WHENEVER. WHEREVER.
We'll be there.

DELIVERED BY HAND

July 13, 2018

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

Ladies & Gentlemen:

Re: Newfoundland Power's 2019 Capital Budget Application

A. 2019 Capital Budget Application

Enclosed are the original and 10 copies of Newfoundland Power Inc.'s (the "Company") 2019 Capital Budget Application and supporting materials (the "Filing").

The Filing outlines a proposed 2019 Capital Budget totaling $93,304,000. Included in that total are 2019 capital expenditures of $17,314,000 previously approved in Order No. P.U. 37 (2017) (the "2018 Capital Order"). Those previously approved expenditures relate to multi-year projects proposed in the 2018 Capital Budget Application. The Filing also outlines multi-year projects commencing in 2019 that include proposed 2020 capital expenditures totaling $1,400,000 and proposed 2021 capital expenditures totaling $700,000. In addition, the Filing seeks approval of a 2017 rate base in the amount of $1,092,254,000.

Newfoundland Power continues to target a stable level of capital investment required to maintain the condition of the electrical system. Included in the Filing is the *Central Newfoundland System Planning Study* (the "Study") that describes the least cost approach to addressing 90 kms of 60 year old transmission line infrastructure between the towns of Grand Falls-Windsor and Gander. The Study recommends the dismantling of the deteriorated 66 kV transmission system and extending the existing 138 kV transmission system to Lewisporte and Rattling Brook substations over a 3-year period starting in 2019. These expenditures are consistent with the delivery of reliable service at least cost.

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

B. Compliance Matters

B.1 Board Orders

In the 2018 Capital Order, the Board required a progress report on 2018 capital expenditures to be provided with the Filing. In Order No. P.U. 35 (2003) (the "2004 Capital Order"), the Board required a 5-year capital plan to be provided with the Filing. In Order No. P.U. 19 (2003) (the "2003 Rate Order"), the Board required that evidence relating to deferred charges and a reconciliation of average rate base to invested capital be filed with capital budget applications.

These requirements are specifically addressed in the Filing in the following:

1. *2018 Capital Expenditure Status Report*: this meets the requirements of the 2018 Capital Order;

2. *2019 Capital Plan*: this meets the requirements of the 2004 Capital Order; and

3. *Rate Base: Additions, Deductions & Allowances*: this meets the requirements of the 2003 Rate Order.

B.2 The Guidelines

In the October 2007 Capital Budget Application Guidelines (the "Guidelines"), the Board provided certain directions on how to categorize capital expenditures. Although compliance with the Guidelines necessarily requires the exercise of a degree of judgment, the Filing, in the Company's view, complies with the Guidelines while remaining reasonably consistent and comparable with past filings.

Section 2 of the *2019 Capital Plan* provides a breakdown of the overall 2019 Capital Budget by definition, classification, and materiality segmentation as described in the Guidelines. Pages i through viii of Schedule B to the formal application provide details of these categorizations by project.

C. Filing Details and Circulation

The Filing will be posted on the Company's website (newfoundlandpower.com) in the next few days. Copies of the Filing will be available for review by interested parties at the Company's offices throughout its service territory.

The enclosed material has been provided in binders with appropriate tabbing. For convenience, additional materials such as Responses to Requests for Information will be provided on three-hole punched paper.

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

A PDF file of the Filing will be forwarded to the Board in due course. A copy of the Filing has been forwarded directly to Mr. Geoffrey Young, Senior Legal Counsel of Newfoundland and Labrador Hydro and Mr. Dennis Browne, the Consumer Advocate.

D. Concluding

We trust the foregoing and enclosed are found to be in order.

If you have any questions on the Filing, please contact us at your convenience.

Yours very truly,

Kelly Hopkins
Corporate Counsel

Enclosures

c. Geoffrey Young
Newfoundland and Labrador Hydro

Dennis Browne, QC
Browne Fitzgerald Morgan & Avis

Newfoundland Power Inc.
2019 Capital Budget Application
Filing Contents

Application

Supporting Materials

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 a 2019 Capital Budget of $93,304,000;
(b) approving certain capital expenditures related to multi-year projects commencing in 2019; and
(c) fixing and determining a 2017 rate base of $1,092,254,000

2019 Capital Budget Application

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:

(a) approving a 2019 Capital Budget of $93,304,000;

(b) approving certain capital expenditures related to multi-year projects commencing in 2019; and

(c) fixing and determining a 2017 rate base of $1,092,254,000

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

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

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

2. Schedule A to this Application is a summary of Newfoundland Power's 2019 Capital Budget in the amount of $93,304,000, which includes forecast 2019 capital expenditures previously approved in Order No. P.U. 37 (2017) and also includes an estimated amount of $2,500,000 in contributions in aid of construction that the Applicant intends to demand from its customers in 2019. All contributions to be recovered from customers shall be calculated in a manner approved by the Board.

3. Schedule B to this Application provides detailed descriptions of the projects for which the proposed capital expenditures included in Newfoundland Power's 2019 Capital Budget are required.

4. Schedule C to this Application is a listing of multi-year projects including:

   (a) ongoing projects for which capital expenditures were approved in Order No. P.U. 37 (2017); and

   (b) projects which will commence as part of the 2019 Capital Budget but will not be completed in 2019.

5. 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.

6. Schedule D to this Application shows Newfoundland Power's actual average rate base for 2017 of $1,092,254,000.

7. Communication with respect to this Application should be forwarded to the attention of Liam P. O'Brien and Kelly Hopkins, Counsel to Newfoundland Power.

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

   (a) pursuant to Section 41 of the Act, approving Newfoundland Power's 2019 Capital Budget in the amount of $93,304,000 as set out in Schedules A and B to the Application;

   (b) pursuant to Section 41 of the Act, approving Newfoundland Power's purchase and construction in 2020 of improvements and additions to its property in the amount of $1,400,000, as set out in Schedule C to the Application;

   (c) pursuant to Section 41 of the Act, approving Newfoundland Power's purchase and construction in 2021 of improvements and additions to its property in the amount of $700,000, as set out in Schedule C to the Application;

   (d) pursuant to Section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2017 in the amount of $1,092,254,000 as set out in Schedule D to the Application.

DATED at St. John's, Newfoundland and Labrador, this 13th day of July, 2018.

NEWFOUNDLAND POWER INC.

Kelly Hopkins

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

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

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

IN THE MATTER OF capital expenditures and rate base of Newfoundland Power Inc.; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:
(a) approving a 2019 Capital Budget of $93,304,000;
(b) approving certain capital expenditures related to multi-year projects commencing in 2019; and
(c) fixing and determining a 2017 rate base of $1,092,254,000

AFFIDAVIT

I, Gary Murray of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. That I am Vice-President, Customer Operations and Engineering of Newfoundland Power Inc.

2. 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 St. John's in the Province of Newfoundland and Labrador this 13th day of July, 2018:

Barrister

Gary Murray

2019 CAPITAL BUDGET SUMMARY

Asset Class	Budget (000s)
1. Generation - Hydro	$ 2,663
2. Generation - Thermal	8,242
3. Substations	13,039
4. Transmission	10,781
5. Distribution	40,001
6. General Property	2,630
7. Transportation	3,990
8. Telecommunications	233
9. Information Systems	6,975
10. Unforeseen Allowance	750
11. General Expenses Capitalized	4,000
Total	**$ 93,304**

2019 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
1. Generation – Hydro		
Facility Rehabilitation	$ 1,502	2
Rattling Brook Plant Refurbishment	1,161	4
Total Generation – Hydro	**$ 2,663**	
2. Generation – Thermal		
Facility Rehabilitation Thermal	$ 327	7
Purchase Mobile Generation[2]	7,915	9
Total Generation – Thermal	**$ 8,242**	
3. Substations		
Substations Refurbishment and Modernization	$ 8,580	12
Replacements Due to In-Service Failures	3,547	14
PCB Bushing Phase-out	912	16
Total Substations	**$ 13,039**	
4. Transmission		
Transmission Line Rebuild[3]	$ 10,781	19
Total Transmission	**$ 10,781**	

1 Project descriptions can be found in Schedule B at the page indicated.
2 This is a multi-year project approved in Order No. P.U. 37 (2017).
3 This includes 2 multi-year projects with $6,359,000 in expenditures approved in Order No. P.U. 37 (2017).

2019 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[4]
5. Distribution		
Extensions	$ 10,725	23
Meters	622	25
Services	3,037	28
Street Lighting	2,301	31
Transformers	6,716	34
Reconstruction	5,376	36
Rebuild Distribution Lines	3,977	38
Relocate/Replace Distribution Lines for Third Parties	2,442	41
Trunk Feeders	400	43
Feeder Additions for Load Growth[5]	1,715	45
Distribution Reliability Initiative[6]	1,800	47
Distribution Feeder Automation	675	50
Allowance for Funds Used During Construction	215	52
Total Distribution	**$ 40,001**	
6. General Property		
Tools and Equipment	$ 467	55
Additions to Real Property	489	58
Company Building Renovations	1,374	60
Physical Security Upgrades	300	62
Total General Property	**$ 2,630**	
7. Transportation		
Purchase Vehicles and Aerial Devices	$ 3,990	65
Total Transportation	**$ 3,990**	

4 Project descriptions can be found in Schedule B at the page indicated.
5 This includes a multi-year project with $665,000 in expenditures approved in Order No. P.U. 37 (2017).
6 This includes 2 multi-year projects with $1,200,000 in 2019 expenditures and future commitments identified in Schedule C of this Application.

2019 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[7]
8. Telecommunications		
Replace/Upgrade Communications Equipment	$ 106	69
Fibre Optic Network	127	71
Total Telecommunications	**$ 233**	
9. Information Systems		
Application Enhancements	$ 1,252	74
System Upgrades[8]	1,258	76
Personal Computer Infrastructure	472	78
Shared Server Infrastructure	848	81
Network Infrastructure	322	83
Cybersecurity Upgrades	398	85
Outage Management System[9]	1,210	87
Human Resource Management System Replacement[10]	1,215	89
Total Information Systems	**$ 6,975**	
10. Unforeseen Allowance		
Allowance for Unforeseen Items	$ 750	92
Total Unforeseen Allowance	**$ 750**	
11. General Expenses Capitalized		
General Expenses Capitalized	$ 4,000	94
Total General Expenses Capitalized	**$ 4,000**	

7 Project descriptions can be found in Schedule B at the page indicated.
8 This is a multi-year project approved in Order No. P.U. 37 (2017) with future commitments for the Microsoft Enterprise Agreement identified in Schedule C of this Application.
9 This is a multi-year project approved in Order No. P.U. 37 (2017).
10 This is a multi-year project approved in Order No. P.U. 37 (2017).

2019 CAPITAL PROJECTS SUMMARY

2019 Capital Project Summary

On October 29, 2007, the Board issued Capital Budget Application Guidelines (the "Guidelines") to provide direction for utility capital budget applications filed pursuant to section 41 of the *Public Utilities Act.*

The Guidelines provide that utilities present their annual capital budget with sufficient detail for the Board and interested parties to understand the nature, scope and justification for individual expenditures and the capital budget overall.

Specifically, the Guidelines require each expenditure to be defined, classified, and segmented in the following manner:

1. *Definition of the Capital Expenditure*

   Capital expenditures are to be defined as clustered, pooled or other.

   Clustered expenditures are those which would logically be undertaken together. Pooled expenditures are a series of expenditures which are neither inter-dependant nor related, but which nonetheless are logically grouped together. Other expenditures are those which do not fit the definition of clustered or pooled.

2. *Classification of the Capital Expenditure*

   Capital expenditures are to be classified as mandatory, normal capital or justifiable.

   Mandatory capital expenditures are those a utility is obliged to carry out as the result of legislation, Board Order, safety issues or risk to the environment. Normal capital expenditures are those that are required based on identified need or on a historical pattern of repair and replacement. Justifiable capital expenditures are those which are justified based on the positive impact the project will have on the utility's operations.

3. *Segmentation of the Capital Expenditure by Materiality*

   Capital expenditures are to be segmented by their materiality as follows:
   - Expenditures under $200,000;
   - Expenditures between $200,000 and $500,000; and
   - Expenditures over $500,000

This 2019 Capital Project Summary provides a summary of the planned capital expenditures contained in Newfoundland Power's (the "Company") 2019 Capital Budget Application by definition (pages ii to iv), classification (pages v to vi), and segmentation by materiality (pages vii to viii), as required by the Guidelines. In addition, each of the project descriptions in Schedule B indicate the definitions, classifications and forecast costs as provided for in the Guidelines.

Summary of
2019 Capital Projects by Definition
(000's)

Clustered	**$19,761**	**Page**
Distribution	**400**	
Trunk Feeders	400	43
Substations	**8,580**	
Substation Refurbishment and Modernization	8,580	12
Transmission	**10,781**	
Transmission Line Rebuild	10,781	19

Pooled	**$58,326**	**Page**
Distribution	**39,601**	
AFUDC	215	52
Distribution Reliability Initiative	1,800	47
Distribution Feeder Automation	675	50
Extensions	10,725	23
Feeder Additions for Load Growth	1,715	45
Meters	622	25
Rebuild Distribution Lines	3,977	38
Reconstruction	5,376	36
Relocate/Replace Distribution Lines for Third Parties	2,442	41
Services	3,037	28
Street Lighting	2,301	31
Transformers	6,716	34
General Property	**2,630**	
Additions to Real Property	489	58
Tools and Equipment	467	55
Company Building Renovations	1,374	60
Physical Security Upgrades	300	62
Generation - Hydro	**2,663**	
Hydro Facility Rehabilitation	1,502	2
Rattling Brook Plant Refurbishment	1,161	4
Generation – Thermal	**327**	
Thermal Plant Facility Rehabilitation	327	7
Information Systems	**4,550**	
Application Enhancements	1,252	74
Network Infrastructure	322	83
Personal Computer Infrastructure	472	78
Shared Server Infrastructure	848	81
System Upgrades	1,258	76
Cyber Security Upgrades	398	85

Pooled (continued)		**Page**
Substations	**4,459**	
Replacement Due to In-Service Failures	3,547	14
PCB Bushing Phase-out	912	16
Telecommunications	**106**	
Replace/Upgrade Communications Equipment	106	69
Transportation	**3,990**	
Purchase Vehicles and Aerial Devices	3,990	65

Other	**$15,217**	**Page**
General Expenses Capitalized	**4,000**	
General Expenses Capitalized	4,000	94
Generation - Thermal	**7,915**	
Purchase Mobile Generation	7,915	9
Information Systems	**2,425**	
Outage Management System	1,210	87
Human Resource Management System	1,215	89
Telecommunications	**127**	
Fibre Optic Network	127	71
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	92

Project Clustering

Clustered expenditures are those which would logically be undertaken together. Clustered expenditures are either inter-dependent or related. Inter-dependent items are necessarily linked together, as one item necessarily triggers the other. Related items are not necessarily linked to each other, but are nonetheless logically undertaken together.

In 2019, the following projects have expenditures which are clustered:

1. The *Trunk Feeders* Distribution project involving the termination of distribution plant leaving Pepperell Substation has aspects which are clustered with the *Substation Refurbishment and Modernization* project. The existing distribution feeders at Pepperrell Substation exit the substation from the existing 12.5 kV switchgear via underground cables. The refurbishment of the substation infrastructure necessitates the replacement of the distribution plant terminated on that same infrastructure. These items are interdependent, and are therefore clustered.

2. The *Substations Refurbishment and Modernization* Substations project has aspects which are clustered with the *Transmission Line Rebuild* Transmission project. Commencing in 2019, the Company will transfer the Lewisporte and Rattling Brook substations from the existing 66 kV transmission lines in Central Newfoundland to the 138 kV transmission lines. To coincide with the transmission line upgrades necessary to complete the transfer,

the refurbishment and modernization of Lewisporte Substation is also planned for 2019. Adding the 138 kV infrastructure as part of the Lewisporte substation refurbishment and modernization projects is required in advance of the termination of the 138 kV transmission line. These projects are interdependent, and are therefore clustered.

**Summary of
2019 Capital Projects by Classification
(000's)**

Normal Capital	$91,140	Page
Distribution	**40,001**	
AFUDC	215	52
Distribution Feeder Automation	675	50
Distribution Reliability Initiative	1,800	47
Extensions	10,725	23
Feeder Additions for Load Growth	1,715	45
Meters	622	25
Rebuild Distribution Lines	3,977	38
Reconstruction	5,376	36
Relocate/Replace Distribution Lines for Third Parties	2,442	41
Services	3,037	28
Street Lighting	2,301	31
Transformers	6,716	34
Trunk Feeders	400	43
General Expenses Capitalized	**4,000**	
General Expenses Capitalized	4,000	94
General Property	**2,630**	
Additions to Real Property	489	58
Tools and Equipment	467	55
Company Building Renovations	1,374	60
Physical Security Upgrades	300	62
Generation – Hydro	**2,663**	
Hydro Facility Rehabilitation	1,502	2
Rattling Brook Plant Refurbishment	1,161	4
Generation – Thermal	**8,242**	
Thermal Plant Facility Rehabilitation	327	7
Purchase Mobile Generation	7,915	9
Information Systems	**5,723**	
Network Infrastructure	322	83
Personal Computer Infrastructure	472	78
Shared Server Infrastructure	848	81
System Upgrades	1,258	76
Outage Management System	1,210	87
Human Resource Management System	1,215	89
Cyber Security Upgrades	398	85
Substations	**12,127**	
Substations Refurbishment and Modernization	8,580	12
Replacement Due to In-Service Failures	3,547	14

Normal Capital (continued)		**Page**
Telecommunications	**233**	
Replace/Upgrade Communications Equipment	106	69
Fibre Optic Network	127	71
Transmission	**10,781**	
Transmission Line Rebuild	10,781	19
Transportation	**3,990**	
Purchase Vehicles and Aerial Devices	3,990	65
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	92

Justifiable	**$1,252**	**Page**
Information Systems	**1,252**	
Application Enhancements	1,252	74

Mandatory	**$912**	**Page**
Substations	**912**	
PCB Bushing Phase-out	912	16

Summary of
2019 Capital Projects by Materiality
(000's)

Large – Greater than $500	**$89,681**	**Page**
Distribution	**39,386**	
Distribution Feeder Automation	675	50
Distribution Reliability Initiative	1,800	47
Extensions	10,725	23
Feeder Additions for Load Growth	1,715	45
Meters	622	25
Rebuild Distribution Lines	3,977	38
Reconstruction	5,376	36
Relocate/Replace Distribution Lines for Third Parties	2,442	41
Services	3,037	28
Street Lighting	2,301	31
Transformers	6,716	34
General Expenses Capitalized	**4,000**	
General Expenses Capitalized	4,000	94
General Property	**1,374**	
Company Building Renovations	1,374	60
Generation - Hydro	**2,663**	
Hydro Facility Rehabilitation	1,502	2
Rattling Brook Plant Refurbishment	1,161	4
Generation – Thermal	**7,915**	
Purchase Mobile Generation	7,915	9
Information Systems	**5,783**	
Application Enhancements	1,252	74
Shared Server Infrastructure	848	81
System Upgrades	1,258	76
Outage Management System	1,210	87
Human Resource Management System	1,215	89
Substations	**13,039**	
Replacement and In-Service Failures	3,547	14
Substations Refurbishment and Modernization	8,580	12
PCB Bushing Phase-out	912	16
Transmission	**10,781**	
Transmission Line Rebuild	10,781	19
Transportation	**3,990**	
Purchase Vehicles and Aerial Devices	3,990	65
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	92

GENERATION - HYDRO

Project Title: **Facility Rehabilitation (Pooled)**

Project Cost: **$1,502,000**

Project Description

This Generation Hydro project is necessary to improve the efficiency and reliability of various hydro plants or to replace plant components due to in-service failures. This project involves the replacement or rehabilitation of deteriorated plant components that have been identified through routine inspections, operating experience and engineering studies. The 2019 project includes the following items:

- Replacement of Frozen Ocean Access Road Bridge ($175,000);
- Rehabilitation of Pierre's Brook Intake Structure ($300,000);
- Replacement of Pierre's Brook Tailrace Bridge ($145,000);
- Rehabilitation of Rose Blanche Fishway ($110,000);
- Rehabilitation of Thomas Pond Spillway ($163,000); and
- Equipment replacements due to in-service failures ($609,000).

The refurbishment, replacement or rehabilitation of deteriorated components at individual plants is not inter-dependent or related. However, all budget items included in this project are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Details on 2019 proposed expenditures are included in ***1.1*** *2019 Facility Rehabilitation*.

Justification

The Company's 23 hydro plants range in age from 19 to 118 years old. These facilities provide relatively inexpensive energy to the Island Interconnected System. Maintaining these generating facilities reduces the need for additional, more expensive generation.

Replacement and rehabilitation projects are identified during ongoing inspections and maintenance activities. These projects are necessary for the continued operation of generation facilities in a safe, reliable and environmentally compliant manner. The alternative to maintaining these generation facilities would be to retire them. The Company's hydro generation facilities produce a combined normal annual production of 439.1 GWh. Replacing the energy produced by these facilities by increasing production at Newfoundland and Labrador Hydro's Holyrood Thermal Generating Station would require approximately 711,000 barrels of fuel annually. At an oil price of $85.55 per barrel, this translates into approximately $61 million in annual fuel savings.[1]

[1] The price forecast per barrel of oil used at Holyrood as per Newfoundland and Labrador Hydro – 2018 Utility Customer Interim Rates Application dated April 20, 2018.

All expenditures on individual hydro plants, such as the replacement of dam structures, runners, or forebays, are justified on the basis of maintaining access to hydro generation at a cost that is lower than the cost of replacement energy.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$1,123	-	-	-
Labour – Internal	116	-	-	-
Labour – Contract	-	-	-	-
Engineering	126	-	-	-
Other	137	-	-	-
Total	**$1,502**	**$1,419**	**$4,578**	**$7,499**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2
Expenditure History
(000s)

Year	2014	2015	2016	2017	2018F
Total	$1,825	$1,545	$1,689	$1,564	$2,119

The budget estimate for this project is based on engineering estimates for the individual budget items and an assessment of historical expenditures for the remainder.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Rattling Brook Plant Refurbishment (Pooled)**

Project Cost: **$1,161,000**

Project Description

This Generation Hydro project involves the refurbishment of the turbine and generator at the Company's Rattling Brook hydroelectric development in Central Newfoundland. The components requiring refurbishment include the Unit 1 turbine runner's components and the rewinding of the generator rotor poles.

Rattling Brook is the largest generating plant operated by Newfoundland Power. It was commissioned in 1958 and underwent major upgrades in 2007 and 2011. The normal annual plant production is approximately 67.1 GWh of energy, or about 15% of Newfoundland Power's total hydroelectric generation.

Details on 2019 proposed expenditures are included in ***1.2*** *2019 Rattling Brook Plant, Unit 1 Turbine - Generator Refurbishment*.

Justification

Engineering assessments of the mechanical and electrical systems have revealed a number of deficiencies. The mechanical assessment identified that the turbine runner requires an overhaul to replace the wearing components such as operating bushings and seals which were last replaced in 1987. The electrical assessment has identified that the generator's rotor pole windings, which are original to the 59 year old generator, are deteriorated and require rewinding in 2019.

A feasibility analysis of projected capital and operating expenditures for the Rattling Brook Hydroelectric Generating Plant has determined the levelized cost of energy from the plant over the next 50 years to be 1.81 cents per kilowatt-hour, which is significantly less than the cost of replacement energy at Holyrood.[2]

[2] The avoided cost of No. 6 fuel at the Holyrood Thermal Generating Station is estimated at 13.8¢ per kWh for 2019. This is based upon a 618 kWh/barrel conversion efficiency and oil price forecast of $85.55 per barrel for 2019, as per Newfoundland and Labrador Hydro – 2018 Utility Customer Interim Rates Application dated April 20, 2018. The avoided cost of fuel for the Holyrood 123 MW combustion turbine in 2017 was 26.5 ¢/kWh as per Hydro's 2017 General Rate Application response to Request for Information NP-NLH-337. Also, an estimate of the marginal cost of production during the transition period prior to the Muskrat Falls project completion is 5.0 ¢/kWh for energy in 2019 and 5.3 ¢/kWh for energy in 2020 as per Hydro's 2017 General Rate Application responses to Request for Information CA-NLH-081 and CA-NLH-258 respectively. This marginal cost increases into the future.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$716	-	-	-
Labour – Internal	248	-	-	-
Labour – Contract	-	-	-	-
Engineering	50	-	-	-
Other	147	-	-	-
Total	**$1,161**	**-**	**-**	**$1,161**

Costing Methodology

The budget estimate for this project is based on engineering cost estimates.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

GENERATION - THERMAL

Project Title: **Facility Rehabilitation Thermal (Pooled)**

Project Cost: **$327,000**

Project Description

This Generation Thermal project is necessary for the replacement or rehabilitation of deteriorated thermal plant components that are identified through routine inspections, operating experience and engineering studies.

The 2019 project consists of the refurbishment or replacement of thermal plant structures and equipment due to damage, deterioration, corrosion and in-service failure. This equipment is critical to the safe and reliable operation of thermal generating facilities and must be replaced in a timely manner. Based on historical information, $327,000 is estimated to be the cost of refurbishment or replacement of thermal plant structures in 2019.

The replacement or rehabilitation of deteriorated components at individual plants is not inter-dependent or related. However, all budget items included in this project are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Justification

The Company maintains 41.5 MW of thermal generation consisting of gas turbine and diesel units. These units are generally used to provide emergency generation, both locally and for the Island Interconnected System, and to facilitate scheduled maintenance on transmission and distribution lines or substation assets. Replacement and rehabilitation projects are identified during ongoing inspections and maintenance activities. These projects are necessary for the continued operation of thermal generation facilities in a safe, reliable and environmentally compliant manner.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$232	-	-	-
Labour – Internal	50	-	-	-
Labour – Contract	-	-	-	-
Engineering	23	-	-	-
Other	22	-	-	-
Total	**$327**	**$333**	**$1,039**	**$1,699**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2
Expenditure History
(000s)

Year	2014	2015	2016	2017	2018F
Total	$331	$228	$424	$242	$301

The budget requirement for rehabilitation of thermal generating facilities is based on a historical average, and is adjusted for anticipated expenditure requirements for extraordinary items.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Purchase Mobile Generation (Other, Multi-Year)**

Project Cost: **$7,915,000**

Project Description

This Generation Thermal project is necessary for the replacement of the existing Mobile Gas Turbine ("MGT"), which has reached the end of its mobile service life. The existing MGT is 43 years old and, while the generating equipment can provide some additional years of service, the condition of the trailers' chassis and equipment enclosures have deteriorated to the point where replacement is the only viable option.[3]

The Company's mobile generation serves 3 main roles: (i) emergency generation during long duration customer outages; (ii) temporary generation to minimize customer outages during planned construction projects; and (iii) system support during times of high demand or low generation reserve. The availability of mobile generation can greatly improve the reliability of electrical service to customers when responding to extended customer outages. Also, mobile generation provides flexibility to operating and maintenance staff for planned outages associated with transmission, substation and distribution maintenance.

This multi-year project was approved in Order No. P.U. 37 (2017). In 2018, the Company issued a Request for Proposals for both new and refurbished mobile gas turbine units in the 3.5 to 7.5 MW range, leading to the delivery of a new mobile generator in 2019.

Details on the proposed expenditures for the purchase of a new mobile generator are included in the Company's 2018 Capital Budget Application as report ***1.2*** *Purchase Mobile Generation*.

Justification

A detailed engineering assessment has been completed on the existing MGT and, given the overall poor condition of the chassis and enclosures, it is recommended that the unit be retired from mobile service over the next 2 to 3 years. The existing MGT operates multiple times every year in support of planned and unplanned, long duration outages. If the MGT is not replaced as planned, the Company would not be able to deploy mobile generation in some situations and reliability would be negatively impacted.[4]

---

[3] Following the commissioning of a new mobile generator, the existing MGT will be installed at a permanent location to continue to provide standby and emergency generation for the remainder of its service life.

[4] For example, in 2015, Newfoundland Power deployed the MGT in 4 locations to avoid extensive customer outages: Trepassey, Abrahams Cove, Lewisporte and Twillingate. In these cases, approximately 28 million customer outage minutes were avoided. Similarly, in Port aux Basques in the summer of 2015 it was used along with the mobile and Port aux Basques diesel generators, as well as the Rose Blanche hydro plant, to avoid 6 million customer outage minutes during Hydro's annual maintenance on the TL214 and TL215 transmission system.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2018, 2019 and a projection of expenditures through 2023.

Table 1
Projected Expenditures
(000s)

Cost Category	2018	2019	2020 - 2023	Total
Material	$4,731	$5,869	-	-
Labour – Internal	35	195	-	-
Labour – Contract	-	-	-	-
Engineering	154	231	-	-
Other	1,080	1,620	-	-
Total	**$6,000**	**$7,915**	**-**	**$13,915**

Costing Methodology

The budget for this project is based on an engineering cost estimate.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is a multi-year project approved in Order No. P.U. 37 (2017) to be completed over 2 years commencing in 2018.

SUBSTATIONS

Project Title: **Substations Refurbishment and Modernization (Clustered)**

Project Cost: **$8,580,000**

Project Description

This Substations project is a continuation of work started in 2007 as a result of the *Substation Strategic Plan*. The work included in this project is consistent with that plan. An update to the *Substation Strategic Plan* is included in ***2.1** 2019 Substation Refurbishment and Modernization*.

The Company has 130 substations ranging in age from 16 years to greater than 100 years. This project is necessary for the planned replacement of deteriorated and substandard substation infrastructure, such as bus structures, breakers, potential transformers, protective relaying, support structures, equipment foundations, grounding, switches and fencing. Infrastructure to be replaced is identified as a result of inspections, engineering assessments and operating experience.

In 2019, this project will refurbish and modernize Lewisporte and Pepperrell substations. In addition, the 2019 project includes the upgrading of automation equipment in substations, including the automation of distribution feeder breakers and reclosers.[5]

For 2019, a portion of the Substation Refurbishment and Modernization project proposed for Lewisporte Substation is clustered with the *Transmission Line Rebuild* Transmission project. (Schedule B, page 19 of 94) The *Central Newfoundland System Planning Study* requires the extension of transmission line 136L to Lewisporte Substation requiring the construction of a new 138 kV bus structure. Also, for 2019, a portion of the Substation Refurbishment and Modernization project proposed for Pepperrell Substation is clustered with the *Trunk Feeders* Distribution project. (Schedule B, page 43 of 94) This is because the refurbishment of Pepperrell Substation requires new terminations for the distribution feeders.

The individual requirements for the replacement of substation infrastructure are not inter-dependent. However, they are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

This project is justified based on the need to maintain safe, reliable electrical service and ensure workplace safety by replacing deteriorated or substandard substation infrastructure.

[5] At the end of 2017, approximately 89% of distribution feeder breakers and reclosers located in Company substations were automated through the SCADA system. By the end of 2018, there will be 284 distribution feeders automated, representing approximately 93% of all distribution feeders. By the end of 2019, there will be 304 distribution feeders automated, representing all distribution feeders serving customers.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023. Appendix A of ***2.1*** *2019 Substation Refurbishment and Modernization* details the work planned for each year.

Table 1
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$6,607	-	-	-
Labour – Internal	285	-	-	-
Labour – Contract	-	-	-	-
Engineering	1,522	-	-	-
Other	166	-	-	-
Total	**$8,580**	**$6,557**	**$27,301**	**$42,438**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2
Expenditure History
(000s)

Year	2014	2015	2016	2017	2018F
Total	$6,411	$10,938	$7,044	$10,777	$8,001

The budget for this project is based on engineering estimates for the cost of individual budget items.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Replacements Due to In-Service Failures (Pooled)**

Project Cost: **$3,547,000**

Project Description

This Substations project is necessary to replace substation equipment that has been retired due to storm damage, lightning strikes, vandalism, electrical or mechanical failure, corrosion damage, technical obsolescence and failure during maintenance testing. Substation equipment that fails in-service requires immediate attention as it is essential to the integrity and reliability of the electrical supply to customers.

The individual requirements for substation equipment are not inter-dependent. However, they are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

This project is justified based on the need to maintain safe, reliable electrical service and ensure workplace safety by replacing deteriorated or substandard substation plant and equipment.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$2,464	-	-	-
Labour – Internal	716	-	-	-
Labour – Contract	-	-	-	-
Engineering	278	-	-	-
Other	89	-	-	-
Total	**$3,547**	**$3,616**	**$11,273**	**$18,436**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2 Expenditure History (000s)					
Year	**2014**	**2015**	**2016**	**2017**	**2018F**
Total	$4,797	$3,116	$2,561	$2,230	$3,814

The Company has 130 substations. The major equipment items comprising a substation include substation transformers, circuit breakers, reclosers, voltage regulators, potential transformers and battery banks. In total, Newfoundland Power has approximately 180 substation transformers, 400 circuit breakers, 200 reclosers, 360 voltage regulators, 220 potential transformers, 115 battery banks and 2,500 high-voltage switches in service.

The need to replace equipment is determined on the basis of tests, inspections, in-service and imminent failures and operational history of the equipment. An adequate pool of spare equipment is necessary to enable the Company to quickly respond to in-service failure. The size of the pool is based on past experience and engineering judgement, as well as a consideration of the impact that the loss of a particular apparatus would have on the electrical system.

The budget for this project is based on engineering assessment of historical expenditures and inventory requirements.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **PCB Bushing Phase-out (Pooled)**

Project Cost: **$912,000**

Project Description

This Substations project is proposed to facilitate the phase-out of polychlorinated biphenyls ("PCB") from breaker and substation transformer bushings with concentrations of greater than 50 parts-per-million ("ppm").[6]

Over the period from 2011 to 2014, Newfoundland Power identified 68 power transformers and 28 bulk oil circuit breakers with bushings having PCB concentrations greater than 500 ppm which were removed from service.[7] Expenditures are now required to address the phase-out of PCBs in equipment with concentrations greater than 50 ppm and less than 500 ppm.

Inspections completed before the end of 2014 identified 24 substation transformers with PCB concentrations greater than 50 ppm and less than 500 ppm. The bushings on these substation transformers will be replaced by 2025 to ensure compliance with government regulations regarding the phase out of PCBs in substation equipment.

Similarly, inspections have identified 42 bulk oil circuit breakers with PCB concentrations greater than 50 ppm and less than 500 ppm. These circuit breakers will be replaced by 2025.

In 2019, the Company will replace bushings on 3 substation transformers and replace 6 bulk oil circuit breakers.

Justification

The project is justified on the requirement to meet the Government of Canada's *PCB Regulations*. Newfoundland Power has completed the work required under the end-of-life date extension of December 31, 2014 for PCB concentrations greater than 500 ppm in accordance with subsection 17(2) of the *PCB Regulations*. Substation equipment with PCB concentrations greater than 50 ppm must now be addressed by 2025 as per the *PCB Regulations*.

---

6 Government of Canada Regulations required that, by the end of 2025, substation transformer bushings, breakers and instrument transformers with PCB concentrations of greater than 50 ppm be removed from service.

7 Expenditures related to the 2011 to 2014 program to address the Company's substation equipment with PCB concentrations greater than 500 ppm were approximately $8.7 million. Details on the PCB Bushing Phase-out project were included in the 2011 Capital Budget Application in ***2.3*** *2011 PCB Removal Strategy*, and in the 2012 Capital Budget Application in ***2.3*** *2012 PCB Removal Strategy*.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1 **Projected Expenditures** **(000s)**				
Cost Category	**2019**	**2020**	**2021 – 2023**	**Total**
Material	$722	-	-	-
Labour – Internal	27	-	-	-
Labour – Contract	-	-	-	-
Engineering	142	-	-	-
Other	21	-	-	-
Total	**$912**	**$754**	**$2,151**	**$3,817**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2 **Expenditure History** **(000s)**					
Year	**2014**	**2015**	**2016**	**2017**	**2018F**
Total	$2,800	-	-	$849	$973

The budget for this project is based on engineering estimates for the cost of individual budget items.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

TRANSMISSION

Project Title: **Transmission Line Rebuild (Clustered, Multi-year)**

Project Cost: **$10,781,000**

Project Description

This Transmission project is necessary to replace deteriorated transmission line infrastructure. The 2019 project involves:

1. The rebuilding of the Company's oldest, most deteriorated transmission lines in accordance with the program outlined in the report ***3.1** Transmission Line Rebuild Strategy* that was filed with the 2006 Capital Budget Application.

   Proposed 2019 transmission line rebuild work will take place on transmission lines 302L and 363L. Transmission line 302L operates between Salt Pond Substation and Laurentian Substation on the Burin Peninsula.[8] Transmission line 363L operates between Baie Verte Junction Substation on the Trans-Canada Highway and Seal Cove Road Substation located in Baie Verte.[9] ($6,359,000)

2. The extension of 138 kV transmission line 136L near the Trans-Canada Highway at Notre Dame Junction to Lewisporte Substation in accordance with the *Central Newfoundland Planning Study*. ($2,322,000)

3. The replacement of poles, crossarms, conductors, insulators and hardware due to deficiencies identified during inspections and engineering reviews, or due to in-service and imminent failures. ($2,100,000).

Details on the proposed 2019 rebuilds are included in ***3.1** 2019 Transmission Line Rebuild*.

For 2019, a portion of the Transmission Line Rebuild is clustered with the *Substation Refurbishment and Modernization* project proposed for Lewisporte Substation. (Schedule B, page 12 of 94) The *Central Newfoundland System Planning Study* requires the extension of transmission line 136L to Lewisporte Substation requiring the construction of a new 138 kV bus structure.

Transmission line rebuilds and replacements to address identified deficiencies are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

---

[8] This is a multi-year project approved in Order No. P.U. 37 (2017) with expenditures planned for 2018 and 2019. Details of the planned expenditures can be found in Schedule C of this Application.

[9] This is a multi-year project approved in Order No. P.U. 37 (2017) with expenditures originally planned for 2018 through 2021. The Company now plans to complete this project over 3 years with expenditures within the original estimates. Details of the planned expenditures can be found in Schedule C of this Application.

Justification

The Company has 107 transmission lines interconnecting substations and hydro plants across its service territory. Approximately 60% of the total kilometres of line construction are in excess of 40 years of age. Many of these lines are experiencing pole, crossarm, conductor, insulator and hardware deterioration. Based on inspection and engineering review, replacement is required to maintain the strength and integrity of these lines.

This project is justified based on the need to replace deteriorated infrastructure in order to ensure the continued provision of safe, reliable electrical service.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023. Appendix A of ***3.1*** *2019 Transmission Line Rebuild* details the transmission line rebuilds planned for each year.

Table 1
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$3,831	-	-	-
Labour – Internal	388	-	-	-
Labour – Contract	5,165	-	-	-
Engineering	272	-	-	-
Other	1,125	-	-	-
Total	**$10,781**	**$9,137**	**$41,351**	**$61,269**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period. Annual expenditures are a function of the number of lines rebuilt, the distance covered and the construction standard used in the design.

Table 2
Expenditure History
(000s)

Year	2014	2015	2016	2017	2018F
Total	$4,664	$6,391	$4,944	$6,699	$7,512

The budget estimates for rebuilding and upgrade projects are based on engineering cost estimates. The budget estimates for addressing deficiencies identified during inspections are based on an assessment of historical expenditures.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

The rebuilding of transmission line 302L is a multi-year project approved in Order No. P.U. 37 (2017). Table 3 details the 2018 and 2019 project expenditures for this multi-year project.

Table 3
302L Multi-Year Projected Expenditures
(000s)

Cost Category	2018F	2019B	Total
Material	$600	$840	$1,440
Labour – Internal	72	99	171
Labour – Contract	1,118	1,406	2,524
Engineering	70	86	156
Other	208	248	456
Total	**$2,068**	**$2,679**	**$4,747**

The rebuilding of transmission line 363L is a multi-year project approved in Order No. P.U. 37 (2017). This project as approved was planned to be completed over 4 years. The Company now plans to complete the project over 3 years within the original project estimates. Table 4 details the revised 2018 through 2020 project expenditures for this multi-year project.

Table 4
363L Multi-Year Projected Expenditures
(000s)

Cost Category	2018F	2019B	2020B	Total
Material	$1,040	$1,301	$1,324	$3,665
Labour – Internal	150	111	148	409
Labour – Contract	1,300	1,759	1,730	4,789
Engineering	130	61	108	299
Other	380	448	468	1,296
Total	**$3,000**	**$3,680**	**$3,778**	**$10,458**

DISTRIBUTION

Project Title: **Extensions (Pooled)**

Project Cost: **$10,725,000**

Project Description

This Distribution project involves the construction of both primary and secondary distribution lines to connect new customers to the electrical distribution system. The project also includes upgrades to the capacity of existing lines to accommodate customers' increased electrical loads. The project includes labour, materials, and other costs to install poles, wires and related hardware.

Distribution line extensions and upgrades for new customers and for increased loads are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

This project is justified based on the need to address customers' new or additional service requirements.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$3,308	-	-	-
Labour – Internal	3,158	-	-	-
Labour – Contract	2,521	-	-	-
Engineering	1,387	-	-	-
Other	351	-	-	-
Total	**$10,725**	**$11,079**	**$34,784**	**$56,588**

Costing Methodology

Table 2 shows the annual expenditures and unit costs for this project for the most recent five-year period, as well as a projected unit cost for 2019.

Table 2
Expenditure History and Unit Cost Projection

Year	2014	2015	2016	2017	2018F	2019B
Total (000s)	$ 15,467	$ 15,423	$ 13,009	$13,371	$ 11,555	$ 10,725
Adjusted Costs (000s)[1]	$ 15,235	$ 16,497	$ 13,687	$13,809	$ 12,023	-
New Customers	4,308	3,786	3,528	3,271	2,805	2,593
Unit Costs ($/customer)[1]	$ 3,536	$ 4,357	$ 3,880	$ 4,222	$ 4,286	$ 4,136

[1] 2018 dollars.

The project cost for the connection of new customers is calculated on the basis of historical data. Historical annual expenditures over the most recent five-year period, including the current year, are expressed in current-year dollars (“Adjusted Costs”). The Adjusted Costs are divided by the number of new customers in each year to derive the annual extension cost per customer in current-year dollars (“Unit Costs”). The average of these Unit Costs, with unusually high and low data excluded, is inflated by the GDP Deflator for Canada before being multiplied by the forecast number of new customers for the budget year to determine the budget estimate. The forecast number of new customers is derived from economic projections provided by independent agencies.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Meters (Pooled)**

Project Cost: **$622,000**

Project Description

This Distribution project includes the purchase and installation of meters for new customers and replacement meters for existing customers. Table 1 lists the meter requirement for 2019.

Table 1
2019 Proposed Meter Acquisition

Program	Number of Meters
Energy Only Domestic Meters	5,076
Other Energy Only and Demand Meters	1,090

The expenditures for individual meters are not inter-dependent. However, because the individual expenditure items are similar in nature and justification, they have been pooled for consideration as a single capital project.

The 2016 Capital Budget Application included an updated metering strategy in the report ***4.4*** *2016 Metering Strategy*. In 2019, the Company will continue with the objectives outlined in the *2016 Metering Strategy* with respect to accuracy and timeliness, cost management, worker safety and ratemaking.

The Company achieved 100% penetration of AMR meters at the end of 2017. As a result, the metering budget is significantly less than expenditures in previous periods.[10]

Justification

The purchase of new meters is necessary to accommodate customer growth and to replace deteriorated meters. Revenue metering of electrical service is regulated under the *Electricity and Gas Inspection Act (Canada).*

---

[10] Once the newer AMR meters reach an age where they are subject to the sampling regulations, metering requirements, and expenditures, are expected to increase.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 2
Projected Expenditures (000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$494	-	-	-
Labour – Internal	114	-	-	-
Labour – Contract	14	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$622**	**$672**	**$2,169**	**$3,463**

Costing Methodology

Table 3 shows the annual expenditures for the most recent five-year period, as well as a projection for 2019.

Table 3
Expenditure History and Unit Cost Projection

Year	2014	2015	2016	2017	2018F	Avg	2019B
Meter Requirements							
New Connections	4,308	3,786	3,528	3,271	2,805		2,593
GROs/CSOs	20,009	18,856	3,670	4,042	575		1,073
Replacements	8,825	12,894	41,020	36,681	2,218		2,500
Total	33,142	35,536	48,218	43,994	5,598		6,166
Meter Costs							
Actual (000s)	$3,002	$3,107	$4,496	$3,625	$546		$622
Adjusted[1] (000s)	$3,245	$3,286	$4,738	$3,778	$559		
Unit Costs[1]	$ 98	$ 92	$ 98	$ 86	$ 100	$ 95	$ 99

[1] 2018 dollars.

The project cost for meters is calculated on the basis of historical data. Historical annual expenditures over the most recent five-year period, including the current year, are expressed in current year dollars ("Adjusted Meter Costs"). The Adjusted Meter Costs are divided by the total meter requirements in each year to derive the annual meter cost in current-year dollars ("Unit Costs"). The average of the Unit Costs, with unusually high and low data excluded, is inflated by the GDP Deflator for Canada before being multiplied by forecast meter installations. The expected number of meter installations is based on projected new customer connections, projected requirements to meet Industry Canada regulations and other requirements based on historical trends.

The quantity of meters for *new* customers is based on the Company's forecast growth in the number of customers the Company serves. The quantity for *replacement* purposes is based on historic data. Sampling and replacement requirements are governed by Compliance Sampling Orders ("CSOs") and Government Retest Orders ("GROs") issued in accordance with regulations under the *Electricity and Gas Inspection Act (Canada).*

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Services (Pooled)**

Project Cost: **$3,037,000**

Project Description

This Distribution project involves the installation of service wires to connect new customers to the electrical distribution system. Service wires are low voltage wires that connect the customer's electrical service equipment to the Company's transformers. Also included in this project is the replacement of existing service wires due to deterioration, failure or damage, as well as the installation of larger service wires to accommodate customers' additional loads.

The proposed expenditures for new and replacement services are similar in nature. The expenditures are therefore pooled for consideration as a single capital project.

Justification

The *new* component of this project is justified based on the need to address customers' new service requirements. The *replacement* component is justified on the basis of the obligation to provide safe, reliable electrical service.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$927	-	-	-
Labour – Internal	1,628	-	-	-
Labour – Contract	161	-	-	-
Engineering	277	-	-	-
Other	44	-	-	-
Total	**$3,037**	**$3,129**	**$9,812**	**$15,978**

Costing Methodology

Table 2 shows the annual expenditures and unit costs for *new* services for the most recent five-year period, as well as a projected unit cost for 2019.

