.08 | |
| 140.70 | 461.62 | Int Riser | 003 | 0.352 | | 8 | 1,601 | 0.11 | 1,200 | 0.08 | |
| 140.00 | 459.32 | Int Riser | 001 | 0.350 | 0.351 | 8 | 1,713 | 0.11 | 1,285 | 0.09 | GFT Above Transition |
| 140.00 | 459.32 | Int Riser | 002 | 0.352 | | 8 | 1,713 | 0.11 | 1,285 | 0.09 | |
| 140.00 | 459.32 | Int Riser | 003 | 0.351 | | 8 | 1,713 | 0.11 | 1,285 | 0.09 | |
| 139.00 | 456.04 | Int Riser | 001 | 0.241 | 0.242 | 6 | 2,724 | 0.18 | 2,043 | 0.14 | Below Expansion Joint |
| 139.00 | 456.04 | Int Riser | 002 | 0.242 | | 6 | 2,724 | 0.18 | 2,043 | 0.14 | |
| 139.00 | 456.04 | Int Riser | 003 | 0.242 | | 6 | 2,724 | 0.18 | 2,043 | 0.14 | |
| 125.16 | 410.64 | Int Riser | 001 | 0.238 | 0.238 | 6 | 6,063 | 0.40 | 4,547 | 0.30 | |
| 125.16 | 410.64 | Int Riser | 002 | 0.239 | | 6 | 6,063 | 0.40 | 4,547 | 0.30 | |
| 125.16 | 410.64 | Int Riser | 003 | 0.238 | | 6 | 6,063 | 0.40 | 4,547 | 0.30 | |
| 119.50 | 392.05 | Int Riser | 001 | 0.238 | 0.238 | 6 | 7,415 | 0.49 | 5,561 | 0.37 | Horizontal Weld |
| 119.50 | 392.05 | Int Riser | 002 | 0.239 | | 6 | 7,415 | 0.49 | 5,561 | 0.37 | |
| 119.50 | 392.05 | Int Riser | 003 | 0.238 | | 6 | 7,415 | 0.49 | 5,561 | 0.37 | |
| | | | | | | Max | 7,415 | 0.49 | 5,561 | 0.37 | |

***Notes:***

1- Surge Tank Reading Location:

Shell = Exterior Shell
Int Riser = Interior Riser

2- UT Thickness Gage Reading Number

3- Shell & Riser Thickness Readings

4- 97.5% Confidence that the results will be at or above = Avg - 1.96*StdDev
5- Hoop Stress = Pr/Et, where:

P = Pressure = γw*Head

| | | |
|---|---|---|
| γw = | 62.4 | pcf |
| Head = | NP - C.L. Elev | |
| NP = | 494 ft | (Per Newfoundland Power Inc.) |

Stresses shown use 97.5% confindence interval thickness for calculations

| | | |
|---|---|---|
| r_shell = | 101.5 | in |
| r_internal riser= | 30.0 | in |
| r_lower riser= | 36.0 | in |

E = joint efficiency

| | | |
|---|---|---|
| Joint Efficiency | 0.75 | |
| t = avg. thickness | | |
| 5mm | 0.178 | in |
| 6mm | 0.241 | in |
| 8mm | 0.351 | in |

6- Stress Ratio = Actual Stress/Allowable Stress

| | | |
|---|---|---|
| $R_{shell}$ = | 101.52 | in |
| $F_y$ = | 43500 | psi |
| $F_u$ = | 65267 | psi |
| Class 2 shell plate | | |
| $\sigma_{allow}$ = | 15000.0 | psi |
| | | |
| $F_y$ = | 42000 | psi |
| $F_u$ = | 60000 | psi |
| Class 2 shell plate | | |
| $\sigma_{allow}$ = | 15000.0 | psi |

## Table 2: Surge Tank Thickness Measurements and Stresses (Dynamic Water Elevation)

### References

*1- CISC Steel Design Handbook 12th Edition - 2021*
*2- AWWA D100-11 - Welded Steel Tanks for Water Storage*
*3- ASTM A139/A139M-22*
*4- Hydroelectric Handbook Justin & Creager 1950*

**TABLE 2 - SURGE TANK THICKNESS MEASUREMENTS AND STRESSES (DYNAMIC WATER ELEVATIONS)**

| Elevation (m) | Elevation (ft) | Location[1] | Reading No.[3,4] | Thickness Reading (in) | Avg. Thickness (in) | Original Plate Thickness (mm) | at Joints | | Base Material | | Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | Stress (psi)[6] | Stress Ratio[7] | Stress (psi)[6] | Stress Ratio[7] | |
| 159.70 | 523.96 | Shell | 001 | 0.178 | 0.178 | 5 | 0 | 0.00 | 0 | 0.00 | Roof |
| 159.70 | 523.96 | Shell | 002 | 0.178 | | 5 | 0 | 0.00 | 0 | 0.00 | |
| 159.70 | 523.96 | Shell | 003 | 0.178 | | 5 | 0 | 0.00 | 0 | 0.00 | |
| 158.12 | 518.77 | Shell | 001 | 0.239 | 0.239 | 6 | 0 | 0.00 | 0 | 0.00 | PL1 Top |
| 158.12 | 518.77 | Shell | 002 | 0.239 | | 6 | 0 | 0.00 | 0 | 0.00 | |
| 158.12 | 518.77 | Shell | 003 | 0.238 | | 6 | 0 | 0.00 | 0 | 0.00 | |
| 155.86 | 511.34 | Shell | 001 | 0.274 | 0.276 | 6 | 0 | 0.00 | 0 | 0.00 | PL2 |
| 155.86 | 511.35 | Shell | 002 | 0.278 | | 6 | 0 | 0.00 | 0 | 0.00 | |
| 155.86 | 511.35 | Shell | 003 | 0.276 | | 6 | 0 | 0.00 | 0 | 0.00 | |
| 153.45 | 503.44 | Shell | 001 | 0.272 | 0.270 | 6 | 0 | 0.00 | 0 | 0.00 | PL3 |
| 153.45 | 503.44 | Shell | 002 | 0.269 | | 6 | 0 | 0.00 | 0 | 0.00 | |
| 153.45 | 503.44 | Shell | 003 | 0.269 | | 6 | 0 | 0.00 | 0 | 0.00 | |
| 151.04 | 495.53 | Shell | 001 | 0.289 | 0.289 | 6 | 0 | 0.00 | 0 | 0.00 | PL4 |
| 151.04 | 495.54 | Shell | 002 | 0.292 | | 6 | 0 | 0.00 | 0 | 0.00 | |
| 151.04 | 495.54 | Shell | 003 | 0.285 | | 6 | 0 | 0.00 | 0 | 0.00 | |
| 148.63 | 487.62 | Shell | 001 | 0.269 | 0.276 | 6 | 1,761 | 0.12 | 1,320 | 0.09 | PL5 |
| 148.63 | 487.63 | Shell | 002 | 0.286 | | 6 | 1,758 | 0.12 | 1,318 | 0.09 | |
| 148.63 | 487.63 | Shell | 003 | 0.274 | | 6 | 1,758 | 0.12 | 1,318 | 0.09 | |
| 146.22 | 479.71 | Shell | 001 | 0.282 | 0.279 | 6 | 3,900 | 0.26 | 2,925 | 0.20 | PL6 |
| 146.22 | 479.72 | Shell | 002 | 0.272 | | 6 | 3,898 | 0.26 | 2,923 | 0.19 | |
| 146.22 | 479.72 | Shell | 003 | 0.284 | | 6 | 2,998 | 0.20 | 2,249 | 0.15 | |
| 139.56 | 457.87 | Int Riser | 001 | 0.250 | 0.247 | 6 | 3,291 | 0.22 | 2,468 | 0.16 | Top - Horizontal |
| 139.56 | 457.87 | Int Riser | 002 | 0.247 | | 6 | 3,291 | 0.22 | 2,468 | 0.16 | Top - Joint |
| 139.56 | 457.87 | Int Riser | 003 | 0.245 | | 6 | 3,291 | 0.22 | 2,468 | 0.16 | Top - 40' Above hatch |
| 140.70 | 461.62 | Int Riser | 001 | 0.350 | 0.351 | 8 | 2,081 | 0.14 | 1,561 | 0.10 | At First Organic Material |
| 140.70 | 461.62 | Int Riser | 002 | 0.351 | | 8 | 2,081 | 0.14 | 1,561 | 0.10 | |
| 140.70 | 461.62 | Int Riser | 003 | 0.352 | | 8 | 2,081 | 0.14 | 1,561 | 0.10 | |
| 140.00 | 459.32 | Int Riser | 001 | 0.350 | 0.351 | 8 | 2,227 | 0.15 | 1,670 | 0.11 | GFT Above Transition |
| 140.00 | 459.32 | Int Riser | 002 | 0.352 | | 8 | 2,227 | 0.15 | 1,670 | 0.11 | |
| 140.00 | 459.32 | Int Riser | 003 | 0.351 | | 8 | 2,227 | 0.15 | 1,670 | 0.11 | |
| 139.00 | 456.04 | Int Riser | 001 | 0.241 | 0.242 | 6 | 3,541 | 0.24 | 2,656 | 0.18 | Below Expansion Joint |
| 139.00 | 456.04 | Int Riser | 002 | 0.242 | | 6 | 3,541 | 0.24 | 2,656 | 0.18 | |
| 139.00 | 456.04 | Int Riser | 003 | 0.242 | | 6 | 3,541 | 0.24 | 2,656 | 0.18 | |
| 125.16 | 410.64 | Int Riser | 001 | 0.238 | 0.238 | 6 | 7,881 | 0.53 | 5,911 | 0.39 | |
| 125.16 | 410.64 | Int Riser | 002 | 0.239 | | 6 | 7,881 | 0.53 | 5,911 | 0.39 | |
| 125.16 | 410.64 | Int Riser | 003 | 0.238 | | 6 | 7,881 | 0.53 | 5,911 | 0.39 | |
| 119.50 | 392.05 | Int Riser | 001 | 0.238 | 0.238 | 6 | 9,640 | 0.64 | 7,230 | 0.48 | Horizontal Weld |
| 119.50 | 392.05 | Int Riser | 002 | 0.239 | | 6 | 9,640 | 0.64 | 7,230 | 0.48 | |
| 119.50 | 392.05 | Int Riser | 003 | 0.238 | | 6 | 9,640 | 0.64 | 7,230 | 0.48 | |
| | | | | | | Max | 9,640 | 0.64 | 7,230 | 0.48 | |

## Notes:

1- Surge Tank Reading Location:

Shell = Exterior Shell
Int Riser = Interior Riser

2- UT Thickness Gage Reading Number

3- Shell & Riser Thickness Readings

4- 97.5% Confidence that the results will be at or above = Avg - 1.96*StdDev

5- Hoop Stress = Pr/Et, where: **Stresses were multiplied by 1.3 to account for the Dynamic Water Elevation** *Ref. 4*

P = Pressure = γw*Head

γw = 62.4 pcf

Head = NP - C.L. Elev

NP = 494 ft (Per Newfoundland Power Inc.)

Stresses shown use 97.5% confindence interval thickness for calculations

| | | |
|---|---|---|
| r_shell = | 101.5 | in |
| r_internal riser= | 30.0 | in |
| r_lower riser= | 36.0 | in |

E = joint efficiency
Joint Efficiency 0.75
t = avg. thickness

| | | |
|---|---|---|
| 5mm | 0.178 | in |
| 6mm | 0.241 | in |
| 8mm | 0.351 | in |

6- Stress Ratio = Actual Stress/Allowable Stress

| | | |
|---|---|---|
| $R_{shell}$ = | 101.52 | in |
| $F_y$ = | 43500 | psi |
| $F_u$ = | 65267 | psi |
| Class 2 shell plate | | |
| $\sigma_{allow}$ = | 15000.0 | psi |

| | | |
|---|---|---|
| $F_y$ = | 42000 | psi |
| $F_u$ = | 60000 | psi |
| Class 2 shell plate | | |
| $\sigma_{allow}$ = | 15000.0 | psi |

NEWFOUNDLAND POWER
A FORTIS COMPANY

# 5.1 2024 Application Enhancements

## June 2023

# TABLE OF CONTENTS

## 1.0 INTRODUCTION

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") operates approximately 190 software applications necessary to provide 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 business requirements. It can also include enhancements that provide an improved customer service experience and other customer benefits.