Table 2

**Expenditure History and Unit Cost Projection
New Services**

Year	2014	2015	2016	2017	2018F	2019B
Total (000s)	$3,300	$2,970	$3,196	$2,748	$2,568	$2,373
Adjusted Costs (000s)[1]	3,657	3,178	3,362	2,836	2,631	
New Customers	4,308	3,786	3,528	3,271	2,805	2,593
Unit Costs ($/customer)[1]	$ 849	$ 839	$ 953	$ 867	$ 938	$ 915

[1] 2018 dollars.

The project cost for the connection of new customers is calculated on the basis of historical data. For *new* services, historical annual expenditures over the most recent five-year period, including the current year, are converted to current-year dollars ("Adjusted Costs"). The Adjusted Costs are divided by the number of new customers in each year to derive the annual services cost per customer in current-year dollars ("Unit Costs"). The average of the Unit Costs, with unusually high and low data excluded, is inflated by the GDP Deflator for Canada before being multiplied by the forecast number of new customers for the budget year to determine the budget estimate. The forecast number of new customers is derived from economic projections provided by independent agencies.

Table 3 shows the annual expenditures for *replacement* services for the most recent five-year period, as well as a projected cost for 2019.

Table 3

**Expenditure History and Average Cost Projection
Replacement Services
(000s)**

Year	2014	2015	2016	2017	2018F	2019B
Total	$544	$757	$543	$607	$632	$664
Adjusted Costs[1]	$603	$810	$571	$626	$647	

[1] 2018 dollars.

The process of estimating the budget requirement for *replacement* services is similar to that for *new* services, except the budget estimate is based on the historical average of the total cost of replacement services, as opposed to a unit cost.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Street Lighting (Pooled)**

Project Cost: **$2,301,000**

Project Description

This Distribution project involves the installation of new street lighting fixtures, the replacement of existing fixtures, and the provision of associated overhead and underground wiring. A street light fixture includes the light head complete with bulb, photocell and starter as well as the pole mounting bracket and other hardware. The project is driven by customer requests and historical levels of lighting fixtures requiring replacement.

In 2018, Newfoundland Power installed additional LED street lights to field test its draft LED street light specification and expand upon the experience the Company has gained with the limited number of LED streetlights it has in service. In 2019, the Company will adopt LED technology as a new street lighting standard increasing LED deployment following the approval of LED street light rates in its 2019/2020 General Rate Application.

The proposed expenditures for new and replacement street lights are similar in nature. The expenditures are therefore pooled for consideration as a single capital project.

Justification

The *new* component of this project is justified based on the need to address customers' new street light requirements. The *replacement* component is justified on the basis of the obligation to provide safe, reliable electrical service.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1

**Projected Expenditures
(000s)**

Cost Category	2019	2020	2021 - 2023	Total
Material	$1,246	-	-	-
Labour – Internal	819	-	-	-
Labour – Contract	178	-	-	-
Engineering	34	-	-	-
Other	24	-	-	-
Total	**$2,301**	**$2,337**	**$7,237**	**$11,875**

Costing Methodology

Table 2 shows the annual expenditures and unit costs for *new* street lights for the most recent five-year period, as well as a projected unit cost for 2019.

Table 2

Expenditure History and Unit Cost Projection
New Street Lights

Year	**2014**	**2015**	**2016**	**2017**	**2018F**	**2019B**
Total (000s)	$2,265	$1,906	$1,274	$1,319	$1,174[4]	$1,542[5]
Adjusted Costs (000s)[1]	$2,493[2]	$2,022[3]	$1,341	$1,370	$1,202	
New Customers	4,308	3,786	3,528	3,271	2,805	2,593
Unit Costs ($/customer)[1]	$ 579	$ 534	$ 380	$ 419	$ 429	$ 595

1 2018 dollars.
2 Amount adjusted for the timing of a large number of street light poles installed in 2014.
3 Amount adjusted to remove third-party survey costs and one-time extraordinary duct bank costs.
4 Does not include additional $519,000 for additional street light installations delayed from prior years.
5 Amount adjusted to cover additional cost related to the purchase of LED street lights.

The project cost for street lights is calculated on the basis of historical data. For *new* street lights, historical annual expenditures over the most recent five-year period, including the current year, are expressed in current-year dollars (“Adjusted Costs”). The Adjusted Costs are divided by the number of new customers in each year to derive the annual street light cost per customer in current-year dollars (“Unit Costs”). The average of the Unit Costs, with unusually high and low data excluded, is inflated by the GDP Deflator for Canada before being multiplied by the forecast number of new customers for the budget year to determine the budget estimate. Unit cost are adjusted to account for the forecast increase in cost for LED technology as compared to existing High Pressure Sodium technology. The forecast number of new customers is derived from economic projections provided by independent agencies.

Table 3 shows the annual expenditures and unit costs for *replacement* street lights for the most recent five-year period, as well as a projected cost for 2019.

Table 3

Expenditure History and Average Cost Projection
Replacement Street Lights
(000s)

Year	**2014**	**2015**	**2016**	**2017**	**2018F**	**2019B**
Total	\$1,157	\$1,013	\$453	\$706	\$640	\$759[2]
Adjusted Costs[1]	\$530	\$661	\$477	\$733	\$655	

[1] 2018 dollars.
[2] Amount adjusted to cover additional cost related to the purchase of LED street lights.

The process of estimating the budget requirement for *replacement* street lights is similar to that for *new* street lights, except the budget estimate is based on the historical average of the total cost of replacement street lights, as opposed to a unit cost. The estimate is based on historical annual expenditures for the replacement of damaged, deteriorated or failed street lights with an adjustment for LED technology.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Transformers (Pooled)**

Project Cost: **$6,716,000**

Project Description

This Distribution project includes the cost of purchasing transformers to serve customer growth and the replacement or refurbishment of units that have deteriorated or failed.

Transformer requirements are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

This project is justified on the basis of the obligation to meet customers' electrical service requirements and the need to replace defective or worn out electrical equipment in order to maintain a safe, reliable electrical system.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$6,716	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$6,716**	**$6,844**	**$21,330**	**$34,890**

Costing Methodology

Table 2 shows the annual expenditures for the most recent five-year period, as well as an estimate for 2019.

Table 2
Expenditure History (000s)

Year	**2014**	**2015**	**2016**	**2017**	**2018F**
Total	$7,106	$7,463	$4,956	$5,835	$6,084
Adjusted Costs[1]	$7,577	$7,809	$5,228	$6,118	$6,224

[1] 2018 dollars.

The process of estimating the budget requirement for transformers is based on a historical average. Historical annual expenditures related to distribution transformers over the most recent five-year period, including the current year, are expressed in current-year dollars ("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.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Reconstruction (Pooled)**

Project Cost: **$5,376,000**

Project Description

This Distribution project involves the replacement of deteriorated or damaged distribution structures and electrical equipment. This project comprises smaller unplanned projects that are identified during the budget year or recognized during follow-up on operational problems, including power interruptions and customer trouble calls. This project consists of high priority projects that cannot wait until the next budget year.

This project differs from the *Rebuild Distribution Lines* project which involves rebuilding sections of lines or the selective replacement of various line components based on preventive maintenance inspections or engineering reviews.

Distribution Reconstruction requirements are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

This project is justified on the basis of the need to replace defective or deteriorated electrical equipment in order to maintain a safe, reliable electrical system.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$1,272	-	-	-
Labour – Internal	2,164	-	-	-
Labour – Contract	1,213	-	-	-
Engineering	544	-	-	-
Other	183	-	-	-
Total	**$5,376**	**$5,482**	**$17,106**	**$27,964**

Costing Methodology

Table 2 shows the annual expenditures and costs in current dollars for the most recent five-year period, as well as the projected expenditure for 2019.

Table 2
Expenditure History
(000s)

Year	**2014**	**2015**	**2016**	**2017**	**2018F**
Total	\$5,041	\$5,059	\$4,876	\$4,575	\$5,366
Adjusted Costs[1]	\$5,596	\$5,428	\$5,128	\$4,710	\$5,497

[1] 2018 dollars.

The process of estimating the budget requirement for Reconstruction is based on a historical average. Historical annual expenditures related to unplanned repairs to distribution feeders over the most recent five-year period, including the current year, are expressed in current-year dollars ("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.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Rebuild Distribution Lines (Pooled)**

Project Cost: **$3,977,000**

Project Description

This Distribution project involves the replacement of deteriorated distribution structures and electrical equipment that have been previously identified through the ongoing preventative maintenance program or engineering reviews.

Distribution rebuild projects are preventative capital maintenance projects that consist of either the complete rebuilding of deteriorated distribution line sections or the selective replacement of various line components based on preventative maintenance reviews of the power line or engineering reviews. These typically include the replacement of poles, crossarms, conductor, cutouts, surge/lightning arrestors, insulators and transformers.

Based on a 7-year inspection cycle for distribution feeders, the work for 2019 will be performed on the following 44 of the Company's 305 feeders:

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

While the various components of the project are not inter-dependent, they are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

This project is justified on the basis of the need to replace defective or deteriorated electrical equipment in order to maintain a safe, reliable electrical system.

The Company has over 10,000 kilometres of distribution lines in service and has an obligation to maintain this plant in good condition to safeguard the public and its employees and to maintain reliable electrical service. The replacement of deteriorated distribution structures and equipment is an important element of this obligation.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1

Projected Expenditures (000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$1,635	-	-	-
Labour – Internal	1,858	-	-	-
Labour – Contract	243	-	-	-
Engineering	40	-	-	-
Other	201	-	-	-
Total	**$3,977**	**$4,055**	**$12,652**	**$20,684**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period, as well as the projected expenditure for 2019.

Table 2

Expenditure History (000s)

Year	2014	2015	2016	2017	2018F
Total	$4,338	$4,137	$2,846	$3,269	$3,844
Adjusted Costs[1]	$4,787	$4,415	$2,993	$3,372	$3,936

[1] 2018 dollars

Distribution feeders are inspected in accordance with Newfoundland Power's distribution inspection standards to identify the following:

a) Deficiencies that are a risk to public or employee safety, or that are likely to result in imminent failure of a structure or hardware. This includes primary components, such as poles, crossarms and conductor; and
b) Specific line components targeted for replacement based on engineering reviews, including lightning arrestors, CP8080 and 2-piece insulators, current limiting fuses, automatic sleeves, porcelain cutouts and transformers.

Report ***4.4*** *Rebuild Distribution Lines Update* included with the 2013 Capital Budget Application described the Company's current preventative maintenance program, distribution inspection standards and targeted replacement programs. Proposed expenditures under this Distribution project are consistent with that report.

Inspections for the lines on which work is to take place in 2019 are ongoing throughout 2018. Complete inspection data will not be available until late 2018. Therefore, the 2019 budget estimate is based on average historical expenditures over the previous 5 years.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Relocate/Replace Distribution Lines for Third Parties (Pooled)**

Project Cost: **$2,442,000**

Project Description

This Distribution project is necessary to accommodate 3rd party requests for the relocation or replacement of distribution lines. The relocation or replacement of distribution lines results from: (i) work initiated by municipal, provincial and federal governments; (ii) work initiated by other users, such as Bell Aliant, Eastlink and Rogers Cable; or (iii) requests from customers.[11]

The Company's response to requests for relocation and replacement of distribution facilities by governments and other service providers is governed by the provisions of agreements in place with the requesting parties. Relocation or replacement of facilities by customers is governed by the Company's policy respecting contributions in aid of construction.

While the individual requirements are not inter-dependent, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Justification

This project is justified on the basis of the need to respond to legitimate requirements for plant relocations resulting from third party activities.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$867	-	-	-
Labour – Internal	790	-	-	-
Labour – Contract	488	-	-	-
Engineering	253	-	-	-
Other	44	-	-	-
Total	**$2,442**	**$2,490**	**$7,762**	**$12,694**

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

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period, as well as the projected expenditure for 2019.

Table 2 Expenditure History (000s)					
Year	**2014**	**2015**	**2016**	**2017**	**2018F**
Total	\$2,077	\$2,118	\$2,454	\$2,445	\$2,837[2]
Adjusted Costs[1]	\$2,245	\$2,232	\$2,585	\$2,547	\$2,373

1 2018 dollars
2 Includes an additional \$520,000 associated with Rogers Communications fibre build in St. John's area.

The budget estimate is based on historical expenditures. Generally, these expenditures are associated with a number of small projects that cannot be specifically identified at the time the budget is prepared. Historical annual expenditures related to distribution line relocations and replacements over the most recent five-year period, including the current year, are expressed in current-year dollars ("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.

Estimated contributions from customers and requesting parties associated with this project are included in the estimated contributions in aid of construction referred to in the Application.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Trunk Feeders (Clustered)**

Project Cost: **$400,000**

Project Description

This Distribution project includes the replacement of deteriorated underground distribution infrastructure at Pepperrell ("PEP") Substation. In 2019, PEP Substation will undergo a *Substation Refurbishment and Modernization* project, which will include the replacement of the switchgear for all 4 distribution feeders. As part of the switchgear replacement new feeder terminations will be completed.

PEP supplies electricity to approximately 3,300 customers in the Pleasantville and other St. John's east neighborhoods from a location at the bottom of Quidi Vidi Lake. There is some congestion in the vicinity of the substation with the lake and walking trails on the south side, commercial customers on the north side, and the White Hills to the east of the substation. As a result the final substation design will require the re-routing of the existing distribution feeders.

For 2019, this Trunk Feeders Distribution project is clustered with a portion of the *Substation Refurbishment and Modernization* project proposed for Pepperrell Substation. (Schedule B, page 12 of 94) This is because the refurbishment of Pepperrell Substation, specifically the replacement of the existing switchgear building, requires new terminations for the distribution feeders.

Justification

The project is justified based on the obligation to provide safe, least cost reliable service. *Substation Refurbishment and Modernization* projects are justified based on the need to maintain safe, reliable electrical service and ensure workplace safety by replacing deteriorated or substandard substation infrastructure. The work associated with the substation project necessitates the relocation of the distribution feeder switchgear and subsequent replacement of the existing underground cable and terminations.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$120	-	-	-
Labour – Internal	100	-	-	-
Labour – Contract	100	-	-	-
Engineering	40	-	-	-
Other	40	-	-	-
Total	**$400**	**-**	**$1,170**	**$1,570**

Costing Methodology

The budget estimate is based on detailed engineering estimates.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Feeder Additions for Load Growth (Pooled, Multi-Year)**

Project Cost: **$1,715,000**

Project Description

This Distribution project consists of expenditures to address overload conditions and provide additional capacity to address growth in the number of customers and volume of energy deliveries.

For 2019, the *Feeder Additions for Load Growth* project will include the upgrading of the following distribution feeders:

1. Blaketown Substation feeder BLK-02 serves approximately 1,800 customers from Whitbourne to Brigus Junction. An analysis of distribution feeder BLK-02 was completed using a distribution feeder computer modelling application.[12] The results show that BLK-02 distribution feeder exceeds the Company's planning criteria for both maximum current on a single-phase distribution line and for maximum neutral current on an unbalanced 3-phase distribution line. The completion of the work over 2 years was approved in Order No. P.U. 37 (2017). ($319,000 in 2018 and $665,000 in 2019)

2. Seal Cove ("SCV") Substation serves approximately 2,200 customers in the Conception Bay South and Holyrood areas using 2 distribution feeders. An analysis of distribution feeder SCV-01 has determined that a 1.5 km section of the trunk feeder leaving SCV Substation is overloaded. The least cost solution to address the overloaded conductor on SCV-01 feeder is to construct an additional 2.5 km extension along the Conception Bay South Bypass Road and transfer sufficient customer load to this new extension to reduce the overload condition. ($650,000 in 2019)

3. Stamps Lane Substation feeder SLA-05 serves approximately 730 customers in the University Avenue and Larkhall Street area in St. John's. An analysis of the SLA-05 distribution feeder has determined that the main trunk cable of SLA-05 is overloaded. It is recommended to convert the 4.16 kV load on SLA-05 north of Prince Philip Drive to 12.5 kV and transfer this section to SLA-08. Completing this voltage conversion work will transfer approximately 1.26 MVA from SLA-05 to SLA-08, alleviating the overload condition. ($400,000 in 2019)

Details on the proposed expenditures are included in ***4.2*** *Feeder Additions for Load Growth*.

[12] Actual load measurements were taken to verify the results of the computer simulation.

Justification

The project is justified based on the obligation to provide safe, least cost reliable service. Actual peak load conditions and customer growth indicate that this project is warranted in order to maintain the electrical system within recommended guidelines.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1

Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$364	-	-	-
Labour – Internal	561	-	-	-
Labour – Contract	257	-	-	-
Engineering	212	-	-	-
Other	321	-	-	-
Total	**$1,715**	**$2,242**	**$9,155**	**$13,112**

Costing Methodology

The budget estimate is based on detailed engineering estimates of individual feeder requirements.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

The BLK-02 *Feeder Additions for Load Growth* item was approved in Order No. P.U. 37 (2017) to be completed in 2018 and 2019. Otherwise, this is not a multi-year project.

Project Title: Distribution Reliability Initiative (Pooled, Multi-Year)

Project Cost: $1,800,000

Project Description

This Distribution project involves the replacement of deteriorated poles, conductor and hardware to reduce both the frequency and duration of power interruptions to the customers served by specific distribution lines.[13] The upgrading work is typically determined through assessments of past service problems, knowledge of local environmental conditions (such as salt contamination, wind and ice loading), and application of location-specific design and construction standards.

In the past, Newfoundland Power identified worst performing feeders on the basis of SAIDI, SAIFI and customer minutes.[14] These indices determine reliability performance based on the customer impact of outages. In 2012, the Canadian Electricity Association began capturing and reporting on 2 additional indices: CIKM and CHIKM.[15] These indices determine reliability performance based on the length of line experiencing outages and tend to be more reflective of asset condition. The Company has incorporated CIKM and CHIKM into its reliability analysis.

The 2019 project involves work on feeders DUN-01, GBY-03 and SJM-06. Table 1 shows the number of customers affected and the average unscheduled interruption statistics by feeder for the five-year period ending December 31, 2017. These statistics exclude interruptions due to any causes other than distribution system failure. An analysis of these feeders' performance is contained in report ***4.1** Distribution Reliability Initiative*.

Table 1

Distribution Interruption Statistics
Five-Year Average to December 31, 2017

Feeder	Customers	SAIFI	SAIDI	CHIKM	CIKM
DUN-01	1,043	4.13	9.63	62	27
GBY-03	765	2.87	6.40	45	20
SJM-06	1,211	1.89	1.70	392	437
Company Average	**846**	**1.35**	**1.71**	**44**	**34**

13 These feeders are sometimes referred to in the industry as *worst performing feeders*.

14 System Average Interruption Frequency Index ("SAIFI") is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area. System Average Interruption Duration Index ("SAIDI") is calculated by dividing the number of customer-outage-hours (e.g., a two hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

15 Customers Interrupted per Kilometer ("CIKM") is calculated by dividing the number of customers that have experienced an outage by the kilometres of line. Customer Hours of Interruption per Kilometer ("CHIKM") is calculated by dividing the number of customer-outage-hours by the kilometres of line.

Justification

This project is justified on the basis of the obligation to provide reliable electrical service. Individual feeder projects have been prioritized based on their historic interruption statistics. Customers supplied by the worst-performing feeders experience power interruptions more often, or of longer duration, than the Company average caused by the deteriorated condition of the distribution infrastructure. The *Distribution Reliability Initiative* project has had a positive impact on the reliability performance of the feeders that have been upgraded.[16]

Projected Expenditures

Table 2 provides the breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 2
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$309	-	-	-
Labour – Internal	498	-	-	-
Labour – Contract	373	-	-	-
Engineering	252	-	-	-
Other	368	-	-	-
Total	**$1,800**	**$1,900**	**$4,120**	**$7,820**

Costing Methodology

The budget estimate is based on detailed engineering estimates of individual feeder requirements.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

[16] Chart 6 of the 2019 Capital Plan shows a 54% improvement in SAIDI and 48% improvement in SAIFI over the 20-year period from 1998 to 2017.

Future Commitments

The Distribution Reliability Initiative work for DUN-01 and GBY-03 are multi-year projects with expenditures planned over 3 years for DUN-01 and 2 years for GBY-03.

Table 3 details the 2019, 2020 and 2021 expenditures for DUN-01.

Table 3
DUN-01 Multi-Year Projected Expenditures
(000s)

Cost Category	2019B	2020B	2021B	Total
Material	$160	$160	$160	$480
Labour – Internal	208	208	208	624
Labour – Contract	52	52	52	156
Engineering	78	78	78	232
Other	202	202	202	606
Total	**$700**	**$700**	**$700**	**$2,100**

Table 4 details the 2019 and 2020 expenditures for GBY-03.

Table 4
GBY-03 Multi-Year Projected Expenditures
(000s)

Cost Category	2019B	2020B	Total
Material	$49	$69	98
Labour – Internal	130	182	260
Labour – Contract	141	197	282
Engineering	74	104	148
Other	106	148	212
Total	**$500**	**$700**	**$1,000**

The Distribution Reliability work for SJM-06 is planned to be completed in 2019.

Project Title: **Distribution Feeder Automation (Pooled)**

Project Cost: **$675,000**

Project Description

This Distribution project is necessary to increase the level of automation in the Company's distribution system. The project consists of expenditures to address remote control limitations in the distribution system. Increasing the level of automation in the distribution system will improve the efficiency of restoration following both local and system wide outages.[17] Installing automated reclosers on distribution feeders allows for the isolation of the section of feeder closest to the fault from the remainder of the customers upstream of the fault location. This will isolate the outage to only those customers closest to the fault, thereby reducing the duration of the outage for customers upstream of the fault location. In addition, installation of automated reclosers improves the Company's capability to deal with cold load pickup.

Increasing automation of distribution feeders will involve the addition of new equipment to the distribution system or the replacement of some older generation equipment in service with modern, communications-capable equipment. The increase in automation will include the addition of technologies, such as automated downline reclosers and sectionalizing switches, sensors for voltage and load flow, and fault indicators.

In 2019, downline automated reclosers will be installed on each of the following distribution feeders:

St. John's	Eastern	Western
KEN-01	ISL-01	LGL-02
KEN-03	NWB-02	GLV-02
KEN-04 (2)		BHD-01
HWD-08 (2)		

Justification

The project is justified based on the obligation to provide safe, least-cost, reliable service.

Installing automated reclosers to sectionalize distribution feeders provides a greater degree of reliability in all operating conditions, including local and system-wide outages.

[17] Increasing the level of automation in the distribution system is consistent with Recommendation 2.4 of Liberty's *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power*, December 17, 2014.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$405	-	-	-
Labour – Internal	61	-	-	-
Labour – Contract	58	-	-	-
Engineering	67	-	-	-
Other	84	-	-	-
Total	**$675**	**$675**	**$1,875**	**$3,225**

Costing Methodology

The budget estimate is based on detailed engineering estimates of individual feeder requirements.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Allowance for Funds Used During Construction (Pooled)**

Project Cost: **$215,000**

Project Description

This Distribution project is an allowance for funds used during construction ("AFUDC") which will be charged on distribution work orders with an estimated expenditure of less than $50,000 and a construction period in excess of three months.

Effective January 1, 2008, the Company calculates AFUDC in a manner consistent with Order No. P.U. 32 (2007). This method of calculating AFUDC is the mainstream practice for regulated Canadian utilities.

Justification

The AFUDC is justified on the same basis as the distribution work orders to which it relates.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1

Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	-	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	$215	-	-	-
Total	**$215**	**$220**	**$684**	**$1,119**

Costing Methodology

Table 2 shows the annual expenditures for the most recent five-year period.

Table 2
Expenditure History
(000s)

Year	2014	2015	2016	2017	2018F
Total	$208	$214	$197	$179	$210

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

Future Commitments

This is not a multi-year project.

GENERAL PROPERTY

Project Title: **Tools and Equipment (Pooled)**

Project Cost: **$467,000**

Project Description

This General Property project is necessary to add or replace tools and equipment used in providing safe, reliable electrical service. Tools and equipment are used by line staff, engineering technicians, engineers and electrical and mechanical tradespersons. The majority of these tools are used in normal day-to-day operations. As well, specialized tools and equipment are required to maintain, repair, diagnose or commission Company assets required to deliver service to customers.

Most items within this project involve expenditures of less than $50,000. These items are consolidated into the following categories:

1. *Operations Tools and Equipment ($150,000)*: This is the replacement of tools and equipment used by line and field technical staff in the day-to-day operations of the Company. These tools are maintained on a regular basis. However, over time they degrade and wear out, especially hot line equipment which must meet rigorous safety requirements. Where appropriate, such tools will be replaced with battery and hydraulic alternatives to improve working conditions.

2. *Engineering Tools and Equipment ($188,000)*: This item includes engineering test equipment and tools used by electrical and mechanical maintenance personnel and engineering technicians. Engineering test equipment is required to perform system calibration, commissioning and testing of power system facilities and testing and analysis of associated data communications facilities.

3. *Office Furniture ($129,000)*: This item includes the replacement of office furniture that has deteriorated. The office furniture utilized by the Company's employees deteriorates through normal use and must be replaced.

Individual requirements for the addition or replacement of tools and equipment are not inter-dependent. However, the expenditure requirements are similar in nature and justification. They are therefore pooled for consideration as a single capital project.

Justification

Suitable tools and equipment in good condition enable staff to perform work in a safe, effective and efficient manner.

Additional or replacement tools are purchased to either maintain or improve quality of work and overall operational efficiency.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1

Projected Expenditures (000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$467	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$467**	**$476**	**$1,483**	**$2,426**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2

Expenditure History (000s)

Year	2014	2015	2016	2017	2018F
Total	$440	$328	$443[1]	$499	$479

[1] Excludes cost of a load cell and tools for a new line truck. ($113,000)

The project cost is based on an assessment of historical expenditures for the replacement of tools and equipment that become broken or worn out, and is adjusted for anticipated expenditure requirements for extraordinary items.

The budget for this project is calculated on the basis of historical data respecting operations tools and equipment, engineering tools and equipment, and office furniture. To ensure consistency from year to year, expenditures related to large unplanned additions are excluded from the historical average calculation.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Additions to Real Property (Pooled)**

Project Cost: **$489,000**

Project Description

This General Property project is necessary to ensure the continued safe operation of Company facilities and workplaces. The Company has in excess of 20 office and other buildings. There is an ongoing requirement to upgrade or replace equipment and facilities at these buildings due to failure or normal deterioration. Past expenditures have included such items as emergency roof replacement and correcting major drainage problems.

The 2019 project consists of the upgrading, refurbishment or replacement of equipment and facilities due to organizational changes, damage, deterioration, corrosion and in-service failure. Based on recent historical information, $339,000 is required for 2019.

The Company has standby emergency diesel generators at each of its 8 operations buildings across its service territory. In 2019, the Company plans to install technology to remotely start and continuously monitor these generators from its System Control Centre at an estimated cost of $50,000. In addition, refurbishment of deteriorated transformer storage racks at Company service centres is estimated at $100,000 for 2019.

The individual budget items are less than $50,000 each and are not inter-dependent. However, they are similar in nature and are therefore pooled for consideration as a single capital project.

Justification

This project is necessary to maintain Company buildings and other facilities, and to operate them in a safe and efficient manner.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1 **Projected Expenditures** **(000s)**				
Cost Category	**2019**	**2020**	**2021 – 2023**	**Total**
Material	$387	-	-	-
Labour – Internal	17	-	-	-
Labour – Contract	-	-	-	-
Engineering	42	-	-	-
Other	43	-	-	-
Total	**$489**	**$395**	**$1,127**	**$2,011**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2 **Expenditure History** **(000s)**					
Year	**2014**	**2015**	**2016**	**2017**	**2018F**
Total	$368[1]	$412[2]	$391[3]	$467[4]	$341[5]

1 Excludes corporate security upgrades ($96,000).
2 Excludes corporate security upgrades ($106,000).
3 Excludes corporate security upgrades ($98,000).
4 Excludes corporate security upgrades ($94,000).
5 Excludes corporate security upgrades ($100,000), Duffy Place backflow prevention ($200,000) and energy efficient lighting upgrades ($30,000).

The budget for this project is calculated on the basis of historical data as well as engineering estimates for planned budget items as required. To ensure consistency from year to year, expenditures related to large unplanned additions are excluded from the historical average calculation.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Company Building Renovations (Other)**

Project Cost: **$1,374,000**

Project Description

This General Property project involves undertaking renovations of Company facilities across its service territory. This project is necessary to ensure the continued safe operation of Company facilities and workplaces. The Company has in excess of 20 office and other buildings. There is an ongoing requirement to upgrade or replace equipment and building systems at these facilities due to failure or normal deterioration. Once a facility has been in service for an extended period of time more significant renovation is required to extend the service life of the facility.

In 2019, the Company will renovate the following facilities:

1. *Salt Pond Facility ($950,000)*
   The Salt Pond Facility is the Company's primary operations facility for the Burin Peninsula. The Burin Peninsula service territory includes approximately 12,000 customers, 4.6% of all customers served by Newfoundland Power. The existing facility consists of separate office and service buildings.

   The office building was originally constructed in 1969 and the service building constructed in 1974. Many of the systems in both buildings have reached an age where capital improvements are necessary to ensure continued provision of safe and reliable service to employees and the public. In 2019, the Company intends to consolidate its Burin operations into an expanded service building. Details on the proposed expenditures are included in *5.1 Company Building Renovations, Salt Pond Facility*.

2. *Glovertown District Building ($178,000)*
   The Glovertown District Building was originally constructed in 1967. The building envelope consists of timber framing with metal siding and asphalt shingles. Inspections completed in 2017 identified issues with lead paint and inadequate headroom in some areas. The site of the existing building is adjacent to the Terra Nova River and the elevation is below that of the main road. In times of high river flow the water backs up onto the site and into the building. As a result of this situation, the building will be replaced with a new building adjacent to Glovertown Substation. Details on the proposed expenditures are included in *5.2 Company Building Renovations, District and Other Building Refurbishment*.

3. *Storage Buildings Carbonear and Port aux Basques ($246,000)*
   The Carbonear project involves constructing a new 24' x 30' storage shed located at Newfoundland Power's Regional Facility at 30 Goff Avenue in Carbonear. The Port Aux Basques project involves constructing a new 24' x 30' storage shed located at Newfoundland Power's District Facility in Port Aux Basques. The primary use of the proposed buildings will be equipment and material storage. Details on the proposed

expenditures are included in *5.2 Company Building Renovations, District and Other Building Refurbishment*.

While the individual requirements are not inter-dependent, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Justification

The project is justified based on the age and the deterioration of the existing Company buildings identified. Justifications for Company building renovations are based on inspections completed by professional engineers or independent experts.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$1,108	-	-	-
Labour – Internal	15	-	-	-
Labour – Contract	-	-	-	-
Engineering	124	-	-	-
Other	127	-	-	-
Total	**$1,374**	**-**	**-**	**$1,374**

Costing Methodology

The budget estimate for this project is based on an engineering estimate.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all construction materials and services for this project will be purchased using competitive bids of prospective contractors.

Future Commitments

This is not a multi-year project.

Project Title: **Physical Security Upgrades (Pooled)**

Project Cost: **$300,000**

Project Description

This General Property project consists of capital expenditures necessary for the upgrading of security infrastructure at Company locations.[18]

In recent years, there have been a number of unauthorized persons entering Newfoundland Power substations to commit vandalism or theft. This results in damaged property and presents a significant safety risk to Newfoundland Power staff and the public when substation grounding has been altered or removed.

Company offices contain equipment and information that needs to be effectively secured from intrusion and theft. In addition, Newfoundland Power has a number of sites where electrical equipment and hazardous materials are stored. These sites are vulnerable to theft, vandalism and trespassing. These sites are secured by perimeter fencing and controlled access gates. As this infrastructure ages, it requires refurbishment to ensure safe and secure operation of the sites.

Security upgrades will be performed in selected substations to deter the entry of unauthorized persons and reduce the likelihood of theft occurring. This project also includes upgrades to the security infrastructure of Company facilities, including improvements in public entrances, access control, surveillance and lighting. Based on engineering estimates, $300,000 is required for physical security upgrades in 2019.

Justification

This project is necessary to maintain and operate Company facilities including substations, generating plants, office buildings and storage sites in a safe and efficient manner. Securing substations and generating plants will prevent theft of material, the unintended operation of equipment and also prevent the general public from being injured if they enter the property without proper supervision. Securing office buildings will protect Company equipment, including computing equipment, and access to Company information. Secure storage sites will ensure that the Company's inventory of materials and spare equipment are not stolen or damaged. Securing these storage sites will also prevent the general public from being injured if they enter the property without proper supervision.

[18] In prior years corporate security upgrades for office buildings and storage sites were included in the *Additions to Real Property* General Property project. Substation security was included in the *Substation Refurbishment and Modernization* Substations project. Combining all physical security upgrades in a single project is intended to focus Company security efforts.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$245	-	-	-
Labour – Internal	22	-	-	-
Labour – Contract	-	-	-	-
Engineering	18	-	-	-
Other	15	-	-	-
Total	**$300**	**$350**	**$1,050**	**$1,700**

Costing Methodology

The budget estimate for this project is based on engineering estimates.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

TRANSPORTATION

Project Title: **Purchase Vehicles and Aerial Devices (Pooled)**

Project Cost: **$3,990,000**

Project Description

This Transportation project involves the addition and necessary replacement of heavy fleet, passenger and off-road vehicles. Detailed evaluation of the units to be replaced indicates they have reached the end of their useful service lives.

Table 1 summarizes the units to be replaced in 2019.

Table 1
2019 Proposed Vehicle Replacements

Category	No. of Units
Heavy Fleet Vehicles	8
Passenger Vehicles[1]	30
Off-road Vehicles[2]	4
Total	**42**

[1] The Passenger Vehicles category includes the purchase of cars and light duty trucks.
[2] The Off-road Vehicles category includes snowmobiles, ATVs, trailers and specialized mobile equipment.

In 2019, there are 8 heavy fleet vehicles that meet the age, mileage and condition parameters that indicate replacement is necessary. Also in 2019, the Company has identified 30 passenger and 4 off-road vehicles for replacement.

The Company's replacement criteria for vehicles are described in the 2016 Capital Budget Application report ***5.1*** *Vehicle Replacement Criteria*. This report also compared these criteria to those used by other Canadian electrical utilities and shows the current approach of the Company is: (i) consistent with current Canadian utility practice; and (ii) consistent with the least cost delivery of service to customers.

Also in 2019, the Company plans to purchase a tension stringer at an estimated cost of $200,000 and a backlot utility transport at an estimated cost of $275,000. The additional tension stringer is necessary due to the increased requirement for conductor replacement. The backlot utility transport is used to access customer property when it is not possible to do so with traditional heavy fleet vehicles. Access to customer property is increasingly necessary due to the requirement to replace poles in some older neighborhoods in St. John's Region and throughout the Company's service territory.

The expenditures for individual vehicle replacements are not inter-dependent. However, they are similar in nature and justification. The expenditures are therefore pooled for consideration as a single capital project.

Justification

This project is justified on the basis of the need to replace existing vehicles and aerial devices that have reached the end of their useful service lives.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 2

Projected Expenditures (000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$3,990	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$3,990**	**$3,931**	**$11,511**	**$19,432**

Table 3 shows the expenditures for this project for the most recent five-year period.

Table 3

Expenditure History (000s)

Year	2014	2015	2016	2017	2018F
Total	$2,872	$3,080	$3,377	$3,776	$3,362

Costing Methodology

Newfoundland Power individually evaluates all vehicles considered for replacement according to a number of criteria to ensure replacement is the least-cost option.

Evaluation for replacement is initiated when individual vehicles reach a threshold age or level of usage. Heavy fleet vehicles are considered for replacement at 10 years of age or usage of 250,000 kilometres. For passenger vehicles, the guideline is 5 years of age or 150,000 kilometres. Vehicles reaching the threshold are evaluated on a number of criteria, such as overall condition, maintenance history and immediate repair requirements, to determine whether they have reached the end of their useful service lives. Based on such evaluations, it has been forecast that each unit proposed for replacement will reach the end of its useful service life and require replacement in 2019.

New vehicles are acquired through competitive tendering to ensure the lowest possible cost consistent with safe, reliable service.

Future Commitments

This is not a multi-year project.

TELECOMMUNICATIONS

Project Title: **Replace/Upgrade Communications Equipment (Pooled)**

Project Cost: **$106,000**

Project Description

This Telecommunications project is necessary to ensure the continued integrity of the Company's operational voice systems and the remote monitoring and control of field devices. This, in turn, allows the Company to provide acceptable levels of customer service and achieve operational efficiencies. The 2019 project involves the replacement and/or upgrade of communications equipment, including radio communication equipment associated with electrical system operations, and data communications equipment providing remote monitoring and control capabilities associated with the Company's Supervisory Control and Data Acquisition ("SCADA") system.

The Company has mobile radio, portable radio, base station radio and radio console equipment in service providing operational voice communications for field staff. The radio equipment is used for communications between: (i) field staff working in multiple crews; (ii) field staff and operations centres; and (iii) field staff and the System Control Centre.

Data communications equipment is used to link the monitoring and control technologies on distribution lines, in substations and hydro plants to the SCADA system at the System Control Centre. A variety of different technologies are used to provide these data communications links depending on local conditions and available service offerings from telecommunications providers. The technologies used include land line communications, fibre optic communications and wireless communications.

Over time, this voice and data communications equipment fails in service, becomes obsolete or no longer supports the most cost-effective service offering from telecommunications providers. As a result the equipment must be upgraded or replaced.

Justification

This project is justified on the basis that reliable operational voice and data communications is necessary to provide reliable, least-cost service to customers.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1 **Projected Expenditures** **(000s)**				
Cost Category	**2019**	**2020**	**2021 - 2023**	**Total**
Material	$66	-	-	-
Labour – Internal	10	-	-	-
Labour – Contract	-	-	-	-
Engineering	20	-	-	-
Other	10	-	-	-
Total	**$106**	**$108**	**$336**	**$550**

Costing Methodology

Table 2 shows the annual expenditures and costs in current dollars for the most recent five-year period.

Table 2 **Expenditure History** **(000s)**					
Year	**2014**	**2015**	**2016**	**2017**	**2018F**
Total	$97	$78	$109	$111	$99
Adjusted Cost[1]	$105	$83	$115	$116	

[1] 2018 dollars.

The process of estimating the budget requirement for communications equipment is based on a historical average. Historical annual expenditures related to upgrading and replacing communications equipment over the most recent five-year period, including the current year, are expressed in current-year dollars ("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 to determine the budget estimate. To ensure consistency from year to year, expenditures related to planned projects are excluded from the calculation of the historical average.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

Project Title: **Fibre Optic Network (Other)**

Project Cost: **$127,000**

Project Description

This Telecommunications project involves the addition of a new fibre optic link in the Company's fibre optic network connecting its substations and office in the City of Corner Brook.

The Company currently operates more than 36 fibre optic links. These fibre optic links are used for corporate data, substation, voice and SCADA communications, protective relay communications, as well as data communications between Newfoundland Power's and Newfoundland and Labrador Hydro's control centres.[19] In 2019, the Company will build a fibre optic cable link between Humber Substation and Bayview Substation in Corner Brook.[20]

Included in the Company's five-year *Substation Refurbishment and Modernization Plan*, the protection system on the 66 kV transmission lines interconnecting the 4 Corner Brook substations will be upgraded. As part of this protection upgrade, the Company has undertaken a program to install fibre optic cables between all 4 substations in the City of Corner Brook.

The individual budget items are similar in nature and are therefore pooled for consideration as a single capital project.

Justification

Reliable communications equipment is essential to the provision of safe, reliable electrical service.

Fibre optic cables are used to provide communications between digital protective relays in selected substations. The communication established between relays monitors the substation equipment at both ends of the associated transmission lines interconnecting the substations, protecting employees and the public from energized failures of transmission line infrastructure. Also, the fibre optic cables provide SCADA communications between the substations and the System Control Centre, allowing for the remote monitoring and control of all critical substation equipment.

---

[19] The Company's fibre optic network in St. John's includes a cable to Newfoundland and Labrador Hydro's Energy Management Centre. This fibre cable carries the Inter Control Centre Protocol ("ICCP") link, which is used to exchange real-time power system data between the 2 SCADA systems.

[20] This fibre optic link will allow for the connection of corporate and SCADA data traffic to these substations, thereby reducing the number of leased circuits used for SCADA communications in Corner Brook. Also, the link will carry data communications between digital protection relays in the substation to improve clearing times for faults on the 66 kV transmission system.

The communications transmitted by the fibre optic cables, for both protection and remote control functionality, are essential for the provision of safe and reliable service to customers.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$101	-	-	-
Labour – Internal	5	-	-	-
Labour – Contract	-	-	-	-
Engineering	16	-	-	-
Other	5	-	-	-
Total	**$127**	**-**	**-**	**$127**

Costing Methodology

The budget for this project is based on an engineering cost estimate.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all material will be obtained through competitive tendering.

Future Commitments

This is not a multi-year project.

INFORMATION SYSTEMS

Project Title: **Application Enhancements (Pooled)**

Project Cost: **$1,252,000**

Project Description

This Information Systems project is necessary to enhance the functionality of software applications. The Company's software applications are used to support all aspects of business operations, including the provision of service to customers, the effective operation of the electrical system, and compliance with regulatory and financial reporting requirements.

The application enhancements proposed in 2019 include: (i) enhancement of the Company's electronic tailboards application; (ii) enhancements to Technical Work Request billing integration; (iii) consolidation of all customer contact into a single interface; (iv) automating the collection of weather normalization data and (v) enhancements to the corporate and energy conservation websites.

The application enhancements proposed for 2019 are not inter-dependent, but are similar in nature and justification and are therefore pooled for consideration as a single capital project.

Details on proposed expenditures are included in ***6.1*** *2019 Application Enhancements*.

Justification

The proposed enhancements included in this project are justified on the basis of improving customer service and operational efficiencies, and achieving compliance with regulatory and legislative requirements.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1

Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$170	-	-	-
Labour – Internal	797	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	285	-	-	-
Total	**$1,252**	**$1,200**	**$2,250**	**$4,702**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2 Expenditure History (000s)					
Year	**2014**	**2015**	**2016**	**2017**	**2018F**
Total	$1,382	$1,301	$1,143	$820	$786

The budget for this project is based on cost estimates for the individual budget items.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist, all materials and services will be negotiated with the sole-source supplier to ensure least cost.

Future Commitments

This is not a multi-year project.

Project Title: **System Upgrades (Pooled)**

Project Cost: **$1,258,000**

Project Description

This Information Systems project involves upgrades to third-party software products that comprise the Company's information systems. Such upgrades are necessary to ensure continued vendor support, to improve compatibility with software or hardware upgrades, or to take advantage of newly developed functionality.

For 2019, the project includes upgrades to the Company's Supervisory Control and Data Acquisition system, Customer Outage Reporting system, Meter Data Collection system and various other minor system upgrades.

This project also includes the Microsoft Enterprise Agreement.[21] This agreement covers the purchase of Microsoft software products and provides access to the latest versions of each product purchased under the agreement. Details on the multi-year expenditures associated with the Microsoft Enterprise Agreement are included in *Schedule C* to this Application.

Details on proposed expenditures are included in 6***.2*** *2019 System Upgrades*.

Justification

This project is justified on the basis of maintaining current levels of customer service and operational efficiency supported by the software.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

[21] The Microsoft Enterprise Agreement was approved as a multi-year project in Order No. P.U. 37 (2017).

Table 1 **Projected Expenditures** **(000s)**				
Cost Category	**2019**	**2020**	**2021 - 2023**	**Total**
Material	$440	-	-	-
Labour – Internal	543	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	275	-	-	-
Total	**$1,258**	**$1,742**	**$6,106**	**$9,206**

Costing Methodology

Table 2 shows the annual expenditures and unit costs for this project for the most recent five-year period.

Table 2 **Expenditure History** **(000s)**					
Year	**2014**	**2015**	**2016**	**2017**	**2018F**
Total	$1,066	$1,163	$1,664	$1,676	$1,343

The budget for this project is based on cost estimates for the individual budget items.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist, all materials and services will be negotiated with the sole-source supplier to ensure least cost.

Future Commitments

This project includes provision in 2019 for the Microsoft Enterprise Agreement, which was approved as a multi-year project in Order No. 37 (2017). This is not otherwise a multi-year project.

Project Title: **Personal Computer Infrastructure (Pooled)**

Project Cost: **$472,000**

Project Description

This Information Systems project is necessary for the replacement or upgrade of personal computers ("PCs"), workgroup printers and associated assets that have reached the end of their useful lives.

In 2019, a total of 137 PCs will be purchased, consisting of 68 desktop computers and 69 mobile computers. This project also includes the purchase of peripheral equipment, such as monitors, mobile devices, and workgroup printers, to replace existing units that have reached the end of their useful life.

The individual PCs and peripheral equipment are not inter-dependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Specifications for replacement PCs and peripheral equipment are reviewed annually to ensure the personal computing infrastructure remains effective. Industry best practices, technology trends, and the Company's experience are considered when establishing specifications.

Newfoundland Power is currently able to achieve an approximate five-year lifecycle for its PCs before they require replacement.

Table 1 outlines the PC additions and retirements for 2017 and 2018, as well as the proposed additions and retirements for 2019.

Table 1

PC Additions and Retirements
2017 – 2019B

	2017			**2018F**			**2019B**		
	Add	**Retire**	**Total**	**Add**	**Retire**	**Total**	**Add**	**Retire**	**Total**
Desktop	80	99	405	88	88	405	68	68	405
Mobile	91	94	322	47	47	322	69	69	322
Total	**171**	**193**	**727**	**135**	**135**	**727**	**137**	**137**	**727**

Justification

This project is justified on the basis of the need to replace personal computers and associated equipment that have reached the end of their useful service life.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 2
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$325	-	-	-
Labour – Internal	102	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	45	-	-	-
Total	**$472**	**$492**	**$1,561**	**$2,525**

Costing Methodology

Table 3 shows the annual expenditures for this project for the most recent five-year period.

Table 3
Expenditure History
(000s)

Year	2014	2015	2016	2017	2018F
Total	$455	$488	$470	$493	$472

The cost for this project is calculated on the basis of historical expenditures and on cost estimates for the individual budget items. Historical annual expenditures over the most recent three-year period are considered and an approximate unit cost is determined based on historical average prices and a consideration of pricing trends. These unit costs are then multiplied by the quantity of units (i.e. desktop, mobile, workgroup printer, etc.) to be purchased. Quantities are forecast by identifying the number of unit replacements resulting from lifecycle retirements and the number of new units required to accommodate new software applications or work methods.