The 2024 *Application Enhancements* project includes the enhancement of six 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 2024 *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 Enhancement

#### *Description*

Newfoundland Power routinely seeks to digitize paper-based forms through its Digital Forms Portfolio.[1] The digitization of paper-based forms and elimination of manual processes can provide multiple operational benefits, including a reduction in data-entry requirements, improved data quality and enhanced record keeping. For 2024, the Company is proposing to digitize forms related to its vegetation management processes.

Newfoundland Power manages vegetation growth near its electrical system infrastructure to ensure the delivery of safe and reliable service to customers. The Company's vegetation management involves several manual processes. Over 88 inspections are completed each year, with an average of approximately 4,500 deficiencies identified annually. The location of each deficiency must be recorded to facilitate its correction by noting the address or pole number or by marking the location on a paper map. Work packages are then manually created and sent to utility arborists for execution. Once complete, feedback is provided via email and the work status is manually updated in the Company asset management technology.

The proposed solution would eliminate existing manual processes for vegetation management. Location information would be captured by using a digital form to identify deficiencies directly in the Company's Geographical Information System. The Company's asset management records

---

[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 in the *2022 Capital Budget Application* and approved by the Board in Order No. P.U. 36 (2021), as well in the *2023 Capital Budget Application* and approved by the Board in Order No. P.U. 38 (2022).

would then be automatically updated to facilitate dispatching the required work, which would reduce data entry and scheduling requirements. Compiling this information in one system would also create a wholistic view of vegetation deficiencies going forward, thereby providing greater opportunities to gain efficiencies through pooling work.

Table 1 provides the cost breakdown of the Digital Forms Portfolio Enhancement.

Table 1
Digital Forms Portfolio Enhancement
2024 Project Cost
($000s)

| Cost Category | 2024 |
|---|---|
| Material | - |
| Labour – Internal | 202 |
| Labour – Contract | - |
| Engineering | - |
| Other | 25 |
| Total | 227 |

The estimated cost of the Digital Forms Portfolio Enhancement is $227,000 in 2024. This cost includes the configuration of a new digital form and integration with other Company systems.

### *Justification*

The Digital Forms Portfolio Enhancement is justified on the basis of improved operating efficiency. A net present value analysis determined that implementing this enhancement would provide cost savings for customers.

Appendix A provides a detailed breakdown of the net present value analysis for this item.

## 2.2 Workforce Management System Enhancement

### *Description*

This item involves enhancing Newfoundland Power's Workforce Management System by expanding its functionality to include two additional work groups.

The Company's Workforce Management System ensures the effective and efficient management of field work, including the scheduling, dispatching and monitoring of field crews.[2] The system is currently designed to support the daily operations of 144 Powerline Technicians, seven Operations Coordinators and 14 Line Supervisors across the Company.[3] The proposed enhancement would expand the current solution to include the Electrical Maintenance and Metering groups, which represent an additional 62 field employees.

The Electrical Maintenance group is responsible for preventive and corrective maintenance of Substation and Generation assets to ensure the delivery of safe, reliable and least-cost service to customers. The group follows manual scheduling and monitoring processes to plan and execute an average of approximately 7,200 work orders annually. Excel spreadsheets are used to develop daily work schedules for field workers and details are communicated via email. The field worker must locate corresponding work orders in the asset management technology to plan and execute their work. Upon completion, paperwork is filed and information is later manually entered in the Company's asset management technology.

The Metering group also follows a manual process for dispatching and monitoring its work. Approximately 1,450 meters were replaced annually over the period from 2019 to 2022 due to Compliance Sampling Orders and Government Retest Orders issued in accordance with Federal Government regulations.[4] Excel spreadsheets are used to track annual requirements to replace these meters. Service orders for meter replacements are created in the Company's Customer Service System. The service order is then printed and provided to a Meter Technician to complete. Upon completion, details are recorded on a paper form, updates are provided by email and data is manually entered in the Customer Service System.

Expanding the Company's Workforce Management System to include the Electrical Maintenance and Metering groups will provide operating efficiencies by reducing manual efforts for the dispatching and monitoring of work tasks. The system will utilize existing mobile device technology to provide real-time data updates on work orders completed in the field, which will assist in the assignment and prioritization of tasks in real time.

---

2 For example, schedules are created by a Central Dispatch Team for each field crew based on the job type, location and crew capacity and requirements are then loaded onto mobile devices for each crew prior to being dispatched into the field. Crews use their mobile devices to provide updates to the Central Dispatch Team on each job being completed. For more information, see Newfoundland Power's *2022 Capital Budget Application,* report *7.3 Workforce Management System Replacement.*

3 The Company's *Workforce Management System Replacement* project was included as a two-year project in its *2022 Capital Budget Application*, which was approved by the Board in Order No. P.U. 36 (2021). This project was justified as a like-for-like replacement of the existing system, which had been discontinued by its vendor.

4 Revenue metering of electrical service is regulated under the *Electricity and Gas Inspection Act (Canada)*. Pursuant to these regulations, meters are required to be removed from service and tested after eight years in service and periodically thereafter. Over the period from 2018 to 2022, approximately 6,000 meters were replaced to comply with government regulations.

Table 2 provides the cost breakdown for the Workforce Management System Enhancement.

Table 2
Workforce Management
System Enhancement
2024 Project Cost
($000s)

| Cost Category | 2024 |
|---|---|
| Material | - |
| Labour – Internal | 199 |
| Labour – Contract | - |
| Engineering | - |
| Other | 175 |
| Total | 374 |

The estimated cost of the Workforce Management System Enhancement is $374,000 in 2024. This includes costs associated with configuration of additional workflows, roles and permissions, automation of data sharing between systems and change management activities.

### *Justification*

The Workforce Management System Enhancement is justified on the basis of improved operating efficiency. A net present value analysis determined that implementing this enhancement would provide cost savings for customers.

Appendix B provides a detailed breakdown of the net present value analysis for this item.

## 2.3 Daily Time Entry Application Enhancement

### *Description*

This item involves enhancing the software used by Powerline Technicians for daily time entry and approval. Powerline Technicians are integral to maintaining the electrical system, including responding to customer outages, initiating repairs on the electrical system and performing capital work. Powerline Technicians are required to record their hours worked each day and associate them with specific job assignments, such as a capital project. There is significant variability in the daily work completed by Powerline Technicians.[5] As a result, time entries are recorded on a daily basis to ensure accurate financial reporting and payroll.