Once the unit price estimates and quantities have been determined, the work associated with the procurement and installation of the units is estimated based on experience and historical pricing.

To ensure this project is completed at the lowest possible cost consistent with safe and reliable service, all materials and services for this project will be purchased after examining the competitive bids of prospective suppliers.

Future Commitments

This is not a multi-year project.

Project Title: **Shared Server Infrastructure (Pooled)**

Project Cost: **$848,000**

Project Description

This Information Systems project includes the addition, upgrade and replacement of computer hardware components and related technology associated with shared server infrastructure and peripheral equipment. The Company's shared servers are used for the routine operation, testing, and disaster recovery of the Company's corporate applications. Management of these shared servers and their components are critical to ensuring these applications operate effectively at all times.

The project is necessary to ensure the secure operation of the Company's shared sever infrastructure, and to complete lifecycle replacement of equipment that is at the end of its expected service life.

For 2019, the project includes:

1. Lifecycle replacement of the Company's email infrastructure used for internal and external email communications with customers and employees;
2. Lifecycle replacement of the Company's workforce management system infrastructure used to support the mobile dispatch of field work;
3. Lifecycle replacement of the Company's blade server chassis infrastructure. Blade server infrastructure is hardware that houses multiple server modules (blades) in a single chassis. Multiple applications reside within this architecture including systems such as the Company's Asset Management System, Financial System and Intranet; and
4. Infrastructure upgrades including additional components to increase disk storage, along with processor and memory capacity upgrades to various systems to accommodate information storage growth.

The shared server infrastructure requirements for 2019 are not inter-dependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Details on proposed expenditures are included in 6***.3*** *2019 Shared Server Infrastructure*.

Justification

This project is justified on the basis of maintaining current levels of customer service and operational efficiencies, while protecting corporate and customer information on the Company's shared server infrastructure.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1

Projected Expenditures (000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$590	-	-	-
Labour – Internal	148	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	110	-	-	-
Total	**$848**	**$1,210**	**$2,075**	**$4,033**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2

Expenditure History (000s)

Year	2014	2015	2016	2017	2018F
Total	$832	$997	$847	$707	$648

The budget for this project is based on cost estimates for the individual budget items.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist, all materials and services will be negotiated with the sole-source supplier to ensure least cost.

Future Commitments

This is not a multi-year project.

Project Title: **Network Infrastructure (Pooled)**

Project Cost: **$322,000**

Project Description

This Information Systems project involves the addition of network components that provide employees with access to applications and data in order to provide service to customers and to operate efficiently.

Network components, such as routers and switches, interconnect shared servers and personal computers throughout the Company, enabling the transport of Supervisory Control and Data Acquisition ("SCADA"), corporate and customer service data. In addition to traditional wired network technologies, the Company has increased its use of wireless communications technologies in recent years.

For 2019, this project includes the purchase and implementation of network equipment that has reached the end of useful life and to increase overall network availability and disaster recovery capabilities.

The individual network infrastructure requirements for 2019 are not inter-dependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Justification

The reliability and availability of the network infrastructure is critical to enabling the Company to continue to provide least cost, reliable service to customers. This project will replace components of the network equipment that facilitate communication between all of the Company's shared servers and related applications. These components have reached the end of their useful lives.

This project is necessary to ensure the continued integrity of Company and customer data. This, in turn, allows the maintenance of acceptable levels of customer service and operational efficiency.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1

Projected Expenditures
(000s)

Cost Category	**2019**	**2020**	**2021 - 2023**	**Total**
Material	$195	-	-	-
Labour – Internal	92	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	35	-	-	-
Total	**$322**	**$354**	**$1,326**	**$2,002**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period.

Table 2

Expenditure History
(000s)

Year	**2014**	**2015**	**2016**	**2017**	**2018F**
Total	$345	$307	$312	$407	$467

The budget for this project is based on cost estimates for the individual budget items based on past experiences and pricing. The historical average cost for the past 5 years is approximately $337,000, excluding additional expenditures required in 2018 for the secure use of public networks used by the SCADA system and remote management of mobile computers.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist, all materials and services will be negotiated with the sole-source supplier to ensure least cost.

Future Commitments

This is not a multi-year project.

Project Title: **Cybersecurity Upgrades (Pooled)**

Project Cost: **$398,000**

Project Description

This Information Systems project involves the additions to and enhancements of the Company's existing cybersecurity infrastructure. Cybersecurity infrastructure is used to address vulnerabilities and respond to cyber threats in a timely manner and assures normal utility operating conditions for the near term. The pace of change in this area is extremely fast with cybersecurity threats challenging the reliability, resiliency and safety of the electricity system. If not addressed in a timely and effective manner cybersecurity treats could impact the delivery of electricity service.

Today's power system interconnects physical electrical infrastructure such as control systems with less tangible information technology such as networks, software and data. Cybersecurity is critically important to keep the power system operating and protect Company and customer information. Security of the power system is an important concern for the protection of life and to provide and maintain a safe and reliable power system.[22]

The risk of security breaches and exposure to cyber-attacks within the power system has grown substantially with the implementation of operations technology such as smart grids, smart metering and customer owned-generation. Increased use of operations technologies by utilities, public communication networks, other wireless networks, hand-held electronic devices and the Internet have created vulnerabilities that did not exist in the past. As well, the growing demand for real-time data exchange between utilities has increased cybersecurity risks.

For 2019, this project includes the purchase and implementation of a privilege access management system to improve authentication and authorized access to critical infrastructure.[23]

The individual cybersecurity infrastructure requirements for 2019 are not inter-dependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

---

22 Cybersecurity standards, such as those developed by the North American Electric Reliability Corporation ("NERC") for the bulk transmission system continue to evolve. For utilities that operate below the bulk transmission system level not under the direction of NERC, other standards have been developed at the provincial and state level.

23 In prior years cybersecurity infrastructure was included in the System Upgrades, Shared Server Infrastructure, and Network Infrastructure Information Systems projects. Combining all cybersecurity upgrades in a single project is intended to focus the Company's cybersecurity efforts.

Justification

The security, reliability and availability of the Company's critical infrastructure enables it to continue to provide least cost, reliable service to customers. This project will enable the Company to maintain its cybersecurity efforts in a manner that is reflective of the threats that exist and must be dealt with in a timely manner. The components being upgraded or replaced have reached the end of their useful lives.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2019 and a projection of expenditures through 2023.

Table 1
Projected Expenditures
(000s)

Cost Category	2019	2020	2021 - 2023	Total
Material	$40	-	-	-
Labour – Internal	153	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	205	-	-	-
Total	**$398**	**$556**	**$1,735**	**$2,689**

Costing Methodology

The budget for this project is based on cost estimates for the individual budget items based on past experiences and pricing.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers. Where alternative suppliers do not exist, all materials and services will be negotiated with the sole-source supplier to ensure least cost.

Future Commitments

This is not a multi-year project.

Project Title: **Outage Management System (Other, Multi-year)**

Project Cost: **$1,210,000**

Project Description

This Information Systems project is a multi-year project to replace the Company's existing Outage Management System ("OMS") approved in Order No. P.U. 37 (2017).

The existing OMS was deployed in 2003 and is now functionally obsolete.[24] Following a review of commercial OMS products and current Canadian utility practice, the Company has determined the most appropriate approach to modernizing its OMS is to replace the existing system with a commercially available product that offers enhanced functionality.

This is a multi-year project, with a total project cost of $3,570,000 over 2 years, starting in 2018. Expenditures estimated for 2019 are $1,210,000.

Details on the OMS replacement and enhancement project are included in the 2018 Capital Budget Application report ***5.5*** *Outage Management System Replacement & Enhancement.*

Justification

The OMS is a cornerstone of reliability management at Newfoundland Power. Implementation of a new OMS will address the functional obsolescence of the Company's existing system. The inclusion of enhanced functionality will: (i) ensure crews are dispatched more quickly, thereby reducing the duration of customer outages; (ii) improve the accuracy and timeliness of customer communications during outages; and (iii) reduce or eliminate manual processes, which will ensure the Company can continue to manage outages in a cost-effective way.

This project is justified on the basis of improving reliability performance and customer service.

[24] Newfoundland Power's existing OMS was developed internally and cannot integrate with the Company's Supervisory Control and Data Acquisition ("SCADA") system or Geographic Information System ("GIS"). This practically requires Company employees to assess and respond to outages without the benefit of real-time information. The existing OMS is therefore considered functionally obsolete.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2018 and 2019 and a projection of expenditures through 2023.

Table 1

Projected Expenditures (000s)

Cost Category	2018	2019	2020 - 2023	Total
Material	$1,665	$505	-	$2,170
Labour – Internal	640	650	-	1,290
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	55	55	-	110
Total	**$2,360**	**$1,210**	-	**$3,570**

Costing Methodology

The budget for this project is based on cost estimates obtained through a Request for Proposals process for the new OMS.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers.

Future Commitments

This is a multi-year project approved in Order No. P.U. 37 (2017) to be completed in 2018 and 2019.

Project Title: **Human Resource Management System Replacement (Other, Multi-year)**

Project Cost: **$1,215,000**

Project Description

This Information Systems project is a multi-year project to replace the Company's existing Human Resource Management System ("HRMS") approved in Order No. P.U. 37 (2017).

Newfoundland Power manages a workforce of approximately 686 regular and temporary employees. In addition, the Company has approximately 775 retirees. As part of its HRMS, the Company currently uses a combination of software applications to ensure effective human resource management.[25]

The core component in the Company's HRMS is the 15-year-old Empower application. Empower is now functionally obsolete and at the end of its service life. The Company was recently informed by the vendor that the application is no longer being advanced, improved or supported. In 2018, the Company commenced a 2-year project to replace the existing HRMS with a commercially available application.

This is a multi-year project, with a total project cost of $1,637,000 over 2 years, starting in 2018. Expenditures estimated for 2019 are $1,215,000.

Details on proposed expenditures are included in the 2018 Capital Budget Application report ***5.4*** *Human Resource Management System Replacement.*

Justification

The acquisition of a commercially available HRMS is necessary to address the functional obsolescence of the Empower application. In addition, implementing a replacement HRMS application will ensure an appropriate level of vendor support, improve the Company's ability to update the system, and achieve operational efficiencies through a reduction in manual data entry. Overall, the replacement application will better enable the Company to effectively manage its workforce and retirees.

[25] The Company's HRMS is provided through a variety of different software applications and tools that deliver the required functionality. In addition to the Empower application, the existing HRMS incorporates a number of in-house developed applications, workflows, spreadsheets, databases and reports.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2018 and 2019, along with a projection of expenditures through 2023.

Table 1
Projected Expenditures
(000s)

Cost Category	2018	2019	2020 – 2023	Total
Material	$17	$360	-	$377
Labour – Internal	305	400	-	705
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	100	455	-	555
Total	**$422**	**$1,215**	-	**$1,637**

Costing Methodology

The budget for this project is based on cost estimates provided by potential suppliers and an estimate for the internal effort required to complete the project.

All materials and services for this project will be purchased after examining the competitive bids of prospective suppliers.

Future Commitments

This is a multi-year project approved in Order No. P.U. 37 (2017) to be completed in 2018 and 2019.

UNFORESEEN ALLOWANCE

Project Title: **Allowance for Unforeseen Items (Other)**

Project Cost: **$750,000**

Project Description

This Allowance for Unforeseen Items project 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 damages 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.

Justification

This project provides funds for timely service restoration in accordance with Section B Supplementary Capital Budget Expenditures of the *Capital Budget Application Guidelines*.

Projects for which these funds are intended are justified on the basis of reliability, or on the need to immediately replace deteriorated or damaged equipment.

Costing Methodology

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 balance in the Allowance for Unforeseen Items is depleted in the year, the Company may be required to file an application for approval of an additional amount in accordance with the *Capital Budget Application Guidelines.*

Future Commitment

This is not a multi-year project.

GENERAL EXPENSES CAPITALIZED

Project Title: **General Expenses Capitalized (Other)**

Project Cost: **$4,000,000**

Project Description

General Expenses Capitalized ("GEC") are general expenses of Newfoundland Power that are capitalized due to the fact that they are related, directly or indirectly, to the Company's capital projects. GEC includes amounts from two sources: direct charges to GEC and amounts allocated from specific operating accounts.

Justification

Certain of Newfoundland Power's general expenses are related, either directly or indirectly, to the Company's capital program. Expenses are charged to GEC in accordance with guidelines approved by the Board in Order No. P.U. 3 (1995-96).

Costing Methodology

In Order No. P.U. 3 (1995-96), the Board approved guidelines to determine the expenses of the Company to be included in GEC. The budget estimate of GEC is determined in accordance with pre-determined percentage allocations to GEC based on the guidelines approved by the Board.

Future Commitment

This is not a multi-year project.

Newfoundland Power Inc.
2019 Capital Budget
Multi-Year Projects Approved in Previous Years

Class	Project Description	CBA/ Board Order		Expenditure (000s) 2018	2019	2020	2021	Total
Generation Thermal	Purchase Mobile Generation[1]	2018 CBA P.U. 37 (2017)	Approved	$6,000	$7,915			$13,915
			Forecast	6,000	7,915			13,915
Transmission	Transmission Line Rebuild[2]	2018 CBA P.U. 37 (2017)	Approved	5,068	6,064	$3,600	$3,750	18,482
			Forecast[3]	5,068	6,359	3,778	-	15,205
Distribution	Feeder Additions for Growth[4]	2018 CBA P.U. 37 (2017)	Approved	319	665			984
			Forecast	319	665			984

1 A detailed project description can be found in the 2018 Capital Budget Application, Schedule B pages 7 to 8 of 90, and report ***1.2*** *Purchase Mobile Generation.*
2 A detailed project description can be found in the 2018 Capital Budget Application, Schedule B pages 17 to 19 of 90, and report ***3.1*** *2018 Transmission Line Rebuild.*
3 Lower forecast expenditures for Transmission Line Rebuild projects are the result of lower contractor pricing received in the 2018 tenders for these projects. Also, the 363L rebuild project is now planned to be completed over 3 years, hence there is no forecast expenditure for 2021.
4 A detailed project description can be found in the 2018 Capital Budget Application, Schedule B pages 43 to 44 of 90, and report ***4.2*** *Feeder Additions for Growth.*

Newfoundland Power Inc.
2019 Capital Budget
Multi-Year Projects Approved in Previous Years (continued)

Class	Project Description	CBA/ Board Order		Expenditure (000s) 2018	2019	2020	2021	Total
Information Systems	Microsoft Enterprise Agreement[5]	2018 CBA P.U. 37 (2017)	Approved	245	245	245		735
			Forecast	245	245	245		735
Information Systems	Outage Management System[6]	2018 CBA P.U. 37 (2017)	Approved	2,360	1,210			3,570
			Forecast	2,360	1,210			3,570
Information Systems	Human Resource Management System Replacement[7]	2018 CBA P.U. 37 (2017)	Approved	422	1,215			1,637
			Forecast	422	1,215			1,637
			Total Approved	**$14,414**	**$17,314**	**$3,845**	**$3,750**	**$39,323**
			Total Forecast	**$14,414**	**$17,609**	**$4,023**	**-**	**$36,046**

5 A detailed project description can be found in the 2018 Capital Budget Application, Schedule B pages 74 and 75 of 90, and report ***5.2** 2018 System Upgrades.*
6 A detailed project description can be found in the 2018 Capital Budget Application, Schedule B pages 83 and 84 of 90, and report ***5.5** Outage Management System Replacement & Enhancement.*
7 A detailed project description can be found in the 2018 Capital Budget Application, Schedule B pages 85 and 86 of 90, and report ***5.4** Human Resource Management System Replacement.*

Newfoundland Power Inc.
2019 Capital Budget
Multi-Year Projects Commencing in 2019

Class	**Project Description**	**CBA/ Board Order**		**Expenditure (000s)** 2019	2020	2021	**Total**
Distribution	Distribution Reliability Initiative[8]	2019 CBA	Budget	$1,200	$1,400	$700	$3,100
			Total	**$1,200**	**$1,400**	**$700**	**$3,100**

[8] A detailed project description can be found in the 2019 Capital Budget Application, Schedule B pages 47 to 49 of 94, and report ***4.1*** *Distribution Reliability Initiative.* The DRI feeders included in the 2019 Capital Budget Application as new multi-year projects are DUN-01 and GBY-03.

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

	2017	2016
Net Plant Investment		
Plant Investment	1,804,559	1,741,193
Accumulated Depreciation	(725,127)	(694,843)
Contributions in Aid of Construction	(38,373)	(36,094)
	1,041,059	1,010,256
Additions to Rate Base		
Deferred Pension Costs	92,017	94,775
Deferred Credit Facility Costs	110	94
Cost Recovery Deferral – Hearing Costs	341	682
Cost Recovery Deferral – Conservation	14,116	11,304
Weather Normalization Reserve	4,771	1,721
Customer Finance Programs	1,496	1,341
Demand Management Incentive Account	1,490	-
	114,341	109,917
Deductions from Rate Base		
Other Post-Employment Benefits	52,584	46,083
Customer Security Deposits	1,066	786
Accrued Pension Obligation	5,572	5,285
Accumulated Deferred Income Taxes	3,915	2,186
2016 Cost Recovery Deferral	723	1,445
	63,860	55,785
Year End Rate Base	1,091,540	1,064,388
Average Rate Base Before Allowances	1,077,964	1,046,262
Rate Base Allowances		
Materials and Supplies Allowance	6,137	6,464
Cash Working Capital Allowance	8,153	8,318
Average Rate Base at Year End	1,092,254	1,061,044

2018 Capital Expenditure Status Report

July 2018

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

**2018 Capital Expenditure
Status Report**

Explanatory Note

This report is presented in compliance with the directive of the Board of Commissioners of Public Utilities (the "Board") contained in paragraph 6 of Order No. P.U. 37 (2017).

Page 1 of the 2018 Capital Expenditure Status Report outlines the forecast variances from budget of the capital expenditures approved by the Board. The detailed tables on pages 2 to 13 provide additional detail on capital expenditures in 2018, which were approved in Order No. P.U. 37 (2017). The detailed tables also include information on those capital projects approved for 2017 (and approved in Order No. P.U. 39 (2016)) that were not completed prior to 2018.

Variances of more than 10% of approved expenditure and $100,000 or greater are explained in the Notes contained in Appendix A, which immediately follows at the conclusion of the 2018 Capital Expenditure Status Report. These variance criteria are as outlined in the *Capital Budget Application Guidelines*.

Newfoundland Power Inc.

2018 Capital Budget Variances
(000s)

Approved by Order No.
P.U. 37 (2017)

	Budget	**Forecast**	**Variance**
Generation – Hydro	$2,119	$2,119	-
Generation - Thermal	6,301	6,301	-
Substations	12,788	12,788	-
Transmission	7,168	7,512	344
Distribution	38,857	39,713	856
General Property	1,763	1,763	-
Transportation	3,362	3,362	-
Telecommunications	198	198	-
Information Systems	6,570	6,498	(72)
Unforeseen Items	750	750	-
General Expenses Capitalized	4,000	4,020	20
Total	$83,876	$85,024	$1,148

Projects carried forward from prior years $5,770[1]

1 Forecast 2018 expenditures associated with projects carried forward from prior years.

2018 Capital Expenditure Status Report
(000s)

	Capital Budget			Actual Expenditure			Forecast			
	2017	2018	Total	2017	YTD 2018	Total To Date	Remainder 2018	Total 2018	Overall Total	Variance
	A	B	C	D	E	F	G	H	I	J
2018 Projects	$ -	$ 83,876	$ 83,876	$ -	$ 19,658	$ 19,658	$ 65,366	$ 85,024	85,024	$ 1,148
2017 Projects	35,695	-	35,695	29,485	977	30,462	4,794	5,771	35,256	(439)
Grand Total	**$ 35,695**	**$ 83,876**	**$ 119,571**	**$ 29,485**	**$ 20,635**	**$ 50,120**	**$ 70,160**	**$ 90,795**	**$ 120,280**	**$ 709**

Column A	Approved Capital Budget for 2017
Column B	Approved Capital Budget for 2018
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2017
Column E	Actual Capital Expenditures for 2018 YTD
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2018
Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2018 Capital Expenditure Status Report
(000s)

Category: Generation - Hydro

	Capital Budget			Actual Expenditure			Forecast				
Project	**2017**	**2018**	**Total**	**2017**	**YTD 2018**	**Total To Date**	**Remainder 2018**	**Total 2018**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	I	J	
2018 Projects											
Facility Rehabilitation	$ -	$ 2,119	$ 2,119	$ -	$ 113	$ 113	$ 2,006	$ 2,119	$ 2,119	$ -	
Total - 2017 Generation Hydro	**$ -**	**$ 2,119**	**$ 2,119**	**$ -**	**$ 113**	**$ 113**	**$ 2,006**	**$ 2,119**	**$ 2,119**	**$ -**	
2017 Projects											
Facility Rehabilitation (2017)	$ 1,607	$ -	$ 1,607	$ 1,250	$ 24	$ 1,274	$ 291	$ 315	$ 1,565	$ (42)	
Rose Blanche Plant Refurbishment	3,281	-	3,281	2,453	206	2,659	74	280	2,733	(548)	1
Tors Cove Plant Refurbishment	1,476	-	1,476	301	257	558	625	882	1,183	(293)	2
Total - Generation Hydro	**$ 6,364**	**$ 2,119**	**$ 8,483**	**$ 4,004**	**$ 600**	**$ 4,604**	**$ 2,996**	**$ 3,596**	**$ 7,600**	**$ (883)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2017
Column B	Approved Capital Budget for 2018
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2017
Column E	Actual Capital Expenditures for 2018 YTD
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2018
Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2018 Capital Expenditure Status Report
(000s)

Category: Generation - Thermal

	Capital Budget		Actual Expenditures		Forecast				
Project	**2018**	**Total**	**YTD 2018**	**Total To Date**	**Remainder 2018**	**Total 2018**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2018 Projects									
Facility Rehabilitation Thermal	$ 301	$ 301	$ 1	$ 1	$ 300	$ 301	$ 301	$ -	
Purchase Mobile Generation	6,000	6,000	50	50	5,950	6,000	6,000	-	
Total - 2018 Generation Thermal	**$ 6,301**	**$ 6,301**	**$ 51**	**$ 51**	**$ 6,250**	**$ 6,301**	**$ 6,301**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2018
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2018 YTD
Column D	Total of Column C
Column E	Forecast for Remainder of 2018
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2018 Capital Expenditure Status Report
(000s)

Category: Substations

	Capital Budget			Actual Expenditure			Forecast				
Project	**2017**	**2018**	**Total**	**2017**	**YTD 2018**	**Total To Date**	**Remainder 2018**	**Total 2018**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	I	J	
2018 Projects											
Substation Refurbishment and Modernization	$ -	$ 8,001	$ 8,001	$ -	$ 1,622	$ 1,622	$ 6,379	$ 8,001	$ 8,001	$ -	
Replacements Due to In-Service Failures	-	3,814	3,814	-	747	747	3,067	$ 3,814	3,814	-	
PCB Bushing Phaseout	-	973	973	-	-	-	973	$ 973	973	-	
Total - 2018 Substations	$ -	$ 12,788	$ 12,788	$ -	$ 2,369	$ 2,369	$ 10,419	$ 12,788	$ 12,788	$ -	
2017 Projects											
Substation Refurbishment and Modernization	$ 10,350	$ -	$ 10,350	$ 10,027	$ 192	$ 10,219	$ 559	$ 751	$ 10,778	$ 428	
Total - Substations	**$ 10,350**	**$ 12,788**	**$ 23,138**	**$ 10,027**	**$ 2,561**	**$ 12,588**	**$ 10,978**	**$ 13,539**	**$ 23,566**	**$ 428**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2017
Column B	Approved Capital Budget for 2018
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2017
Column E	Actual Capital Expenditures for 2018 YTD
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2018
Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2018 Capital Expenditure Status Report
(000s)

Category: Transmission

Project	Capital Budget 2017	Capital Budget 2018	Capital Budget Total	Actual Expenditure 2017	Actual Expenditure YTD 2018	Actual Expenditure Total To Date	Forecast Remainder 2018	Forecast Total 2018	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2018 Projects											
Rebuild Transmission Lines	$ -	$ 7,168	$ 7,168	$ -	$ 433	$ 433	$ 7,079	$ 7,512	$ 7,512	$ 344	
Total - 2018 Transmission	$ -	$ 7,168	$ 7,168	$ -	$ 433	$ 433	$ 7,079	$ 7,512	$ 7,512	$ 344	
2017 Projects											
Rebuild Transmission Lines	$ 6,711	$ -	$ 6,711	$ 6,224	$ 35	$ 6,259	$ 440	$ 475	$ 6,699	$ (12)	
Total - Transmission	**$ 6,711**	**$ 7,168**	**$ 13,879**	**$ 6,224**	**$ 468**	**$ 6,692**	**$ 7,519**	**$ 7,987**	**$ 14,211**	**$ 332**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2017
Column B	Approved Capital Budget for 2018
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2017
Column E	Actual Capital Expenditures for 2018 YTD
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2018
Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2018 Capital Expenditure Status Report
(000s)

Category: Distribution

Project	Capital Budget 2017	Capital Budget 2018	Capital Budget Total	Actual Expenditure 2017	Actual Expenditure YTD 2018	Actual Expenditure Total To Date	Forecast Remainder 2018	Forecast Total 2018	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2018 Projects											
Extensions	$ -	$ 11,738	$ 11,738	$ -	$ 3,542	$ 3,542	$ 8,013	$ 11,555	$ 11,555	$ (183)	
Meters	-	546	546	-	478	478	68	546	546	-	
Services	-	3,200	3,200	-	1,398	1,398	1,802	3,200	3,200	-	
Street Lighting	-	1,814	1,814	-	708	708	1,625	2,333	2,333	519	3
Transformers	-	6,084	6,084	-	2,090	2,090	3,994	6,084	6,084	-	
Reconstruction	-	5,366	5,366	-	1,901	1,901	3,465	5,366	5,366	-	
Rebuild Distribution Lines	-	3,844	3,844	-	1,302	1,302	2,542	3,844	3,844	-	
Relocate/Rebuild Distribution Lines for Third Parties	-	2,317	2,317	-	538	538	2,299	2,837	2,837	520	4
Trunk Feeders	-	798	798	-	65	65	733	798	798	-	
Feeder Additions for Growth	-	539	539	-	26	26	513	539	539	-	
Distribution Reliability Initiative	-	1,789	1,789	-	1,146	1,146	643	1,789	1,789	-	
Distribution Feeder Automation	-	612	612	-	67	67	545	612	612	-	
Allowance for Funds Used During Construction	-	210	210	-	55	55	155	210	210	-	
		-									
Total - 2018 Distribution	$ -	$ 38,857	$ 38,857	$ -	$ 13,316	$ 13,316	$ 26,397	$ 39,713	$ 39,713	$ 856	
2017 Projects											
Distribution Feeder Automation	$ 568	$ -	$ 568	$ 221	$ -	$ 221	$ 420	$ 420	$ 641	$ 73	
Distribution Reliability Initiative	1,415	-	1,415	816	-	816	700	700	1,516	101	
Meters	4,391	-	4,391	3,625	-	3,625	300	300	3,925	(466)	5
SJM Underground Refurbishment	2,440	-	2,440	1,015	40	1,055	1,385	1,425	2,440	-	
Total - Distribution	**$ 8,814**	**$ 38,857**	**$ 47,671**	**$ 5,677**	**$ 13,356**	**$ 19,033**	**$ 29,202**	**$ 42,558**	**$ 48,235**	**$ 564**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2017
Column B	Approved Capital Budget for 2018
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2017
Column E	Actual Capital Expenditures for 2018 YTD
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2018
Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2018 Capital Expenditure Status Report
(000s)

Category: General Property

Project	Capital Budget 2018	Capital Budget Total	Actual Expenditures YTD 2018	Actual Expenditures Total To Date	Forecast Remainder 2018	Forecast Total 2018	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2018 Projects									
Tools and Equipment	$ 479	$ 479	$ 192	$ 192	$ 287	$ 479	$ 479	$ -	
Additions to Real Property	671	671	120	120	551	671	671	-	
Company Buildings Renovations	298	298	23	23	275	298	298	-	
Fencing Refurbishment	315	315	2	2	313	315	315	-	
Total - General Property	**$ 1,763**	**$ 1,763**	**$ 337**	**$ 337**	**$ 1,426**	**$ 1,763**	**$ 1,763**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2018
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2018 YTD
Column D	Total of Column C
Column E	Forecast for Remainder of 2018
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2018 Capital Expenditure Status Report
(000s)

Category: Transportation

Project	Capital Budget 2017	Capital Budget 2018	Capital Budget Total	Actual Expenditure 2017	Actual Expenditure YTD 2018	Actual Expenditure Total To Date	Forecast Remainder 2018	Forecast Total 2018	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2018 Projects											
Purchase Vehicles and Aerial Devices	$ -	$ 3,362	$ 3,362	$ -	$ 521	$ 521	$ 2,841	$ 3,362	$ 3,362	$ -	
Total - 2018 Transportation	**$ -**	**$ 3,362**	**$ 3,362**	**$ -**	**$ 521**	**$ 521**	**$ 2,841**	**$ 3,362**	**$ 3,362**	**$ -**	
2017 Projects											
Purchase Vehicles and Aerial Devices	$ 3,456	$ -	$ 3,456	$ 3,553	$ 223	$ 3,776	$ -	$ 223	$ 3,776	$ 320	
Total - Transportation	**$ 3,456**	**$ 3,362**	**$ 6,818**	**$ 3,553**	**$ 744**	**$ 4,297**	**$ 2,841**	**$ 3,585**	**$ 7,138**	**$ 320**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2017
Column B	Approved Capital Budget for 2018
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2017
Column E	Actual Capital Expenditures for 2018 YTD
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2018
Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2018 Capital Expenditure Status Report
(000s)

Category: Telecommunications

	Capital Budget		Actual Expenditures		Forecast				
Project	**2018**	**Total**	**YTD 2018**	**Total To Date**	**Remainder 2018**	**Total 2018**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2018 Projects									
Replace/Upgrade Communications Equipment	$ 99	$ 99	$ 21	$ 21	$ 78	$ 99	$ 99	$ -	
Fibre Optic Network	99	99	71	71	28	99	99	-	
Total - Telecommunications	**$ 198**	**$ 198**	**$ 92**	**$ 92**	**$ 106**	**$ 198**	**$ 198**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2018
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2018 YTD
Column D	Total of Column C
Column E	Forecast for Remainder of 2018
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2018 Capital Expenditure Status Report
(000s)

Category: Information Systems

	Capital Budget		Actual Expenditures		Forecast				
Project	**2018**	**Total**	**YTD 2018**	**Total To Date**	**Remainder 2018**	**Total 2018**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2018 Projects									
Application Enhancements	$ 858	$ 858	$ 144	$ 144	$ 642	$ 786	$ 786	$ (72)	
System Upgrades	1,343	1,343	306	306	1,037	1,343	1,343	-	
Personal Computer Infrastructure	472	472	110	110	362	472	472	-	
Shared Server Infrastructure	648	648	35	35	613	648	648	-	
Network Infrastructure	467	467	145	145	322	467	467	-	
Outage Management System Replacement	2,360	2,360	167	167	2,193	2,360	2,360	-	
Human Resource Management System	422	422	148	148	274	422	422	-	
Total - 2018 Information Systems	**$ 6,570**	**$ 6,570**	**$ 1,055**	**$ 1,055**	**$ 5,443**	**$ 6,498**	**$ 6,498**	**$ (72)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2018
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2018 YTD
Column D	Total of Column C
Column E	Forecast for Remainder of 2018
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2018 Capital Expenditure Status Report
(000s)

Category: Unforeseen Allowance

Project	Capital Budget 2018	Capital Budget Total	Actual Expenditures YTD 2018	Actual Expenditures Total To Date	Forecast Remainder 2018	Forecast Total 2018	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2018 Projects									
Allowance for Unforeseen Items	$ 750	$ 750	$ -	$ -	$ 750	$ 750	$ 750	$ -	
Total - 2018 Unforeseen Items	**$ 750**	**$ 750**	**$ -**	**$ -**	**$ 750**	**$ 750**	**$ 750**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2018
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2018 YTD
Column D	Total of Column C
Column E	Forecast for Remainder of 2018
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2018 Capital Expenditure Status Report
(000s)

Category: General Expenses Capitalized

	Capital Budget		Actual Expenditures		Forecast				
Project	**2018**	**Total**	**YTD 2018**	**Total To Date**	**Remainder 2018**	**Total 2018**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2018 Projects									
General Expenses Capitalized	$ 4,000	$ 4,000	$ 1,371	$ 1,371	$ 2,649	$ 4,020	$ 4,020	$ 20	
Total - 2018 General Expenses Capitalized	**$ 4,000**	**$ 4,000**	**$ 1,371**	**$ 1,371**	**$ 2,649**	**$ 4,020**	**$ 4,020**	**$ 20**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2018
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2018 YTD
Column D	Total of Column C
Column E	Forecast for Remainder of 2018
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

Generation - Hydro

1. *Rose Blanche Plant Refurbishment (2017 Project):*

Budget: $3,281,000 Actual: $2,733,000 Variance: ($548,000)

The project included a $400,000 contingency to cover the possibility of an additional requirement for slope stabilization, which ultimately was not required during construction. Also, the turbine rehabilitation expenditure was $100,000 less than budget because contractor assistance with the turbine reassembly was not required.

2. *Tors Cove Plant Refurbishment (2017 Project):*

Budget: $1,476,000 Actual: $1,183,000 Variance: ($293,000)

Pending a review of the long-term potential for automating unit G1, the valve replacement aspect of the 2017 project was removed from the project scope.

Distribution

3. *Street Lighting:*

Budget: $1,814,000 Forecast: $2,333,000 Variance: $519,000

Street lighting is typically installed at the request of a customer, developer or municipality. In 2016 and 2017, many new subdivisions experienced slow housing sales. Requests to complete street lighting requirements for the entirety of these subdivisions were accordingly delayed. In 2018, requests are being received to complete street lighting in these subdivisions resulting in higher forecast 2018 street lighting costs.

4. *Relocate/Rebuild Distribution Lines for 3rd Parties:*

Budget: $2,317,000 Forecast: $2,837,000 Variance: $520,000

The increase is principally driven by Rogers Communications rebuilding its fiber system in the St. John's area. In addition, Bell is extending its fiber-op system to some of the more remote locations of the province. It is estimated that 52% will be recovered through CIAC's.

5. *Meters (2017 Project):*

Budget: $4,391,000 Forecast: $3,925,000 Variance: ($466,000)

A large portion of the AMR meters installed in 2017 were placed in urban areas. The higher urban population density resulted in a lower average installation cost than prior years. Also, the availability of Company employees to complete the installations rather than contractors resulted in lower costs than anticipated.

2019 Capital Plan

July 2018

WHENEVER. WHEREVER.
We'll be there.

Table of Contents

Page

1.0 Introduction

Newfoundland Power's *2019 Capital Plan* provides an overview of the Company's 2019 capital budget, together with an outlook for capital expenditures through 2023.

Newfoundland Power's 2019 capital budget totals $93,304,000. The Company's annual capital expenditure for the next 5 years is forecast to average approximately $107 million.

The Company's 2019 capital budget targets a stable level of capital investment required to maintain the condition of the electrical system.[1] Consistent with previous capital budgets, it focuses primarily on expenditures related to plant replacement. Expenditures on plant replacement account for 58% of total expenditures over the next 5 years.

The Company ranks its distribution feeders based on reliability performance. Capital upgrades are performed on the worst-performing feeders under the Distribution Reliability Initiative project. The *2019 Capital Plan* includes $7.8 million to address the reliability performance of the worst-performing feeders.

The *2019 Capital Plan* includes a 3 year project to replace the Company's 25 year old Customer Service System. Overall, the *CSS Replacement* project is estimated to cost $30 million, to be completed over the 2021 to 2023 period.

The *2019 Capital Plan* also includes a 3 year project related to reconfiguration of the 138 kV transmission system serving customers in Central Newfoundland from Lewisporte and Rattling Brook substations. The *Central Newfoundland System Planning Study* identifies Transmission and Substations projects for the *2019 Capital Plan* totalling $13.6 million.

Stability and predictability in capital planning are conducive to rate stability for customers. Accordingly, to the extent that it can, Newfoundland Power continues to target stability and predictability in its annual capital budgeting. In addition, Newfoundland Power's *2019 Capital Plan* is consistent with the Company's obligation to provide least-cost reliable electrical service to its customers as required by the *Public Utilities Act* and the *Electrical Power Control Act, 1994*.

[1] In its report titled *Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power*, December 17, 2014, page ES-2, Liberty Consulting Group found that Newfoundland Power's effective maintenance and capital programs, that appropriately recognize the age of its assets, have contributed materially to improve reliability.

2.0 2019 Capital Budget

Newfoundland Power's 2019 capital budget is $93,304,000.

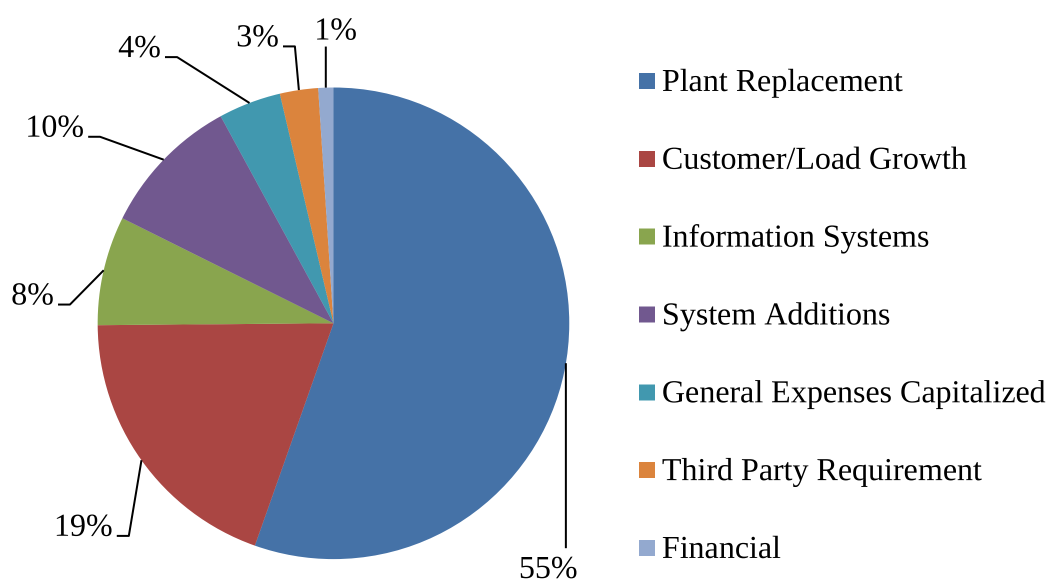
This section of the 2019 Capital Plan provides an overview of the 2019 capital budget by origin (root cause) and asset class. In addition, this section summarizes 2019 capital projects by the various categories set out in the Board's October 2007 Capital Budget Application Guidelines.

2.1 2019 Capital Budget Overview

Newfoundland Power's 2019 Capital Budget contains 38 projects totalling approximately $93.3 million.

Chart 1 shows the 2019 capital budget by origin, or root cause.

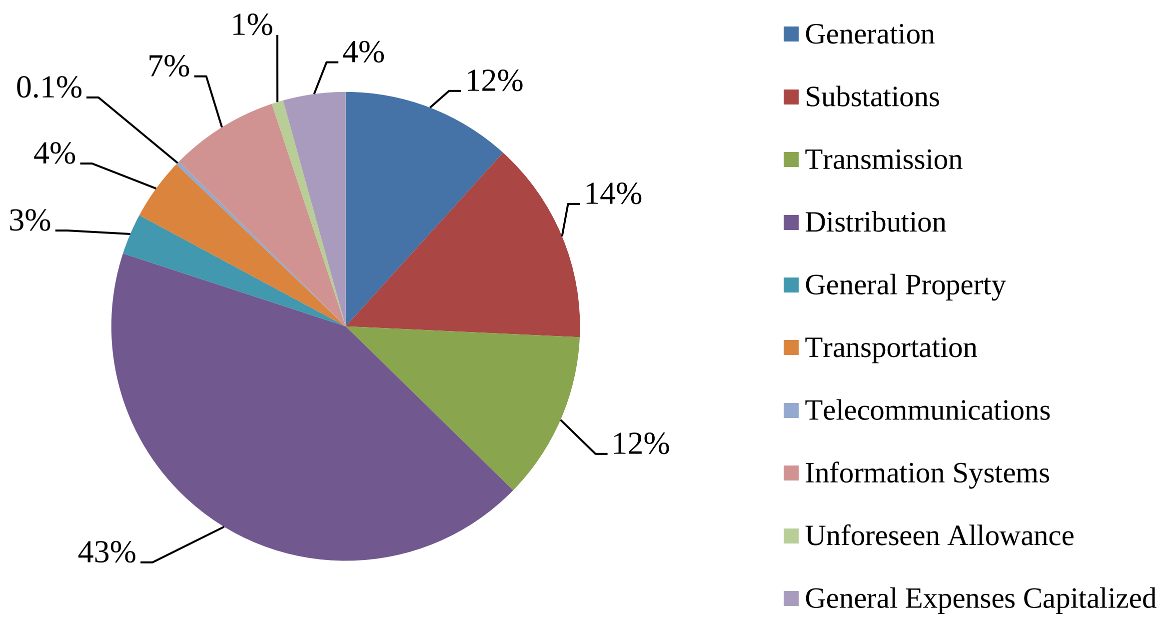
Chart 1
2019 Capital Expenditures by Origin



Approximately 55% of proposed 2019 capital expenditure is related to the replacement of plant. A further 19% of proposed 2019 capital expenditure is required to meet the Company's obligation to serve new customers and meet the requirement for increased system capacity. Information Systems account for 8% of proposed 2019 capital expenditures. The remaining 18% of forecast capital expenditures for 2019 relates to System Additions, General Expenses Capitalized, Third Party Requirements, and Financial Costs (allowance for funds used during construction).[2] The allocation of 2019 capital expenditures is broadly consistent with capital budgets for the past 5 years.

Chart 2 shows the 2019 capital budget by asset class.

Chart 2
2019 Capital Expenditures by Asset Class



As in past years, Distribution capital expenditure accounts for the greatest percentage of overall expenditure at $40.0 million, or 43% of the 2019 capital budget. Substations capital expenditure accounts for $13.0 million, or 14% of the 2019 capital budget. Generation capital expenditure accounts for $10.9 million, or 12% of the 2019 capital budget. Transmission capital expenditure accounts for $10.8 million, or 12% of the 2019 capital budget. Information Systems capital expenditure accounts for $7.0 million, or 7% of the 2019 capital budget. Together, expenditure for these 5 asset classes comprises 88% of the Company's 2019 capital budget.

Distribution capital expenditure is primarily driven by customer requests for new connections to the electrical system and the rebuilding of aged and deteriorated infrastructure. Distribution capital expenditures in 2019 and beyond reflect reduced new customer connections. The 2019 estimate of 2,593 gross new customer connections is the lowest it has been in 20 years.[3]

The Company will continue with the rebuilding of the oldest, most deteriorated transmission lines in its system. In 2019, the Company will continue with multi-year projects to rebuild Transmission lines 302L on the Burin Peninsula and 363L on the Baie Verte Peninsula.

---

2 The purchase of new mobile generation is initially considered a system addition as the Company intends to permanently locate the existing mobile gas turbine and continue to operate the generator until the end of its service life.

3 The previous 20 year low was in 1998 when only 2,695 new customers were connected.

2.2 The Capital Budget Application Guidelines

On October 29, 2007, the Board issued Policy No. 1900.6, referred to as the Capital Budget Application Guidelines (the "CBA Guidelines"), providing for definition and categorization of capital expenditures for which a public utility requires prior approval of the Board. Newfoundland Power's 2019 Capital Budget Application complies with the CBA Guidelines.

The 2019 Capital Budget Application includes 38 projects, as detailed in *Schedule A*. Included in *Schedule B* is a summary of these projects organized by definition, classification, and costing method.

The following section provides a summary of each of these views of the 2019 Capital Budget, along with a summary of costs segmented by materiality.

2019 Capital Projects by Definition

Table 1 summarizes Newfoundland Power's proposed 2019 capital projects by definition, as set out in the CBA Guidelines.

Table 1
2019 Capital Projects
By Definition

Definition	**Number of Projects**	**Budget (000s)**
Pooled	29	$58,326
Clustered	3	19,761
Other	6	15,217
Total	**38**	**$93,304**

There are a total of 29 *pooled* projects, accounting for 63% of total expenditures.

2019 Capital Projects by Classification

Table 2 summarizes Newfoundland Power's proposed 2019 capital projects by classification, as set out in the CBA Guidelines.

Table 2
2019 Capital Projects
By Classification

Classification	**Number of Projects**	**Budget (000s)**
Normal	36	$91,140
Mandatory	1	912
Justifiable	1	1,252
Total	**38**	**$93,304**

There are 36 *normal* projects accounting for 98% of total expenditures.

2019 Capital Projects by Costing Method

Table 3 summarizes Newfoundland Power's proposed 2019 capital projects by costing method (i.e., identified need vs. historical pattern), as set out in the CBA Guidelines.

Table 3
2019 Capital Projects
By Costing Method

Method	**Number of Projects**	**Budget (000s)**
Identified Need	22	$48,207
Historical Pattern	16	45,097
Total	**38**	**$93,304**

Projects with costing method based on *identified need* account for 52% of total expenditures, while those based on *historical pattern* account for 48% of total expenditures.

2019 Capital Projects by Materiality

Table 4 segments Newfoundland Power's proposed 2019 capital projects by materiality, as set out in the CBA Guidelines.

Table 4
2019 Capital Projects
Segmentation by Materiality

Segment	Number of Projects	Budget (000s)
Under $200,000	2	$233
$200,000 - $500,000	9	3,390
Over $500,000	27	89,681
Total	**38**	**$93,304**

There are 27 projects budgeted at over $500,000, accounting for 96% of total expenditures.

3.0 5-Year Outlook

Newfoundland Power's 5-year capital outlook for 2019 through 2023 includes forecast average annual capital expenditure of $106.8 million. Over the 5-year period 2014 through 2018, the average annual capital expenditure is expected to be $97.3 million. Average annual expenditures through the forecast period are estimated to be approximately 10% more than in the period 2014 through 2018.[4] The increase is primarily due to the refurbishment of older assets and the CSS replacement project.