Newfoundland Power implemented its Daily Time Entry Application in 2012. A total of 144 Power Line Technicians and 14 Line Supervisors use the application on a daily basis.[6] Typically, each Powerline Technician returns to the office at the end of their shift to enter their time using a shared computer. Recording time is a manual effort that is subject to errors as each work task must be associated with the appropriate project number. The review and approval process completed daily by Line Supervisors is time consuming, including follow-ups with crews to address any issues.

This enhancement involves designing and deploying a mobile version of the Daily Time Entry Application that is accessible from Powerline Technicians' existing mobile devices. Powerline Technicians will have access to the application from the job site, eliminating the time required to use a shared computer back in the office. The application will also be enhanced through automation by enabling the pre-population of project numbers by accessing daily work assignments from the Company's Workforce Management System. This reduction in manual data entry will improve operating efficiency and data quality.

Table 3 provides the cost breakdown for the Daily Time Entry Application Enhancement.

Table 3
Daily Time Entry Application Enhancement
2024 Project Cost
($000s)

| Cost Category | 2024 |
|---|---|
| Material | - |
| Labour – Internal | 199 |
| Labour – Contract | - |
| Engineering | - |
| Other | 25 |
| Total | 224 |

5 Powerline Technicians complete a variety of operating and capital work each day. A typical day could involve operating work associated with responding to a customer outage and capital work such as connecting a new customer or replacing a failed high pressure sodium streetlight with a new LED streetlight. Each work task would involve a separate entry on their daily timesheet.

6 Data is from March 2023.

The estimated cost of the Daily Time Entry Application Enhancement is $224,000 in 2024. This includes costs associated with the development of the mobile time entry application and integration with the Workforce Management System.

### *Justification*

The Daily Time Entry Application Enhancement is justified based on improved operating efficiency. A net present value analysis determined that implementing this enhancement would provide cost savings for customers.

Appendix C provides a detailed breakdown of the net present value analysis for this item.

## 2.4 Webchat Enhancement

### *Description*

This item involves implementing an automated webchat for customers to interact with Newfoundland Power using an artificial intelligence service and identity verification.

Newfoundland Power has been increasing the digital communication channels available to its customers for over a decade in order to keep pace with customers' evolving service expectations. The Company receives an average of 2.6 million inquiries from customers each year, approximately 79% of which are via Newfoundland Power's website. Visits to the Company's website have more than tripled over the last decade, increasing from approximately 635,000 in 2012 to two million in 2022.

Newfoundland Power implemented a webchat service as an additional communication channel for customers using its website in 2021. Webchat allows customers to interact directly with a Customer Service Representative to report an outage or address other issues related to their account. Customer Service Representatives handled approximately 7,400 webchat interactions with customers in 2022, with growth in customer interactions occurring throughout the year.[7] Growth in webchat interactions has continued in 2023 with customer interactions 36% higher in the first quarter of 2023 when compared to the fourth quarter of 2022. Webchat is only available during regular business hours. Outside of regular business hours, customers can avail of the Company's website self-service options or contact the System Control Centre to report emergencies and outages.

Webchat services have evolved in recent years to include automated options.[8] Automated webchat services use artificial intelligence with identity verification to respond to customers' inquiries in a secure and timely fashion. For Newfoundland Power, implementing automated webchat would keep pace with customers' increasing expectations for digital communication.

---

7 In 2021, the webchat feature was implemented for a limited number of pages on Newfoundland Power's website. The feature was implemented across all pages in July 2022. This caused webchat interactions to more than triple during the second half of 2022. Approximately 77% of all webchat interactions in 2022 occurred during the second half of the year.

8 Aberdeen Research found that companies using automated webchat capabilities achieve an average 3.5 times increase in customer satisfaction rates. Electric utilities, such as SaskPower, and telecommunications companies, such as Bell Canada and Rogers, currently offer automated webchat for customer service.

The service would be available 24 hours a day, seven days a week, and would provide an avenue for customers to obtain information outside of regular business hours. For example, customers could use the automated webchat to report an outage instead of calling the System Control Centre. Customers could also use the automated webchat to check the status of power outages, determine their account balance or usage history and enroll in paperless billing.

Table 4 provides the cost breakdown for the Webchat Enhancement.

Table 4
Webchat Enhancement
2024 Expenditures
($000s)

| Cost Category | 2024 |
|---|---|
| Material | - |
| Labour – Internal | 198 |
| Labour – Contract | - |
| Engineering | - |
| Other | 76 |
| Total | 274 |

The estimated cost of the Webchat Enhancement is $274,000 in 2024. This includes costs associated with the procurement, configuration, testing, implementation and security assessment of the Webchat software.

### *Justification*

The Webchat Enhancement is justified based on improved customer service delivery. The automated solution is an efficient means through which to provide a new communication channel for customers. It would provide enhanced customer service outside of regular business hours and is consistent with customers' increasing expectations for digital communications.

## 2.5 IT Service Management System Enhancement

### *Description*

This item involves enhancing the Company's IT Service Management System by implementing the Software Asset Management module. Software asset management tools provide automation to support tasks required to maintain compliance with and optimize the use of software licenses entered into with vendors.

Newfoundland Power manages over 300 licenses to support the applications, operating systems, databases, cybersecurity tools and other software used in provided service to its customers. These technologies have unique licensing models that dictate the terms of their use. Each license must be reviewed regularly to ensure compliance and make any adjustments based on changes in business requirements.

Licencing models have become more complex in recent years. For example, Newfoundland Power now has 87 software applications that follow subscription-based licencing models where costs are based on the number of users. These licenses require periodic reviews to ensure compliance and to make any necessary adjustments based on changes in business requirements, such as an increase or decrease in the number of allowable users. The frequency of reviews can range from monthly to yearly depending on the terms of the licence, which vary by vendor.

Newfoundland Power currently manages its software licensing using a number of different systems. Information is manually captured and updated by employees in the Technology Department throughout the year using a combination of Excel spreadsheets and other tools, which are manually reviewed multiple times a year. There is currently no automation and reporting capabilities are limited.

A Software Asset Management module would automatically analyze the requirements of software licenses and usage data, and provide reports to ensure compliance with requirements and right size contracts to meet business requirements. Employees would no longer be required to manually review each software license to assess these requirements.

Table 5 provides the cost breakdown for the IT Service Management System Enhancement.

Table 5
IT Service Management System Enhancement
2024 Expenditures
($000s)

| Cost Category | 2024 |
|---|---|
| Material | 175 |
| Labour – Internal | 75 |
| Labour – Contract | - |
| Engineering | - |
| Other | - |
| Total | 250 |

The estimated cost of the IT Service Management System Enhancement is $250,000 in 2024. These costs include configuration and implementation of the Software Asset Management module.

### *Justification*

Enhancing the IT Service Management System by implementing the Software Asset Management module is justified on the basis of improved operating efficiencies. A net present value analysis determined that implementing this enhancement would provide cost savings for customers.

Appendix D provides a detailed breakdown of the net present value analysis for this item.

## 2.6 takeCHARGE Website Enhancement

### *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 education and awareness resources. There were over 660,000 visits to the takeCHARGE website in 2022. This is consistent with promotion of the takeCHARGE website as the primary resource for customer information.

In 2024, takeCHARGE website enhancements are required to ensure customers continue to have access to up-to-date information on customer energy conservation 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.

Table 6 provides the cost breakdown for the takeCHARGE Website Enhancement.

| Table 6<br>takeCHARGE Website Enhancement<br>2024 Expenditures<br>($000s) | |
|---|---|
| Cost Category | 2024 |
| Material | - |
| Labour – Internal | 45 |
| Labour – Contract | - |
| Engineering | - |
| Other | 26 |
| Total | 71 |

The estimated cost of the takeCHARGE Website Enhancement is $71,000 in 2024.

***Justification***

Enhancements to the takeCHARGE website are justified on the basis of improvements in customer service delivery and the continued promotion of energy conservation to customers. Updates to the takeCHARGE website will ensure customers continue to have access to accurate, up-to-date information on energy conservation.

## 2.7 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. It also permits the implementation of opportunities identified by employees to improve customer service and operational efficiency.

Examples of enhancements previously completed under this item include: (i) the development of a customer-facing streetlight outage map on the Newfoundland Power website; (ii) compliance reporting enhancements for the heavy fleet record of duty system; (iii) automation of financial reporting processes; (iv) improved performance testing of the high volume call answering system during upgrades and patching; and (v) the development of dashboards for the System Control Centre to track emergency calls from customers.

For 2024, this item would allow Newfoundland Power continued flexibility in implementing enhancements that improve its operational efficiency and effectiveness in serving customers.

Table 7 provides the cost breakdown for Various Minor Enhancements.

| Table 7<br>Various Minor Enhancements<br>2024 Expenditures<br>($000s) | |
|---|---|
| Cost Category | 2024 |
| Material | - |
| Labour – Internal | 337 |
| Labour – Contract | - |
| Engineering | - |
| Other | 135 |
| Total | 472 |

The estimated cost of Various Minor Enhancements is $472,000 in 2024. The budget for this item is based on the most recent three-year average, adjusted for inflation.

***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 8 summarizes the cost breakdown for the 2024 *Application Enhancements* project.

Table 8
Application Enhancements Project
2024 Project Cost
($000s)

| Cost Category | 2024 |
|---|---|
| Material | 175 |
| Labour – Internal | 1,255 |
| Labour – Contract | - |
| Engineering | - |
| Other | 462 |
| Total | 1,892 |

The total cost of the 2024 *Application Enhancements* project is approximately $1,892,000.

## 4.0 CONCLUSION

The 2024 *Application Enhancements* project will allow Newfoundland Power to reduce manual processes 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 Enhancement

**NET PRESENT VALUE ANALYSIS**

# Digital Forms Portfolio Enhancement

| | | Capital Impacts | | | | | | Operating Cost Impacts | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Capital Additions | | CCA Tax Deductions | | | | Cost Increases | | Cost Benefits | | | | |
| | YEAR | New Software<br>A | New System Software<br>B | Software | System Hardware | Residual CCA | Total<br>C | Labour | Non-Lab<br>D | Labour | Non-Lab<br>E | Net Operating Savings<br>F | Income Tax<br>G | After-Tax Cash Flow<br>H |
| 0 | 2024 | ($227,000) | $0 | $227,000 | $0 | $0 | $227,000 | $0 | $0 | $34,771 | $0 | $34,771 | $57,669 | ($134,560) |
| 1 | 2025 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $35,762 | $0 | $35,762 | ($10,729) | $25,033 |
| 2 | 2026 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $36,783 | $0 | $36,783 | ($11,035) | $25,748 |
| 3 | 2027 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $37,831 | $0 | $37,831 | ($11,349) | $26,482 |
| 4 | 2028 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $38,909 | $0 | $38,909 | ($11,673) | $27,236 |
| 5 | 2029 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $40,018 | $0 | $40,018 | ($12,005) | $28,013 |
| 6 | 2030 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $41,158 | $0 | $41,158 | ($12,347) | $28,811 |
| 7 | 2031 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $42,331 | $0 | $42,331 | ($12,699) | $29,632 |

7 Yr Net Present Value (See Note I) @ 5.44% $19,872

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 ("CCA") 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 Conference Board of Canada's GDP Deflator. 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 Conference Board of Canada's GDP Deflator. 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 – Workforce Management System Enhancement

**NET PRESENT VALUE ANALYSIS**

## Workforce Management System Enhancement

| | | 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 | 2024 | ($374,000) | $0 | $374,000 | $0 | $0 | $374,000 | $0 | $0 | $54,536 | $0 | $54,536 | $95,839 | ($223,625) |
| 1 | 2025 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $56,090 | $0 | $56,090 | ($16,827) | $39,263 |
| 2 | 2026 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $57,688 | $0 | $57,688 | ($17,306) | $40,382 |
| 3 | 2027 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $59,332 | $0 | $59,332 | ($17,800) | $41,532 |
| 4 | 2028 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $61,023 | $0 | $61,023 | ($18,307) | $42,716 |
| 5 | 2029 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $62,763 | $0 | $62,763 | ($18,829) | $43,934 |
| 6 | 2030 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $64,551 | $0 | $64,551 | ($19,365) | $45,186 |
| 7 | 2031 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $66,390 | $0 | $66,390 | ($19,917) | $46,473 |