The forecast annual capital expenditure reflects inflation and requirements for specific projects related to the replacement of deteriorated plant and equipment, meeting customer and load growth, replacing the Company's Outage Management and Customer Service systems, and new mobile generation.

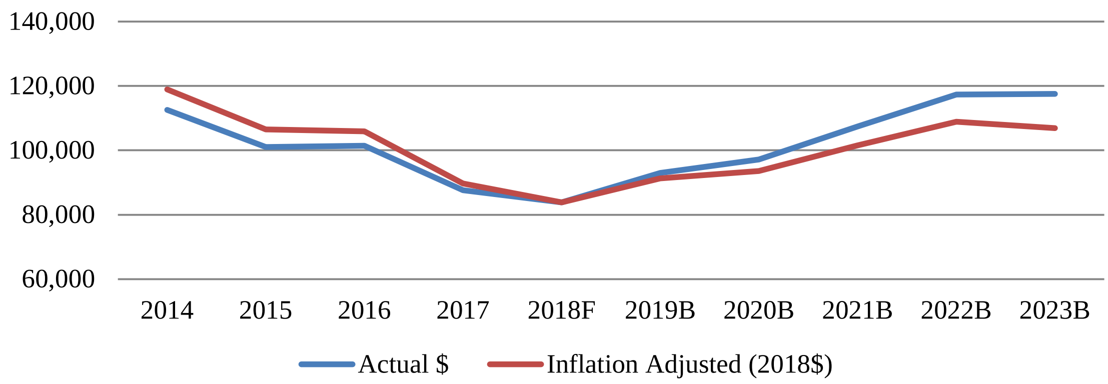
3.1 Capital Expenditures: 2014-2023

The Company plans to invest $534 million in plant and equipment during the 2019 through 2023 period. On an annual basis, capital expenditures are expected to average approximately $106.8 million and range from a low of $93.3 million in 2019, to a high of $117.8 million in 2023.

[4] The cumulative effect of inflation over the 10 year period from 2014 to 2023 is approximately 16%.

Chart 3 shows actual capital expenditures for the period 2014 through 2017, and forecast capital expenditures for the period 2018 through 2023. For comparison purposes, the annual capital expenditures are also expressed in 2018 dollars to remove the effects of inflation.

Chart 3
Capital Expenditures
2014 to 2023F
($000s)



Overall, planned capital expenditures for the 5-year period from 2019 through 2023 are expected to be comparable to the prior 5-year period from 2014 through 2018. Forecast requirements for the 5-year period from 2019 through 2023 include additional power transformers due to forecast load growth, new transmission lines on the Northeast Avalon Peninsula, reconfiguration of the 138 kV transmission system from Grand Falls to Gander, new mobile generation, gas turbine and hydro plant refurbishment, and the replacement of important information technology, such as the Company's Outage Management System and Customer Service System.

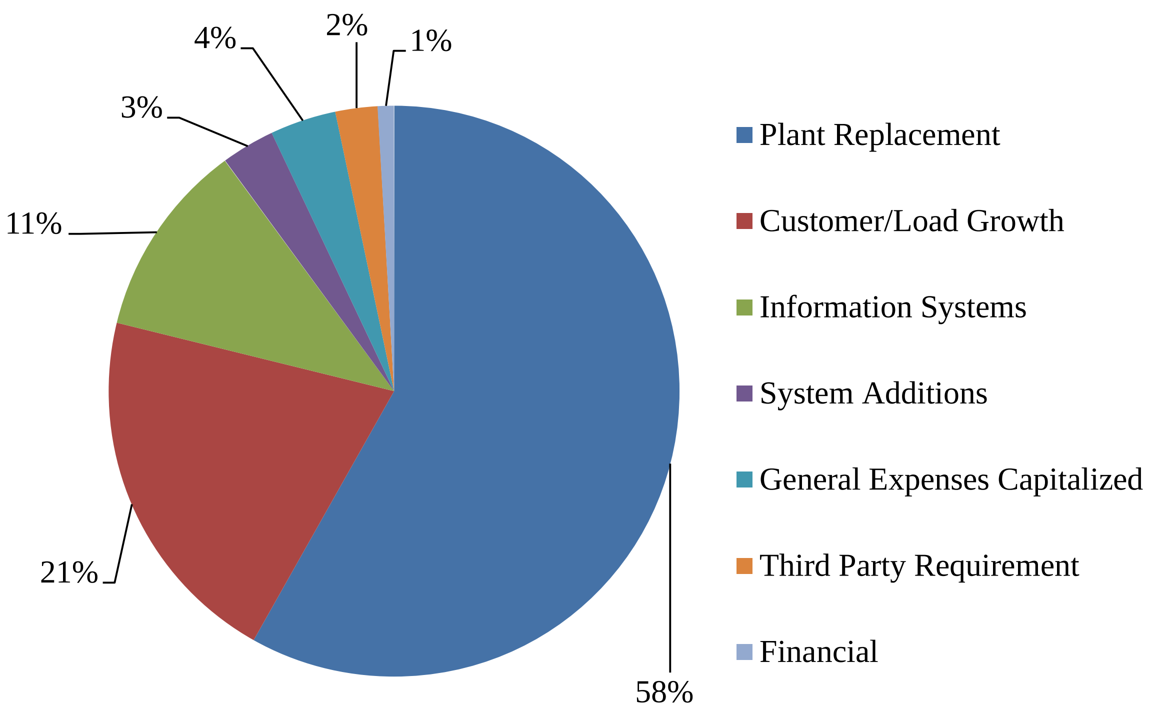
The replacement of plant has been, and is expected to continue to be, the largest driver of Newfoundland Power's capital budget, accounting for 57% of total expenditure for the 10-year period from 2014 through 2023. Over the same 10-year period, capital expenditures to meet increased customer connections and electricity sales account for 25% of total expenditures.

3.2 2019-2023 Capital Expenditures

3.2.1 Overview

Chart 4 shows aggregate forecast capital expenditures by origin for the period 2019 through 2023.

Chart 4
Capital Expenditures by Origin
2019 to 2023

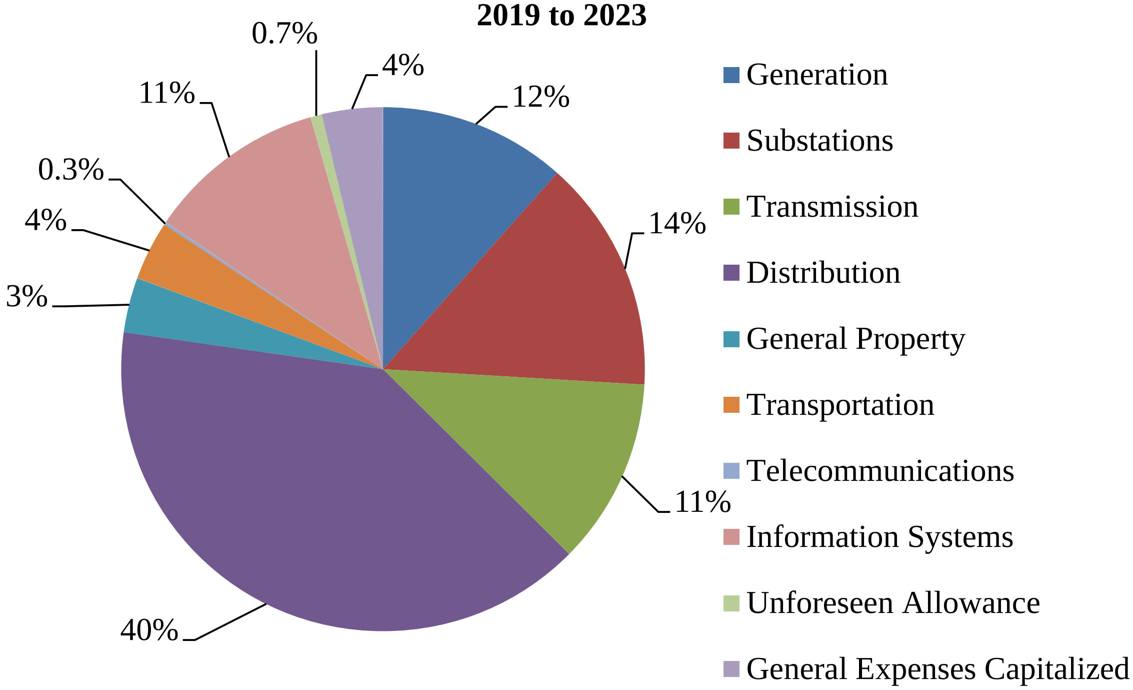


Plant Replacement accounts for 58% of all planned expenditures over the 5-year period from 2019 through 2023. This is greater than the average of 56% in the previous 5-year period from 2014 through 2018. Capital expenditure related to Customer and Load Growth accounts for 21% of planned expenditures over the 5-year period from 2019 through 2023. This is less than the average of 29% in the previous 5-year period from 2014 through 2018. Capital expenditure related to Information Systems accounts for 11% of planned expenditures over the 5-year period from 2019 through 2023. This is greater than the average of 6% in the previous 5-year period from 2014 through 2018. This is largely attributable to the replacement of the Customer Service System planned for 2021 through 2023.

The remaining 10% of total capital expenditures for the 2019 through 2023 period relate to a variety of origins, including System Additions, General Expenses Capitalized, Third Party Requirements, and Financial Costs.

Chart 5 shows aggregate forecast capital expenditures for the period 2019 through 2023 by asset class.

Chart 5
Capital Expenditures by Asset Class
2019 to 2023



The Distribution asset class accounts for 40% of all planned expenditures over the next 5 years, followed by Substations (14%), Generation (12%), Transmission (11 %) and Information Systems (11%). The remaining 5 asset classes account for 12% of total capital expenditures for the 2019 through 2023 period.

Overall, planned expenditures for the period 2019 through 2023 are expected to remain relatively stable in all asset classes with the exception of generation and substations, which vary annually due to refurbishment and system load growth requirements, and the addition of new mobile generation over the forecast period. The replacement of the Company's Customer Service System in the 5-year capital plan increases Information Systems expenditures in 2021 through 2023.

A summary of planned capital expenditures by asset class and by project for 2019 to 2023 is provided in Appendix A.

3.2.2 Generation

Generation capital expenditures will average approximately $12.3 million per year from 2019 through 2023, which is greater than the annual average of $10.1 million from 2014 through 2018.[5]

Generation capital expenditures on the Company's 23 hydroelectric plants, 3 gas turbines and 2 diesel plants are primarily driven by:

- preventive capital maintenance on aged and deteriorated assets;
- specific capital project initiatives, such as plant refurbishment; and
- breakdown capital maintenance associated with in-service failures.

The Company has a preventive maintenance program in place for generation assets. The level of expenditure for capital maintenance, both breakdown and preventive, is expected to be relatively stable over the forecast period and generally consistent with the historical average.

Due to the age of the Company's fleet of generating plants, significant refurbishment will continue to be required over the planning period. Over the next 5 years, the Company plans to continue the practice adopted in recent years of undertaking major plant refurbishment while also identifying opportunities to increase energy production and reduce losses at existing facilities. For example, the following major capital projects are planned:

- In 2018 and 2019, the Company plans to purchase a mobile generator at an estimated cost of $13.9 million. The mobile generator will be used for both emergency generation and to minimize customer outages during planned work.[6]

- In 2019 and 2020, the Company plans to refurbish the turbine and the rotor windings on both units at the Rattling Brook hydro plant at an estimated cost of $2.3 million.

- In 2020, the Company plans to refurbish the generator and surge tank, and replace the penstock at the Sandy Brook hydro plant at an estimated cost of $6.0 million.

- In 2021, the Company plans to replace the woodstave penstock at Topsail hydro plant at an estimated cost of $7.6 million.

- In 2021, the Company plans to refurbish the turbine and the rotor windings at the Cape Broyle hydro plant at an estimated cost of $1.4 million.

- In 2022, the plan includes the refurbishment of the electrical, civil and mechanical systems at the Mobile hydro plant at an estimated cost of $8.8 million. The timing of this project remains subject to the ongoing arbitration process with the City of St. John's.

---

5 This increase is attributable to the purchase of a new mobile generator, the refurbishment of the Greenhill and Wesleyville gas turbines, Mobile Plant refurbishment and penstock replacements at Topsail, Petty Harbour and Sandy Brook hydro plants.

6 The existing mobile gas turbine will be 45 years old in 2018.

- In 2023, the Company plans to refurbish the penstock and surge tank at the Horsechops hydro plant at an estimated cost of $2.1 million.

- In 2023, the Company plans to refurbish the upper section of penstock, refurbish the turbine and the generator stator windings at the Petty Harbour hydro plant at an estimated cost of $4.4 million.

- In 2020 and 2021, the Company plans to upgrade the Wesleyville gas turbine facility at an estimated cost of $3.8 million.

- In 2021 and 2022, the Company plans to refurbish the Greenhill gas turbine facility at an estimated cost of $4.7 million.

3.2.3 Transmission

Transmission capital expenditures are expected to average $12.3 million annually from 2019 through 2023, compared with $6.1 million annually from 2014 through 2018. The increase in annual expenditure is related to an increase in the kilometres of transmission line to be rebuilt each year, the addition of 2 new transmission lines on the Northeast Avalon Peninsula, and the reconfiguration of the 138 kV transmission system in Central Newfoundland.[7] Also, commencing in 2020 the Company will undertake an initiative to increase the automation of the transmission system through the addition of transmission line breakers monitored and controlled through the Supervisory Control and Data Acquisition ("SCADA") system.[8]

The Company operates approximately 2,000 km of transmission lines. Transmission capital expenditures are primarily driven by:

- preventive capital maintenance on aged and deteriorated transmission structures;
- rebuilding aging transmission lines; and
- third party requests.

The Company has a maintenance program in place for its transmission assets. The level of expenditure for capital maintenance, both breakdown and preventive, is expected to be relatively stable over the forecast period.

In its 2006 Capital Budget Application, the Company submitted its transmission strategy in the report titled ***3.1** Transmission Line Rebuild Strategy*. The report outlined the need to completely rebuild certain sections of aging transmission lines that are deteriorated. This proactive approach to managing transmission assets is expected to reduce failures over the long term. An update of the strategic plan is included in the report ***3.1** 2019 Transmission Line Rebuild* included with the 2019 Capital Budget Application.

---

7 The reconfiguration of the 138 kV transmission system in Central Newfoundland is being undertaken as the least cost alternative for dealing with the aged and deteriorated 66 kV transmission lines serving customers in Central Newfoundland. Details of the alternatives evaluated can be found in the report *Central Newfoundland System Planning Study*.

8 Typically these transmission line breakers will be added to rural substations on radial transmission systems. The addition of breakers will permit the upgrading of transmission and substation protective relaying schemes.

In 2019, the Company will rebuild 2 transmission lines, 1 each on the Baie Verte and Burin peninsulas. Transmission line 363L is a 138 kV H-Frame line running between Baie Verte Junction Substation on the Trans-Canada Highway and Seal Cove Road Substation located in Baie Verte. The line was originally constructed in 1963 and includes approximately 62 km of original construction. Transmission line 302L is a 66 kV single-pole line running between Salt Pond Substation in Burin and Laurentian Substation in St. Lawrence. The line was originally constructed in 1959 and includes approximately 27 km of original construction.[9]

The 90 km of 66 kV transmission lines from Grand Falls to Gander are approaching the end of their service lives and must be either rebuilt or retired from service. The 66 kV transmission system interconnects 4 substations serving customers in Central Newfoundland.[10] In its current configuration, the estimated cost to rebuild 66 kV transmission lines 101L and 102L is $16.5 million. The alternative to rebuilding the 66 kV transmission lines is to extend the existing 138 kV transmission system in Central Newfoundland to include Rattling Brook and Lewisporte substations.[11] The estimated cost to extend the existing 138 kV transmission system and to upgrade Rattling Brook and Lewisporte substations is $13.8 million. Extending the 138 kV transmission system is the least-cost alternative for providing reliable service to customers in Central Newfoundland. The extension of the 138 kV transmission system and necessary substation refurbishment, as described in the *Central Newfoundland System Planning Study*, will commence in 2019.

In 2021, the Company anticipates that additional transmission capacity will be required to supply substations in the area from Torbay to Portugal Cove, at an estimated cost of approximately $4.3 million over 2 years. In 2011, the Company installed a new 25 MVA transformer in Pulpit Rock Substation, and in 2020, the Company plans to install a new 25 MVA transformer in Broad Cove Substation. Both transformers are required due to customer and load growth in the area.[12] The transmission lines supplying these 2 substations are radial, with no contingency for the loss of supply other than mobile generation. The construction of new transmission lines is required to provide redundancy of supply to this growing area.

3.2.4 Substations

Substations capital expenditures are expected to average $15.3 million annually from 2019 through 2023, which is less than the average of $17.1 million annually from 2014 through 2018. The reduction in annual expenditure is related to fewer load growth related power transformer additions over the forecast period. Otherwise, the forecast level of expenditure is driven by substation refurbishment and modernization projects over the 5-year period.

---

[9] The projects to rebuild transmission lines 363L and 302L were approved in Order No. P.U. 37 (2017).

[10] The 66 kV transmission system between Grand Falls and Gander supplies substations at Rattling Brook, Notre Dame Junction, Lewisporte and Roycefield Mine. The transmission lines are designated 101L, 102L, 103L and 104L.

[11] This alternative would retire the Notre Dame substation, and continue to serve Roycefield Mine at 66 kV when it returns to production.

[12] Approximately 11,000 customers are served from these 2 substations.

The Company operates 130 substations containing approximately 4,000 pieces of critical electrical equipment. Substation capital expenditures are primarily driven by:

- preventive capital maintenance and modernization;
- breakdown capital maintenance;
- government regulations regarding the elimination of polychlorinated biphenyls ("PCBs"); and
- system load growth.

The Company has a preventive capital maintenance program in place for its substation assets. Preventive maintenance is expected to ensure that the overall reliability of substation assets remains stable.

In its 2007 Capital Budget Application, the Company submitted its *Substation Refurbishment and Modernization Plan* in a report titled *Substation Strategic Plan*. The 2007 plan addressed substation refurbishment and modernization work in 80% of the Company's substations in an orderly way over a multi-year planning horizon. This is consistent with the maintenance of reasonable year-to-year stability in the Company's annual capital budgets. Since 2007, work performed as part of the *Substation Refurbishment and Modernization* capital project has broadly reflected this approach. An update of the plan is included in the report ***2.1** 2019 Substation Refurbishment and Modernization* filed with this 2019 Capital Budget Application.

The *2019 Substation Refurbishment and Modernization* project also includes the automation of 19 distribution feeders. The requirement for increased automation was highlighted during the system events of January 2-8, 2014, which involved lengthy customer outages and successive rotating power outages, revealing control limitations on the Company's transmission and distribution systems.[13] SCADA control and monitoring will be implemented on the remaining distribution feeders by the end of 2019.

Over the 2019 to 2023 forecast period, there is a requirement to install 4 substation transformers to accommodate load growth.[14] The 4 additional substation transformers will be required for the Avalon Peninsula and Western Newfoundland.[15]

Government of Canada regulations require that equipment with PCB concentrations greater than 50 mg/kg and less than 500 mg/kg must be removed from service by 2025. The 5-Year Capital Plan includes expenditures of approximately $3.8 million to address PCB concentrations greater than 50 mg/kg and less than 500 mg/kg in advance of the 2025 deadline.

---

13 The level of monitoring is dependent on the type of protection and communication equipment installed at the substation and ranges from monitoring equipment status to the ability to remotely control equipment and configure protection settings.

14 By comparison, in the period 2014 through 2018, Newfoundland Power has purchased 7 new power transformers and relocated 4 power transformers to serve increased customer load. The purchase of new transformers and the relocation of other transformers to serve customer load growth are in addition to the requirement to replace aged or deteriorated equipment.

15 The Company's annual Capital Budget Applications will include engineering studies detailing the requirements for additional power transformers in the years in which they are required.

3.2.5 Distribution

Distribution capital expenditures from 2019 through 2023 are expected to average approximately $42.6 million annually, compared to an average of $48.0 million annually from 2014 through 2018. This decrease is largely attributable to lower expenditures related to customer growth and lower expenditure for meters, with the deployment of AMR meters completed in 2017.

The Company operates approximately 10,000 km of distribution lines serving approximately 268,000 customers. Distribution capital expenditures are primarily driven by:

- preventive capital maintenance on aged and deteriorated distribution structures;
- specific capital project initiatives, such as distribution reliability initiative rebuilds;
- new customers;
- system load growth;
- third party requests; and
- breakdown capital maintenance.

The number of new customer connections is forecast to decrease over the planning period when compared to the 2014 to 2018 period. Over the 5-year period from 2019 to 2023, growth in the number of new customer connections is anticipated to remain essentially flat. The associated decrease in capital expenditures between 5-year periods is primarily due to this reduction in the number of forecast new customer connections. Costs to connect new customers to the electricity system are included in the distribution projects *Extensions*, *Transformers*, *Services*, *Meters* and *Street Lighting*.

Table 5 shows the forecast number of new customer connections and the total capital expenditures associated with those connections over the next 5 years.

Table 5
New Customer Connections

	2019	**2020**	**2021**	**2022**	**2023**
New Customer Connections	2,593	2,627	2,647	2,687	2,598
Average Cost/Connection	$6,343	$6,449	$6,564	$6,672	$6,845
Capital Expenditure (000s)	$16,447	$16,941	$17,375	$17,928	$17,783

Over the period 2019 to 2023, the annual expenditure associated with new customer connections is forecast to be within the range of $16.4 million to $17.9 million, or approximately 16% of the annual capital expenditures.

Distribution capital expenditure related to system load growth primarily reflects growth in customer electricity requirements. The majority of this growth continues to be located in the St. John's Metropolitan Area. This requires the transfer of customer load or the upgrade of feeders to increase capacity. Expenditures for feeder modifications and additions due to system load growth from 2019 through 2023 are expected to total approximately $13.1 million over the next 5 years.[16]

Distribution capital expenditures are required to relocate or replace distribution lines to meet third party requests from governments, telecommunications companies and individual customers. In 2019, the expenditures associated with third party requests are estimated at $2.4 million. Over the 5-year period from 2019 through 2023, these expenditures are forecast to remain stable and average approximately $2.5 million annually.

In 2016, the Company accelerated the replacement of all remaining non-AMR meters with AMR meters. A detailed description of the Company's strategy to deal with new regulations and improved efficiency in the metering function can be found in the 2016 Capital Budget Application report ***4.4*** *2016 Meter Strategy*. Over the period 2019 to 2023, distribution capital expenditures for meters will be substantially reduced and average $693,000 per year.

In the 2013 Capital Budget Application, the Company outlined its preventive capital maintenance program for Distribution assets in the report ***4.4*** *Rebuild Distribution Lines Update*. The expenditures associated with the preventive capital maintenance program are budgeted in the annual *Rebuild Distribution Lines* project. The Company plans to perform preventive capital maintenance on approximately 43 distribution feeders per year over the planning period.

The Distribution *Reconstruction* project involves the replacement of deteriorated or damaged distribution structures and electrical equipment. The project is comprised of small unplanned projects and is estimated using the historical average of the most recent 5-year period.

The Company ranks its distribution feeders based on reliability performance and completes in-field assessments of those with the poorest performance statistics. Capital upgrades are performed on the worst-performing feeders under the *Distribution Reliability Initiative* project.

The Company has experienced increased failures with distribution conductor. Generally, conductor has a service life that exceeds that of its support structures, including insulators, crossarms and poles. Therefore, most often conductor is not replaced when distribution feeders are rebuilt. As a result, some distribution feeders have good support structures with conductor that is now starting to fail.

---

16 Capital expenditures for the *Feeder Additions for Load Growth* project for the 5-year period 2014 to 2018 were approximately $7.6 million.

Chart 6 shows the number of interruptions experienced related to the 3 largest causes for equipment failure, conductor, insulators and cutouts. In 2017, conductor failures are occurring at a rate 3 times greater than insulator or cutout failures.

Chart 6
Interruptions by Cause
2008 - 2017

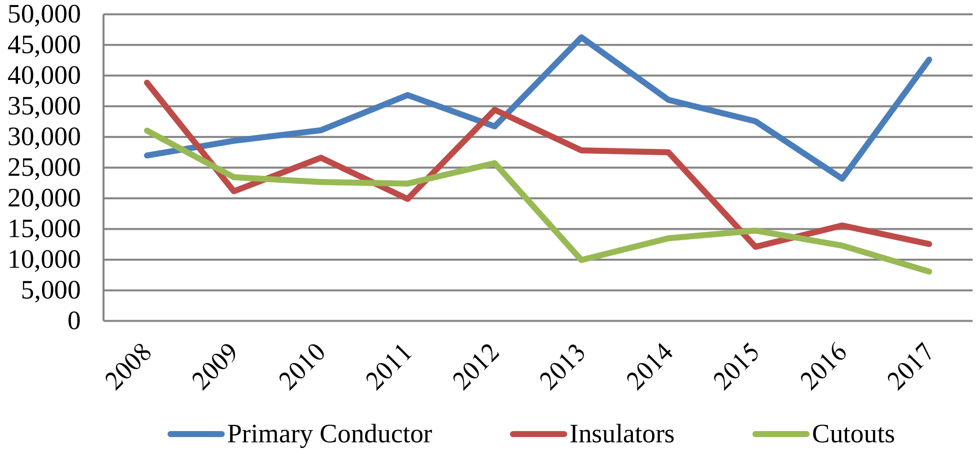
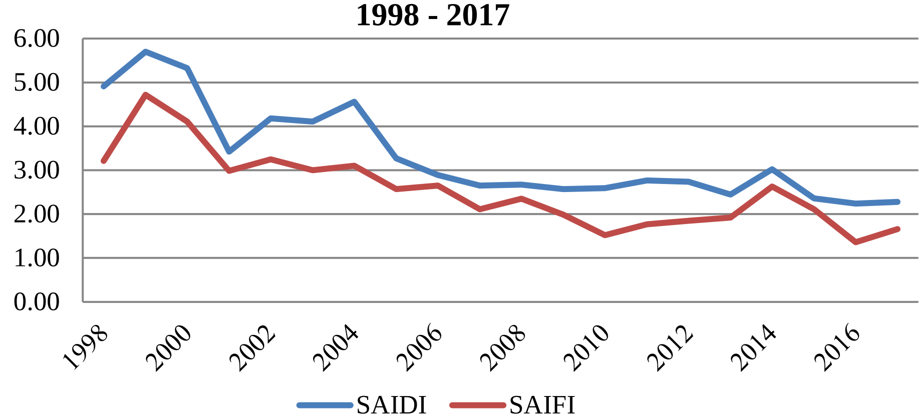


Chart 7 shows SAIDI, or System Average Interruption Duration Index, and SAIFI, or System Average Interruption Frequency Index, for the 20 year period from 1998 through 2017. Chart 7 has been adjusted to remove the effects of severe weather and system events.[17]

Chart 7
SAIDI and SAIFI
1998 - 2017



[17] Adjustments exclude the 2007 and 2010 Bonavista ice storms, Hurricane Igor in 2010, the December 2011 high wind event, Tropical Storm Leslie in September 2012, the Central Newfoundland winter storm in November 2013 and the December 16, 2016 severe wind storm in Western Newfoundland. These exclusions are consistent with the Canadian Electricity Association approved definitions.

Newfoundland Power considers current levels of service reliability on a system-wide basis to be satisfactory.

In 2014, Newfoundland Power incorporated additional reliability indices, CIKM and CHIKM, into its reliability analysis.[18] This has resulted in additional distribution feeders being identified for work under the *Distribution Reliability Initiative* project.[19] In 2019, reliability rebuilds will take place on distribution feeder DUN-01 out of Dunville Substation, GBY-03 out of Gander Bay Substation and SJM-06 in St. John's. Details on these projects can be found in the report ***4.1*** *Distribution Reliability Initiative*.

The Company, through the *Distribution Feeder Automation* project, is increasing the number of downstream reclosers on the distribution system. Installing more of these reclosers over time is a cost-effective way of further improving distribution reliability.[20] In 2019, the Company will install 10 additional automated reclosers on distribution feeders. Additional distribution feeder automation will improve the Company's capability to deal with cold load pickup and improve efficiency of restoration following both local and system-wide outages. Downline reclosers on distribution feeders will improve reliability performance when used to isolate faulted segments downstream from undamaged upstream sections of feeder.

3.2.6 General Property

The General Property asset class includes capital expenditures for:

- the addition or replacement of tools and equipment utilized by line and engineering staff;
- the replacement or addition of office furniture and equipment;
- additions to real property necessary to maintain buildings and facilities;
- the refurbishment of Company buildings and related security infrastructure; and
- backup electricity generation at Company buildings.

General Property capital expenditures are expected to average $3.6 million annually from 2019 through 2023, which is more than the average of $2.0 million for the period from 2014 through 2018. General Property capital expenditures involve addressing deterioration associated with Company-owned office, service and special purpose buildings throughout its service territory.

3.2.7 Transportation

The Transportation asset class includes the heavy truck fleet, passenger and off-road vehicles. The replacement of these vehicles can be influenced by a number of factors, including kilometres traveled, vehicle condition, operating experience and maintenance expenditures.

---

[18] In 2012, the Canadian Electricity Association began capturing and reporting on 2 additional indices: (i) Customer Hours of Interruption per Kilometer ("CHIKM"); and (ii) Customers Interrupted per Kilometer ("CIKM").

[19] It is anticipated that by using indices that consider customer interruptions and circuit length, the worst-performing feeders will be found in urban settings where the Company has issues with older poles and associated infrastructure.

[20] Recommendation 2.4 of Liberty Consulting Group's *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power, December 17, 2014*, identified the potential for downline reclosers to positively impact reliability indices.

Transportation capital expenditures from 2019 through 2023 are expected to increase to an average of approximately $3.9 million annually, compared to an average of $3.3 million annually from 2014 through 2018. The Company operates 71 heavy fleet vehicles, which have an anticipated service life of 10 years. On average, it would be expected that approximately 7 heavy fleet vehicles and 40 passenger vehicles would be replaced annually. The increase in transportation capital expenditures from 2019 through 2023 is principally reflective of inflation and the number of heavy fleet and passenger vehicles expected to meet the replacement parameters over the period.

3.2.8 Telecommunications

Capital expenditure in the Telecommunications asset class includes the replacement or upgrading of various communications systems. These systems contribute to customer service, safety, and power system reliability by supporting communications between the Company's fleet of vehicles, substations, plants and offices.

Telecommunications capital expenditures are expected to average approximately $182,000 annually from 2019 through 2023, similar to the annual average of $163,000 from 2014 through 2018. Over the next 5-year period, the Telecommunications capital expenditures are largely associated with the completing a network of fibre optic cables between substations in the City of Corner Brook and the replacement of the St. John's multiplexer system that provides transmission line protection in the City of St. John's. The Company's fibre optic systems provide telecommunications for the Company's remote control and protective relaying technology.

3.2.9 Information Systems

The Information Systems asset class capital expenditure includes:

- the replacement of shared server and network infrastructure, personal computers, printers and associated assets;
- upgrades to current software tools, processes, and applications, as well as the acquisition of new software licenses; and
- the development of new applications or enhancements to existing applications to support changing business requirements and take advantage of software product improvements.

Information Systems capital expenditures from 2019 through 2023 are expected to increase to an average of approximately $11.8 million annually, compared to an average of $6.1 million annually from 2014 through 2018. The increase is largely driven by the replacement of corporate systems, such as the completion of the Outage Management System in 2018 - 2019 and the Customer Service System in 2021 - 2023.

3.2.10 Unforeseen Allowance

The Unforeseen Allowance covers any unforeseen capital expenditures that have not been budgeted elsewhere. The purpose of the account is to permit the Company to act expeditiously to deal with exigent circumstances in advance of seeking approval of the Board.

The Unforeseen Allowance constitutes $750,000 in each year's capital budget from 2019 through 2023.

3.2.11 General Expenses Capitalized

General Expenses Capitalized is the allocation of a portion of administrative costs to capital. In accordance with Order No. P.U. 3 (1995-96), the Company uses the incremental cost method of accounting for the purpose of capitalization of general expenses.

General Expenses Capitalized of $4.0 million is reflected in each year's capital budget from 2019 through 2023.

3.3 5-Year Plan: Risks

While the Company accepts the Board's view of the desirable effects of year-to-year capital expenditure stability, the nature of the utility's obligation to serve will not, in all circumstances, necessarily facilitate such stability. The Company has identified some risks to such stability in the period 2019 through 2023.

Newfoundland Power has an obligation to serve customers in its service territory. The capital expenditure required to provide such service is impacted by customer and load growth. New home construction on the Northeast Avalon Peninsula has decreased considerably compared with the previous 5-year period, and is expected to deteriorate over the forecast period. The current forecast for new customer connections indicates a decline throughout the Company's service territory.[21]

Should customer and load growth vary from forecast, so will the capital expenditures that are sensitive to growth. For example, there are a number of power transformers in the Company's 5-year forecast. Should customer and load growth materially vary from forecast, the capital expenditure for the required transformers (each in the order of $2 million to $3 million) may also vary from the current 5-year forecast.

The age of the Company's power transformers presents another potential risk to the stability of the capital forecast. In-service failures of power transformers, such as occurred with the Riverhead, Kenmount, Horsechops, Pierre's Brook and Salt Pond power transformers, may necessitate unplanned capital expenditures.[22]

Newfoundland Power's gas turbines range in age from 43 years to 49 years. These gas turbines had a significant increase in usage in recent years for outages and in support of Island reserve. The 5-year forecast has identified refurbishment work on both the Greenhill and Wesleyville gas turbine systems. An in-service failure of either gas turbine system will necessitate a change to this plan.

---

21 Forecast gross new customer connections have declined to levels not seen for the past 20 years.

22 Replacement of the Riverhead power transformer was approved in Board Order No. P.U. 6 (2017). Replacement of the Horsechops power transformer was approved as part of the 2009 Capital Budget Application in Board Order No. P.U. 27 (2008). Replacement of the Pierre's Brook power transformer was approved in Board Order No. P.U. 3 (2008). Replacement of the Salt Pond power transformer was approved in Board Order No. P.U. 15 (2002-2003). Kenmount power transformer failed in-service in March 2009 and its refurbishment was approved in Board Order No. P.U. 29 (2009).

The Company continues to take steps to reduce risks associated with the operation of its Customer Service System, which has been in service since 1991.[23] In recent years, these steps have included upgrades of hardware and software components and removal of technology components that posed the highest risk. While the current versions of hardware, software and database technology continue to be supported, commencing in 2021, the Company has included a project to replace its Customer Service System. Any changes to the availability of support to existing technology platforms could materially impact the capital plan.

Capital expenditures can be impacted by major storms or weather events. In 1984 and 1994, the Company was impacted by sleet storms that resulted in widespread damage and service interruption to customers. On March 5-6, 2010, an ice storm in Eastern Newfoundland caused widespread power outages on the Bonavista and Avalon peninsulas. In September 2010, Hurricane Igor caused extensive damage to the Company's generation and distribution assets. In 2012, Tropical Storm Leslie caused damage to the distribution system. The occurrence and costs of severe storms are not predictable.

The Board is currently conducting an investigation into the adequacy of reliability of electricity supply on the Island of Newfoundland. It is currently uncertain what, if any, impact the results of this investigation may have on Newfoundland Power's capital expenditures. Accordingly, this 5-Year Capital Plan does not include expenditures which may be required as a result of the matters currently under investigation by the Board.

[23] The Company's existing Customer Service System originally cost in excess of $10 million. A replacement system is estimated to cost in the range of $25 million to $30 million.

Appendix A
2019-2023 Capital Plan

Newfoundland Power Inc.
2019-2023 Capital Plan
(000s)

Asset Class	**2019**	**2020**	**2021**	**2022**	**2023**
Generation	$10,905	$12,181	$15,479	$12,894	$10,121
Substations	$13,039	$16,473	$12,824	$16,888	$17,342
Transmission	$10,781	$9,137	$12,877	$14,590	$13,884
Distribution	$40,001	$41,125	$43,232	$44,232	$44,612
General Property	$2,630	$2,749	$3,893	$3,864	$4,941
Transportation	$3,990	$3,931	$3,999	$3,719	$3,793
Telecommunications	$233	$108	$342	$112	$114
Information Systems	$6,975	$6,954	$10,239	$16,584	$18,230
Unforeseen Allowance	$750	$750	$750	$750	$750
General Expenses Capitalized	$4,000	$4,000	$4,000	$4,000	$4,000
Total	**$93,304**	**$97,408**	**$107,635**	**$117,633**	**$117,787**

Newfoundland Power Inc.
2019-2023 Capital Plan
(000s)

GENERATION

Project	2019	2020	2021	2022	2023
Facilities Rehabilitation Hydro	$1,502	$1,419	$1,536	$1,468	$1,574
Facilities Rehabilitation Thermal	$327	$333	$340	$346	$353
Cape Broyle Upgrades	$0	$0	$1,378	$0	$0
Enclosure for Orenda GT	$0	$850	$0	$0	$0
Greenhill Refurbishment	$0	$0	$2,413	$2,245	$0
Horsechops Plant Upgrade	$0	$0	$0	$0	$2,130
Mobile Plant Upgrades	$0	$0	$0	$8,835	$0
Petty Harbour Plant Upgrade	$0	$0	$0	$0	$4,352
Portable Generation	$7,915	$0	$0	$0	$0
Rattling Brook Upgrades	$1,161	$1,161	$0	$0	$0
Rose Blanche Upgrades	$0	$0	$775	$0	$0
Sandy Brook Upgrades	$0	$6,006	$0	$0	$0
Topsail Plant Upgrades	$0	$0	$7,620	$0	$0
Tors Cove Plant Upgrade	$0	$0	$0	$0	$1,712
Wesleyville Refurbishment	$0	$2,412	$1,417	$0	$0
Total - Generation	**$10,905**	**$12,181**	**$15,479**	**$12,894**	**$10,121**

Newfoundland Power Inc.
2019-2023 Capital Plan
(000s)

SUBSTATIONS

Project	2019	2020	2021	2022	2023
Substations Refurbishment and Modernization	$8,580	$6,557	$8,158	$9,559	$9,584
Replacements Due to In-Service Failure	$3,547	$3,616	$3,685	$3,756	$3,832
Additions Due to Load Growth	$0	$5,000	$0	$2,500	$2,500
Substation Feeder Terminations	$0	$546	$200	$259	$870
PCB Bushing Phase Out	$912	$754	$781	$814	$556
Total – Substations	**$13,039**	**$16,473**	**$12,824**	**$16,888**	**$17,342**

Newfoundland Power Inc.
2019-2023 Capital Plan
(000s)

TRANSMISSION

Project	2019	2020	2021	2022	2023
Rebuild Transmission Lines	$8,681	$6,637	$8,397	$8,824	$10,884
Transmission Line Reconstruction	$2,100	$2,000	$2,200	$2,200	$2,200
Transmission Line Additions	$0	$0	$1,580	$2,766	$0
Transmission Line Automation	$0	$500	$700	$800	$800
Total – Transmission	**$10,781**	**$9,137**	**$12,877**	**$14,590**	**$13,884**

Newfoundland Power Inc.
2019-2023 Capital Plan
(000s)

DISTRIBUTION

Project	2019	2020	2021	2022	2023
Extensions	$10,725	$11,079	$11,383	$11,782	$11,619
Meters	$622	$672	$710	$737	$722
Services	$3,037	$3,129	$3,210	$3,312	$3,290
Street Lighting	$2,301	$2,337	$2,374	$2,412	$2,451
Transformers	$6,716	$6,844	$6,974	$7,107	$7,249
Reconstruction	$5,376	$5,482	$5,590	$5,701	$5,815
Rebuild Distribution Lines	$3,977	$4,055	$4,135	$4,216	$4,301
Relocations For Third Parties	$2,442	$2,490	$2,538	$2,586	$2,638
Distribution Reliability Initiative	$1,800	$1,900	$1,200	$1,420	$1,500
Distribution Feeder Automation	$675	$675	$625	$625	$625
Feeder Additions for Load Growth	$1,715	$2,242	$2,937	$2,618	$3,600
Trunk Feeders	$400	$0	$0	$600	$570
St. John's Underground Refurbishment	$0	$0	$1,332	$888	$0
Allowance for Funds Used During Construction	$215	$220	$224	$228	$232
Total – Distribution	**$40,001**	**$41,125**	**$43,232**	**$44,232**	**$44,612**

Newfoundland Power Inc.
2019-2023 Capital Plan
(000s)

GENERAL PROPERTY

Project	2019	2020	2021	2022	2023
Tools and Equipment	$467	$476	$485	$494	$504
Additions to Real Property	$489	$395	$402	$359	$366
Renovations Company Buildings	$1,374	$1,528	$2,656	$2,661	$3,721
Physical Security Upgrades	$300	$350	$350	$350	$350
Total – General Property	**$2,630**	**$2,749**	**$3,893**	**$3,864**	**$4,941**

Newfoundland Power Inc.
2019-2023 Capital Plan
(000s)

TRANSPORTATION

Project	2019	2020	2021	2022	2023
Replace Vehicles and Aerial Devices	$3,515	$3,581	$3,649	$3,719	$3,793
Purchase New Vehicles and Aerial Devices	$475	$350	$350	$0	$0
Total – Transportation	**$3,990**	**$3,931**	**$3,999**	**$3,719**	**$3,793**

Newfoundland Power Inc.
2019-2023 Capital Plan
(000s)

TELECOMMUNICATIONS

Project	2019	2020	2021	2022	2023
Replace/Upgrade Communications Equipment	$106	$108	$110	$112	$114
Fibre Optic Cable	$127	$0	$232	$0	$0
Total – Telecommunications	**$233**	**$108**	**$342**	**$112**	**$114**

Newfoundland Power Inc.
2019-2023 Capital Plan
(000s)

INFORMATION SYSTEMS

Project	2019	2020	2021	2022	2023
Application Enhancements	$1,252	$1,200	$900	$750	$600
System Upgrades	$1,258	$1,742	$1,771	$1,802	$2,533
Personal Computer Infrastructure	$472	$492	$506	$520	$535
Shared Server Infrastructure	$848	$1,210	$930	$559	$586
Network Infrastructure	$322	$354	$565	$375	$386
Cybersecurity Upgrades	$398	$556	$567	$578	$590
Operations Technology	$0	$1,400	$0	$0	$0
Customer Service System	$0	$0	$5,000	$12,000	$13,000
Outage Management System	$1,210	$0	$0	$0	$0
Human Resource System	$1,215	$0	$0	$0	$0
Total – Information Systems	**$6,975**	**$6,954**	**$10,239**	**$16,584**	**$18,230**

Newfoundland Power Inc.
2019-2023 Capital Plan
(000s)

UNFORESEEN ALLOWANCE

Project	2019	2020	2021	2022	2023
Allowance for Unforeseen Items	$750	$750	$750	$750	$750
Total - Unforeseen Allowance	**$750**	**$750**	**$750**	**$750**	**$750**

Newfoundland Power Inc.
2019-2023 Capital Plan
(000s)

GENERAL EXPENSES CAPITALIZED

Project	2019	2020	2021	2022	2023
General Expenses Capitalized	$4,000	$4,000	$4,000	$4,000	$4,000
Total - General Expenses Capitalized	**$4,000**	**$4,000**	**$4,000**	**$4,000**	**$4,000**

Central Newfoundland System Planning Study

July 2018

Prepared by:

Jonathan O'Reilly
Robert Cahill, Eng. L.

REGISTERED LIMITED LICENSEE · ENG. L.
PEG Newfoundland and Labrador
ROBERT J. CAHILL
SIGNATURE
2018-07-08
DATE
NEWFOUNDLAND & LABRADOR

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

This study was initiated as a result of transmission lines 101L and 102L requiring replacement. These two transmission lines form a 66 kV system supplying customers from Norris Arm South to Birchy Bay in Central Newfoundland, including the town of Lewisporte. Both lines combined are over 90 km in length and are in excess of 60 years old. Inspections have identified that both lines are in deteriorated condition and have reached end of life.[1]

Due to the high capital costs required to rebuild both existing 66 kV transmission lines other alternatives were examined to determine the least cost alternative to address their replacement. This study identifies the capital projects required to provide safe, reliable, least cost electrical service to this Central Newfoundland area.

2.0 Background

The electrical transmission system in Central Newfoundland consists of both 66 kV and 138 kV transmission lines.

The 66 kV transmission lines run between Grand Falls ("GFS') Substation and Gander ("GAN") Substation. This 66 kV system includes 2 transmission lines, 101L and 102L, that interconnect Rattling Brook ("RBK"), Notre Dame Junction ("NDJ") and Roycefield ("RFD") substations. These lines were constructed in the late 1950's to create an integrated electrical system in Central Newfoundland by interconnecting the Rattling Brook hydro development to the isolated electrical distribution systems in Grand Falls, Lewisporte and Gander. Today, the 66 kV system supplies electrical service to approximately 5,000 customers in the communities of Norris Arm South, Lewisporte and surrounding areas.

After the construction of the Bay d'Espoir hydroelectric development in 1967, additional transmission infrastructure was required to accommodate the growing demand for electricity in Central Newfoundland. This led to the establishment of a 138 kV transmission system in Central Newfoundland originating from Stoney Brook ("STY") Terminal Station that included TL210, a 138 kV transmission line constructed by Newfoundland and Labrador Hydro to connect Glenwood ("GLN") and Cobb's Pond ("COB") substations. The expansion of the 138 kV transmission system continued throughout the 1970's and early 1980's as demand for electricity increased. In 1981 a 138 kV transmission line, 136L, was constructed between Bishop Falls ("BFS") and COB substations.[2]

[1] A condition assessment of 101L and 102L is included as Appendix C of the *2019 Transmission Line Rebuild* report.

[2] BFS Substation is connected to STY Terminal Station by 138 kV transmission line 133L.

Figure 1 illustrates the current configuration and routing of both the 66 kV and 138 kV Central Newfoundland transmission systems.

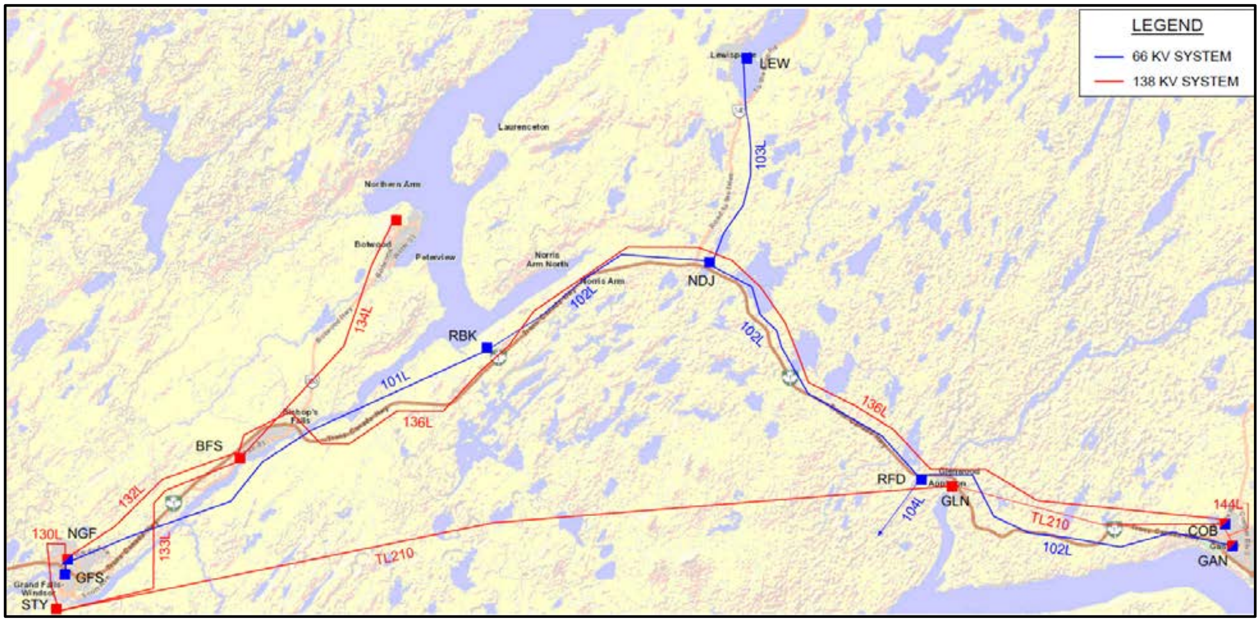


Figure 1: Central Newfoundland Existing System

2.1 Central Newfoundland 66 kV Transmission System

Transmission line 101L was originally constructed in 1957 and is approximately 32.5 km in length. 101L provides a 66 kV link between GFS and RBK substations. 101L leaves GFS Substation and runs east through the Town of Grand Falls-Windsor, along the Trans-Canada Highway to Route 351 and onto RBK Substation.

Transmission line 102L was originally constructed in 1958, is approximately 61 km in length and is divided into three sections. The first section is approximately 17 km and runs from RBK Substation to NDJ Substation. The second section of 102L is approximately 20 km and runs from NDJ Substation to RFD Substation.[3] The third section of 102L is approximately 24 km and runs from RFD Substation to GAN Substation.

Transmission line 103L was originally constructed in 1973, is approximately 14 km in length and provides a 66 kV radial transmission feed from NDJ Substation to Lewisporte ("LEW") Substation.[4]

3 RFD Substation and the associated 104L radial transmission line were constructed in 1997 to provide electrical service to Beaver Brook Antimony Mine.

4 Prior to 1973 the Town of Lewisporte was supplied by a distribution feeder from RBK Substation.

2.2 Transmission Line 136L

Transmission line 136L was originally constructed in 1981, is approximately 81.0 km in length and provides a 138 kV link between BFS and COB substations. 136L leaves BFS Substation and generally follows the Trans-Canada Highway to approximately 6.0 km west of the Town of Gander. It then continues cross country for approximately 7.5 km until it enters COB Substation. Most of the structures on 136L are of H-Frame construction.

2.3 System Reliability

Newfoundland Power calculates its reliability performance according to the Canadian Electricity Association ("CEA") guidelines.[5] The existing electrical system reliability for the customers served by the 66kV Central Newfoundland transmission system are at a satisfactory level as indicated by historical reliability statistics. The overall 5-year average SAIDI for the customers supplied from LEW and RBK substations is 4.93 which is comparable with the Company 5-year average of 5.03 for similar rural substations.[6] However, both 66 kV transmission lines supplying these substations have been in service for approximately 60 years and have reached the point where continued maintenance cannot guarantee the provision of safe reliable service into the future.

3.0 Technical Evaluation

The focus of Newfoundland Power's system planning function is to avoid or minimize equipment overloading and provide adequate system voltages to ensure a reliable electricity supply to customers. This process typically involves engineering studies to identify and evaluate cost effective, technically viable upgrade alternatives where necessary. The technical evaluation criteria used to evaluate the alternatives include the minimum and maximum allowable substation voltage levels for both normal and contingency system conditions.[7] The criteria also includes normal and contingency loading limits for substation transformers and transmission lines during summer and winter conditions.[8]

Each potential alternative is examined under normal and contingency system conditions. The examination was completed using zero projected load growth.[9] However, a sensitivity analysis

---

[5] The CEA's recommended reporting standard is IEEE Std 1366 – 2012, contained within the *IEEE Guide for Electric Power Distribution Reliability Indices*. All reliability data calculated by the Company follows this reporting standard.

[6] "SAIDI" denotes System Average Interruption Duration Index. It is a standard metric used to measure the duration of outages experienced by customers. SAIDI is calculated by dividing the total number of customer outage hours by the total number of customers served. Newfoundland Power calculates SAIDI in accordance with CEA guidelines.

[7] Contingency is defined as the loss of any single system component, possible multiple component failure or cold load pickup.

[8] See Appendix A for Technical Evaluation Criteria.

[9] The current 5 year forecast for the study area shows declining customer usage with uncertainty surrounding long term growth.

was completed to evaluate the impact of potential load growth on each of the selected alternatives.[10]

4.0 Development of Alternatives

Three alternatives have been developed and evaluated to meet the long term electrical transmission system requirements for the customers served from RBK and LEW substations.[11]

The section of 102L that connects GAN Substation to RFD Substation was not addressed in alternatives 2 and 3 which involve transferring LEW and RBK substations to the 138 kV transmission system.[12] Beaver Brook Antimony Mine is the only customer supplied from RFD Substation and has been idled since 2013 with minimal electrical load requirements.[13] If the mine was to re-establish operations Newfoundland Power would assess alternatives to provide reliable service to this customer.

The description of each alternative below includes estimates for all of the capital costs involved including substation and transmission line upgrades. See Appendix B for an illustration of each alternative.

4.1 Alternative 1

- In 2019, rebuild the 32.5 km section of 101L transmission line between RBK Substation and GFS Substation.
- In 2020, rebuild the 17.0 km section of 102L transmission line between RBK Substation and NDJ Substation.
- In 2021 rebuild the 20.5 km section of 102L transmission line between NDJ Substation and RFD Substation.
- In 2021 rebuild the 23.5 km section of 102L transmission line between RFD Substation and GAN Substation.

---

10 Results of the analysis can be found in Section 5.3 of this study.

11 The 3 alternatives evaluated are the only reasonable alternatives. Other alternatives, including upgrading NDJ Substation, were preliminarily evaluated and ruled out based on the significantly higher capital costs that would be associated with the alternative.

12 For Alternative 1, 102L will be rebuilt in 2021 and will continue to supply RFD substation at 66 kV.

13 The existing 66 kV structures from GAN Substation to RFD Substation will remain in place to serve the minimal electrical load requirements of the Beaver Brook Antimony Mine for Alternatives 2 and 3.

Table 1 shows the capital costs estimated for Alternative 1.[14]

Table 1
Alternative 1 Capital Costs
($000)

Year	Item	Cost
2019	Rebuild 32.5 km of 101L transmission line.	$5,582
2020	Rebuild 17.0 km of 102L transmission line between RBK Substation and NDJ Substation.	$2,998
2021	Rebuild 20.5 km of 102L transmission line between NDJ Substation and RFD Substation.	$3,713
2021	Rebuild 23.5 km of 102L transmission line between RFD Substation and GAN Substation.	$4,256
	Total	**$16,549**

4.2 Alternative 2

- In 2019, build a new 14.0 km, 138 kV transmission line extension from 136L to LEW Substation.
- In 2019, convert LEW Substation from 66 kV to 138 kV which would include the following; replace the existing 25 MVA, 66/25 kV LEW-T1 transformer with a new 25 MVA, 138/25 kV transformer, install a new 138 kV steel bus structure and two new 138 kV breakers, install a new 25kV steel bus structure and relocate existing feeder terminations.[15]
- In 2020, rebuild 14.0 km of 103L as a 138 kV transmission line extension from 136L to LEW Substation. This will involve splitting the existing 136L into two transmission lines, one from GAN Substation to LEW Substation and one from BFS Substation to LEW Substation.[16]
- In 2021, rebuild the 32.5 km of transmission line 101L from GFS Substation to RBK Substation.

[14] This alternative only involves the cost to rebuild 101L and 102L. The future capital costs associated with the rebuild of 103L and refurbishment of LEW Substation, which are both approaching 45 years in service, are not included in Alternative 1. In Alternatives 2 and 3 LEW Substation is being refurbished in 2019 and 103L will be rebuilt in 2020. Addressing the age and deterioration of LEW Substation and 103L at a future date will have the effect of increasing the overall capital costs associated with Alternative 1.

[15] See Appendix C for LEW Substation Single Line - Conversion to 138 kV.

[16] Splitting the existing 136L into two transmission lines, one from GAN Substation to LEW Substation and one from BFS Substation to LEW Substation, and terminating these lines with breakers at LEW Substation, will provide the option of energizing LEW Substation from either the Gander or Bishop Falls ends. This additional flexibility will provide reliability benefits for both planned and unplanned outages.

Table 2 shows the capital costs estimated for Alternative 2.[17]

Table 2
Alternative 2 Capital Costs
($000)

Year	Item	Cost
2019	Build a new 14.0 km, 138 kV transmission line extension from 136L to LEW Substation.	$2,322
2019	Convert LEW Substation from 66 kV to 138 kV.	$4,164
2020	Rebuild 14.0 km of 103L transmission line to 138 kV standards. Split 136L into two 138 kV transmission lines.	$2,383
2021	Rebuild 32.5 km section of 101L from GFS Substation to RBK Substation.	$5,886
	Total	**$14,755**

4.3 Alternative 3

- In 2019, build a new 14.0 km, 138 kV transmission line extension from 136L to LEW Substation.
- In 2019, convert LEW substation from 66 kV to 138 kV which would include the following; replace the existing 25 MVA, 66/25 kV LEW-T1 transformer with a new 25 MVA, 138/25 kV transformer, install a new 138 kV steel bus structure and two new 138 kV breakers, install a new 25kV steel bus structure and relocate existing feeder terminations.[18]
- In 2020, rebuild 14.0 km of 103L as a 138 kV transmission line extension from 136L to LEW Substation. This will involve splitting the existing 136L into two transmission lines, one from GAN Substation to LEW Substation and one from BFS Substation to LEW Substation.[19]
- In 2021, construct two new 1.4 km 138 kV transmission lines from 136L to RBK Substation.

[17] Alternative 2 involves the decommissioning of 102L from RBK Substation to RFD Substation, NDJ Substation, 103L and the 66 kV portions of LEW Substation.
[18] See Appendix C for LEW Substation Single Line - Conversion to 138 kV.
[19] Similar to Alternative 2, splitting the existing 136L into two transmission lines provides additional flexibility and reliability benefits for both planned and unplanned outages.

- In 2021, install a new 25 MVA 138 kV/66 kV system transformer at RBK Substation and install a 138 kV bus structure with two new 138 kV breakers.[20]

Table 3 shows the capital costs estimated for Alternative 3.[21]

Table 3
Alternative 3 Capital Costs
($000)

Year	Item	Cost
2019	Build a new 14.0 km, 138 kV transmission line extension from 136L to LEW Substation.	$2,322
2019	Convert LEW Substation from 66 kV to 138 kV.	$4,164
2020	Rebuild 14.0 km of 103L transmission line to 138 kV standards. Split 136L into two 138 kV transmission lines.	$2,383
2021	Build two new 138 kV transmission lines to RBK from 136L. Split 136L into two 138 kV transmission lines.	$507
2021	Install 138 kV system transformer, structure and 2 new 138 kV breakers at RBK Substation.	$4,265
	Total	**$13,641**

5.0 Evaluation of Alternatives

Each of the 3 alternatives have been evaluated to determine the alternative that best meets the long term electrical transmission system requirements of Central Newfoundland area. These alternatives were evaluated using economic and sensitivity analysis as well as technical evaluation to determine the lowest possible cost solution consistent with safe and reliable service. The economic analysis evaluated the value of each alternative in net present dollars. The technical evaluation used power system analysis software to evaluate each alternative to determine possible operational constraints and/or reliability impacts to customers. The sensitivity analysis included an evaluation of changes to the cost of system losses and effect of future system load growth for each alternative.

[20] See Appendix C for RBK Substation Single Line - 138 kV Substation Expansion.
[21] Alternative 3 involves the decommissioning of 101L, 102L from RBK Substation to RFD Substation, NDJ Substation, 103L and the 66 kV portions of LEW Substation.

5.1 Economic Analysis

In order to compare the economic impact of the alternatives, a Net Present Value ("NPV") calculation of customer revenue requirement was completed for each alternative. Capital costs from 2019 to 2021 were converted to the customer revenue requirement and the resulting customer revenue requirement was reduced to a NPV using the Company's weighted average incremental cost of capital.[22] The NPV analysis also accounts for the salvage value of the existing LEW-T1 removed from service when applicable.

The cost of annual system losses for each alternative, calculated at a marginal rate of $0.050/kWh, is also included in the NPV calculation.[23] Sensitivity analysis of the impact of the cost of system losses at other marginal rates were also completed for each alternative and are included in Section 5.3.

Table 5 shows the NPV of customer revenue requirement for each alternative under the base case load forecast.

Table 5
Net Present Value Analysis
($000)

Alternative	NPV
1	29,908
2	25,617
3	24,229

Alternative 3 has the lowest NPV of customer revenue requirement. As a result, Alternative 3 is recommended as the most appropriate alternative from an economic perspective.

5.2 Technical Evaluation

In order to complete the technical evaluation of each alternative, load flows were completed under normal and contingency system conditions using power system analysis software. Each alternative was also evaluated to determine possible operational constraints and/or reliability impacts to customers.

The evaluation concluded that all 3 alternatives will have improved system operation capabilities to provide greater overall reliability to customers. Alternatives 2 and 3 have the greatest

---

22 Annual operating maintenance cost differences for each alternative are negligible and do not impact the NPV analysis. As a result, the NPV analysis does include future operating maintenance costs.

23 An estimate of the marginal cost of production during the transition period prior to the Muskrat Falls project completion is 5.0 ¢/kWh for energy in 2019 and 5.3 ¢/kWh for energy in 2020 as per Hydro's 2017 General Rate Application responses to Request for Information CA-NLH-081 and CA-NLH-258 respectively.

potential positive impact on customer reliability due to the addition of a second transmission supply to the approximate 4,400 customers supplied from LEW Substation. Alternative 3 provides additional positive reliability impacts to the 750 customers served from RBK Substation compared to Alternative 2 due to the looped 138 kV transmission supply to RBK Substation included in Alternative 3.

Alternative 3 will provide enhanced electrical service reliability to customers. This supports the conclusion of the economic analysis.

5.3 Sensitivity Analysis

A sensitivity analysis was completed to evaluate (i) changes in the cost of system losses and (ii) the impact of potential load growth on the Central Newfoundland system.

5.3.1 System Losses

In order to compare the impact of changes in system losses for each alternative, a system loss cost calculation was completed for each alternative at marginal rates of \$0.05/kWh ± \$0.02/kWh. To further test the impact of the cost of losses for each alternative, each alternative was evaluated with the cost of losses excluded (i.e. a marginal rate of \$0/kWh).

Table 6 shows the NPV of customer revenue requirement for each alternative including the cost of system losses at \$0.070/kWh, \$0.030/kWh and \$0/kWh marginal cost scenarios.

Table 6
Sensitivity Analysis – System Losses
(\$000)

Alternatives	\$0.070/kWh NPV	\$0.030/kWh NPV	\$0/kWh NPV
1	34,430	25,385	18,601
2	29,209	22,027	16,639
3	27,774	20,684	15,366

Alternative 3 has the lowest NPV of customer revenue requirement including the cost of system losses at \$0.070/kWh, \$0.030/kWh and \$0/kWh marginal cost scenarios and supports the conclusion of the economic analysis.

5.3.2 Load Growth

In order to compare the impact of load growth, each alternative was analyzed to determine how much extra load growth could be supplied without violating any of the technical criteria. The analysis showed that all 3 alternatives could accommodate over 40% additional load growth under normal conditions while maintaining reliable service to customers. Under contingency conditions Alternatives 1 and 3 could both accommodate approximately 10% additional load growth. Alternative 2 could accommodate approximately 7% additional load growth under contingency conditions.

Alternative 3 provides available system capacity for future load growth and supports the conclusion of the economic analysis.

6.0 Recommendation

The economic analysis performed in Section 5.1 of this study indicates Alternative 3 is the least cost alternative that meets all of the required technical criteria. The sensitivity analysis performed in Section 5.3 for both system losses and potential future load growth supports the conclusion of the economic analysis. The technical evaluation of each alternative indicates that Alternative 3 will provide long term reliable electrical service to customers currently supplied by the existing 66 kV transmission system.

Based on this evaluation, Alternative 3 is recommended as the best alternative to meet the long term electrical transmission system requirements of the Central Newfoundland area at the lowest possible cost consistent with safe and reliable service.

Table 7 shows the 3-year project description and estimated costs for the recommended alternative.

Table 7
Recommended Capital Project Costs
($000)

Year	Item	Cost
2019	Build a new 14.0 km, 138 kV transmission line extension from 136L to LEW Substation.	$2,322
2019	Convert LEW Substation from 66 kV to 138 kV.	$4,164
2020	Rebuild 14.0 km of 103L transmission line to 138 kV standards. Split 136L into two 138 kV transmission lines.	$2,383
2021	Build two new 138 kV transmission line extensions to RBK from 136L.	$507
2021	Install 138 kV transformer, structure and 2 new 138 kV breakers at RBK Substation.	$4,265
	Total	**$13,641**

Appendix A
Technical Evaluation Criteria

Technical Evaluation Criteria

Voltage Criteria

Minimum allowable voltage levels for all substation transmission buses during normal system conditions is 0.95 p.u. (114 V at 120 V base) and during contingency conditions is 0.90 p.u. (108 V on 120 V base).

The minimum allowable distribution system bus voltage is 0.967 p.u. (116 V on 120 V base).

Maximum allowable voltage level on all buses for normal and contingency system conditions is 1.054 p.u. (126.5 V on 120 V base).

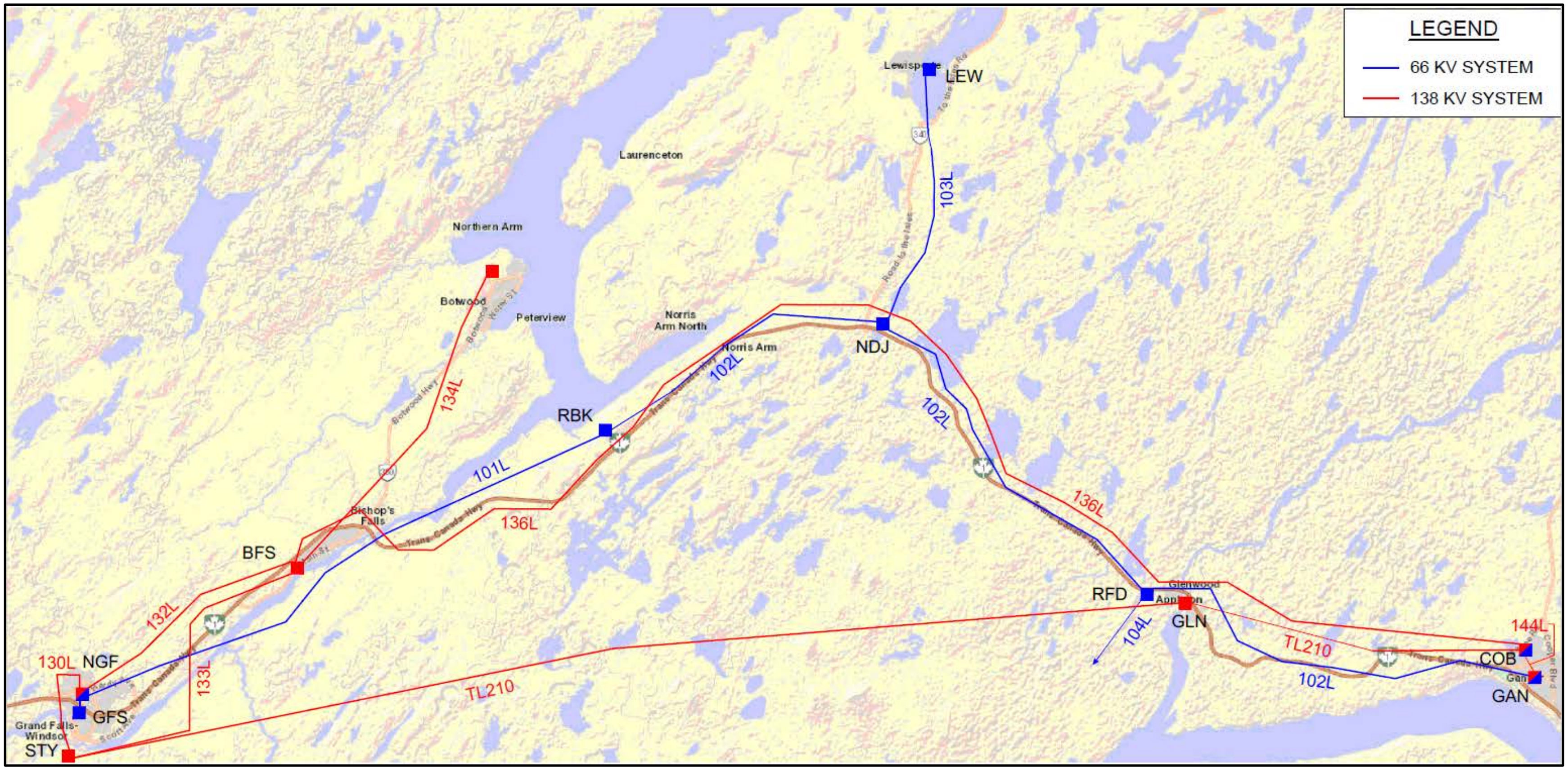
Transformer Loading Criteria

Transformer loading limits are 100% of rated nameplate capacity for normal system conditions. Under contingency conditions the system transformers are permitted to be loaded up to 130% of the nameplate rating during winter conditions.

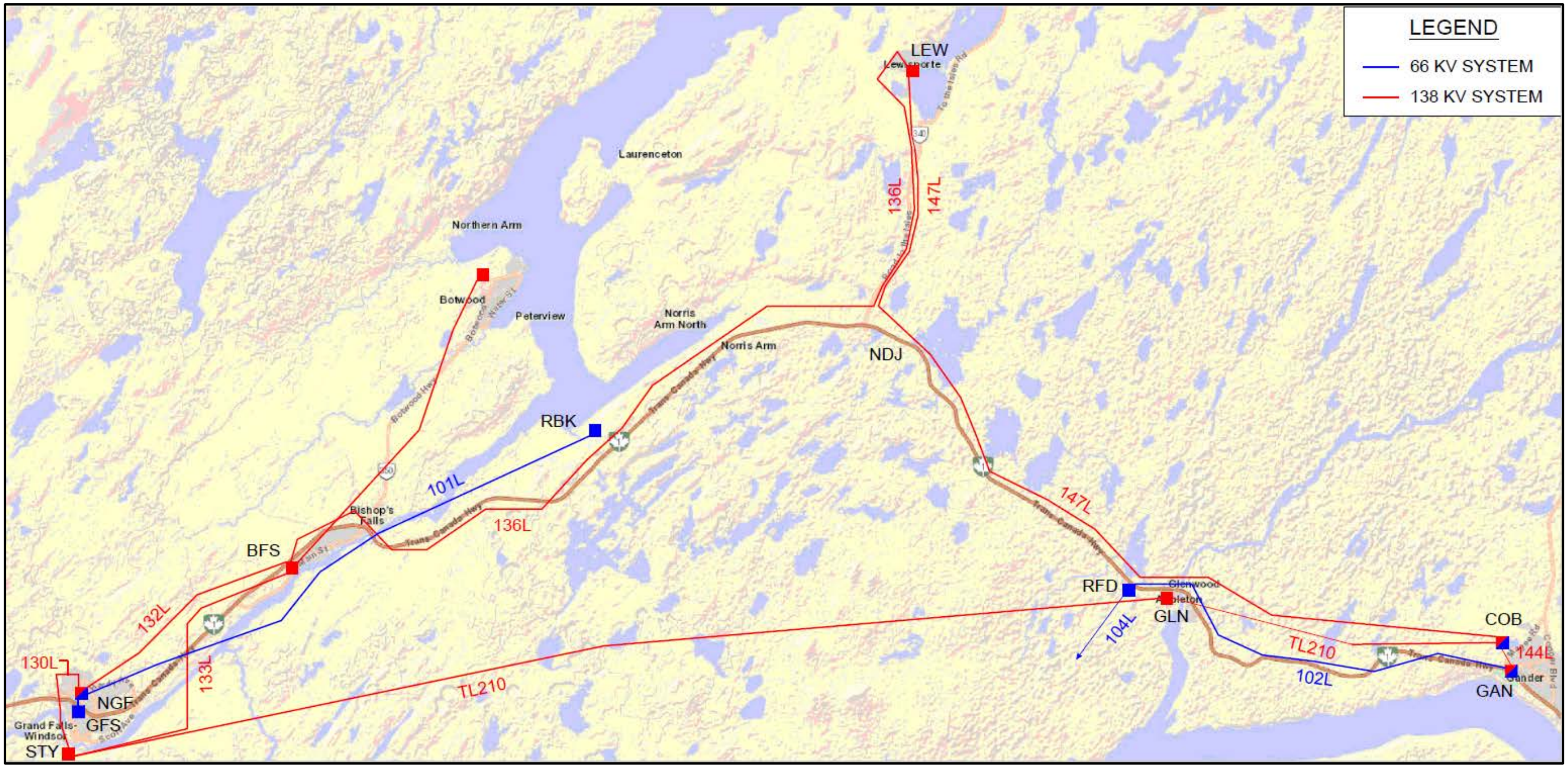
Transmission Line Loading Criteria

Transmission line loading limits are 100% of rated line capacity. Loading limits for transmission lines during the winter are based on a conductor rating at 75°C conductor temperature with 0°C ambient temperature at 2 ft/s (0.61 m/s) wind speed. During the summer the loading limits are based on 75°C conductor temperature with 25°C ambient temperature at 2 ft/s (0.61 m/s) wind speed.

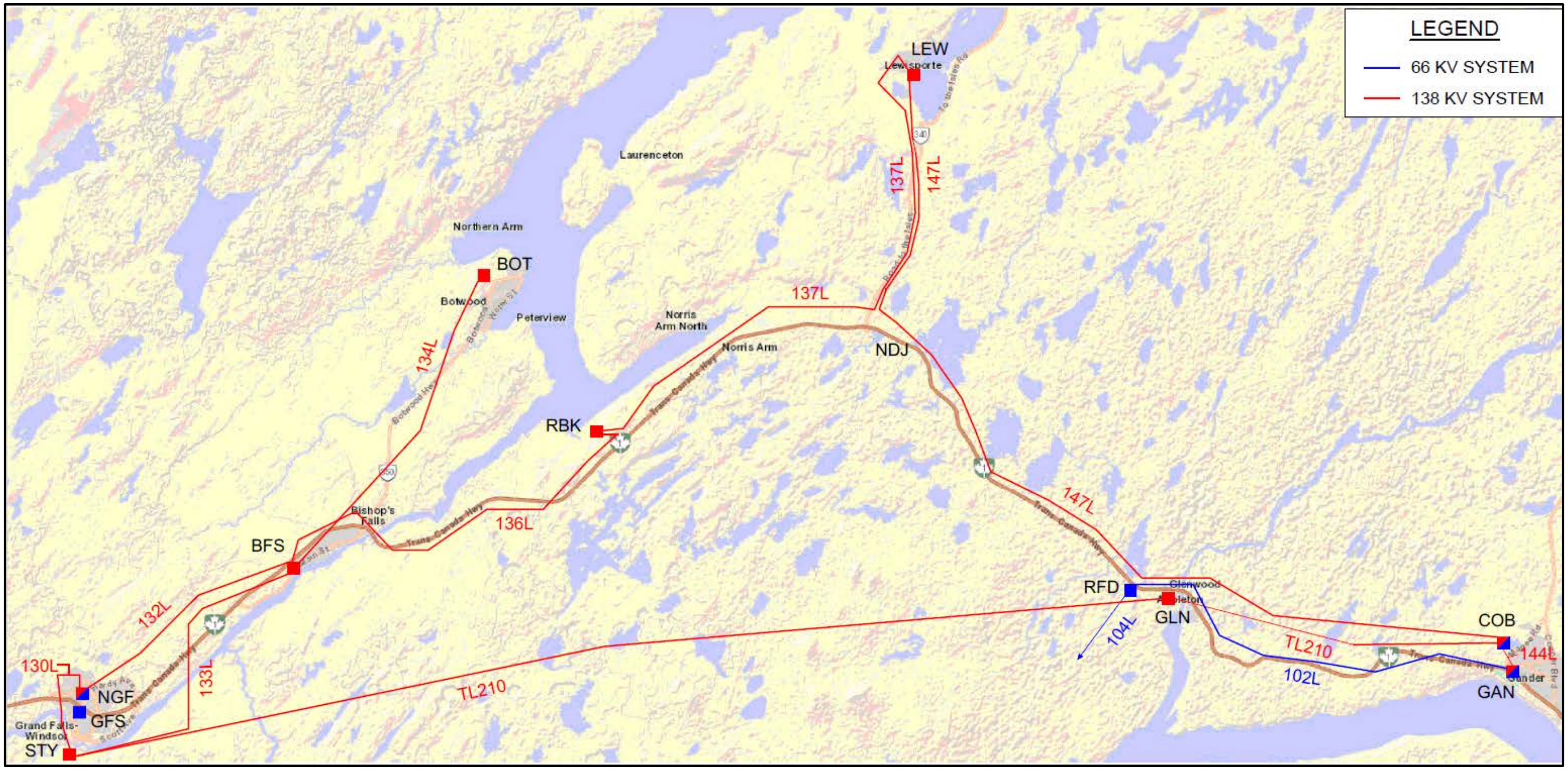
Appendix B
Illustrations of Alternatives



Alternative 1

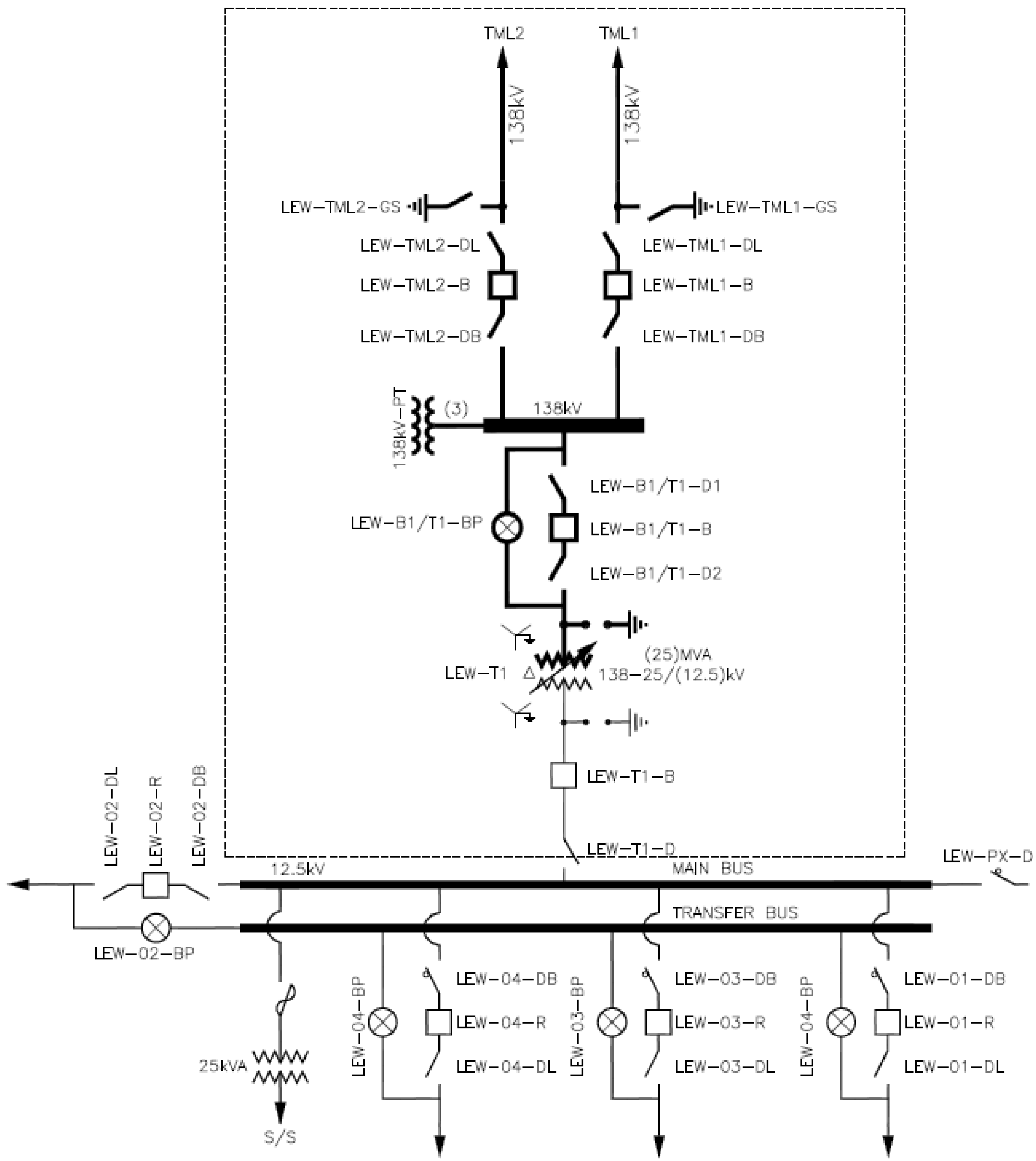


Alternative 2
(New 138 kV Line Designations Included)

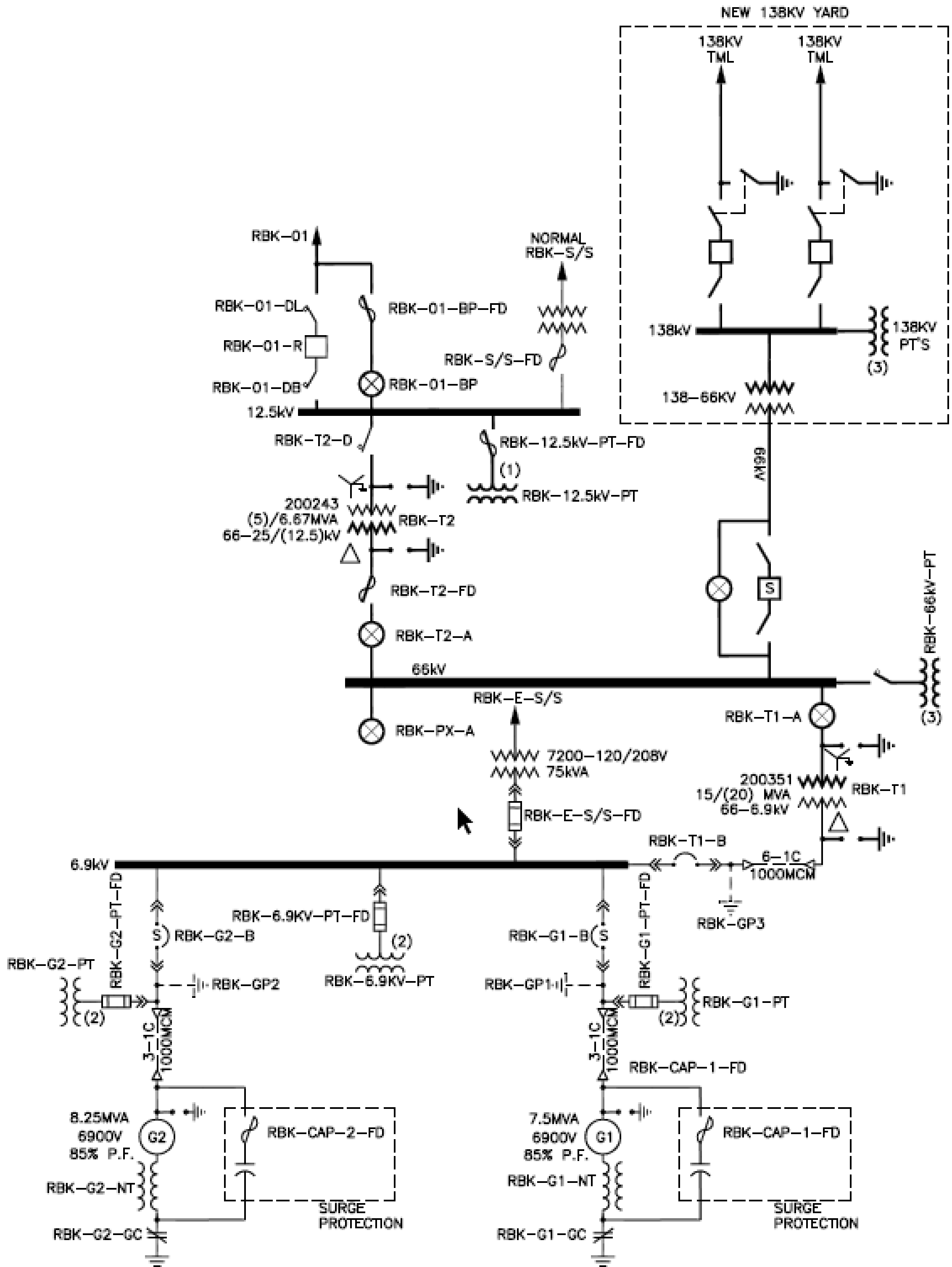


Alternative 3
(New 138 kV Line Designations Included)

Appendix C
Revised Substation Single Line Diagrams



LEW Substation Single Line - Conversion to 138 kV
(Alternatives 2 and 3)



RBK Substation Single Line - 138 kV Substation Expansion (Alternative 3)

2019 Facility Rehabilitation

July 2018

Prepared by:

Alex Hawco, P.Eng.
Michael Brown

LICENSED PROFESSIONAL ENGINEER
08900
ALEX C. HAWCO
SIGNATURE
07/06/2018
DATE
NEWFOUNDLAND & LABRADOR

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

Page

1.0 Introduction

The *2019 Facility Rehabilitation* project is necessary for the replacement or rehabilitation of deteriorated hydroelectric facility components that have been identified through routine inspections, operating experience and engineering studies. The project includes expenditures necessary to ensure the safe, reliable and environmentally compliant operation of various hydroelectric facilities, or to replace equipment due to in-service failures.

Newfoundland Power (the "Company") has 23 hydroelectric facilities that generate a combined normal annual production of 439.1 GWh.[1] Maintaining these facilities reduces the need for additional, more expensive generation on the Island Interconnected System. The alternative to maintaining these facilities is to retire them.

The *2019 Facility Rehabilitation* project totals $1,502,000 and is comprised of: (i) Hydroelectric Dam and Spillway Rehabilitation; (ii) Other Hydroelectric Infrastructure Rehabilitation; and (iii) Generation Equipment Replacements Due to In-Service Failures.

2.0 Hydroelectric Dam and Spillway Rehabilitation

Cost: $463,000

The Company has over 150 dam structures throughout its 23 hydroelectric facilities. Based on the age of the structures in Newfoundland Power's system, deterioration of earth-filled, timber crib, and concrete dams is to be expected.

Each year, refurbishment of deteriorated components at various dam structures is required to ensure an appropriate level of dam safety is maintained, as per the guidelines established by the Canadian Dam Association.[2] The project is justified on the basis of needing to restore the structures to an appropriate safety level, based on current site conditions, and to allow for continued operation of the hydroelectric system in a safe and reliable manner.

Specific work to be completed in 2019 includes:

1. *Pierre's Brook Intake Gate Replacement ($300,000)*

   The Pierre's Brook Intake structure was originally constructed in 1931 as part of the original plant construction and consists of a reinforced concrete foundation and gate conduit, steel head gate and a timber gatehouse. In 1982, an extension was placed on the gate conduit which also included a metal walkway structure to access the trash

---

[1] Normal annual hydroelectric production for 2018 was established as 439.1 GWh in Newfoundland Power's Adjustments to Normal Hydroelectric Production for 2018 in a letter dated January 31, 2018.

[2] The guidelines established by the Canadian Dam Association ("CDA") applicable to the Hydro Dam Rehabilitation projects are *CDA Dam Safety Guidelines 2007 (2013 Edition)*, *Dam Safety Guidelines 2007 Technical Bulletins* and *Guidelines for Public Safety Around Dams 2011*. Copies of these guidelines can be ordered online from www.cda.ca.

racks for the removal of debris.[3] In 2016, upgrades were made to the steel walkway structure to meet provincial occupational health and safety regulations and included the installation of toe boards, raising the handrail height, replacement of the timber decking and re-coating the steel structural components.

In 2016, while the intake structure was dewatered to facilitate the installation of the new penstock, an inspection of the existing head gate and reinforced concrete foundation was completed. The head gate is in poor condition with severely corroded guides and frame (Figure 1) and will require replacement to prevent any future risk of binding and becoming inoperable. The concrete foundation has visible cracking (Figure 2) along the side walls and requires refurbishment to prevent water exfiltration into the dam structure as well as limit corrosion on the reinforcing bars.

To facilitate the work during construction, the reservoir water levels will be lowered and cofferdams will be installed upstream of the intake structure.

Figure 1: Existing Head Gate

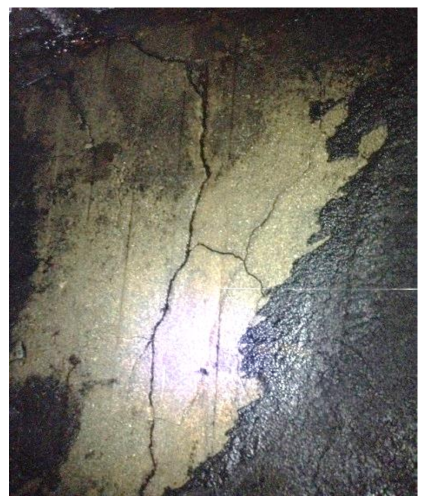


Figure 2: Deteriorated Foundation

2. *Thomas Pond Spillway Refurbishment ($163,000)*

The Thomas Pond Spillway (Figure 3) was constructed in 1956 and is associated with the reservoir system that feeds Topsail Plant. The structure consists of a 46 m reinforced concrete spillway with wooden stoplogs and reinforced concrete abutments.[4] In 1988, the right abutment was extended vertically with reinforced concrete and the left abutment was extended vertically with gabion baskets.[5]

---

3 A gate conduit extends from the reservoir through the dam and provides the initial entry of water into the penstock.

4 Stoplogs are used to increase the storage capacity within a reservoir.

5 Gabion baskets are steel chain link type caged boxes filled with rock.

The stoplogs are deteriorated and leak considerably with the deterioration expected to worsen over time. Leakage through the stoplogs flows out of the system and results in a direct loss in annual production at Topsail Plant.[6] The structure's underlying concrete is in good condition, however, replacement of the wooden stoplogs with reinforced concrete is required at this time.

Both the approach and discharges of the spillway contain low lying vegetation (Figures 4 and 5) that affects its performance. Removal of the vegetation and placement of riprap material will be completed to ensure optimal flows.[7]

The left gabion abutment is showing evidence of settlement and is tilted inward. The gabion baskets will be removed and replaced with a reinforced concrete abutment.

The handrail on the right abutment does not meet the current occupational health & safety regulations and will be replaced.

Figure 3: Thomas Pond Spillway

Figure 4: Discharge Channel

Figure 5: Approach Channel

---

6 Leakage water flows to the Manuals River and is discharged directly into the ocean bypassing Topsail Plant.

7 Rip rap is large sized rock installed to provide erosion protection.

3.0 Other Hydroelectric Infrastructure Rehabilitation

Cost: $430,000

The Company's 23 hydroelectric facilities range in age from 19 to 118 years and have many components, including access roads, bridges, penstocks, surge tanks, powerhouses, ancillary buildings and tailraces. Based on the age of the components in Newfoundland Power's system, deterioration is to be expected.

Each year, refurbishment of deteriorated components at various hydroelectric facilities is required to ensure integrity of the components and the safe and reliable operation of the facilities. The project is justified on the basis of needing to restore the structures to an appropriate level of safety and integrity, based on the current site conditions, and to allow for continued operation of the hydroelectric system in a safe and reliable manner.

Specific work to be completed in 2019 includes:

1. *Rose Blanche Fishway Rebuild ($110,000)*

   The Rose Blanche Hydroelectric development was constructed in 1998 and has an installed capacity of 6 MW at a net head of 114 meters.

   A concrete fishway was installed as part of the original construction to comply with the Fisheries & Oceans Canada permit requirements. The fishway is comprised of a concrete inlet structure (Figure 6) and is covered over its length by a metal grate (Figure 7).

Figure 6

Figure 7

Inspections completed in 2017 determined that the structure has deteriorated and requires refurbishment. The work will include replacement of the inlet trash rack, handrails, metal grating and steel support structures.[8]

2. *Pierre's Brook Tailrace Bridge Replacement ($145,000)*

The Pierre's Brook tailrace bridge was built in 1993. The bridge is constructed on timber rock filled abutments and is comprised of a repurposed railway car complete with timber decking and guardrails. Some deteriorated timber decking and guardrails were replaced in 2016 to accommodate the passage of small vehicular traffic during the *Pierre's Brook Hydro Plant Refurbishment Project*.

The current bridge structure measures 2.6 m in width and cannot physically accommodate the passage of large equipment for material deliveries and snow removal activities at the rear of the plant. The repurposed railway car (Figure 8) is showing evidence of corrosion to the steel members (Figure 9). The abutments are showing signs of settlement and deterioration (Figure 10).

The railway car's original purpose and current condition does not meet the requirement to accommodate traffic loads required under the Canadian Highway Bridge Design Code. The current guardrails are designed to provide protection for light traffic and pedestrians only and are unable to accommodate vehicular impact in accordance with the requirements under the Canadian Highway Bridge Design Code.