7 Yr Net Present Value (See Note I) @ 5.44% $18,582

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 ("CCA") 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 Conference Baord of Canada's GDP Deflator. 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 Conference Board of Canada's GDP Deflator. 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 – Daily Time Entry Application Enhancement

**NET PRESENT VALUE ANALYSIS**

## Daily Time Entry Application Enhancement

| | | Capital Impacts | | | | | | Operating Cost Impacts | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Capital Additions | | CCA Tax Deductions | | | | Cost Increases | | Cost Benefits | | | | |
| | YEAR | New Software A | New System Software B | Software | System Hardware | Residual CCA C | Total | Labour D | Non-Lab | Labour E | Non-Lab | Net Operating Savings F | Income Tax G | After-Tax Cash Flow H |
| 0 | 2024 | ($224,000) | $0 | $224,000 | $0 | $0 | $224,000 | $0 | $0 | $59,094 | $0 | $59,094 | $49,472 | ($115,434) |
| 1 | 2025 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $60,778 | $0 | $60,778 | ($18,233) | $42,545 |
| 2 | 2026 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $62,510 | $0 | $62,510 | ($18,753) | $43,757 |
| 3 | 2027 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $64,292 | $0 | $64,292 | ($19,288) | $45,004 |
| 4 | 2028 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $66,124 | $0 | $66,124 | ($19,837) | $46,287 |
| 5 | 2029 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $68,009 | $0 | $68,009 | ($20,403) | $47,606 |
| 6 | 2030 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $69,947 | $0 | $69,947 | ($20,984) | $48,963 |
| 7 | 2031 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $71,942 | $0 | $71,942 | ($21,583) | $50,359 |

7 Yr Net Present Value (See Note I) @ 5.44% $147,020

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 ("CCA") 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 Conference Board of Canada'sGDP Deflator. 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 Conference Board of Canada's GDP Deflator. 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 D:

## Net Present Value Analysis – IT Service Management System Enhancement

**NET PRESENT VALUE ANALYSIS**

## IT Service Management System Enhancement

| | | 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 | 2024 | ($250,000) | $0 | $250,000 | $0 | $0 | $250,000 | $0 | $0 | $28,129 | $45,500 | $73,629 | $52,911 | ($123,460) |
| 1 | 2025 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($43,603) | $28,931 | $92,276 | $77,604 | ($23,281) | $54,323 |
| 2 | 2026 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($88,764) | $29,756 | $93,653 | $34,645 | ($10,394) | $24,251 |
| 3 | 2027 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($90,283) | $30,604 | $95,255 | $35,576 | ($10,673) | $24,903 |
| 4 | 2028 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($91,944) | $31,476 | $97,008 | $36,540 | ($10,962) | $25,578 |
| 5 | 2029 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($94,220) | $32,373 | $99,409 | $37,562 | ($11,269) | $26,293 |
| 6 | 2030 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($95,931) | $33,296 | $101,214 | $38,579 | ($11,574) | $27,005 |
| 7 | 2031 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($97,627) | $34,245 | $103,003 | $39,621 | ($11,886) | $27,735 |

7 Yr Net Present Value (See Note I) @ 5.44% $50,775

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 ("CCA") 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 Conference Board of Canada's GDP Deflator. 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 Conference Board of Canada's GDP Deflator. 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.

# 6.1 Rate Base: Additions, Deductions and Allowances

June 2023

# TABLE OF CONTENTS

Page

# 1.0 INTRODUCTION

In the *2024 Capital Budget Application* (the "Application"), Newfoundland Power Inc. ("Newfoundland Power" or the "Company") seeks final approval of its 2022 average rate base. This is consistent with current regulatory practice before the Board.

Newfoundland Power's 2022 average rate base of $1,230,434,000 is set out in Schedule D to the Application.

To meet the cost of service standard, rate base, as calculated in accordance with the Asset Rate Base Method, should reflect what the utility must finance. For investment in utility plant, it is the depreciated value of the plant that must be effectively financed. However, for rate base to fully reflect the financing requirements associated with the provision of regulated service, it must also be adjusted to reflect other costs required to provide service.

Conceptually, additions to rate base are costs that have been incurred to provide service, but have not yet been recovered through customer rates. Deductions from rate base represent amounts that have been recovered through customer rates in advance of the required utility payment for those costs. Rate base allowances simply reflect the cost associated with maintaining the required working capital and inventories necessary to provide service. Each of these items affects what the utility must finance.

In Order No. P.U. 19 (2003), the Board, in effect, ordered Newfoundland Power to file with its capital budget applications: (i) evidence related to changes in deferred charges, including pension costs; and (ii) a reconciliation of average rate base and average invested capital.

In Order No. P.U. 32 (2007), the Board approved Newfoundland Power's calculation of rate base in accordance with the Asset Rate Base Method and required Newfoundland Power to continue to file as part of its annual returns, information relating to changes in deferred charges, including pension costs. The Company's calculation of rate base included in its annual returns details the additions to, deductions from, and allowances in rate base.[1]

Further to Newfoundland Power's 2022 annual returns, this report provides a review of the 2021 and 2022 additions, deductions and allowances to support the Company's 2022 average rate base set out in Schedule D to the Application.

[1] Newfoundland Power's 2022 annual returns are provided in its *2022 Annual Report to the Board* which was filed with the Board on March 31, 2023. Return 3 provides the calculation of the Company's 2022 average rate base.

## 2.0 ADDITIONS TO RATE BASE

### 2.1 Summary

Table 1 summarizes Newfoundland Power's additions to rate base for 2021 and 2022.

Table 1
Additions to Rate Base
2021-2022
($000s)

| | 2021 | 2022 |
|---|---|---|
| Deferred Pension Costs | 88,888 | 95,095 |
| Credit Facility Costs | 96 | 87 |
| Cost Recovery Deferral – Conservation | 16,421 | 19,359 |
| Cost Recovery Deferral – 2022 Revenue Shortfall | - | 459 |
| Cost Recovery Deferral – Load Research and Retail Rate Design Review | - | 20 |
| Customer Finance Programs | 1,755 | 1,472 |
| Total Additions | 107,160 | 116,492 |

Additions to rate base were approximately $116.5 million in 2022. This is approximately $9.3 million higher than 2021. The higher additions to rate base in 2022 primarily reflect: (i) increases in deferred pension costs which reflects a higher discount rate and its impact on interest costs; and (ii) increases in deferred recovery of annual customer energy conservation program costs.