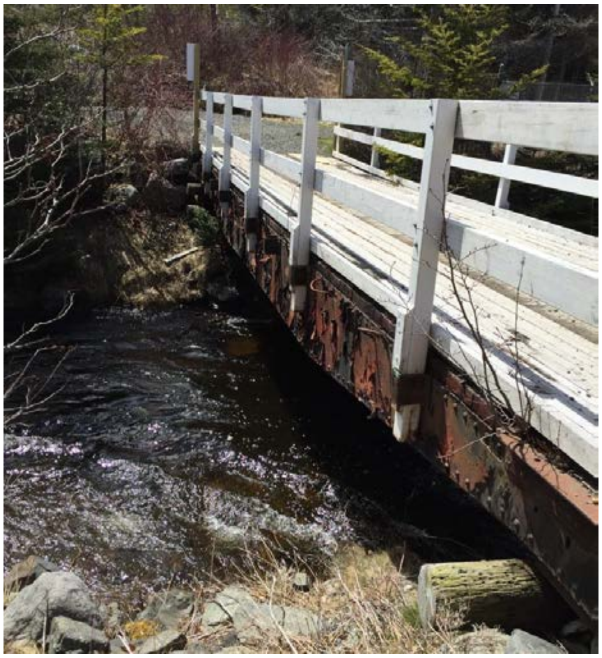


Figure 8: Railway Car Bridge

Figure 9: Typical Underside Deterioration

[8] A trash rack is a slotted steel structure at the inlet to the fishway to prevent sticks, logs and other large debris from entering the structure.

Figure 10: Abutment Deterioration

The Pierre's Brook tailrace bridge requires replacement due to its condition and the inability to accommodate the passage of large equipment for the purpose of material deliveries and snow removal activities. The new structure will be constructed on concrete abutments and designed to the current version of the Canadian Highway Bridge Design Code.

3. *Frozen Ocean Access Road Bridge Replacement ($175,000)*

The Frozen Ocean dam and spillway is accessed via a 7 km gravel road extending from the Trans-Canada Highway near the community of Norris Arm South. A 12.5 m long steel bridge (Figure 11) spans one of the streams accessing the dam. The bridge, installed in 2000, sits on timber rock filled abutments and is comprised of a repurposed railway car complete with timber decking and guardrails.[9]

The current bridge structure measures 2.6 m in width and cannot physically accommodate, without the removal of the guardrails, the passage of large equipment for any work required at the dam site. The original timber abutments are showing

9 An abutment is a structure on which the ends of the bridge rest.

signs of deterioration (Figure 12) and temporary repairs have been required to extend the life of the structures (Figure 13). The abutments are key components to ensuring the overall structural stability of the bridge. Given the level of deterioration observed there is a risk of erosion of the internal ballast and overall failure of the structure.

The current timber guardrails are designed to provide protection for light traffic and pedestrians only and are unable to accommodate vehicular impact in accordance with the requirements under the Canadian Highway Bridge Design Code.

Figure 11: Existing Bridge Approach

Figure 12: Deteriorated Abutment

Figure 13: Temporary Abutment Repair

The Frozen Ocean access road bridge requires replacement due to the condition of the abutments, its inability to accommodate the passage of large equipment required for future planned or emergency repairs and overall safety of passing vehicles. The new structure will be constructed on concrete abutments and designed to the current version of the Canadian Highway Bridge Design Code.

4.0 Generation Equipment Replacements Due to In-Service Failures

Cost: $609,000

Equipment and infrastructure at generating facilities routinely require upgrading or replacement to extend the life of the assets.

This item involves the refurbishment or replacement of structures and equipment due to damage, deterioration, corrosion, technical obsolescence, and in-service failure. This equipment is critical to the safe and reliable operation of generating facilities and must be replaced in a timely manner. Equipment replaced under this item includes civil infrastructure, instrumentation, mechanical, electrical, and protection and controls equipment.

Replacements under this item are typically due to 1 of 2 reasons:

1. Emergency replacements – where components fail and require immediate replacement to return a unit to service; or

2. Observed deficiencies – where components are identified for replacement due to imminent failure or for safety or environmental reasons.

Table 1 shows the expenditures for replacements due to in-service failures since 2014.

Table 1
Expenditures Due to In-Service Failures
(000s)

Year	**2014**	**2015**	**2016**	**2017**	**2018F**
Total	$580	$524	$582	$571	$568

Based on recent expenditures and engineering judgement, $609,000 is estimated to be required in 2019 for replacement of equipment due to in-service failures or equipment at risk of imminent failure.

Generation equipment, buildings, intakes, dams and control structures are critical components in the safe and reliable operation of generating facilities. This item is required to enable the timely refurbishment or replacement of equipment to support the continued operation of generating facilities in a safe and reliable manner.

5.0 Conclusion

This project, for which there is no feasible alternative, is required to ensure the continued provision of safe, reliable generating facility operations. A 2019 budget of $1,502,000 for Facility Rehabilitation is recommended as follows:

- $463,000 for Hydro Dam and Spillway Rehabilitation;
- $430,000 for Other Hydroelectric Infrastructure Rehabilitation; and
- $609,000 for Generation Equipment Replacements Due to In-Service Failures.

Rattling Brook Hydro Plant
Unit 1 Turbine – Generator Refurbishment

July 2018

Prepared by:

Monty Hunter, P.Eng.
Bradley Tooktoshina, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
M.C. HUNTER
SIGNATURE
July 6, 2018
PROVINCE OF NEWFOUNDLAND

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Background

1.1 General

The Rattling Brook hydroelectric development ("the Plant") is the largest generating station operated by Newfoundland Power. It is located approximately 50 kilometres west of Gander in the Notre Dame Bay community of Norris Arm South. The development went into service in December 1958 and has provided 59 years of reliable energy production.

The normal annual plant production is approximately 67.1 GWh of energy, or about 15.2% of Newfoundland Power's total hydroelectric generation.[1]

The generating station contains 2 vertical shaft Francis turbines connected to separate generators each with an original rating of 7,500 kVA for a total of 15 MVA.

This report provides a summary of the engineering assessment of the Unit 1 turbine and generator, and the refurbishment proposed for 2019.[2]

1.2 Previous Upgrades

The following is a list of the major electrical and mechanical upgrades that have been completed:

- 1986 – Unit 2 turbine runner replacement
- 1987 – Unit 1 turbine runner replacement
- 1994 – Plant remote control through System Control Centre SCADA system
- 2002 – Unit 2 generator stator rewind
- 2004 – Unit 1 generator stator rewind
- 2007 – Unit 1 and 2 generator exciter refurbishment
- 2007 – Unit 1 and 2 inlet valve and control panel replacement
- 2007 – Unit 1 and 2 field breaker and generator breaker replacement
- 2007 – Plant protection, controls and switchgear upgrade

2.0 Engineering Assessment

2.1 Turbine ($683,000)

The original 8,500 horsepower turbine was supplied by Canadian Allis Chalmers in 1958. In 1987, the runner was replaced with a new Allis-Chalmers runner. The original wicket gates were reused and several wearing components were replaced. During that overhaul, shaft pitting was identified and repairs were made. As well, the stainless steel gland sleeve was found to be worn and was repaired. Severe cavitation was noted in the area of the scroll case head cover and discharge ring seal. This area was repaired with an epoxy overlay.

---

1 For 2018, the annual normal production for Newfoundland Power has been set at 439.1 GWh of energy.

2 A similar refurbishment of the Unit 2 turbine and generator is planned for 2020. A condition assessment of Unit 2 will be presented in the 2020 Capital Budget Application.

A detailed inspection was completed in 2005 which found the runner in good condition.[3] Evidence of minor cavitation was found in the same location between each of the blades. All but two wicket gates were in good condition. These gates were repaired to ensure continued reliable service until the turbine required its next major overhaul.

Another detailed inspection was completed in 2017. The runner was again found in good condition with no advancement of the cavitation between blades (see Figures 1 through 4).

Figure 1: Typical Inlet Runner Blade

Figure 2: Low Pressure Runner Blades

Figure 3: Cavitation between Blades

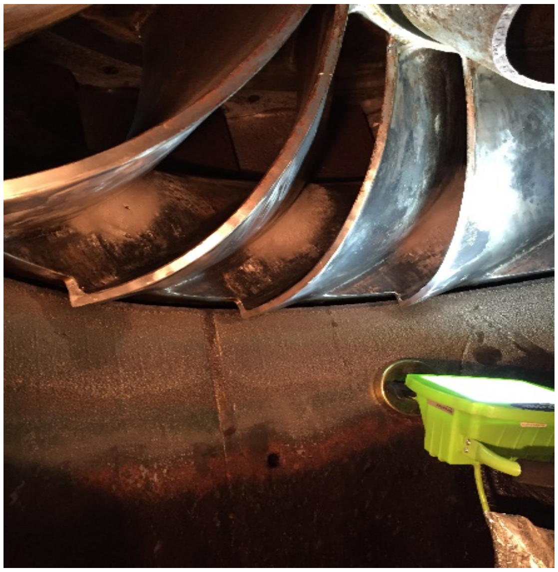


Figure 4: Cavitation between Blades

[3] 2007 Capital Budget Application, Volume 2, Appendix F, Section 2.2.1 included the condition assessment of Unit 1 turbine runner.

The wicket gates were found in fair condition (Figure 5).

Figure 5: Typical Wicket Gate

The wicket gate facing plates were found in good condition (Figures 6 and 7).

Figure 6: Upper Facing Plate

Figure 7: Lower Facing Plate

Index testing, performed by Hatch in 2008, determined the peak efficiency of Unit 1 was 88% with a fairly flat efficiency curve over the range of 50 – 100% wicket gate opening (Figure 8). The Plant is required to provide downstream flows throughout dry periods to ensure the passage of salmon and the maintenance of fish habitat.[4] This requires the plant to operate over a wide operating range. Alternate runner designs could provide peak efficiency improvement, however it would be over a much narrower operating range, resulting in poorer performance when operating solely for fishery requirements.

Given the good condition of the runner and requirement to run at low loads to satisfy downstream fishery requirements, the runner does not require replacement at this time.

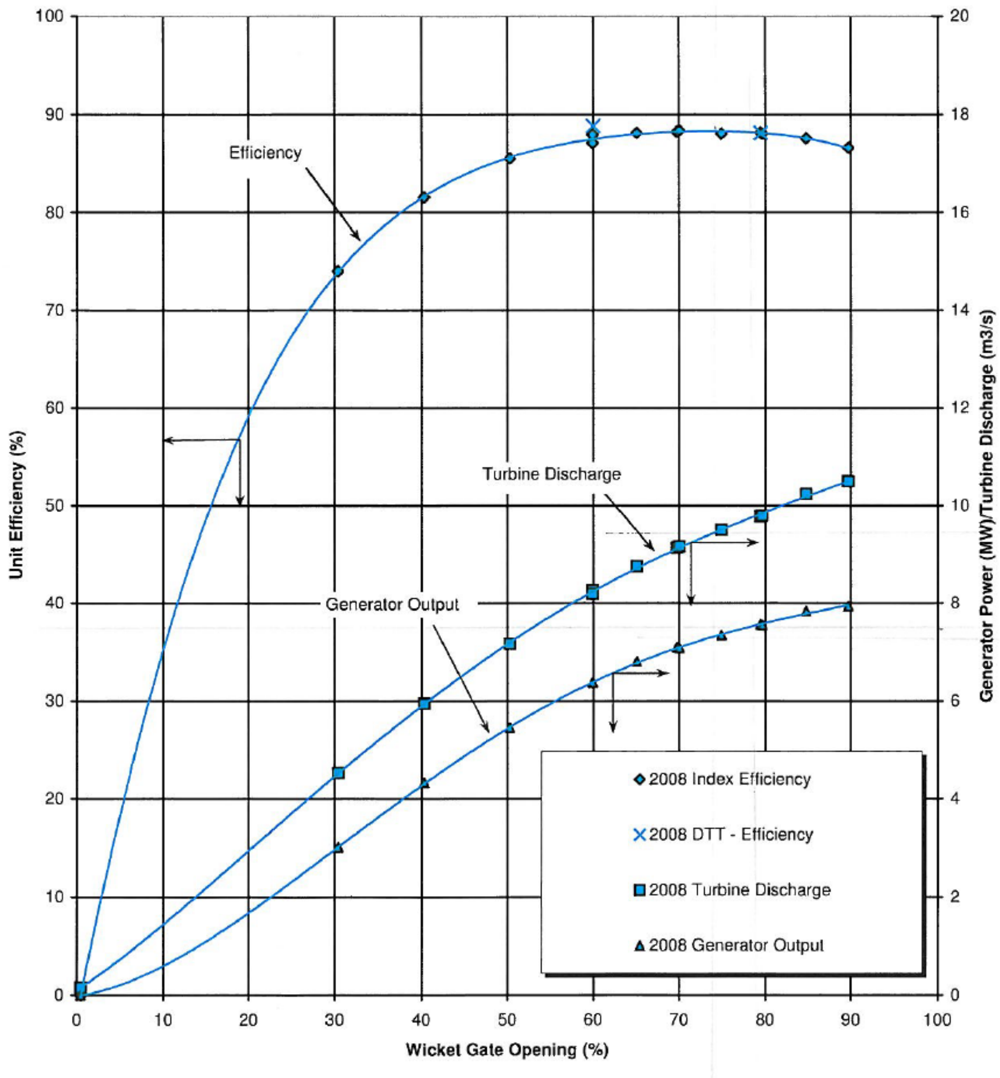


Figure 8: 2008 Unit 1 Efficiency Test Results

[4] A 2013 directive from Fisheries and Oceans Canada requires that flows downstream of the plant be maintained at or above 3 m^3/s at all times.

In 2019, a major overhaul is required to replace the wearing components such as operating bushings and seals which were last replaced in 1987 when the new runner was installed. Self-lubricating bushings, which require no maintenance and have less environmental risk, will be installed. The wicket gates will be removed, sandblasted, inspected and any necessary repairs completed. Inspections will be completed on other minor components and repairs or replacements carried out as required.

2.2 Generator ($478,000)

The original 7,500 kVA generator was supplied by Canadian General Electric in 1958. The generator stator was rewound in 2004. The rotor pole windings are original to the 59 year old generator (Figure 9). The typical lifespan of rotor pole windings is in the 40 to 50 year range.

Figure 9: Typical Condition of Generator Stator and Poles

Electrical insulation of windings comprising the rotor poles is subjected to thermal and mechanical stresses due to normal operation of the generator. The variation of operating temperature caused by load changes and the start/stop cycling of the generator creates thermal cycling in the rotor poles. Thermal cycling causes expansion and contraction of the copper windings relative to the insulating material creating an abrasive effect on the insulation.

Mechanical stresses experienced by rotor poles are high due to centrifugal forces present during normal operation. Also, during an emergency shutdown the speed of the rotor accelerates dramatically increasing the magnitude of the centrifugal force exerted on the rotor poles.[5] As the generator ages, the loss of insulating material causes pole movement when the rotor experiences centrifugal forces during normal operation and during emergency shutdown. Over time thermal and mechanical stresses weaken the rotor poles.

To ensure the continued reliable operation of Unit 1, considering the condition and age of the rotor pole insulation, rewinding and re-insulation is required in 2019. While the unit is dismantled for the pole winding work, the 15 year old stator windings will be cleaned, inspected and any necessary repairs completed.

3.0 Project Proposal

3.1 Cost Breakdown

The total project cost for the refurbishment of Unit 1 in 2019 is estimated at $1,161,000. Table 1 provides the cost breakdown.

Table 1
Project Cost
($000s)

Cost Category	Cost
Material	716
Labour - Internal	248
Labour - Contract	-
Engineering	50
Other	147
Total	**$1,161**

3.2 Feasibility Analysis

Appendix A provides an economic feasibility analysis for the continued operation of the Plant. The results of the analysis show that the continued operation of the Plant is economical over the long term. Investing in the life extension of the Plant ensures the availability of 67.1 GWh of energy to the Island Interconnected System.

The feasibility analysis includes estimates for work to be completed over the next 25 years including expenditures in 2019. The major items included in the 2020 estimate include similar turbine and generator work for Unit 2. The estimated levelized cost of energy from the Plant over the next 50 years, including the capital expenditure of $4.9 million over the next 25 years, is 1.81¢ per kWh. This energy is lower in cost than replacement energy from sources such as the

[5] 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. For example, if during an emergency shutdown, if rotor speed were to double, the centrifugal force would increase by a factor of 4.

Holyrood thermal generating station, or other sources such as combustion turbines and marginal cost of supply in the transition period to the Muskrat Falls era.[6]

4.0 Conclusion

An engineering assessment completed on the Rattling Brook hydroelectric development has determined that it is in generally good condition. The primary systems requiring refurbishment at this time for the life extension of the Plant are the Unit 1 and Unit 2 turbine overhauls and generator pole rewinds.

The feasibility analysis included in Appendix A verifies the financial viability of completing this project. The 67.1 GWh of energy that will be available from the Plant each year will provide affordable energy to the customers of Newfoundland Power. The planned schedule for project execution ensures the minimum amount of lost production due to spill. Based upon these considerations, and others outlined in this report and attached analysis, the project to refurbish the Unit 1 turbine and generator is recommended to proceed in 2019. A project proposal to refurbish the Unit 2 turbine and generator will be filed in a future capital budget application for 2020.

[6] The avoided cost of No. 6 fuel at the Holyrood Thermal Generating Station is estimated at 13.8¢ per kWh for 2019. This is based upon a 618 kWh/barrel conversion efficiency and oil price forecast of $85.55 per barrel for 2019, as per Newfoundland and Labrador Hydro – 2018 Utility Customer Interim Rates Application dated April 20, 2018. The avoided cost of fuel for the Holyrood 123 MW combustion turbine in 2017 was 26.5 ¢/kWh as per Hydro's 2017 General Rate Application response to Request for Information NP-NLH-337. Also, an estimate of the marginal cost of production during the transition period prior to the Muskrat Falls project completion is 5.0 ¢/kWh for energy in 2019 and 5.3 ¢/kWh for energy in 2020 as per Hydro's 2017 General Rate Application responses to Request for Information CA-NLH-081 and CA-NLH-258 respectively.

Appendix A
Rattling Brook Hydro Plant
Feasibility Analysis

Table of Contents

1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Rattling Brook hydroelectric development (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2019.

With investment required in 2019 to permit the continued reliable operation of the Plant, an economic analysis of this development was completed. The analysis includes all costs and benefits for the next 50 years to determine the levelized cost of energy from the Plant.

2.0 Capital Costs

All significant capital expenditures for the Plant over the next 25 years have been identified. The capital expenditures required to maintain the safe and reliable operation of the facilities are summarized in Table 1.

Table 1
Rattling Brook Hydroelectric Plant
Capital Expenditures

Year	($000s)
2019	$1,161
2020	$1,161
2021	$116
2022	$230
2027	$12
2036	$1,200
2038	$1,000
Total	**$4,880**

The estimated capital expenditure for the Plant listed above is $4,880,000. A more comprehensive breakdown of capital costs is provided in Attachment A.

3.0 Operating Costs

Operating costs for the Plant are estimated to be approximately $616,000 per year.[1] This estimate is based primarily upon recent historical operating experience. 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. A summary of operating costs is provided in Attachment B.

[1] 2019 dollars.

The annual operating cost also includes a water power rental rate of \$2.50 per MWh.[2] This fee is paid annually to the Provincial Department of Municipal Affairs and Environment based on yearly hydro plant generation/output. This charge is reflected in the historical annual operating costs for the Plant.

4.0 Benefits

The maximum output from the Plant is 14,680 kW. The Plant normally operates at an efficient load of 13,400 kW to maximize the energy from the water.

The estimated long-term normal production of the Plant under present operating conditions is 67.1 GWh per year.

5.0 Financial Analysis

An overall financial analysis of combined costs and benefits has been completed in Attachment C using the levelized cost of energy approach. The levelized cost of energy is representative of the revenue requirement to support the combined capital and operating costs associated with the development.

The estimated levelized cost of energy from the Plant over the next 50 years is 1.81¢ per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Rattling Brook can be produced at a significantly lower price than the cost of replacement energy, assumed to come from Newfoundland and Labrador Hydro's Holyrood thermal generating station, or other sources such as combustion turbines and marginal cost of supply in the transition period to the Muskrat Falls era.[3]

The future capacity benefits of the continued availability of the Plant have not been considered in this analysis. If factored into the feasibility analysis, the financial benefit associated with system capacity would further support the viability of continued plant operations.

6.0 Conclusion

The results indicate that continued operation of the Plant is economically viable. Investing in the current upgrades of the facilities at the Plant guarantees the availability of low cost energy to the Province. Otherwise, the projected annual production of 67.1 GWh would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood

---

[2] The water power rental rate increased from \$0.80/MWh in 2015 to \$2.50/MWh in 2016. The additional cost is added to the annual operating cost.

[3] The avoided cost of No. 6 fuel at the Holyrood Thermal Generating Station is estimated at 13.8¢ per kWh for 2019. This is based upon a 618 kWh/barrel conversion efficiency and oil price forecast of \$85.55 per barrel for 2019, as per Newfoundland and Labrador Hydro – 2018 Utility Customer Interim Rates Application dated April 20, 2018. The avoided cost of fuel for the Holyrood 123 MW combustion turbine in 2017 was 26.5 ¢/kWh as per Hydro's 2017 General Rate Application response to Request for Information NP-NLH-337. Also, an estimate of the marginal cost of production during the transition period prior to the Muskrat Falls project completion is 5.0 ¢/kWh for energy in 2019 and 5.3 ¢/kWh for energy in 2020 as per Hydro's 2017 General Rate Application responses to Request for Information CA-NLH-081 and CA-NLH-258 respectively.

Thermal Generating Station. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

Attachment A
Summary of Capital Costs

Rattling Brook Feasibility Analysis
Summary of Capital Costs
($000s)

Description	**2019**	**2020**	**2021**	**2022**	**2027**	**2036**	**2038**
Civil							
Dam, Spillways and Gates			116				
Powerhouse						100	
Mechanical							
Turbine & Wicket Gates	683	683				900	1,000
Electrical							
Generator Pole Reinsulation	478	478					
P&C and Gov. Controls				200		200	
Battery Bank/Charger				30	12		
Annual Totals ($2019)	**$1,161**	**$1,161**	**$116**	**$230**	**$12**	**$1,200**	**$1,000**

Attachment B
Summary of Operating Costs

Rattling Brook Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs ($2019)

Year	Amount[1]
2013	$447,000
2014	$407,000
2015	$376,000
2016	$447,000
2017	$469,000
Average	**$429,000**
Escalated to 2019	**$438,000**

2019 Water Power Rental	$178,000[2]
5 -Year Average Operating Cost	**$616,000[3]**

1 Cost with Water Power Rental removed as it changed over the timeframe noted.
2 Calculated using the current rate ($2.50/MWh - 2016 base plus a CPI Inflator) multiplied by the normal annual output of the plant.
3 2019 dollars.

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

	Weighted Average Incremental Cost of C:			5.92%								
	Escalation Rate			See following worksheet								
	PW Year			2019								
		Generation	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net benefit	Present Worth	Cumulative Present Value	Present Worth of Sunk Costs	Total Present Worth	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr)
		Hydro					Benefit +ve	Benefit +ve		Benefit +ve		50 years
		64.4yrs										
		8% CCA										
YEAR	YEAR											
1	2019	1,161,000	98,615	616,017	0	-714,632	-714,632	-714,632	-5,248,007	-5,962,639	1.065	1.8056
2	2020	1,182,726	208,312	627,545	0	-835,857	-789,140	-1,503,772	-5,051,337	-6,555,110	1.246	1.8056
3	2021	120,390	224,769	639,328	0	-864,097	-770,205	-2,273,978	-4,850,991	-7,124,969	1.288	1.8056
4	2022	243,245	240,126	651,492	0	-891,618	-750,317	-3,024,295	-4,648,920	-7,673,215	1.329	1.8056
5	2023	0	235,770	664,327	0	-900,097	-715,118	-3,739,413	-4,461,603	-8,201,016	1.341	1.8056
6	2024	0	229,106	676,854	0	-905,960	-679,546	-4,418,959	-4,289,755	-8,708,714	1.350	1.8056
7	2025	0	222,743	689,616	0	-912,359	-646,098	-5,065,057	-4,132,017	-9,197,073	1.360	1.8056
8	2026	0	216,659	702,717	0	-919,376	-614,678	-5,679,734	-3,987,162	-9,666,897	1.370	1.8056
9	2027	13,948	212,015	716,017	0	-928,033	-585,787	-6,265,521	-3,853,335	-10,118,856	1.383	1.8056
10	2028	0	206,533	729,641	0	-936,174	-557,898	-6,823,419	-3,730,255	-10,553,674	1.395	1.8056
11	2029	0	201,118	743,699	0	-944,817	-531,579	-7,354,998	-3,617,101	-10,972,099	1.408	1.8056
12	2030	0	195,904	758,133	0	-954,037	-506,766	-7,861,764	-3,513,041	-11,374,805	1.422	1.8056
13	2031	0	190,875	772,853	0	-963,728	-483,302	-8,345,066	-3,417,318	-11,762,385	1.436	1.8056
14	2032	0	186,016	787,831	0	-973,847	-461,081	-8,806,147	-3,329,247	-12,135,394	1.451	1.8056
15	2033	0	181,313	803,143	0	-984,457	-440,053	-9,246,200	-3,248,199	-12,494,400	1.467	1.8056
16	2034	0	176,755	819,206	0	-995,961	-420,313	-9,666,513	-3,173,606	-12,840,119	1.484	1.8056
17	2035	0	172,329	835,272	0	-1,007,601	-401,459	-10,067,972	-3,104,945	-13,172,917	1.502	1.8056
18	2036	1,659,050	308,944	851,670	0	-1,160,613	-436,578	-10,504,550	-2,988,732	-13,493,282	1.730	1.8056
19	2037	0	317,952	868,469	0	-1,186,420	-421,342	-10,925,892	-2,875,815	-13,801,708	1.768	1.8056
20	2038	1,437,363	431,409	885,441	0	-1,316,849	-441,524	-11,367,417	-2,731,169	-14,098,586	1.963	1.8056
21	2039	0	434,530	902,832	0	-1,337,362	-423,340	-11,790,757	-2,593,619	-14,384,376	1.993	1.8056
22	2040	0	422,570	920,551	0	-1,343,121	-401,400	-12,192,157	-2,467,331	-14,659,489	2.002	1.8056
23	2041	0	411,071	938,699	0	-1,349,770	-380,842	-12,572,999	-2,351,346	-14,924,345	2.012	1.8056
24	2042	0	399,995	957,205	0	-1,357,200	-361,535	-12,934,534	-2,244,794	-15,179,329	2.023	1.8056
25	2043	0	389,309	976,076	0	-1,365,385	-343,387	-13,277,921	-2,146,885	-15,424,807	2.035	1.8056
26	2044	0	378,981	995,319	0	-1,374,301	-326,312	-13,604,233	-2,056,901	-15,661,133	2.048	1.8056
27	2045	0	368,983	1,014,942	0	-1,383,925	-310,231	-13,914,464	-1,974,187	-15,888,650	2.062	1.8056
28	2046	0	359,289	1,034,951	0	-1,394,240	-295,075	-14,209,539	-1,898,147	-16,107,686	2.078	1.8056
29	2047	0	349,873	1,055,355	0	-1,405,228	-280,778	-14,490,317	-1,828,239	-16,318,556	2.094	1.8056
30	2048	0	340,715	1,076,161	0	-1,416,875	-267,282	-14,757,600	-1,763,966	-16,521,565	2.112	1.8056
31	2049	26,721	334,062	1,097,377	0	-1,431,439	-254,937	-15,012,537	-1,704,470	-16,717,007	2.133	1.8056
32	2050	0	325,570	1,119,011	0	-1,444,581	-242,898	-15,255,435	-1,649,727	-16,905,163	2.153	1.8056
33	2051	0	316,992	1,141,072	0	-1,458,064	-231,463	-15,486,898	-1,599,406	-17,086,304	2.173	1.8056
34	2052	3,305,499	589,368	1,163,568	0	-1,752,936	-262,720	-15,749,618	-1,511,075	-17,260,693	2.612	1.8056
35	2053	0	607,450	1,186,508	0	-1,793,958	-253,841	-16,003,459	-1,425,122	-17,428,581	2.674	1.8056
36	2054	3,054,124	849,755	1,209,899	0	-2,059,654	-275,147	-16,278,606	-1,311,604	-17,590,210	3.070	1.8056
37	2055	0	857,532	1,233,752	0	-2,091,284	-263,758	-16,542,365	-1,203,450	-17,745,814	3.117	1.8056
38	2056	0	833,187	1,258,075	0	-2,091,262	-249,014	-16,791,378	-1,104,239	-17,895,618	3.117	1.8056
39	2057	0	809,749	1,282,878	0	-2,092,626	-235,250	-17,026,628	-1,013,209	-18,039,837	3.119	1.8056
40	2058	0	787,144	1,308,169	0	-2,095,313	-222,386	-17,249,014	-929,665	-18,178,679	3.123	1.8056
41	2059	0	765,306	1,333,959	0	-2,099,265	-210,353	-17,459,367	-852,979	-18,312,346	3.129	1.8056
42	2060	0	744,173	1,360,258	0	-2,104,431	-199,085	-17,658,452	-782,578	-18,441,030	3.136	1.8056
43	2061	0	723,690	1,387,075	0	-2,110,765	-188,523	-17,846,975	-717,942	-18,564,917	3.146	1.8056
44	2062	0	703,804	1,414,421	0	-2,118,225	-178,616	-18,025,591	-658,595	-18,684,185	3.157	1.8056
45	2063	0	684,468	1,442,305	0	-2,126,773	-169,313	-18,194,904	-604,104	-18,799,008	3.170	1.8056
46	2064	0	665,637	1,470,740	0	-2,136,377	-160,572	-18,355,475	-554,074	-18,909,550	3.184	1.8056
47	2065	0	647,271	1,499,735	0	-2,147,007	-152,351	-18,507,827	-508,144	-19,015,971	3.200	1.8056
48	2066	0	629,333	1,529,302	0	-2,158,635	-144,615	-18,652,442	-465,982	-19,118,425	3.217	1.8056
49	2067	506,301	654,794	1,559,452	0	-2,214,246	-140,050	-18,792,492	-424,567	-19,217,059	3.300	1.8056
50	2068	0	641,640	1,590,196	0	-2,231,836	-133,273	-18,925,765	-386,252	-19,312,017	3.326	1.8056

Feasibility Analysis
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 2018 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55.00%	3.815%	2.10%
Common Equity	45.00%	8.500%	3.82%
Total	**100.00%**		**5.92%**

CCA Rates:

Class	Rate	Details
47	8.00%	All transmission, substation and distribution equipment not otherwise noted.
17(c)	8.00%	Expenditures related to generation or additions/alterations.

Escalation Factors: Conference Board of Canada GDP deflator, January 26, 2018.

2019 Substation Refurbishment and Modernization

July 2018

Prepared by:

Adam Wong, P.Eng.
Barry Hogan, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
ADAM E.H. WONG
Adam Wong
SIGNATURE
July 6, 2018
DATE
NEWFOUNDLAND & LABRADOR

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

Page

1.0 Substation Refurbishment and Modernization Strategy

Newfoundland Power (the "Company") has 130 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.

Substations are critical to electrical system reliability; an unplanned substation outage can affect thousands of customers. The Company's substation maintenance program and the *Substation Refurbishment and Modernization Plan* ensure the delivery of reliable, least-cost electricity to customers in a safe and environmentally responsible manner.[1]

The *Substation Refurbishment and Modernization Plan* was first established in 2007. The plan is reviewed and updated annually to provide a structured approach for the overall refurbishment and modernization of substations. The annual review identifies projects based on: (i) the condition of the infrastructure and equipment; (ii) the need to upgrade and modernize protection and control systems; and (iii) other relevant work. In 2015, an initiative to accelerate substation feeder automation was incorporated into the *Substation Refurbishment and Modernization Plan*. This initiative will ensure all distribution feeders are automated by the end of 2019.[2] Feeder automation will enhance system reliability and reduce the duration of distribution feeder outages. With the substation feeder automation initiative coming to an end in 2019 the Company is reviewing the automation of its transmission network to identify opportunities to enhance system reliability into the future.

The *Substation Refurbishment and Modernization Plan* is coordinated with the maintenance cycle for major substation equipment and replacement activities. Such coordination minimizes customer service interruptions and ensures the optimum use of resources. This approach is consistent with the least-cost delivery of reliable service. Additionally, substation refurbishment and modernization typically requires power transformers to be removed from service. If customer outages are to be avoided, the timing of the work must be coordinated with the availability of a portable substation. Due to capacity limitations of portable substations, this work is often completed in the late spring through early fall, when substation load is reduced.

The current 5-year forecast for the *Substation Refurbishment and Modernization Plan* is shown in Appendix A.

---

1 The Company's *Substation Refurbishment and Modernization Plan* is the result of the *Substation Strategic Plan* filed with the 2007 Capital Budget Application.

2 By the end of 2019, all distribution feeders will be automated. In its *Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power, December 17th, 2014*, (the "Liberty Report"), the Board's consultants, the Liberty Consulting Group, observed in Conclusion 2.9 that executing the 5-year plan to automate all distribution feeders by 2019 will bring "Newfoundland Power into conformity with good utility practices."

2.0 2019 Substation Refurbishment and Modernization Projects

For 2019, Substation Refurbishment and Modernization Projects include planned refurbishment and modernization of 2 substations. This substation work is estimated to cost a total of $7,088,000, comprising approximately 83% of the total 2019 project cost. The remaining project cost includes: (i) $1,312,000 for Substation Feeder Automation to automate 18 distribution feeders; and (ii) $180,000 associated with Substation Monitoring Upgrades to upgrade substation communication systems

Table 1 identifies expenditures for the 2019 Substation Refurbishment and Modernization Projects.

Table 1
2019 Substation Refurbishment and Modernization Projects
(000s)

Project	Budget
Lewisporte (LEW) Substation	$4,164
Pepperrell (PEP) Substation	$2,924
Substation Feeder Automation	$1,312
Substation Monitoring Upgrades	$180
Total	**$8,580**

2.1 2019 Substation Projects ($7,088,000)

The locations of the two substations undergoing refurbishment and modernization projects in 2019 are shown on the map below. (see Figure 1)

Figure 1: 2019 Substation Refurbishment and Modernization Projects

Lewisporte Substation ($4,164,000)

The Central Newfoundland System Planning Study has determined that the least cost alternative to address the deteriorating condition of transmission lines 101L and 102L involves decommissioning the existing 66 kV transmission lines and transferring Lewisporte (“LEW”) Substation to the 138 kV transmission line 136L.[3] In order to accommodate the new 138 kV transmission line infrastructure, modifications to LEW Substation are required.

LEW Substation was built in 1974 as both a transmission and distribution substation. The transmission portion of the substation contains a single 66 kV transmission line.[4] The 25 kV distribution bus structure is energized by a single 66 kV to 25 kV power transformer, LEW-T1 (25 MVA). There are four 25 kV distribution feeders (LEW-01, LEW-02, LEW-03, and LEW-04) serving approximately 4,400 customers in the Lewisporte area. (see Figure 2)

Figure 2 LEW Substation

The existing 28 year old 66 kV to 25 kV, 25MVA power transformer LEW-T1, installed in 1990, will be replaced with a new 138 kV to 25 kV, 25 MVA power transformer. The existing LEW-T1 will be placed into inventory as a spare transformer. A new spill containment foundation will be constructed for the new LEW-T1 transformer to protect against environmental damage in the event of an oil spill from the unit.

3 The *Central Newfoundland System Planning Study* is included in this Application following the *2019 Capital Plan*.

4 The single 66 kV transmission line is 103L from Notre Dame Junction Substation.

The existing 66 kV steel bus structure will be replaced with a new 138 kV steel bus structure equipped with new 138 kV rated equipment. This includes 3 circuit breakers, 1 set of potential transformers, 6 side break switches, and 1 air break switch.
A new 25 kV steel bus structure will be constructed to align with the new 138 kV steel bus structure and LEW-T1. All of the switches on the existing 25 kV bus structure are in excess of 30 years in service will be replaced due to their mechanical condition and age.[5] This includes 1 side break switch, 4 feeder air break switches, and 8 sets of feeder hook stick operated switches. The new 25 kV bus structure will also be equipped with 1 circuit breaker, 4 reclosers and 1 set of potential transformers. The existing 25 kV reclosers will be relocated to the new 25 kV bus structure.

The protection relays for the existing LEW-T1 transformer are vintage electromechanical type that was installed in 1991. (see Figure 3)

Figure 3: Existing LEW-T1 Protection and Control Cabinet

Electromechanical relays operate by using torque-producing coils energized by current and voltage inputs, which open or close contacts based on mechanically calibrated thresholds. At present, there are 4 electromechanical relays installed in an outdoor control cabinet. These relays are used for the protection of transformer LEW-T1 and are approximately 27 years old.

[5] The Company's strategy for switches is to operate and maintain switches whenever opportunities and substation work permit, and to replace switches when they are more than 30 years old. Over the life of the switches there is 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.

Electromechanical relays contain moving parts that can fail as they age, wear, and accumulate dirt and dust. The age and condition of these relays dictate they are to be replaced in 2019.[6]

The protection and control of substation assets will be modernized by installing microprocessor based digital relays to monitor and control substation assets. Circuit breakers monitored and controlled by digital protection relays will be installed to replace the existing high-speed ground switch and electromechanical relay protection on LEW-T1 transformer. Also, the two transmission line breakers, 136L-B and 147L-B, will be monitored and controlled by digital protection relays.[7] This will improve automation capabilities and reduce the duration of substation outages by providing 2 alternatives for supplying LEW substation.

LEW Substation does not have a control building and the existing equipment storage shed cannot accommodate the new relay and communication panels required to complete the protection upgrades. (see Figure 4) A control building will be erected to provide a climate controlled environment for the new microprocessor based digital relays that will be installed for transmission line, transformer and feeder protection and control upgrades.

Figure 4: Existing LEW Equipment Storage Shed

The communications equipment will be upgraded. This includes a gateway that will be installed to enhance SCADA system remote control and monitoring of the power system protection

6 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electromechanical relays contain moving parts that can fail as they age, wear and accumulate dirt and dust. The Liberty Report examined Newfoundland Power's practice of replacing multiple obsolete electromechanical relays with a single modern microprocessor controlled relay.

7 Transmission line 136L is the existing 138 kV line from Bishop Falls Substation to Cobbs Pond Substation. Transmission line 147L will be the new transmission line from Lewisporte Substation to Cobbs Pond Substation, which will be terminated at LEW Substation in 2020 following the 138 kV conversion.

equipment.[8] The gateway will integrate all substation devices that provide monitoring, protection and control of the transmission lines, distribution feeders and substation transformer into the SCADA system. The enhancement will allow for remote administration of upgraded devices.

All low-voltage equipment will have standard varmint protection installed.
A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation.

Pepperrell Substation ($2,924,000)

Pepperrell ("PEP") Substation, located in the Pleasantville neighborhood of St. John's, was built in 1977 as both a transmission and distribution substation. The transmission portion of the substation contains two 66 kV transmission lines.[9]

The 12.5 kV distribution switchgear is energized by one 66 kV to 12.5 kV power transformer PEP-T1 (25 MVA). There are four 12.5 kV distribution feeders (PEP-01, PEP-02, PEP-03, and PEP-04) serving approximately 3,300 customers in St. John's.

Engineering assessments have determined that the 12.5 kV switchgear, installed in 1977, has deteriorated and requires replacement. The exterior and the interior of the outdoor switchgear building is heavily corroded and is no longer weather tight. (See Figures 5 and 6)

Figure 5: PEP Switchgear Building Exterior

[8] The enhanced capabilities provided by the microprocessor based digital relays provide greater options for the remote control and monitoring through the SCADA system.

[9] The 66 kV transmission lines are 16L to King's Bridge Substation and 74L to Virginia Waters Substation.

Figure 6: PEP Switchgear Building Interior

It has been determined that the least cost option is to replace the existing switchgear with standard outdoor overhead equipment.[10] This would include a new 12.5 kV bus structure, reclosers and breakers.

The existing 66 kV steel bus structure will be relocated and new foundations will be constructed. The existing foundations are deteriorated. (see Figure 7) The existing transformer air break switch PEP-T1-A will be replaced with a 66 kV breaker controlled by the new bus and transformer protection to better protect the transformer from high voltage faults.[11] The 3 side break switches on the 66 kV bus structures are in excess of 30 years in service and will be replaced due to their mechanical condition and age.[12]

---

[10] Cost estimates to replace the existing switchgear building with a new switchgear building are greater than replacing the existing switchgear building with standard outdoor breakers, switches and reclosers. In addition, the salt laden marine environment in this location makes a switchgear building susceptible to corrosion.

[11] The high voltage breaker in conjunction with the upgraded protection relays will improve equipment protection and reliability.

[12] The Company's strategy for switches is to operate and maintain switches whenever opportunities and substation work permit, and to replace switches when they are more than 30 years old. Over the life of the switches, there is 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.

Figure 7: PEP 66 kV Bus Foundations

Power transformer PEP-T1, installed in 1977, will be refurbished and upgrades made to the transformers' auxiliary protection. (see Figure 8) The existing 41-year-old auxiliary protection and control devices used to monitor and protect the power transformers will be upgraded to ensure continued protection and safe operation of the power transformer.

Figure 8: PEP-T1

PEP Substation is located adjacent to Quidi Vidi Lake and its outflow to the Atlantic Ocean. Spill containment foundations will be constructed for transformer PEP-T1 to protect against environmental damage in the event of an oil spill from the units.

The relays for the transformer PEP-T1, bus protection and 2 tie breakers are vintage electromechanical type and are original to the 1977 construction. (see Figure 9) Electromechanical relays operate by using torque-producing coils energized by current and voltage inputs, which open or close contacts based on mechanically calibrated thresholds. At present, there are 20 electromechanical relays installed on 3 switchgear cubicles and 1 individual protection panels inside the substation control building. These 41 year old relays are used for the protection of transformer PEP-T1, the 66 kV bus and the 2 tie breakers. Electromechanical relays contain moving parts that can fail as they age, wear, and accumulate dirt and dust. The age of these relays dictate they be replaced.[13]

Figure 9: PEP Electromechanical Type Relays

The protection and control of substation assets will be modernized by replacing the obsolete electromechanical relays with microprocessor-based digital relays, reducing the total protection

[13] Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electromechanical relays contain moving parts that can fail as they age, wear and accumulate dirt and dust. The Liberty Report examined Newfoundland Power's practice of replacing multiple obsolete electromechanical relays with a single modern microprocessor controlled relay.

relay device count from 11 electromechanical relays to 2 digital relays. The protection upgrade will also involve replacing all of the 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. The protection upgrade will also include replacement of all existing protection and control cables.

The existing 41-year-old control building at PEP Substation has insufficient space to accommodate both the existing and the new protection and communication panels required to complete the protection upgrades. The building is deteriorated and does not meet current standards (see Figure).[14]

Figure 10: PEP Control Building

All low-voltage equipment will have standard varmint protection installed.[15]

A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation.[16]

[14] There is insufficient clearance between the control building and the power transformer.

[15] Report ***2.1*** *Substation Strategic Plan,* included with the 2007 Capital Budget Application, verified that these barriers can be effective in preventing damage to equipment and customer outages caused by small animals and birds. The Liberty Report's Conclusion 2.10 states that "The use of insulated coverings, guards and insulated leads have been effective in preventing animal-caused damage and outages."

[16] Newfoundland Power designs substation ground grids using the *ANSI/IEEE Standard 80-2013 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practice for designing substation ground grids.

2.2 Substation Feeder Automation - SFA ($1,312,000)

At the end of 2019, all distribution feeders will be automated at the substation breaker or recloser. Automation of distribution feeders at the substation breaker or recloser reduces restoration time during local and system wide-outages. In addition to the opening and closing of the devices under remote control, automation also allows for the adjusting of operational parameters, such as automatic reclosing, protection settings and temporary adjustment of trip settings to allow for cold load pickup and other system events.

In 2019, the Company plans to automate the remaining 18 distribution feeders.[17] The distribution feeders are located in Bonavista (3), Indian River (1), Gander Bay (3), Milton (2), Marystown (2), Pasadena (2), Petty Harbour (1), Terra Nova (1), Placentia Junction (1), and Western Avalon (2).

2.3 Substation Monitoring Upgrades – SMU ($180,000)

Over the past decade, there has been a substantial increase of computer-based digital equipment in electrical system control and operations. Periodic upgrades of this equipment are necessary to ensure continued effective electrical system control and operations.

In 2019, hardware and software upgrades are planned to the communications gateways that connect multiple digital devices in substations to the SCADA system. This work will incorporate manufacturers' upgrades to gateways and other computer-based equipment located in Company substations.

These upgrades are required to effectively manage increased volumes of electrical system data. Upgrades typically increase the functionality of the equipment and software, and remedy known deficiencies.

[17] The Company plans to automate *all* distribution feeders by 2019. The Substation Feeder Automation item has been included in all *Substation Refurbishment and Modernization* projects since the 2015 Capital Budget Application.

Appendix A
Substation Refurbishment and Modernization Plan
5-Year Forecast 2019 to 2023

Substation Refurbishment and Modernization Plan 5-Year Forecast 2019 to 2023 ($000s)									
2019		**2020**		**2021**		**2022**		**2023**	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
LEW[1]	$4,164	BCV	$2,442	MOL	$3,713	GBS	$3,497	GAM	$3,900
PEP	$2,924	DUN	$1,393	RBK[1]	$4,265	GOU	$3,976	PAS	$1,604
SFA	$1,312	MSY	$2,542	SMU	$180	HUM	$1,906	WAL	$3,900
SMU	$180	SMU	$180			SMU	$180	SMU	$180
	$8,580		**$6,557**		**$8,158**		**$9,559**		**$9,584**

Note: SUB: Substation - Refer to the Electrical System handbook included with the 2006 Capital Budget Application for 3-letter substation designations.

[1] The upgrades planned for LEW and RBK substations are associated with work described in the *Central Newfoundland System Planning Study*.

2019 Transmission Line Rebuild

July 2018

Prepared by:

L. Palmera-Nunez, P.Eng.
M. R. Murphy, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
LIZ PALMERA-NUNEZ
SIGNATURE
July 6/2018
DATE
NEWFOUNDLAND & LABRADOR

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Transmission Line Rebuild Strategy

Newfoundland Power's transmission lines are the backbone of the electricity network providing service to customers. The Company's transmission lines operate at 66 kV or 138 kV and are often located across country, away from road right of ways.

In 2006, Newfoundland Power (the "Company") submitted its *Transmission Line Rebuild Strategy* outlining a long-term plan to rebuild aging transmission lines. This plan laid out the investment in rebuild projects based on physical condition, risk of failure, and potential customer impact in the event of a failure.

The *Transmission Line Rebuild Strategy* is regularly updated to ensure it reflects the latest reliability data, inspection information, and condition assessments.

Appendix A contains the updated Transmission Line Rebuild Strategy Schedule.

2.0 2019 Transmission Line Rebuild Projects

In 2019, the Company will rebuild sections of 2 transmission lines totalling 38 km, with an average age of 58 years.[1] Appendix B contains maps of each of the lines to be rebuilt.

The transmission line sections to be rebuilt in 2019 are included in Table 1.

Table 1
2019 Transmission Line Rebuilds

Transmission Line	Distance to be Rebuilt	Year Constructed
363L	22 km	1963
302L	16 km	1959

These transmission line sections have deteriorated poles, crossarms, hardware, and conductor. This makes the lines vulnerable to large-scale damage when exposed to heavy wind, ice, and snow loading, thus increasing the risk of power outages. Inspections have identified evidence of decaying wood, worn hardware and damage to insulators.

Upgrading these sections of line will improve the overall reliability of the transmission system that serves customers in the Baie Verte and Burin peninsulas.

[1] This 38 km represents approximately 1.9% of the total 2,000 km of transmission lines owned and maintained by Newfoundland Power.

2.1 Transmission Line 363L ($3,000,000 in 2018, $3,680,000 in 2019 and $3,778,000 in 2020)

Transmission line 363L is a 138 kV H-Frame line running between Baie Verte Junction ("BVJ") Substation on the Trans-Canada Highway, and Seal Cove Road ("SCR") Substation located in Baie Verte. The line was originally constructed in 1963, and includes approximately 62 km of original construction consisting of 478 two-pole and three-pole H-Frame structures, with non-standard 266.8 ACSR transmission line conductor.[2]

Transmission line 363L is a radial line that serves as the only supply to Newfoundland Power and Newfoundland Hydro customers on the Baie Verte Peninsula. This makes 363L critical for the residents and mining operations in the area.

Inspections have identified significant deterioration of the line due to decay, splits and checks in the poles and spar arms, cracks in insulators and other hardware deficiencies. Many of these components are in advanced stages of deterioration and require replacement. The inspection also identified conductor damage requiring immediate repair. Additional details on the condition assessment completed on 363L can be found in the 2018 Capital Budget Application at report ***3.1*** *2018 Transmission Line Rebuild*.

Based on its age, deteriorated condition and criticality, the line will be rebuilt over 3 years.[3] In Order No. P.U. 37 (2017) the Board approved a multi-year project to rebuild transmission line 363L. In 2018, work is ongoing to rebuild 20 km of 363L at an estimated cost of $3,000,000. In 2019, a further 22 km section of the transmission line will be rebuilt at an estimated cost of $3,680,000. In 2020, the final 21 km section will be rebuilt at an estimated cost of $3,778,000.[4]

2.2 Transmission Line 302L ($2,068,000 in 2018, $2,679,000 in 2019)

Transmission line 302L is a 66 kV single-pole line running between Salt Pond ("SPO") Substation in Burin and Laurentian ("LAU") Substation in St. Lawrence. The line was constructed in 1959, with the exception of a 2.4 km section extending into LAU, which was constructed in 1974. Approximately 26.6 km of original vintage line consisting of 315 single-pole structures with non-standard 4/0 ACSR conductor, remain in service.

Transmission line 302L is the most heavily loaded line in the Burin transmission system. As one of two lines feeding LAU, 302L is integral in bringing power generated by the St. Lawrence Wind Farm onto the grid. The new fluorspar mine in St. Lawrence will be adding an estimated load of 8 MW to LAU over the next couple of years, which will further increase the area's reliance on 302L.

---

[2] ACSR, or Aluminum Conductor Steel Reinforced, is a bare overhead conductor constructed with aluminum outer strands and a steel core to support the weight of the cable.

[3] In the original project description filed with the 2018 Capital Budget Application completion of this project was proposed over 4 years. The project is now forecast to be completed over 3 years. Customer outages related to the condition of 363L have caused the Company to accelerate the completion of the rebuild. Overall the project budget has also reduced by approximately $2.9 million as the result of lower than anticipated contractor pricing.

[4] Figure 1 of Appendix B shows the route taken by 363L and identifies the sections to be rebuilt in 2018 to 2020.

Inspections have identified significant deterioration of the line due to decay, splits and checks in the poles and crossarms, cracks in insulators and other hardware deficiencies. Many of these components are in advanced stages of deterioration and require replacement. Additional details on the condition assessment completed on 302L can be found in the 2018 Capital Budget Application at report ***3.1*** *2018 Transmission Line Rebuild*.

In Order No. P.U. 37 (2017) the Board approved a multiyear project to rebuild transmission line 302L. In 2018 work is ongoing to rebuild 11 km of 302L at an estimated cost of $2,068,000. In 2019, the remaining 16 km will be rebuilt. The revised estimate is based on lower than anticipated contractor pricing which was received for the 2018 work. The 2019 work will be completed at an estimated cost of $2,679,000.

3.0 Central Newfoundland Transmission System

The Central Newfoundland area from Grand Falls-Windsor to Gander is supplied by two separate transmission systems. The first transmission system consists of two 66 kV transmission lines, 101L from Grand Falls ("GFS") Substation to Rattling Brook ("RBK") Plant and 102L from RBK Plant to Gander ("GAN") Substation respectively. The second transmission system consists of 136L, a 138 kV transmission line between Bishop Falls ("BFS") Substation and Cobbs Pond ("COB") Substation and TL210 a 138 kV transmission line between Stoney Brook ("STY") Terminal Station and COB Substation.

Transmission line 101L was originally constructed in 1957 and is approximately 32.5 km in length. 101L provides a 66 kV link between GFS Substation and RBK Plant. 101L leaves GFS Substation and runs through the Town of Grand Falls-Windsor, along the Trans-Canada Highway to Route 351 and on to RBK Substation.

Transmission line 102L originally constructed in 1958 is approximately 61 km in length and is divided into 3 sections. The first section is approximately 17 km and runs from RBK Substation to NDJ Substation. This section leaves RBK Substation and runs along Route 351 and then along the Trans-Canada Highway until it enters NDJ Substation at Notre Dame Junction. The second section of 102L is approximately 20 km and runs from NDJ Substation to RFD substation. This section leaves NDJ Substation and follows the Trans-Canada Highway until it enters RFD Substation.[5] The third section of this line is approximately 24 km and runs from RFD Substation to GAN Substation. This section leaves RFD Substation and travels along the Trans-Canada Highway until it enters GAN Substation.

Both transmission lines have reached a point where the Company must now act to ensure reliable service to the approximately 5,100 customers in Central Newfoundland served by these 2 lines. Appendix C to this report provides a detailed condition assessment of transmission lines 101L and 102L.

[5] RFD Substation and the associated 104L radial transmission line were constructed in 1997 to provide electrical service to Beaver Brook Antimony Mine.

3.1 Transmission Line 136L Extension ($2,322,000 in 2019)

At a total 93.5 kms in length, the capital cost to rebuild transmission lines 101L and 102L to current standards will be in the range of $15 to $20 million. Due to the high capital costs required to rebuild both existing 66 kV transmission lines, and the presence of the 138 kV transmission system serving the Central Newfoundland area, other alternatives were examined to identify the best alternative to address the replacement.

The *Central Newfoundland System Planning Study* has determined that the least cost alternative to address the deteriorating condition of transmission lines 101L and 102L involves extending the 138kV transmission system into LEW Substation and RBK Substation.

In 2019, transmission line 136L will be extended to Lewisporte ("LEW") Substation along the existing right of way for 66 kV transmission line 103L. This new 14.0 km extension will provide a 138 kV radial feed from 136L near NDJ Substation to LEW Substation. The new 136L transmission line extension will consists of single pole structures with 559.5 AASC conductor. The 2019 work will be completed at an estimated cost of $2,322,000.

In 2020, transmission line 103L will be rebuilt to 138 kV standards providing a second 138 kV supply to LEW Substation. This will provide redundant supplies for LEW Substation from both BFS Substation and COB Substation.

A detailed description of the alternatives to deal with the deteriorated 66 kV transmission lines can be found in the *Central Newfoundland System Planning Study*.

4.0 Concluding

In 2019, the Company will continue rebuilding sections of 363L and 302L, with the remainder of 363L to be rebuilt in 2020. Each of these transmission lines has structures experiencing deterioration of the poles, crossarms, hardware, and conductor. Recent inspections and engineering assessments have determined the transmission lines have reached a point where continued maintenance is no longer feasible and they must be rebuilt to continue providing safe, reliable electrical service.

As well in 2019, the Company will extend transmission line 136L into LEW Substation as recommended in the *Central Newfoundland System Planning Study* as part of the multiyear plan to ensure the continued provision of safe, reliable electrical service to the area.

Appendix A:
Transmission Line Rebuild Strategy Schedule

Transmission Line Rebuilds 2019 – 2023 ($000s)						
Line	**Year Built**	**2019**	**2020**	**2021**	**2022**	**2023**
302L SPO-LAU	1959	2,679				
363L BVJ-SCR	1963	3,680	3,778			
136L-LEW[1]	1981	2,322				
147L-LEW[2]	NEW		2,383			
137L-RBK[3]	NEW			507		
403L ROB TAP	1960			705		
49L HWD-CHA	1966		476			
105L GFS-SBK	1963			2,291		
124L CLV-GAM	1964			4,894	8,454	
35L KEN-OXP	1965				370	
100L SUN-CLV	1964					3,180
146L GAN-GAM	1964					7,704
TOTAL		**8,681**	**6,637**	**8,397**	**8,824**	**10,884**

[1] As per the *Central Newfoundland System Planning Study*, in 2019, 136L will be extended to LEW Substation. Transmission line 136L will continue to run between BFS, LEW and COB substations.

[2] As per the *Central Newfoundland System Planning Study*, in 2020, 136L will be reconfigured into 136L and 147L. Transmission line 136L will run between BFS and LEW substations. Transmission line 147L will run between LEW and COB substations on structures that were formerly transmission line 103L.

[3] As per the *Central Newfoundland Planning Study*, in 2021, 136L will be divided into 136L and137L. Transmission line 136L will run between BFS and RBK substations. Transmission line 137L will run between RBK and LEW substations.

Appendix B:
Maps of Transmission Lines
363L and 302L

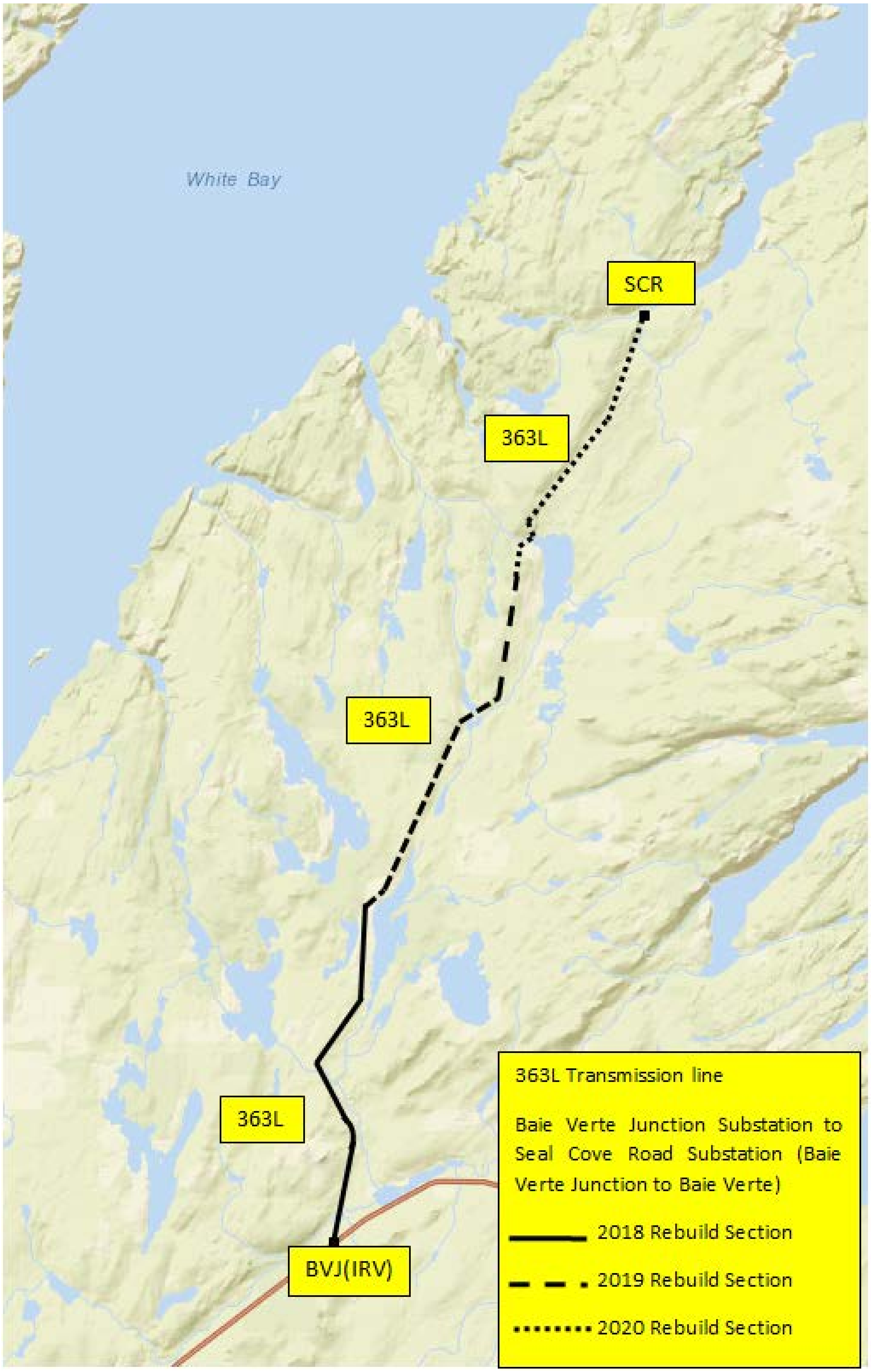


Figure 1: Map of 363L Route

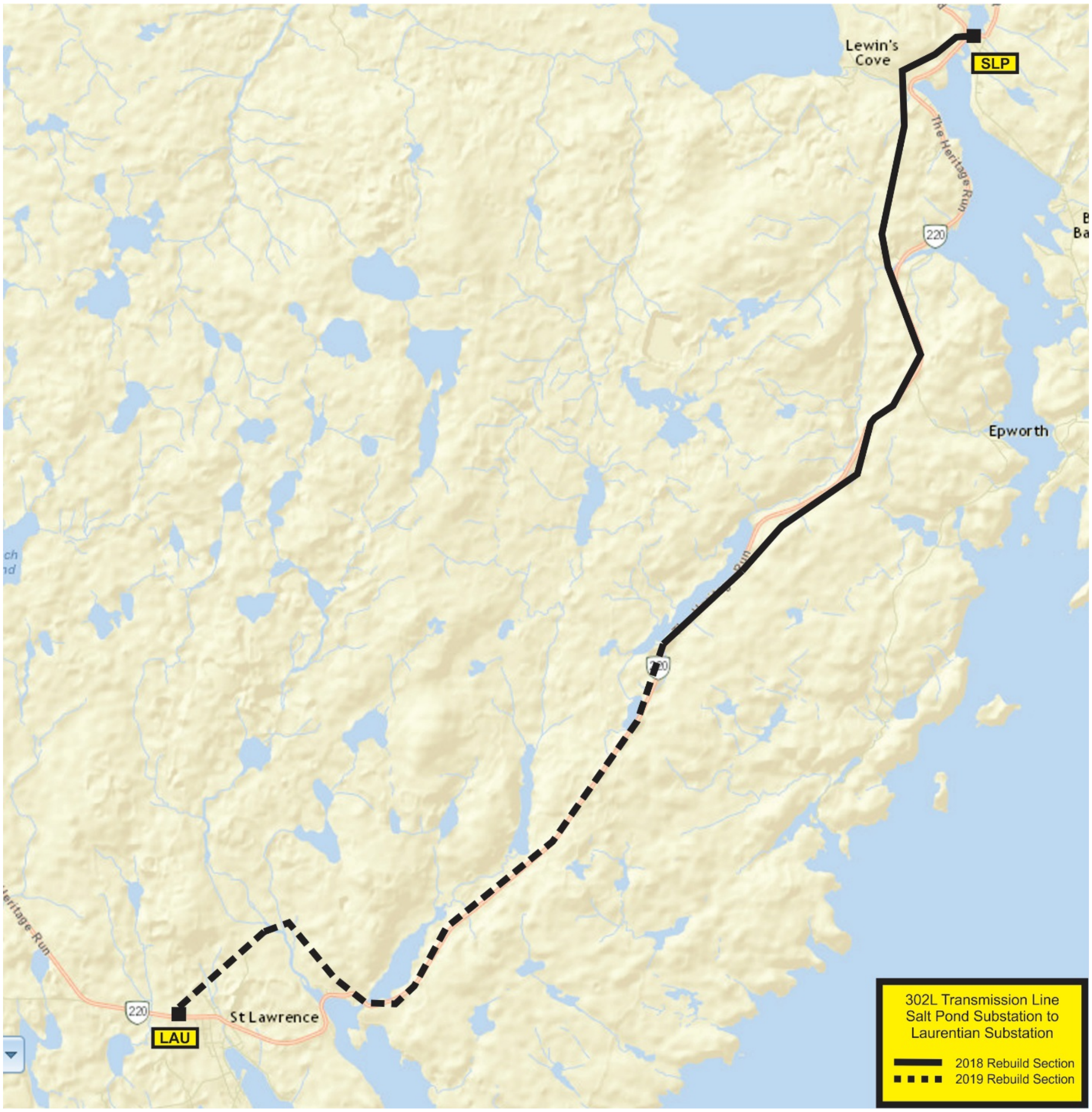


Figure 2: Map of 302L Route

Appendix C:
101L and 102L Transmission Line Condition Assessment

Table of Contents

1.0 Transmission Line Condition Assessment

The Company's 66 kV transmission system in Central Newfoundland is comprised of 2 transmission lines operating between the towns of Grand Falls-Windsor and Gander, along the way interconnecting with Rattling Brook ("RBK") Plant, Notre Dame Junction ("NDJ") Substation, Lewisporte ("LEW") Substation and Roycefield ("RFD") Substation. The 66 kV transmission system was constructed in 1957 and 1958 to deliver electricity from what was at the time the new Rattling Brook hydroelectric plant to the growing communities of Grand Falls and Gander.[1] The 66 kV transmission lines have been in service for approximately 60 years and have reached the point where continued maintenance cannot guarantee the provision of safe reliable service into the future.

This report provides a condition assessment of the existing 66 kV transmission lines and estimates the cost to rebuild the existing transmission line infrastructure to current standards.

1.1 Transmission Line 101L

Transmission line 101L originally constructed in 1957 is a 66 kV transmission line operating between Grand Falls ("GFS") Substation and RBK Plant. The line, with the exception of a 2.2 km section built in 1975 and a 0.8 km section built in 1989, is the original 1957 construction. Approximately 29.5 km of original vintage line consisting of 236 single-pole and 5 two-pole structures with non-standard 2/0 ACSR conductor, remain in service.[2] The route taken by the transmission line, as shown in Figure 1 of Attachment A, starts along the Trans-Canada Highway in Grand Falls – Windsor, traveling along the Trans-Canada Highway and ending on Route 351 in Norris Arm South.[3]

The major components of the transmission line including the poles, crossarms and conductor have reached the end of their useful life. The transmission line has reached a point where a complete rebuild will be required for the line to continue its safe, reliable operation.

1.2 Transmission Line 102L

Transmission Line 102L, originally constructed in 1958, is a 66 kV transmission line divided into three sections. The first section operates between RBK Plant and NDJ Substation, the second section runs between NDJ Substation to RFD Substation, and the third section links RFD Substation to Gander ("GAN") Substation. The route taken by the transmission line, as shown in Figure 2 of Attachment A, starts near Route 351 in Norris Arm South and ends along the Trans-Canada Highway in Gander.

---

[1] In Grand Fall's electricity had been provided by the hydro plants serving the paper mill while in Gander electricity was supplied by the diesel plant built to serve the airport. In the late 1950s both communities customer load growth was exceeding the available capacity of the existing generators.

[2] ACSR, or Aluminum Conductor Steel Reinforced, is a bare overhead conductor constructed with aluminum outer strands and a steel core to support the weight of the cable.

[3] RBK Plant is located in the community of Norris Arm South.

Transmission line 102L is approximately 61 km in length and is comprised of 500 mostly single pole structures. The line was built with 2/0 ACSR conductor which is no longer a standard conductor for Newfoundland Power.

The major components of the transmission line, including the poles, crossarms and conductor, have reached the end of their useful life. The transmission line has reached a point where a complete rebuild will be required for the line to continue its safe, reliable operation.

1.3 Condition Assessment

Due to the age and condition of both transmission lines they are susceptible to damage when exposed to wind, ice or snow loading. At more than 60 years in service, many of the components are in advanced stages of deterioration and require replacement. As both transmission lines are of similar vintage the condition assessment was completed for both lines with the results detailed below.

Poles, Cross Braces and Crossarms
The wooden components of the transmission line structures are experiencing a significant level of deterioration. Many of the poles are showing signs of significant shell separation. This phenomenon causes the outer shell of the poles to separate longitudinally, resulting in deep checks extending from the bottom of the pole to the top.[4] These checks extend deep enough to allow moisture and fungus to enter the pole past the treated outer layer and into the untreated heart of the pole. Repeated freeze and thaw cycles exacerbate this problem by widening the checks, and the result is failure of the poles.

The outer shell separation on the poles of both transmission lines presents a safety risk to employees who carry out maintenance work on the line. The compromised outer layer on the pole shell makes climbing the poles hazardous. The deteriorated outer shell is unable to support the weight of the climber and as a result the climber's spikes 'tear out' of the poles. Without the ability to climb the poles performing maintenance on the line requires off-road aerial equipment to access the structures in order to reach the crossarms and insulators. Accessing the transmission line can be particularly difficult in winter with snow on the ground.

The poles and crossarms, in many cases, are now moss-covered which indicates advanced decay and, therefore, their strength has been compromised. The original poles on both lines are Class 5 which is a substandard pole class compared to current design criteria. Considerable narrowing has occurred at the top of many poles and has reduced the strength of the structures. Some of the pole tops have rot as shown in Figures 1, 7, and 8 of Attachment B. This level of deterioration makes it susceptible for hardware to disconnect from the pole.

The majority of the two-pole structures on these lines do not have cross braces. During wind, ice or snow loading events the structure can experience excessive torsional forces which may result

[4] Pictures of this phenomenon and the resulting condition of the poles can be found on Figures 10 and 11 in Attachment B.

in failure of the pole. These structures are also significantly deteriorated and will require replacement.

Hardware
101L and 102L have numerous long spans which require deadend structures on both ends. During inspections, connectors not typically used by Newfoundland Power on transmission lines of this vintage were observed as shown in Figure 8 of Attachment B. These connections are made by tightly bending the conductor around the connector separating the strands over time. Due to corrosion and wear at these connection points, the conductor has deteriorated exposing the steel core creating a potential failure point. Thermal scan inspections have indicated abnormal heating at these connections.

Insulators
The original 1950 vintage porcelain insulators on both transmission lines were manufactured by Canadian Ohio Brass ("COB"). Premature failure of these porcelain insulators due to cement growth and radial cracking is a known problem through the utility industry. Since the 1990s, the Company has replaced a significant number of insulators on these lines.[5]

Conductor
The 2/0 ACSR conductor used in the original construction of 101L and 102L is particularly susceptible to corrosion between the inner steel core and the outer aluminum strands. The existing conductors do not meet present standards and the steel core of each conductor shows evidence of corrosion. This reduces the physical strength and current carrying capacity of the conductor.

The conductor on these lines is damaged and deteriorated in many places.[6] Over the years, many inline splices have been installed along the length of the conductor. These are evidence of repairs made after the conductor failed during various sleet storms in the area. The condition of the conductor combined with the poor general condition of the poles places these transmission lines at risk of a costly, extended repair should conductor failure occur.[7]

Pole Cribs
Inspections have also identified pole cribs that have rotted and no longer contain a suitable quantity of rock. This compromises the overall strength of the cribbed structures. A number of pole cribs on transmission lines 101L and 102L are damaged and have compromised the support of the pole. The wooden pole cribs are deteriorated and no longer contain the rock ballast necessary to support the structures.[8]

---

5 Many of the pictures in Attachment B show that the original COB insulators have been replaced with vertical line post clamp top insulators.

6 Picture of the deteriorated conductor with multiple sleeves can be found in Figure 15 of Attachment B.

7 Conductor failure on sections of tangent transmission line structures can result in cascading pole failures. This risk is increased when existing pole strengths are decreased due to decay and deterioration.

8 Pictures of the deteriorated pole cribs can be found in Figure 3 and Figure 4 of Attachment B.

2.0 Cost Estimate

Table 3 below includes the cost estimates for rebuilding transmission lines 101L and 102L to current standards.

Table 3
Capital Cost Estimates
(000s)

Item	Amount
Rebuild 32.5 kms of transmission line 101L	$5,582
Rebuild 61.0 kms of transmission line 102L	$10,967
Total	**$16,549**

Due to the high capital costs required to rebuild both existing 66 kV transmission lines other alternatives will be examined to determine the best alternative to address the replacement of transmission lines 101L and 102L. The communities in Central Newfoundland area are also served by two reliable 138 kV transmission lines. Alternatives taking advantage of the 138 kV transmission lines to serve customers should be considered and the least cost alternative chosen.

3.0 Concluding

Transmission lines 101L and 102L have structures experiencing significant deterioration of the poles, crossarms, pole cribs, hardware, and conductor. Original vintage poles, hardware and conductor comprise a large percentage of both lines. These components have been in service for over 60 years and have reached the end of their service life. Recent inspections and engineering assessments have determined the transmission lines will require major rebuild and maintenance work to continue providing safe, reliable electrical service.

At approximately $16.5 million the rebuild of these 2 transmission lines requires further investigation to determine if other least cost alternatives exist. The Company has undertaken the *Central Newfoundland System Planning Study* to determine the least cost alternative to addressing the deteriorating condition of transmission lines 101L and 102L. This condition assessment conducted on transmission lines 101L and 102L is one input to this planning study.

Attachment A:
Maps of Transmission Lines
101L and 102L

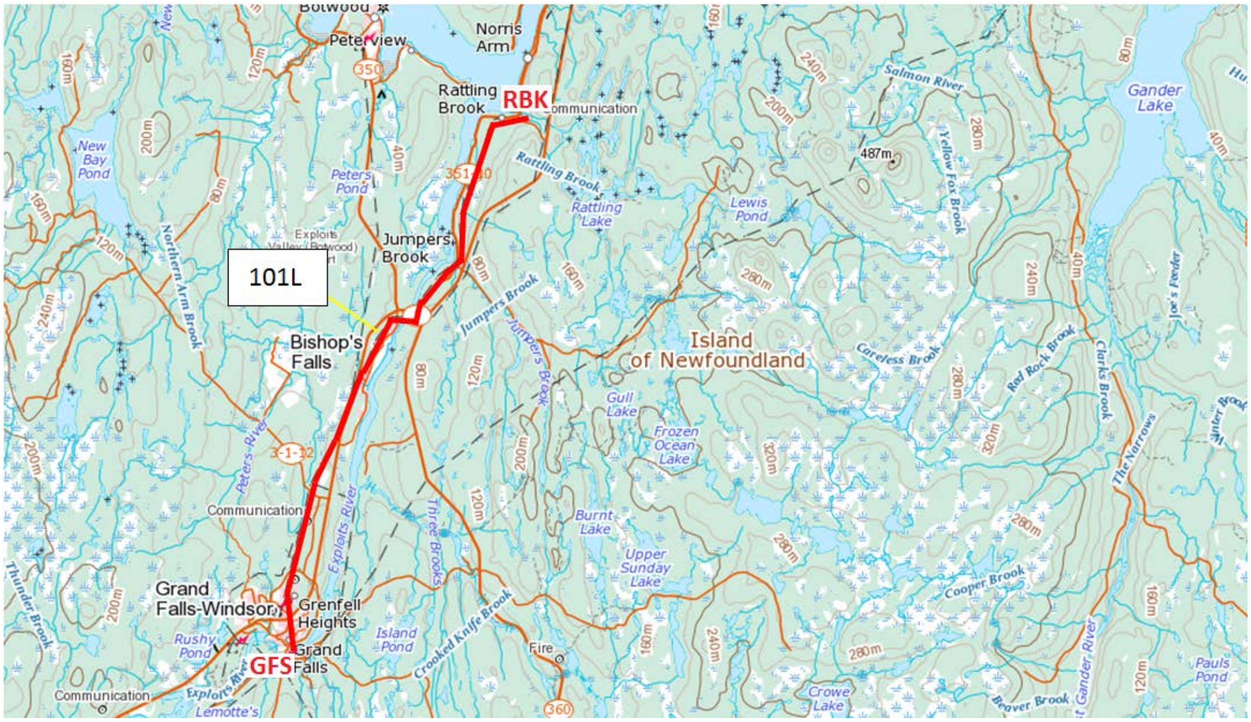


Figure 1: Map of 101L Route

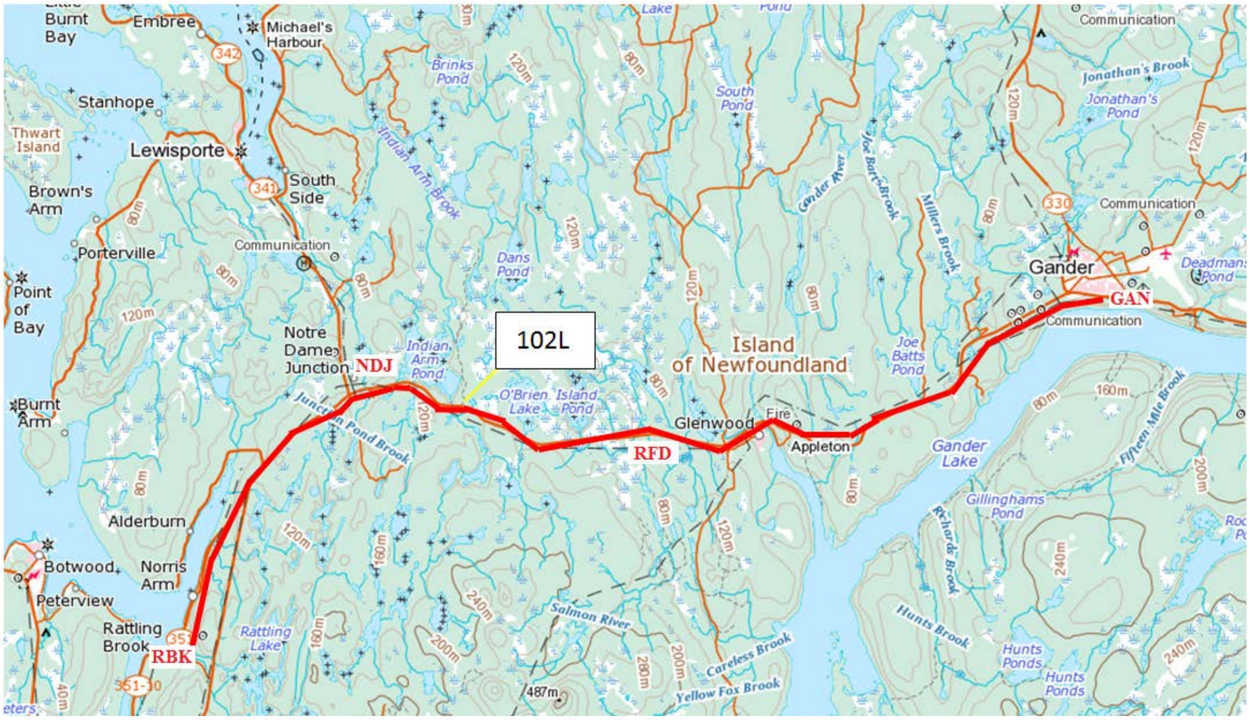


Figure 2: Map of 102L Route

**Attachment B:
Photographs of Transmission Lines
101L and 102L**

<u>Transmission Line 101L</u>

Figure 1: Deteriorated Pole Top

Figure 2: Pole Checking

Figure 3: Deteriorated Pole Crib Timber

Figure 4: Rock Ballast No Longer Contained

Transmission Line 102L

Figure 5: Deteriorated Pole

Figure 6: Pole Splitting

Figure 7: Cross Arm Deterioration

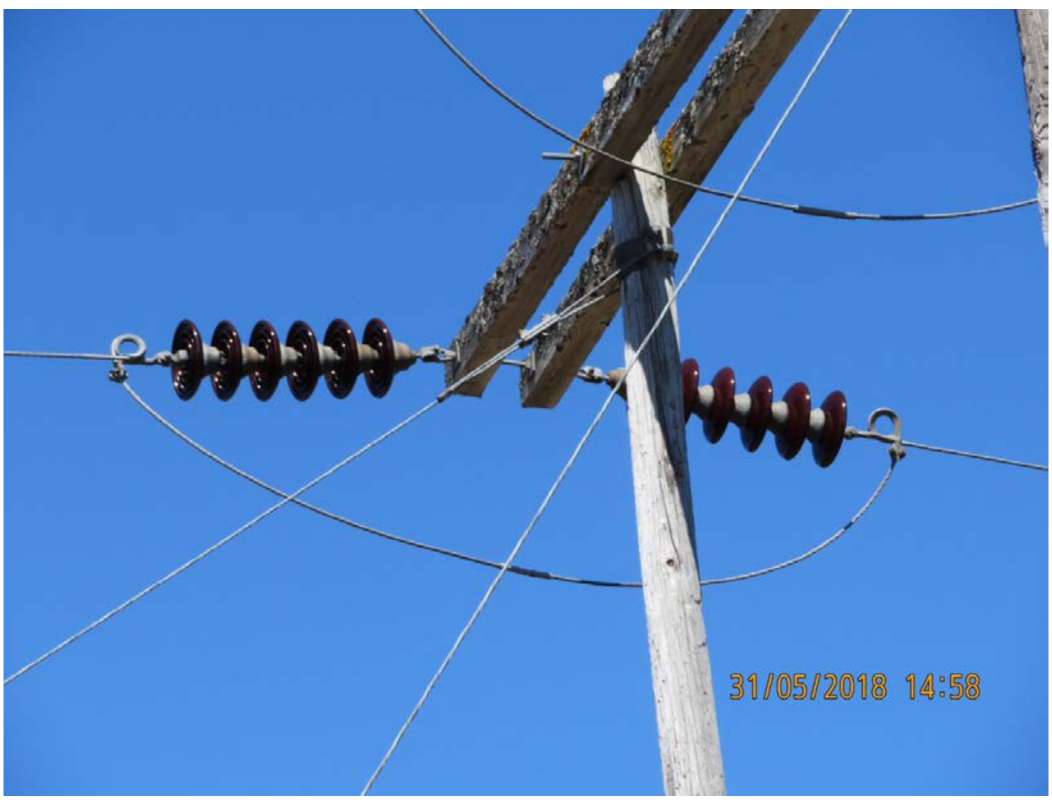


Figure 8: Cross Arm Deterioration

Figure 9: Deteriorated Pole with Vintage Insulators and Connectors

Figure 9: Pole Top with Significant Rot

Figure 10: Delamination near Pole Top

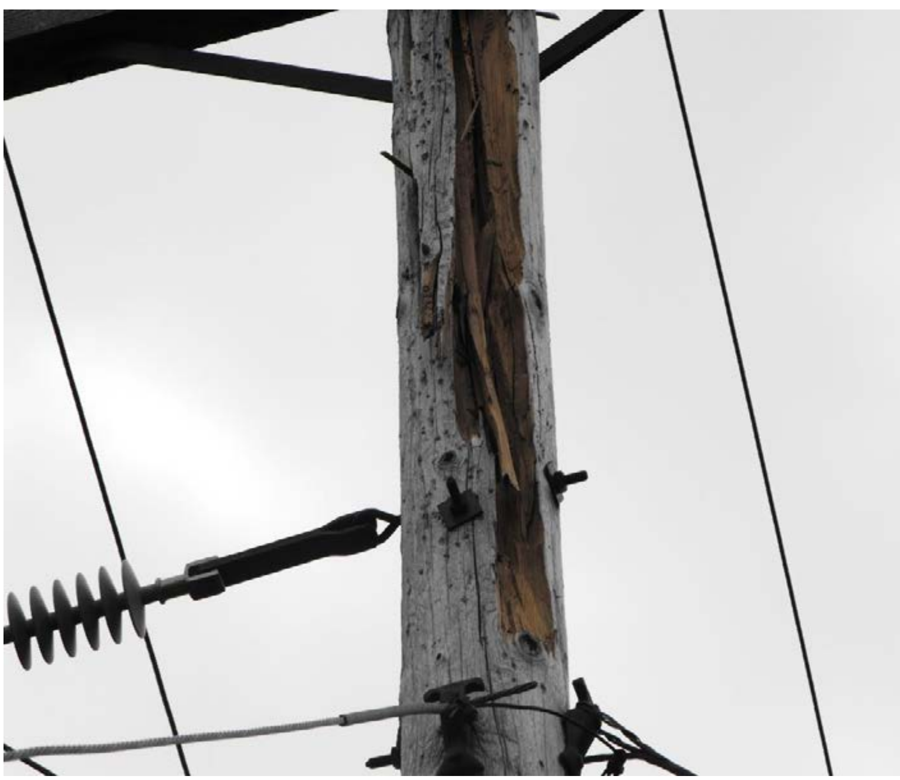


Figure 11: Delamination at Pole Top

Figure 12: Broken Insulators

Figure 13: Pole Shell Separation Showing Exposed Inner Wood

Figure 14: Severely Leaning Structure

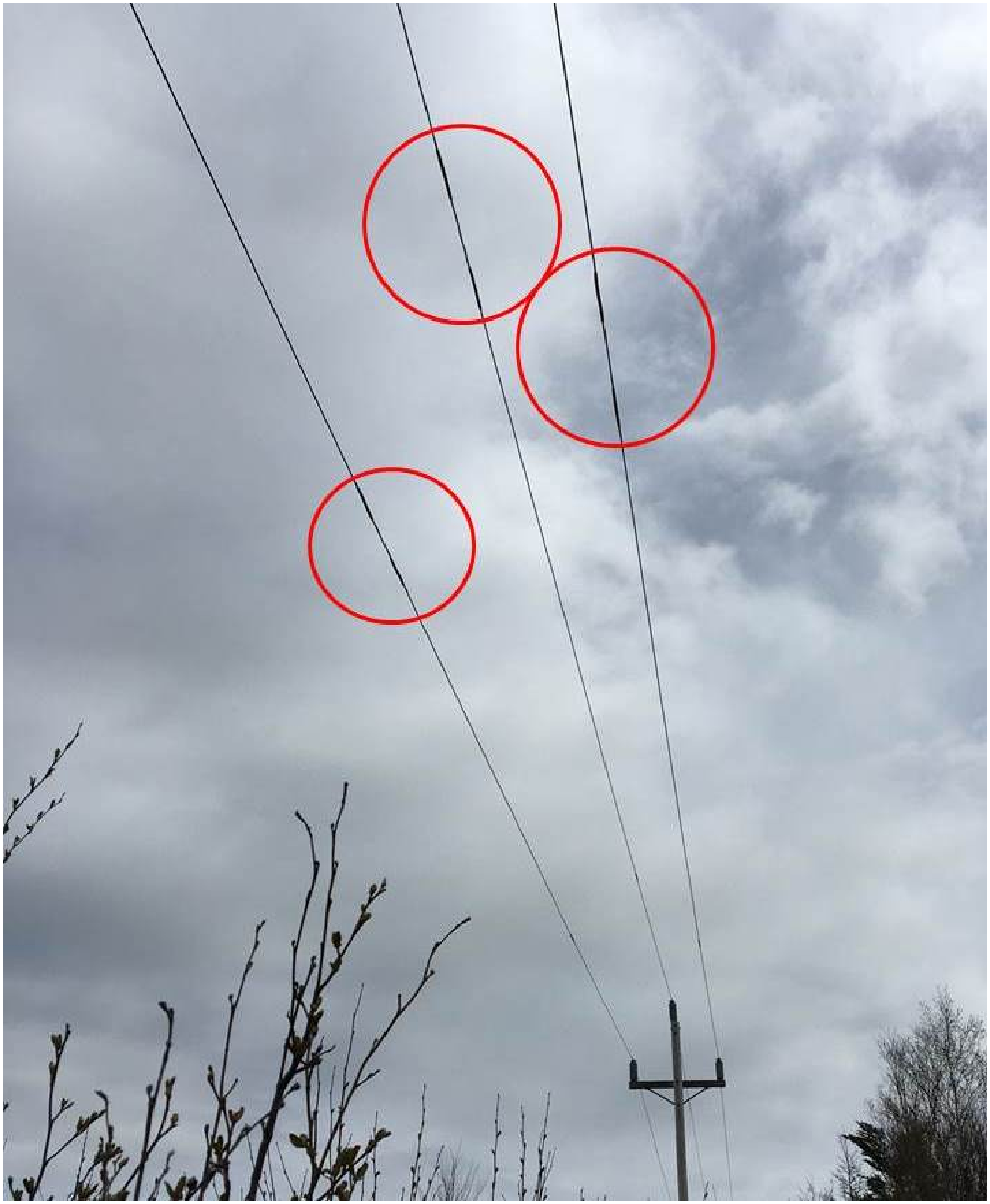


Figure 15: Conductor with Multiple Splices

Distribution Reliability Initiative

July 2018

Prepared by:

Ralph Mugford, P.Eng.
Robert Cahill, Eng. L.

REGISTERED PROFESSIONAL ENGINEER
RALPH W. MUGFORD
SIGNATURE
July 6, 2018
DATE
NEWFOUNDLAND & LABRADOR

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

Newfoundland Power manages system reliability through capital investment, maintenance practices and operational deployment. On an ongoing basis, Newfoundland Power examines its actual distribution reliability performance to assess where targeted capital investment is warranted to improve service reliability.

The *Distribution Reliability Initiative* is a capital project focusing on the reconstruction of the worst-performing distribution feeders. Customers served by these feeders experience more frequent and longer duration outages than average.

The process used by Newfoundland Power to identify which distribution feeders will benefit from targeted capital investment involves: (i) calculating reliability performance indices for all feeders; (ii) analysing the reliability data for the worst-performing feeders to identify the cause of the poor reliability performance; and (iii) where appropriate, completing engineering assessments for those feeders where poor reliability performance cannot be directly related to isolated events that have already been addressed. The decision to make capital investment to improve the reliability performance of the worst-performing feeders is based on the engineering assessments completed as part of the process.

2.0 Background

Historically, Newfoundland Power identified its worst-performing feeders exclusively on the basis of System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and customer minutes of outage.[1] These are the indices most commonly used in Canada and are reflective of overall system condition.

SAIDI and SAIFI are used to rank the reliability performance of distribution feeders on the impact outages have on individual customers. However, it is recognized that relying solely on these indices to identify worst-performing feeders can lead to overlooking smaller feeders with chronic issues.[2]

In 2012, the Canadian Electricity Association began reporting on 2 additional indices: Customer Hours of Interruption per Kilometer ("CHIKM") and Customers Interrupted per Kilometer ("CIKM").[3] CHIKM and CIKM are used to rank the reliability performance of distribution feeders on the length of line exposed to the outage. These indices tend to be more reflective of

---

1 System Average Interruption Duration Index (SAIDI) is calculated by dividing the number of customer-outage-hours (e.g., a 2-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area. Distribution SAIDI records the average hours of outage related to distribution system failure. System Average Interruption Frequency Index (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 records the average number of outages related to distribution system failure.

2 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.

3 Customers Interrupted per Kilometer (CIKM) is calculated by dividing the number of customers that have experienced an outage by the kilometers of line. Customer Hours of Interruption per Kilometer (CHIKM) is calculated by dividing the number of customer-outage-hours by the kilometers of line.

infrastructure condition and better identify issues associated with shorter feeders. Similar to SAIDI and SAIFI, CHIKM and CIKM are used to rank worst-performing feeders that require further analysis of reliability data and, where appropriate, complete engineering assessments to determine if targeted capital investment is warranted to improve service reliability.

Newfoundland Power has incorporated CIKM and CHIKM into its reliability analysis in this report.[4] Appendix A contains the 5-year average distribution reliability data, excluding significant events, for the 15 worst-performing feeders based on data for 2013 to 2017, utilizing SAIDI, SAIFI, customer minutes, CIKM and CHIKM.

Appendix B contains a summary of the assessment carried out on each of the feeders listed in Appendix A.

3.0 Project Description

The examination of the worst-performing feeders, as listed in Appendix A and Appendix B, has resulted in *Distribution Reliability Initiative* work being identified for 3 distribution feeders in 2019. Work on DUN-01, GBY-03 and SJM-06 is proposed for 2019. The DUN-01 project is spread over 3 years with work proposed to start in 2019 and continue in 2020 and 2021. The GBY-03 project is spread over 2 years with work proposed to start in 2019 and continue in 2020. The work required on SJM-06 will be carried out in 2019.

A detailed engineering assessment of distribution feeders DUN-01, GBY-03 and SJM-06 is included in Appendix C, Appendix D and Appendix E respectively.

Table 1 summarizes the reliability data for each of the distribution feeders identified and compares those data to Company averages.

Table 1
Distribution Interruption Statistics
5-Year Average to December 31, 2017

Feeder	Customers	SAIFI	SAIDI	CHIKM	CIKM
DUN-01	1,043	4.13	9.63	62	27
GBY-03	765	2.87	6.40	45	20
SJM-06	1,211	1.89	1.70	392	437
Company Average	**846**	**1.35**	**1.71**	**44**	**34**

[4] Newfoundland Power started using the CIKM and CHIKM in its analysis of worst-performing feeders in 2015. It is anticipated that by using indices that consider customer interruptions and circuit length that the worst-performing feeders will be found in urban settings where the Company has older poles and associated infrastructure.