This section outlines the additions to rate base in further detail.

### 2.2 Deferred Pension Costs

The difference between pension plan *funding* and pension plan *expense* associated with the Company's defined benefit pension plan is captured as a deferred pension cost in accordance with Order No. P.U. 17 (1987).[2]

[2] Deferred pension costs were approved for inclusion in average rate base in Order No. P.U. 19 (2003).

Table 2 provides details of changes in Newfoundland Power's deferred pension costs for 2021 and 2022.

Table 2
Deferred Pension Costs
2021-2022
($000s)

| | 2021 | 2022 |
|---|---|---|
| Deferred Pension Costs, January 1st | 89,900 | 88,888 |
| Pension Plan Funding | 2,764 | 2,730 |
| Pension Plan Expense | (3,776) | 3,477 |
| Deferred Pension Costs, December 31st | 88,888 | 95,095 |

## 2.3 Credit Facility Costs

In Order No. P.U. 1 (2005), the Board approved Newfoundland Power's issue of a $100 million committed revolving term credit facility.

The balance as of 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.[3]

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.

In August 2022, the committed credit facility was renegotiated to extend its maturity date to August 2027. Costs related to this amendment totalled $38,000 and are being amortized over the five-year life of the agreement, beginning in 2022.

3 In August 2018, the maturity date of the committed credit facility was extended to August 2023 at a cost of $40,000 to be amortized over the five-year life of the agreement, beginning in 2018. In August 2019, the maturity date of the committed credit facility was extended to August 2024 at a cost of $35,000 to be amortized over the five-year life of the agreement, beginning in 2019. There were no amendments to the credit facility in 2020.

The unamortized credit facility issue costs associated with the 2021 and 2022 credit facility amendments are included in rate base for those years 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 for 2021 and 2022.

Table 3
Credit Facility Costs
2021-2022
($000s)

| | 2021 | 2022 |
|---|---|---|
| Balance, January 1st | 46 | 96 |
| Cost – Reduction | - | (31) |
| Cost – Addition | 71 | 38 |
| Amortization | (21) | (16) |
| Balance, December 31st | 96 | 87 |

### 2.4 Cost Recovery Deferral – Conservation

In Order No. P.U. 13 (2013), the Board approved the deferral of annual customer energy conservation program costs and the amortization of annual costs over seven years, with recovery through the RSA. In Order No. P.U. 3 (2022), the Board approved the amortization of annual costs over 10 years, commencing January 1, 2021 for historical balances and annual charges.

Table 4 provides details of the amortizations of the deferred cost recovery related to conservation for 2021 and 2022.

Table 4
Cost Recovery Deferral – Conservation
2021-2022
($000s)

| | 2021 | 2022 |
|---|---|---|
| Balance, January 1st | 17,049 | 16,421 |
| Implementation True-Up[4] | - | 1,875 |
| Cost | 3,494 | 3,659 |
| Amortization | (4,122) | (2,596) |
| Balance, December 31st | 16,421 | 19,359 |

## 2.5 Cost Recovery Deferral – 2022 Revenue Shortfall

The Board's disposition of Newfoundland Power's *2022/2023 General Rate Application* in Order No. P.U. 3 (2022) resulted in a $0.93 million ($0.65 million after-tax) shortfall in the recovery of the revenue 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.

[4] 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 5 provides details of the amortizations of the deferred cost recovery related to the 2022 Revenue Shortfall for 2021 and 2022.

Table 5
Cost Recovery Deferral – 2022 Revenue Shortfall
2021-2022
($000s)

| | 2021 | 2022 |
|---|---|---|
| Balance, January 1st | - | - |
| Cost | - | 651 |
| Amortization | - | (192) |
| Balance, December 31st | - | 459 |

### 2.6 Cost Recovery Deferral – Load Research and Retail Rate Design Review

In Order No. P.U. 3 (2022), the Board approved the deferral of costs incurred in conducting a Load Research Study and a Retail Rate Design Review.

Table 6 provides details of changes to the balances related to Load Research and Retail Rate Design Review for 2021 and 2022.

Table 6
Cost Recovery Deferral – Load Research and Retail Rate Design Review
2021-2022
($000s)

| | 2021 | 2022 |
|---|---|---|
| Balance, January 1st | - | - |
| Cost | - | 20 |
| Balance, December 31st | - | 20 |

### 2.7 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 7 provides details of changes to balances related to customer finance programs for 2021 and 2022.

| Table 7<br>Customer Finance Programs<br>2021-2022<br>($000s) | | |
|---|---|---|
| | 2021 | 2022 |
| Balance, January 1st | 2,098 | 1,755 |
| Change | (343) | (283) |
| Balance, December 31st | 1,755 | 1,472 |

## 3.0 DEDUCTIONS FROM RATE BASE

### 3.1 Summary

Table 8 summarizes Newfoundland Power's deductions from rate base for 2021 and 2022.

| Table 8<br>Deductions from Rate Base<br>2021-2022<br>($000s) | | |
|---|---|---|
| | 2021 | 2022 |
| Other Post-Employment Benefits ("OPEBs") | 73,566 | 80,151 |
| Customer Security Deposits | 1,401 | 1,270 |
| Accrued Pension Obligation | 5,168 | 5,300 |
| Accumulated Deferred Income Taxes | 15,976 | 18,076 |
| Weather Normalization Reserve | 2,020 | 6,576 |
| Demand Management Incentive Account | (1,342) | 107 |
| Total Deductions | 96,789 | 111,480 |

Deductions from rate base were approximately $111.5 million in 2022. Newfoundland Power's total deductions from rate base in 2022 were approximately $14.7 million higher than 2021.

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,[5] (ii) movement in the weather normalization reserve and the demand management incentive account, and (iii) an increase in accumulated deferred income taxes which reflects continued investment in the electricity system and timing differences associated with the Company's employee future benefits.

This section outlines the deductions from rate base in further detail.

## 3.2 Other Post-Employment Benefits

Newfoundland Power's OPEBs are comprised of retirement allowances for retiring employees, as well as health, medical and life insurance for retirees and their dependents.

Table 9 provides details of the changes related to the net OPEBs liability for 2021 and 2022.

Table 9
Other Post-Employment Benefits
2021-2022
($000s)

| | 2021 | 2022 |
|---|---|---|
| Regulatory Asset | 14,016 | 10,512 |
| OPEBs Liability | 87,582 | 90,663 |
| Net OPEBs Liability | 73,566 | 80,151 |

## 3.3 Customer Security Deposits

Customer security deposits are provided by customers in accordance with the *Schedule of Rates, Rules and Regulations*.

[5] In Order No. P.U. 31 (2010), the Board approved, beginning in 2011, the adoption of the accrual method of accounting for OPEBs and related income tax. In addition, the Board approved a 15-year straight line amortization of a transitional balance starting in 2011.

Table 10 provides details on the changes in customer security deposits for 2021 and 2022.

Table 10
Customer Security Deposits
2021-2022
($000s)

| | 2021 | 2022 |
|---|---|---|
| Balance, January 1st | 1,212 | 1,401 |
| Change | 189 | (131) |
| Balance, December 31st | 1,401 | 1,270 |

### 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 11 provides details of changes related to accrued pension obligation for 2021 and 2022.

Table 11
Accrued Pension Obligation
2021-2022
($000s)

| | 2021 | 2022 |
|---|---|---|
| Balance, January 1st | 5,258 | 5,168 |
| Change | (90) | 132 |
| Balance, December 31st | 5,168 | 5,300 |

### 3.5 Accumulated Deferred Income Taxes

Accumulated deferred income taxes result from timing differences related to the payment of income taxes and the recognition of income taxes for financial reporting and regulatory purposes.

Currently, Newfoundland Power recognizes deferred income taxes, for regulatory purposes, with respect to timing differences related to plant investment, pension costs and other employee future benefit costs.[6,7,8]

Table 12 provides details of changes in the accumulated deferred income taxes for 2021 and 2022.

Table 12
Accumulated Deferred Income Taxes
2021-2022
($000s)

| | 2021 | 2022 |
|---|---|---|
| Balance, January 1st | 12,683 | 15,976 |
| Change | 3,293 | 2,100 |
| Balance, December 31st | 15,976 | 18,076 |

## 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.

[6] In Order Nos. P.U. 20 (1978), P.U. 21 (1980) and P.U. 17 (1987), the Board approved the Company's use of Tax Accrual Accounting to recognize deferred income tax liabilities associated with plant investment.

[7] In Order No. P.U. 32 (2007), the Board approved the use of Tax Accrual Accounting to recognize deferred income taxes related to timing differences between pension funding and pension expense.

[8] In Order No. P.U. 31 (2010), the Board approved the use of Tax Accrual Accounting to recognize deferred income taxes related to timing differences between other employee future benefits recognized for tax purposes (cash payments) and other employee future benefit expense recognized for accounting purposes (accrual basis).

Table 13 provides details of changes in the balance of the Weather Normalization Reserve for 2021 and 2022.

| Table 13<br>Weather Normalization Reserve<br>2021-2022<br>($000s) | | |
|---|---|---|
| | 2021 | 2022 |
| Balance, January 1st | 3,734 | 2,020 |
| Operation of the reserve | 2,020 | 6,576 |
| Transfers to the RSA | (3,734) | (2,020) |
| Balance, December 31st | 2,020 | 6,576 |

The disposition of the December 31, 2022 balance in the Weather Normalization Reserve account to the RSA as of March 31, 2023 was approved by the Board in Order No. P.U. 9 (2023).

### 3.7 Demand Management Incentive Account

In Order No. P.U. 32 (2007), the Board approved the Demand Management Incentive Account (the "DMI Account") to replace the Purchase Power Unit Cost Variance Reserve.

Table 14 provides details of the DMI Account for 2021 and 2022.

| Table 14<br>DMI Account<br>2021-2022<br>($000s) | | |
|---|---|---|
| | 2021 | 2022 |
| Balance, January 1st | (1,002) | (1,342) |
| Transfers to the RSA | 1,002 | 1,342 |
| Operation of DMI | (1,342) | 107 |
| Balance, December 31st | (1,342) | 107 |

The disposition of the December 31, 2022 balance in the DMI Account to the RSA as of March 31, 2023 was approved in Order No. P.U. 8 (2023).

# 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 15 provides details on changes in the cash working capital allowance for 2021 and 2022.

Table 15
Rate Base Allowances
Cash Working Capital Allowance[9]
2021-2022
($000s)

| | 2021 | 2022 |
|---|---|---|
| Gross Operating Costs | 534,377 | 556,396 |
| Income Taxes | 10,714 | 14,055 |
| Municipal Taxes Paid | 18,332 | 17,646 |
| Non-Regulated Expenses | (2,521) | (2,264) |
| Total Operating Expenses | 560,902 | 585,833 |
| Cash Working Capital Factor | 1.789% | 1.137% |
| | 10,035 | 6,661 |
| HST Adjustment | 242 | 44 |
| Cash Working Capital Allowance | 10,277 | 6,705 |

[9] The cash working capital allowance for 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 2022 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).

## 4.3 Materials and Supplies Allowance

Including a materials and supplies allowance in rate base provides a utility a means to reasonably recover the cost of financing its inventories that are not related to the expansion of the electrical system.[10]

Table 16 provides details on changes in the materials and supplies allowance for 2021 and 2022.

Table 16
Rate Base Allowances
Materials and Supplies Allowance
2021-2022
($000s)

| | 2021 | 2022 |
|---|---|---|
| Average Materials and Supplies | 10,979 | 14,802 |
| Expansion Factor[11] | 24.05% | 19.08% |
| Expansion | 2,640 | 2,824 |
| Materials and Supplies Allowance | 8,339 | 11,978 |

10 Financing costs for inventory related to the expansion of the electrical system are recovered through the use of an allowance for funds used during construction and are capitalized upon project completion.

11 The expansion factor is based on a review of actual inventories used for expansion projects. The calculation of the 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 2022 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).