Table 1 shows that distribution feeders DUN-01 and GBY-03 are outliers from the Company average for SAIFI and SAIDI.[5] SJM-06 is an urban feeder with an abnormally high CHIKM and CIKM.[6]

4.0 Project Cost

The estimate to complete the 2019 work associated with the *2019 Distribution Reliability Initiative* project is $1,800,000. Table 2 provides a detailed breakdown of the 2019 project cost by distribution feeder.

Table 2
2019 Project Cost

Description	DUN-01	GBY-03	SJM-06	Total
Engineering	$78,000	$74,000	$100,000	$252,000
Labour - Contract	52,000	141,000	180,000	373,000
Labour - Internal	208,000	130,000	160,000	498,000
Material	160,000	49,000	100,000	309,000
Other	202,000	106,000	60,000	368,000
Total	**$700,000**	**$500,000**	**$600,000**	**$1,800,000**

[5] The SAIFI for DUN-01 is 3.1 times the Company average and GBY-03 is 2.1 times the Company average. The SAIDI for DUN-01 is 5.6 times the Company average and GBY-03 is 3.7 times the Company average.
[6] The CHIKM for SJM-06 is 8.9 times the Company average and CIKM is 12.9 times the Company average.

Appendix A:
Distribution Reliability Data:
Worst-Performing Feeders

Unscheduled Distribution-Related Outages **Five-Year Average** **2013-2017** **Sorted By Customer Minutes of Interruption**				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
DUN-01	4,305	602,528	4.13	9.63
SCV-01	1,776	537,561	1.02	5.14
SCR-01	2,784	519,427	2.86	8.89
SUM-01	6,251	516,357	3.43	4.73
CHA-03	4,504	428,037	1.52	2.41
WAV-01	4,375	405,773	3.34	5.17
LEW-02	3,381	390,316	2.25	4.33
GLV-02	2,906	368,260	1.91	4.04
BHD-01	7,040	367,704	7.43	6.47
LAU-01	2,394	359,302	3.39	8.47
SUM-02	2,037	356,556	3.32	9.69
BOT-01	2,884	347,866	1.68	3.39
MOL-06	2,832	332,494	2.07	4.06
DOY-01	3,693	326,182	2.13	3.13
HWD-07	5,336	315,703	2.10	2.07
Company Average	**1,146**	**87,537**	**1.35**	**1.71**

Unscheduled Distribution-Related Outages Five-Year Average 2013-2017 Sorted By Distribution SAIFI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
BHD-01	7,040	367,704	7.43	6.47
SCT-02	1,820	90,056	7.19	5.93
RVH-02	842	95,038	5.26	9.90
TWG-03	1,577	75,900	5.12	4.11
TWG-01	3,736	181,252	5.08	4.11
SCT-01	3,519	151,432	4.92	3.53
TWG-02	3,322	113,811	4.74	2.71
ABC-02	4,650	248,597	4.56	4.06
DUN-01	4,305	602,528	4.13	9.63
SJM-11	5,399	295,813	3.76	3.43
MOB-01	5,541	177,947	3.49	1.87
ABC-01	2,739	74,622	3.44	1.56
SUM-01	6,251	516,357	3.43	4.73
LAU-01	2,394	359,302	3.39	8.47
WAV-01	4,375	405,773	3.34	5.17
Company Average	**1,146**	**87,537**	**1.35**	**1.71**

Unscheduled Distribution-Related Outages Five-Year Average 2013-2017 Sorted By Distribution SAIDI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
RVH-02	842	95,038	5.26	9.90
SUM-02	2,037	356,556	3.32	9.69
DUN-01	4,305	602,528	4.13	9.63
SCR-01	2,784	519,427	2.86	8.89
LAU-01	2,394	359,302	3.39	8.47
TRP-01	1,649	238,358	2.73	6.58
BHD-01	7,040	367,704	7.43	6.47
GBY-03	2,192	293,597	2.87	6.40
SCT-02	1,820	90,056	7.19	5.93
GBS-02	891	108,067	2.84	5.74
LGL-01	575	121,153	1.62	5.69
LGL-02	1,699	201,933	2.71	5.60
GBY-01	1,183	197,127	1.88	5.21
WAV-01	4,375	405,773	3.34	5.17
SCV-01	1,776	537,561	1.02	5.14
Company Average	**1,146**	**87,537**	**1.35**	**1.71**

Unscheduled Distribution-Related Outages Five-Year Average 2013-2017 Sorted By Distribution CHIKM	
Feeder	**Annual Distribution CHIKM**
SJM-06	392
KBR-10	380
GFS-02	330
WAV-03	270
MOL-09	251
SJM-13	237
MOL-06	230
KBR-12	228
SLA-09	223
RRD-10	214
HWD-07	194
SLA-10	194
SPR-02	192
SLA-13	190
GDL-04	179
Company Average	**44**

Unscheduled Distribution-Related Outages Five-Year Average 2013-2017 Sorted By Distribution CIKM	
Feeder	**Annual Distribution CIKM**
SJM-06	437
GFS-02	289
KBR-10	249
KBR-12	220
PAB-03	198
HWD-07	197
TWG-02	169
TWG-01	168
KEN-01	163
MOL-09	155
HWD-08	155
KEN-04	149
GAN-03	149
SJM-02	149
PEP-01	149
Company Average	**34**

Appendix B:
Worst-Performing Feeders:
Summary of Data Analysis

Worst-Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
ABC-01	Reliability statistics were driven by a broken conductor outage in 2014. No work is required at this time.
ABC-02	Reliability historically has been good. There were several insulator failures in 2015, a significant outage in 2016 due to broken conductor and 2 large outages due to broken poles. These will be addressed through the *Rebuild Distribution Lines* project. No additional work required at this time.
BHD-01	Reliability historically has been good. Poor 2015 and 2016 reliability statistics were driven by wind-related incidents. In 2017 there were 2 outages caused by broken poles. No work is proposed at this time but the feeder will continue to be monitored.
BOT-01	In 2013, 2014 and 2015 trees falling across the line during wind storms contributed to poor reliability statistics. Vegetation issues were addressed and no additional work is required at this time.
CHA-03	Poor reliability statistics were driven a single broken pole in 2017. 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 2015 and 2016. Work was completed under the *2014 Feeder Additions for Load Growth* project to address the unbalanced load issue. No additional work is required at this time.
DUN-01	In 2014, outages were caused by high winds and a faulty lightning arrestor. Poor reliability statistics in 2015, 2016 and 2017 were caused by numerous issues. Reliability statistics for this feeder continue to worsen. An engineering assessment has determined this feeder should be included in the *2019 Distribution Reliability* project.
GAN-03	Poor reliability statistics were driven by a damaged insulator in 2015. No work is required at this time.
GBS-02	Wind and sleet caused several reliability issues in 2014 and 2015. Some work was done in 2016 under the *Rebuild Distribution Lines* program. There were outages caused by conductor issues in 2017. No additional work is required at this time
GBY-01	GBY-01 has had good reliability over the years. A lightning-related event resulted in poor overall reliability statistics in 2015. In addition, a significant outage was caused by a tree contacting the line in late 2013. No work is required at this time.

Worst-Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
GBY–03	Poor reliability statistics were driven by equipment failure. Lightning caused an outage in 2015 and broken insulators caused outages in 2016. Conductor and insulator failure caused several large outages again in 2017. An engineering assessment has determined this feeder should be included in the *2019 Distribution Reliability* project.
GDL-04	Poor reliability statistics were driven by two damaged insulators in 2016. No work is required at this time.
GFS-02	Poor reliability statistics were driven by storm damage in November 2013. Broken conductor caused a long duration outage in 2014. This feeder is one of the Company's worst-performing from an interruption per kilometer perspective. This feeder was upgraded as part of the *2016 Distribution Reliability Initiative* project. No work is proposed at this time but the feeder will continue to be monitored.
GLV-02	Poor reliability statistics were driven by a wind-related event in 2017. No work is required at this time.
HWD-07	Outages caused by high winds in 2013 highlighted the poor performance of this feeder. As a result it had significant upgrades as part of the *2016 Distribution Reliability Initiative* project. No additional work is required at this time.
HWD-08	Poor reliability statistics were principally due to high winds and an underground cable fault in 2014. No work is required at this time
KBR-10	Sections of this feeder had significant upgrades as part of the *2015 Distribution Reliability Initiative* project. Historically this feeder had poor reliability statistics due to the condition of the aerial cable along Kings Bridge Road. The aerial cable has now been replaced. No additional work is required at this time.
KBR-12	Reliability has generally been good. Conductor issues in 2015 contributed to reduced reliability in that year. No work is required at this time.
KEN-01	Reliability has generally been good. A broken insulator in 2015 contributed to reduced reliability in that year. No work is required at this time.
KEN-04	Reliability has generally been good. A downline automated recloser was added to the feeder in 2016 as part of the *Distribution Feeder Automation* project. No additional work is required at this time.
LAU-01	Reliability has generally been good. A rodent-related incident in 2015 contributed to reduced reliability in that year. No work is required at this time.
LEW-02	Poor reliability statistics were driven by a wind-related event and a vehicle accident in 2016. No work is required at this time.

Worst-Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
LGL-01	Weather-related outages, including damage from wind in 2013 and 2014, resulted in poor reliability statistics. No work is required at this time.
LGL-02	Poor reliability statistics were driven by salt spray, a broken conductor in 2013 and sleet in 2015. No work is required at this time.
MOB-01	Reliability has generally been good. A broken pole and crossarm related to a vehicle accident in 2013 were the primary reasons for the poor reliability statistics experienced in recent years. Approximately 5 km of the feeder was upgraded as part of the *2015 Feeder Additions for Growth* project. No additional work is required at this time.
MOL-06	Poor reliability statistics were due to a single tree incident in 2013 and damage caused by sleet in 2017. No work is required at this time.
MOL-09	This feeder was included in the *2015 Distribution Reliability Initiative* project to address poor reliability statistics. The feeder also had multiple outages on long single-phase taps due to equipment failure. No work is required at this time.
PAB-03	Poor reliability statistics were due to and underground cable fault in 2013. No work is required at this time.
PEP-01	Poor reliability statistics were caused by a single wind related event in 2017. No work is required at this time.
RRD-10	Poor reliability statistics were caused by a single wind related event in 2017. No work is required at this time.
RVH-02	Poor reliability statistics were due to several equipment failures in 2015 and a wind related event in 2017. Work was carried out on this feeder in the *2017 Distribution Reliability Initiative* project. No work is required at this time.
SCR-01	The feeder had significant reliability issues in 2016 and 2017, caused by broken insulator, birds, trees and vandalism. No work is proposed at this time but the feeder will continue to be monitored.
SCT-01	Poor reliability statistics were driven by wind and tree-related events in 2013 and 2017. No work is required at this time.
SCT-02	Poor reliability statistics were driven by wind and vegetation related events in 2013, 2014, 2016 and 2017. No work is required at this time.
SCV-01	Poor reliability statistics were driven by a wind-related event in 2015. No work is required at this time.
SJM-02	Poor reliability statistics were driven by a broken pole wind-related event in 2017. No work is required at this time.

Worst-Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
SJM-06	A broken conductor and damages by a third party contributed to poor reliability statistics in 2013. A protective relay issue contributed to poor reliability statistics in 2015. Copper conductor corrosion and equipment failures are dominating outage causes in recent years. An engineering assessment has determined this feeder should be included in the *2019 Distribution Reliability* project.
SJM-11	Reliability has generally been good. Damages by a third party contributed to poor reliability statistics in 2014. No work is required at this time.
SJM-13	Conductor failure during high winds in 2013 and 2014 contributed to poor reliability statistics. This feeder will continue to be monitored to determine if it should be considered for rebuilding in a future capital budget.
SLA-09	Historically, poor reliability statistics were due to underground cable faults. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. Work was carried out under the *2016 Distribution Reliability Initiative* project. No additional work is required at this time.
SLA-10	Poor reliability statistics were caused by a downed tree in 2014. No work is required at this time,
SLA-13	Reliability has generally been good. However, a broken insulator and 2 wind-related incidents in 2015 contributed to poor reliability statistics. No work is required at this time.
SPR-02	Poor reliability statistics were caused by tree issues and a snow storm in 2013. No work is required at this time.
SUM-01	Poor reliability statistics were caused by events in 2015 and 2016, one involving salt spray and the others involving broken conductor. In 2013 an issue occurred with a broken insulator. No work is required at this time.
SUM-02	Poor reliability statistics were driven by several incidents of broken conductor in 2014 and 2015. Work is being carried out in 2017 and 2018 as part of the *Distribution Reliability Initiative* project.
TRP-01	This feeder has experienced continuing worsening reliability over the past 5 years. The location of the feeder subjects it to extreme sleet and wind loading conditions. These have resulted in broken poles and numerous incidents of insulator and conductor failure over the past 5 years. Work is being carried out on this feeder in 2017 and 2018 as part of the *Distribution Reliability Initiative* project.
TWG-01	This feeder has good reliability. Poor reliability statistics were caused by a lightning-related event in 2013 and a failed insulator in 2016. No work is required at this time.

Worst-Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
TWG-02	This feeder has good reliability. Poor reliability statistics were caused by a failed insulator in 2016. No work is required at this time.
TWG-03	This feeder has good reliability. Poor reliability statistics were caused by a single wind-related event in 2013 and several insulator failures in 2017. No work is required at this time.
WAV-01	This feeder has good reliability. Poor reliability statistics were caused by wind related issues in 2017. No work is required at this time.
WAV-03	This feeder has good reliability. Poor reliability statistics were caused by wind related issues in 2017. No work is required at this time.

Appendix C
Dunville DUN-01 Feeder Study

July 2018

Table of Contents

1.0 General

The *Distribution Reliability Initiative* is a project that involves the replacement of deteriorated poles, conductor and hardware to reduce both the frequency and duration of power interruptions to the customers served by specific distribution feeders. Distribution feeders are identified for evaluation based on an analysis of reliability statistics over the past 5 years. Once identified, a detailed engineering assessment of the feeder is carried out to determine if any upgrade work is required. The assessment looks at the physical condition of plant, the risk of failure and the potential impact to customers in the event of a failure.

The *Distribution Reliability Initiative* identified the DUN-01 feeder as one of the *worst performing feeders* on Newfoundland Power's distribution system. An engineering evaluation of the feeder was carried out in early 2018. This report summarizes the findings of that evaluation and presents a plan to improve reliability on the feeder.

2.0 DUN-01 Feeder

The DUN-01 feeder is one of two distribution feeders originating from the Dunville ("DUN") Substation. The feeder has no tie points to other feeders which eliminates the possibility for both permanent and temporary load transfers during unplanned or planned outages.

DUN-01 is a 25 kV distribution feeder that was originally constructed in the late 1960's and currently serves 1,043 customers. The feeder extends from DUN Substation located on Fox Harbour Road in the community of Dunville and heads east along Route 100 ("Argentia Access Road"). It then extends through the community of Southeast Placentia and into Point Verde. From there the feeder continues south through the communities of Big Barasway, Ship Cove, Gooseberry Cove, Angel's Cove and on to St. Brides. The feeder then turns east and extends to the community of Branch with 2 taps extending further south to Cape St. Mary's and Point Lance.[1]

The main 3-phase trunk portion of DUN-01 is approximately 80.0 km in length and travels from the DUN Substation to the community of St. Bride's. Much of the pole line infrastructure on the main trunk is currently of 1990's vintage.[2] The 3-phase trunk section that runs from DUN Substation to the community of Point Verde is 22.0 km long and is constructed using #477 Aluminum Stranded Conductor ("ASC"). The remaining 3-phase trunk of the feeder that extends south to St. Brides is 40 km long and is constructed using #4/0 Aluminum Alloy Stranded Conductor ("AASC"). There is a 2-phase section that extends east from St. Bride's to Branch which is 17.5 km long and is constructed using #4/0 AASC Conductor. There are also two 1-phase taps attached to the main trunk between the communities of St, Bride's and Branch. Both are 12.0 km long and are constructed using #2 Aluminum Conductor Steel Reinforced ("ACSR") conductor.

---

1 Attachment C-1 includes a map showing the areas served by distribution feeder DUN-01.

2 DUN-01 was one of the company's first DRI projects. Poor reliability along this coast required that the Company undertake expenditures in the late 1990s to rebuild sections of DUN-01.

3.0 Engineering Assessment

Inspections have identified the major contributing factors to outage duration and frequency to be (i) corroded or broken conductor, (ii) preform ties on insulators, (iii) insulator failures and (iv) decay, splits, and cracks in cross-arms on the feeder. When the feeder was re-conductored in the 1990's the standard construction at the time used porcelain insulators with steel preform conductor ties. The high winds and salt content in the area have resulted in the preform conductor ties corroding and deteriorating to a point where failures occur during high winds. Component failure during high winds has been an issue over the past number of years. Due to the age and condition of the support structures, they are becoming more susceptible to damage when exposed to severe wind, ice and snow loading.[3]

Analysis of the outage data reveals that equipment failure is the cause for most of the outages experienced. However, it is also the geographic location of the feeder which greatly increases response times and therefore outage duration. DUN-01 feeder is in an area of severe ice and wind loading. The routing of the feeder along the coastline also makes it susceptible a high level of salt contamination from onshore winds.

The 40.0 km 3-phase section of DUN-01 from Point Verde to St. Bride's was rebuilt over 25 years ago. Therefore, many of the poles in this section will not need to be replaced at this time. However, the remaining 1960's vintage poles are deteriorated and will need to be replaced. Similarly the 1990's vintage #4/0 AASC primary conductor is in good condition and will not require replacement. Review of the outage data reveals the 3-phase trunk section of the feeder between Point Verde and St. Bride's as the major contributor to the poor outage performance of the DUN-01 feeder. Reframing this section to current standards using treated cross-arms and clamp-top insulators will reduce outage frequency and improve reliability during all weather conditions. Replacement of 2 existing disconnect switches along the main trunk section of the feeder with new hook stick operated disconnect switches will greatly improve sectionalizing and reduce restoration time by allowing a Line Supervisor or Technologist to operate the switches from the ground.

Table 1 summarizes the reliability data for DUN-01 distribution feeder for the most recent 5-year period.

Table 1
DUN-01 Distribution Interruption Statistics
2013 to 2017

	Customers	**SAIFI**	**SAIDI**	**CHIKM**	**CIKM**
DUN-01	1,043	4.13	9.63	62	27
Company Average	**846**	**1.35**	**1.71**	**44**	**34**

[3] Sections of this distribution feeder were built to weather loading criteria that are less than the standard currently used for new construction.

Table 1 shows that distribution feeder DUN-01 is an outlier from the Company average for SAIDI and SAIFI.[4] An analysis of the outage data reveals that equipment failure has been the cause for most of the outages experienced. The main trunk of this distribution feeder has reached a point where continued maintenance is no longer feasible and the feeder has to be rebuilt to current construction standards for continued safe and reliable operation.

4.0 Recommendations

The DUN-01 feeder is a critical part of the company's distribution system in the area of Dunville to St. Bride's. Over the past 5 years, the majority of the reliability issues on this line have been due to equipment failure and deteriorated infrastructure.

To improve the performance and reliability of this feeder, it is recommended to:

- Reframe 900 structures along the main trunk of the feeder with new cross-arms and insulators;
- Replace all original 1960 vintage poles as well as any additional poles showing signs of excessive deterioration; and
- Install 2 new hook stick operated disconnect switches.

It is proposed to complete the required work over a three year period at a total project cost estimated at $2,100,000. The proposed plan is to spend $700,000 in 2019, $700,000 in 2020 and the remaining $700,000 in 2021.

4 The SAIDI for the DUN-01 feeder is 5.6 times the Company average while SAIFI is 3.1 times the Company average.

Attachment C-1
Map Showing Areas Served by DUN-01

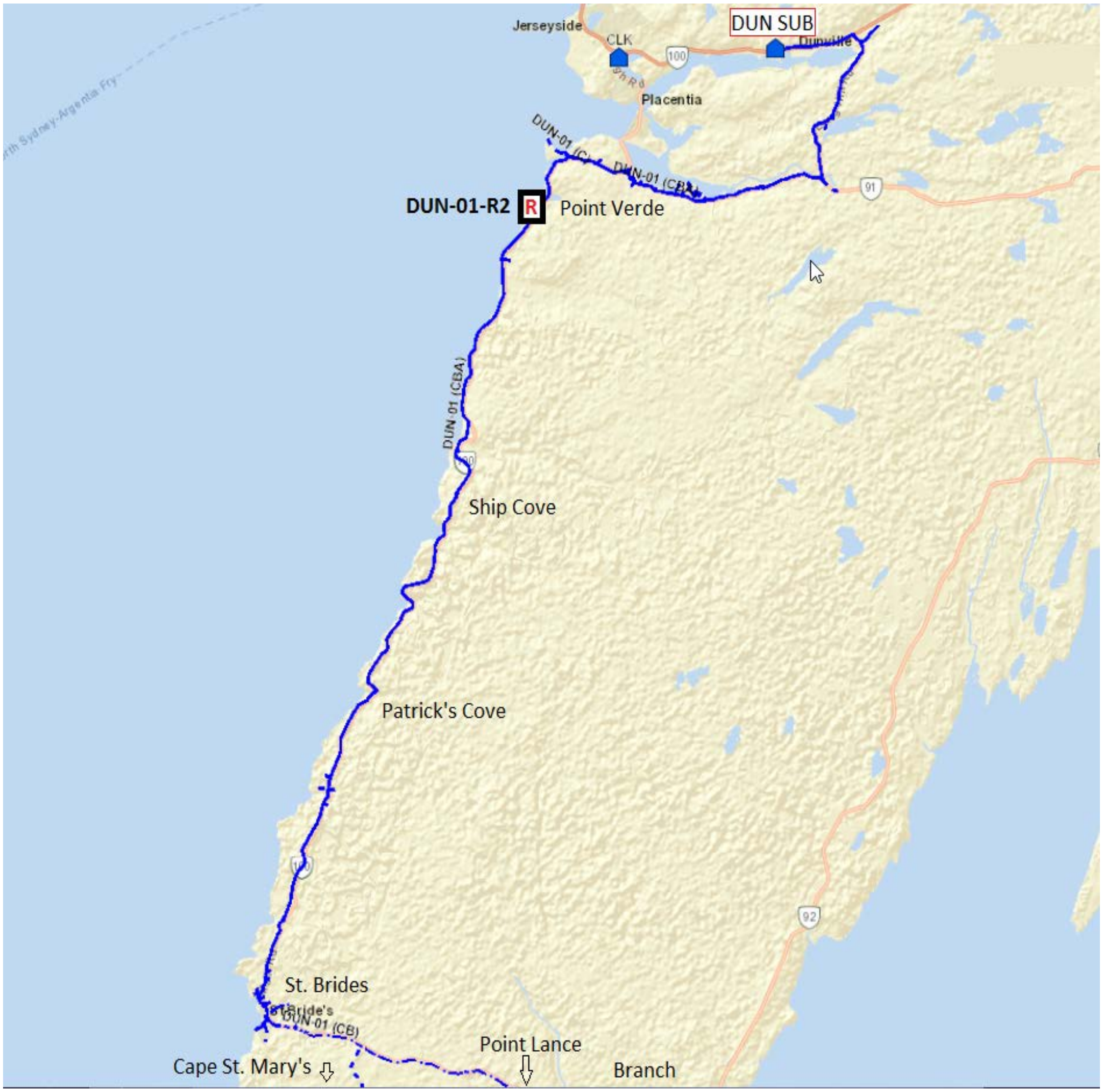


Figure 1 – Map of DUN-01

Attachment C-2
Photographs of DUN-01 Feeder

Figure 1 – Insulator failure resulting in pole fire and structure failure.

Figure 2 – Floating center phase conductor due to broken preform tie. Note left side insulator replaced

.

Figure 3 – Floating right side phase caused by broken preform tie.

Figure 4 – Deteriorated cross-arm.

Figure 5 – Split cross-arm on B structure.

Figure 6 – Deteriorated pole. Note side phase insulator had failed previously.

Appendix D
Gander Bay GBY-03 Feeder Study

July 2018

Table of Contents

1.0 General

The *Distribution Reliability Initiative* is a project that involves the replacement of deteriorated poles, conductor and hardware to reduce both the frequency and duration of power interruptions to the customers served by specific distribution feeders. Distribution feeders are identified for evaluation based on an analysis of reliability statistics over the past 5 years. Once identified, a detailed engineering assessment of the feeder is carried out to determine if any upgrade work is required. The assessment looks at the physical condition of plant, the risk of failure and the potential impact to customers in the event of a failure.

The *Distribution Reliability Initiative* identified the GBY-03 feeder as one of the *worst performing feeders* on Newfoundland Powers distribution system. An engineering evaluation of the feeder was carried out in early 2018. This report summarizes the findings of that evaluation and presents a plan to improve reliability on the feeder.

2.0 GBY-03 Feeder

GBY-03 is one of 3 distribution feeders originating from the Gander Bay ("GBY") Substation. The feeder has a tie to GBY-02 feeder, which allows for both permanent and temporary load transfers between these feeders during unplanned or planned outages.

GBY-03 is a 25 kV distribution feeder that was originally constructed in the mid-1960s. It currently serves approximately 764 customers. The feeder leaves GBY Substation, located in the community of Gander Bay South, and immediately travels cross country for approximately 19.0 km. The remaining 30.0 km of trunk feeder travelling to the community of Musgrave Harbour largely follows the Route 330 right of way, with isolated off road sections where the original highway has been realigned. A long single-phase tap, mid-way along this section serves the community of Aspen Cove and a number of single and 3-phase taps branch out near the end of the trunk to serve the community of Musgrave Harbour.[1]

The first 19.0 km section of the 3-phase, main trunk section of the GBY-03 feeder was constructed in the 1970s. This section was constructed using H-frame transmission line structures with 266 MCM ACSR conductors.[2] The remaining 3-phase trunk was constructed in the 1960s and currently has 1/0 AASC and #2 ACSR conductor. The 1-phase and 3-phase taps are also constructed using both 1/0 AASC and #2 ACSR conductor.

---

[1] Attachment D-1 includes a map showing the areas served by distribution feeder GBY-03.

[2] The 19.0 km line was constructed to transmission standards during a period of significant load growth. A future conversion to transmission and construction of an additional substation in the Carmanville area was contemplated based on the growth predictions in the 1960s. The load did not materialize to warrant the construction of a new substation in Carmanville.

3.0 Engineering Assessment

Inspections have identified deteriorated poles, hardware, 2-piece insulators, damaged conductor and decayed or damaged cross arms on the feeder trunk. It has also been identified that over 50 porcelain cutouts remain in service on the feeder.[3]

The poles, cross arms and conductor on the 19.0 km off road section are in good condition, with only isolated poles requiring replacement at this time. The insulators and associated hardware on this section requires replacement. The distribution type dead end insulators used during original construction are no longer standard today. A failure of one of these insulators occurred in 2016 resulting in an extended outage to the entire feeder. A recent inspection on this line resulted in a planned outage to replace similar hardware on 4 other structures that was in imminent risk of failure.[4] Given the age and type of equipment, failures are expected in the future and are particularly challenging to find and repair given the section of line is cross country.

There is also a significant quantity of the original 1960's vintage poles, insulators and conductor. Some 2-piece insulators are still in use on the main trunk section of the feeder. Two-piece insulators have a documented high failure rate related to cement growth.[5] Component failure, particularly insulators, has been an issue over the past couple of years. In addition, the feeder is particularly impacted by woodpeckers with over 50 poles having significant woodpecker damage, many of which are poles over 40 years old.[6] The conductor is generally in fair condition with isolated sections in poor condition.

Due to the age and condition of many of the poles, insulators, conductor and cutouts, the feeder is becoming more susceptible to damage under normal conditions and when exposed to heavy wind, ice and snow loading.

---

[3] Porcelain cutouts deteriorate over time when exposed to harsh weather conditions and are likely to crack and fail when operated and therefore reduce feeder reliability and create safety concerns for the general public and line staff.

[4] A failure of this insulator under unplanned circumstances would have resulted in a multi-hour duration outage to the entire feeder. During the planned 2018 outage, the GBY-03 load was transferred to GBY-02 avoiding any customer outage.

[5] Since the 1960s the term "cement growth" has been used to categorize a problem with premature failure of porcelain insulators. The cement joining the 2 insulating discs grows over time placing stress on the porcelain disks that fails in tension to cracking.

[6] Not all poles impacted by wood peckers require replacement however damage caused by wood peckers may compromise the structural strength and accelerate rot if it becomes significant enough.

Table 1 summarizes the reliability data for GBY-03 distribution feeder for the most recent 5-year period.

Table 1
GBY-03 Distribution Interruption Statistics
2013 to 2017

	Customers	SAIFI	SAIDI	CHIKM	CIKM
GBY-03	765	2.87	6.40	45	20
Company Average	**846**	**1.35**	**1.71**	**44**	**34**

Table 1 shows that distribution feeder GBY-03 is an outlier from the Company average for SAIDI and SAIFI.[7] A review of the outage data reveals that equipment failure has been the cause for most of the outages experienced. Given the current condition of GBY-03, along with its geographic location, particularly the off-road section, it has reached a point where continued maintenance is no longer beneficial. The feeder must be rebuilt to current construction standards for continued safe and reliable operation.

4.0 Recommendations

The GBY-03 feeder is a critical part of the company's distribution system in the area of Gander Bay to Musgrave Harbour. Over the past 5 years the majority of the reliability issues on this line have been due to equipment failure, and aging and substandard infrastructure.

To improve the performance and reliability of this feeder, it is recommended to:

- Reinsulate 70 structures on the 19.0 km off road section;
- Replace approximately 90 deteriorated poles including poles from the original construction and those impacted by woodpeckers;
- Replace all deteriorated cross arms and insulators on the main trunk of GBY-03 with V-brace cross arms and 25 kV clamp top insulators, involving approximately 100 structures;
- Replace sections of poor conductor; and
- Replace all remaining porcelain cutouts.

It is proposed to complete the required work over a 2 year period, with the total project cost estimated at $1,200,000. The project proposal includes and estimated expenditure of $500,000 in 2019 and the remaining $700,000 in 2020.

[7] The SAIDI for the GBY-03 feeder is 3.7 times the Company average while SAIFI is 2.1 times the Company average.

Attachment D-1
Map Showing Areas Served by GBY-03

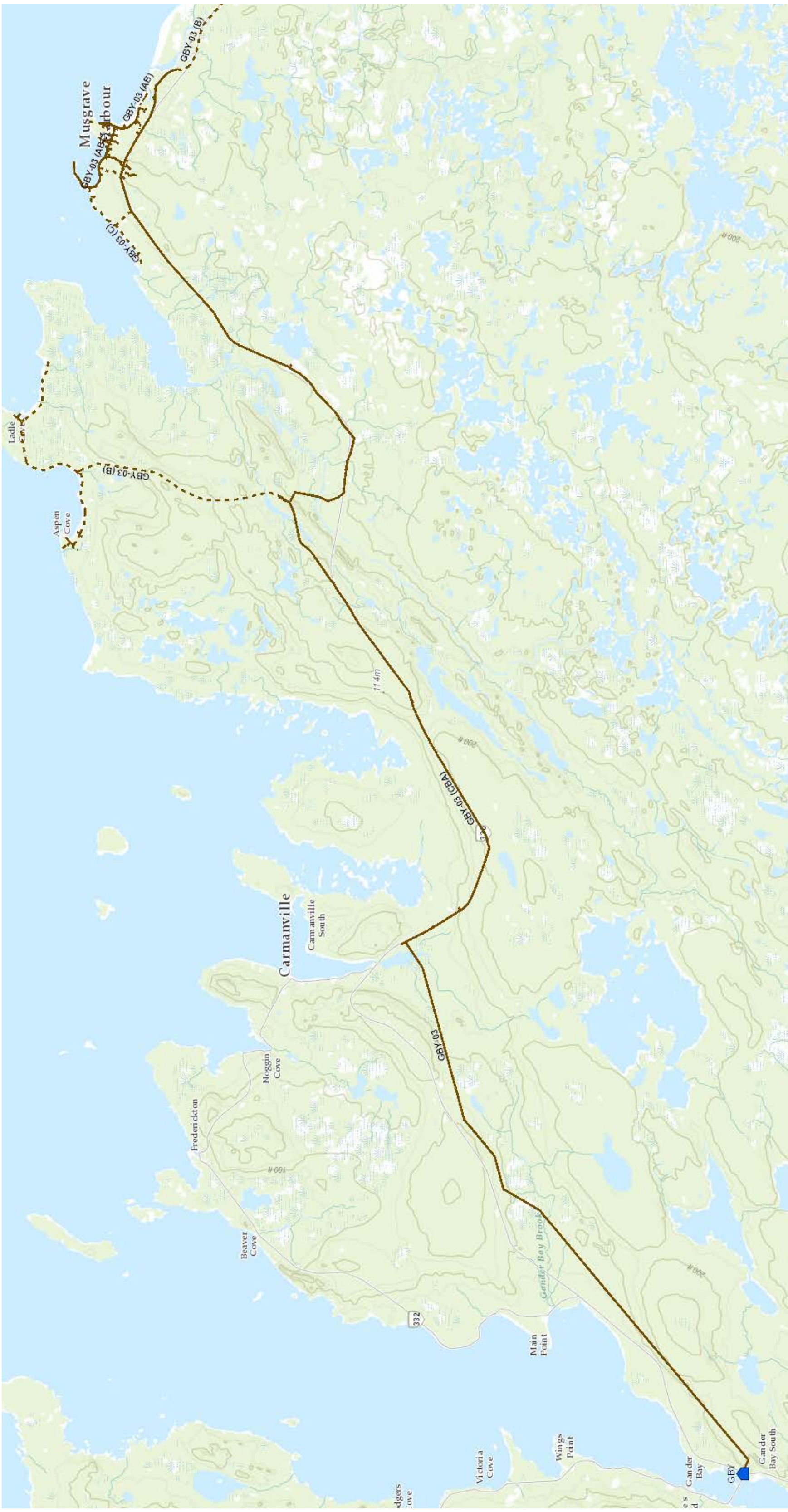


Figure 1 – Map of GBY-03

Attachment D-2
Photographs of GBY-03 Feeder

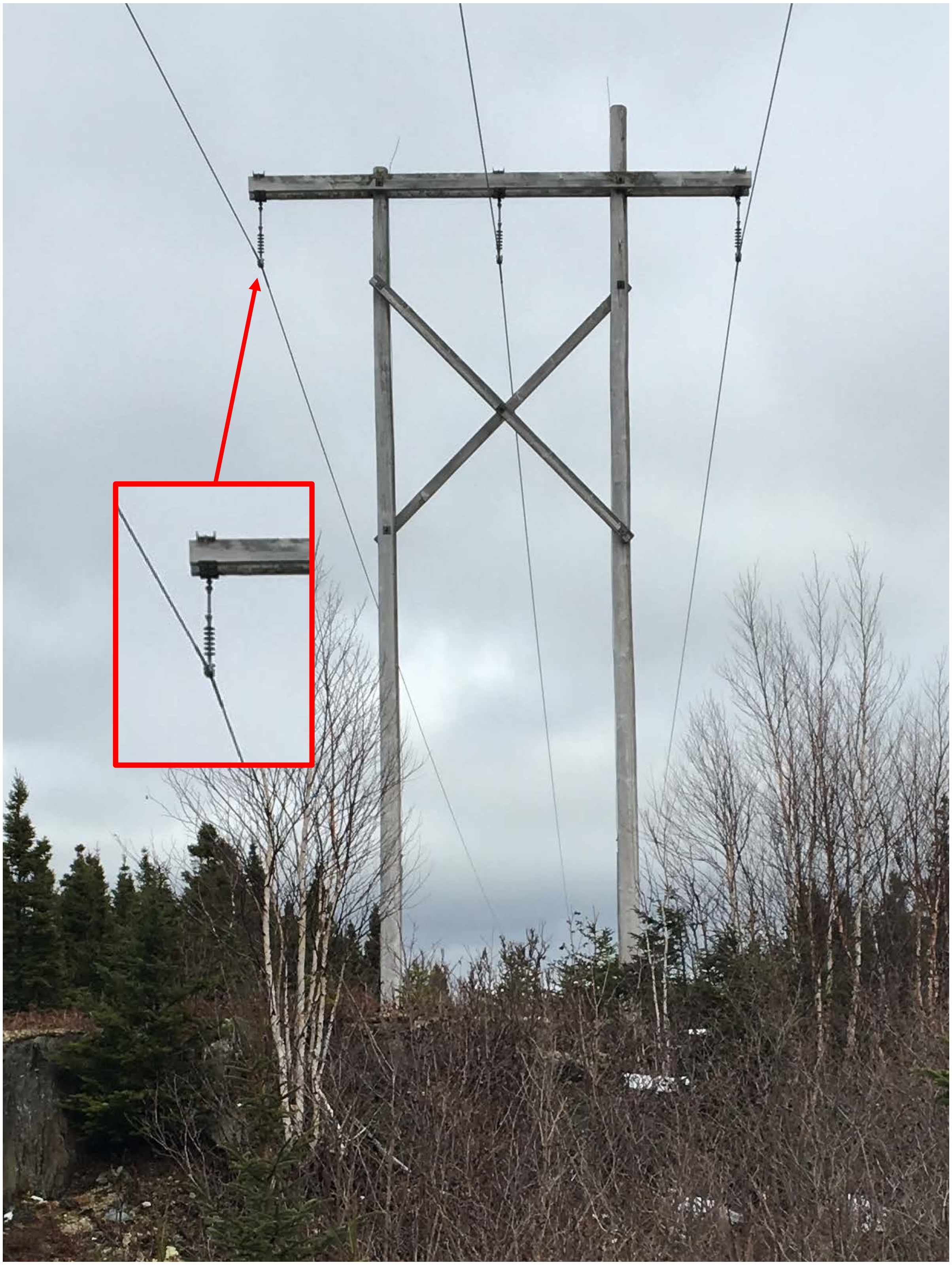


Figure 1 – H-frame transmission type structure with distribution class insulators

Figure 2 – Multiple woodpecker holes

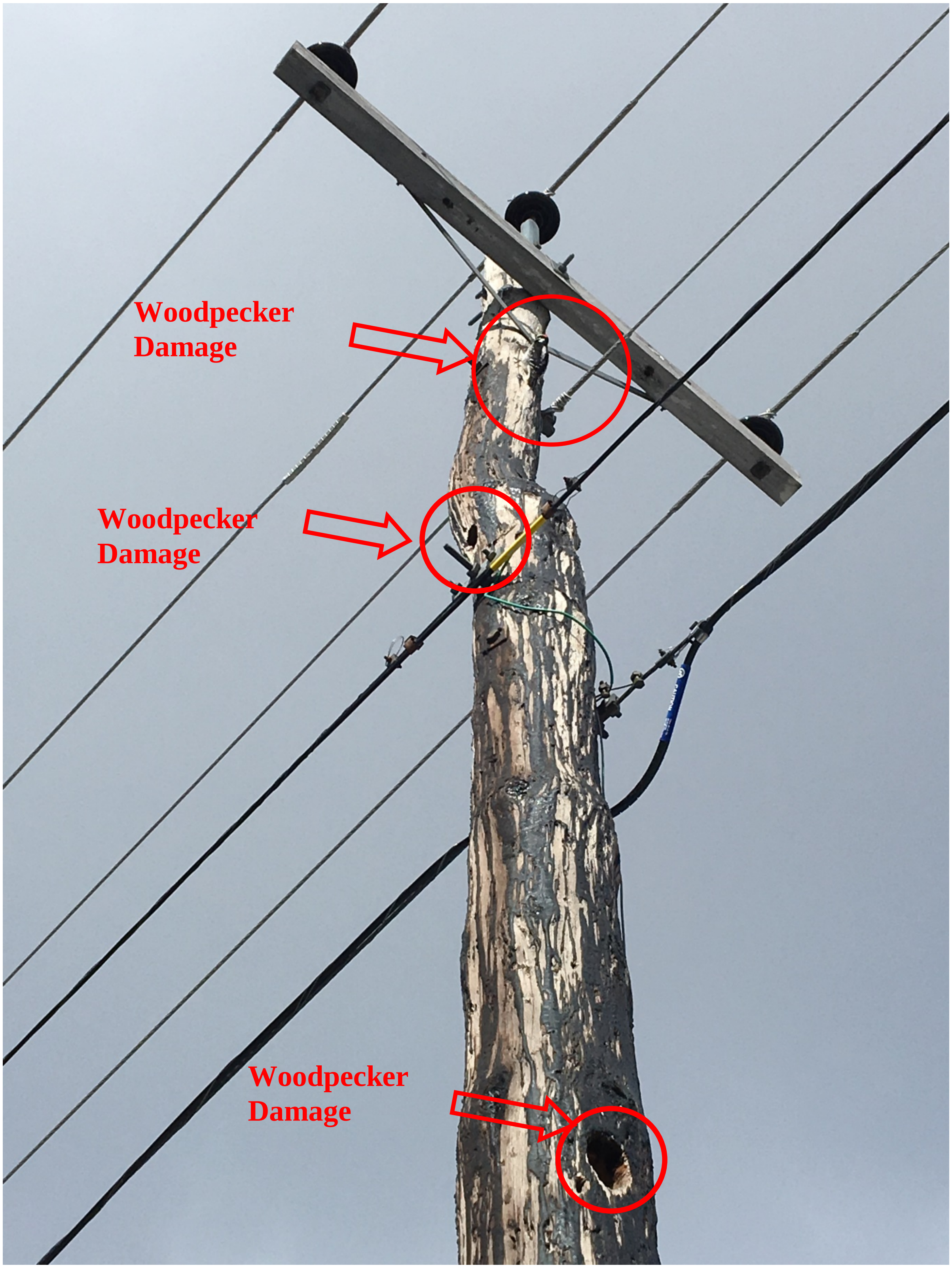


Figure 3 – Woodpecker damage, twisted pole and original insulators

Figure 4 – Two piece insulators

Figure 5 – Two piece insulators and deteriorated crossarm

Appendix E
St. John's SJM-06 Feeder Study

July 2018

Table of Contents

1.0 General

The *Distribution Reliability Initiative* is a project that involves the replacement of deteriorated poles, conductor and hardware to reduce both the frequency and duration of power interruptions to the customers served by specific distribution feeders. Distribution feeders are identified for evaluation based on an analysis of reliability statistics over the past 5 years. Once identified, a detailed engineering assessment of the feeder is carried out to determine if any upgrade work is required. The assessment looks at the physical condition of infrastructure, the risk of failure, and the potential impact to customers in the event of a failure.

The *Distribution Reliability Initiative* has identified SJM-06 as one of the worst-performing feeders on Newfoundland Power's distribution system. An engineering assessment of the feeder was carried out in 2018. This report summarizes the findings of that assessment and presents a plan to improve reliability on the feeder.

2.0 SJM-06 Feeder

SJM-06 is 1 of 11 distribution feeders originating from the St. John's Main ("SJM") Substation.[1] The feeder has a tie to SJM-09, SJM-11 and SJM-13 feeders, which allows for temporary load transfers between these feeders during unplanned or planned outages in order to minimize customer impacts.

SJM-06 is a 12.5 kV distribution feeder. It currently serves 1,211 residential and commercial customers on the west side of downtown St. John's. The trunk of the feeder leaves SJM Substation underground and travels west along Southside Road, then crosses the Waterford River before serving customers along Water Street, Patrick Street, Leslie Street, Sudbury Street, Pleasant Street and Campbell Ave. Some original vintage infrastructure including poles and conductor remain in service and date to the late 1950's.

The majority of the 3-phase, 2.7 km main trunk section of SJM-06 is constructed with 397.5 ACSR and 477 ASC conductor. The 3-phase main trunk also includes 2 small sections of #1/0 Cu conductor along Leslie Street and Campbell Ave which do not meet current standards and are prone to corrosion damage

3.0 Engineering Assessment

Inspections have identified deteriorated poles, hardware and conductor, obsolete insulators and decayed or damaged cross arms. It has also been identified that various types of porcelain cutouts remain on the feeder. Component failure during high winds has been an issue over the past couple of years.

A number of feeder taps serviced by SJM-06 are constructed using #6 Copper ("Cu") conductor. This type of conductor is prone to corrosion and failure. This is especially pronounced in the high salt areas in close proximity to St. John's Harbour serviced by SJM-06. Failure of this conductor has resulted in outages to customers and further failures can be anticipated as the conductor continues to deteriorate.

---

[1] Attachment E-1 is a map showing the areas served by SJM-06.

The route taken by the main 3-phase trunk passes through some high-density residential areas of St. John's including Patrick Street, Leslie Street and Campbell Avenue. Right of way space is limited in these areas and the poles are located adjacent to city streets and are prone to damage by passing snowploughs and other vehicles.

Due to the age and condition of the poles, crossarms, insulators, cutouts and conductor, the feeder is becoming more susceptible to damage when exposed to severe wind, ice and snow loading.

Table 1 summarizes the reliability data for SJM-06 for the most recent 5-year period.

Table 1
SJM-06 Distribution Interruption Statistics
2013 to 2017

	Customers	SAIFI	SAIDI	CHIKM	CIKM
SJM-06	1,210	1.89	1.70	392	437
Company Average	**846**	**1.35**	**1.71**	**44**	**34**

Table 1 shows that SJM-06 compares reasonable with the Company's 5-year average for SAIDI and SAIFI, however it is an outlier from the Company's average for CHIKM and CIKM.[2] An analysis of the outage data reveals that conductor and equipment failure has been the cause of most of the outages experienced in recent years. The main trunk of this distribution feeder has reached a point where continued maintenance is no longer feasible and the feeder has to be rebuilt to current construction standards for continued safe and reliable operation.

4.0 Recommendations

SJM-06 is a critical part of the Company's 12.5 kV distribution system in the St. John's downtown area. The primary contributor to the poor reliability of this feeder is deteriorated conductor and equipment failure of components such as porcelain cutouts.

To improve the reliability performance of SJM-06, the following work is required:

(i) Replacement of deteriorated poles, cross arms and insulators on the main trunk of SJM-06 with V-brace cross arms and 12.5 kV clamp top insulators;
(ii) Relocate where practical, new poles away from streets to mitigate further snow plow and vehicular damage;
(iii) Upgrade the single-phase taps on Eric Street, Warbury Street and McKay Street to replace deteriorated #6 Cu conductor with 1/0 AASC conductor; and
(iv) Removal of any other deteriorated infrastructure or equipment not meeting current standards including, but not limited to porcelain cutouts.

[2] The CHIKM for the SJM-06 feeder is 8.9 times the Company average while CKIM is 12.9 times the Company average.

The required work will be completed in 2019 at a total project cost estimated at $600,000.

Attachment E-1
Map Showing Areas Served by SJM-06

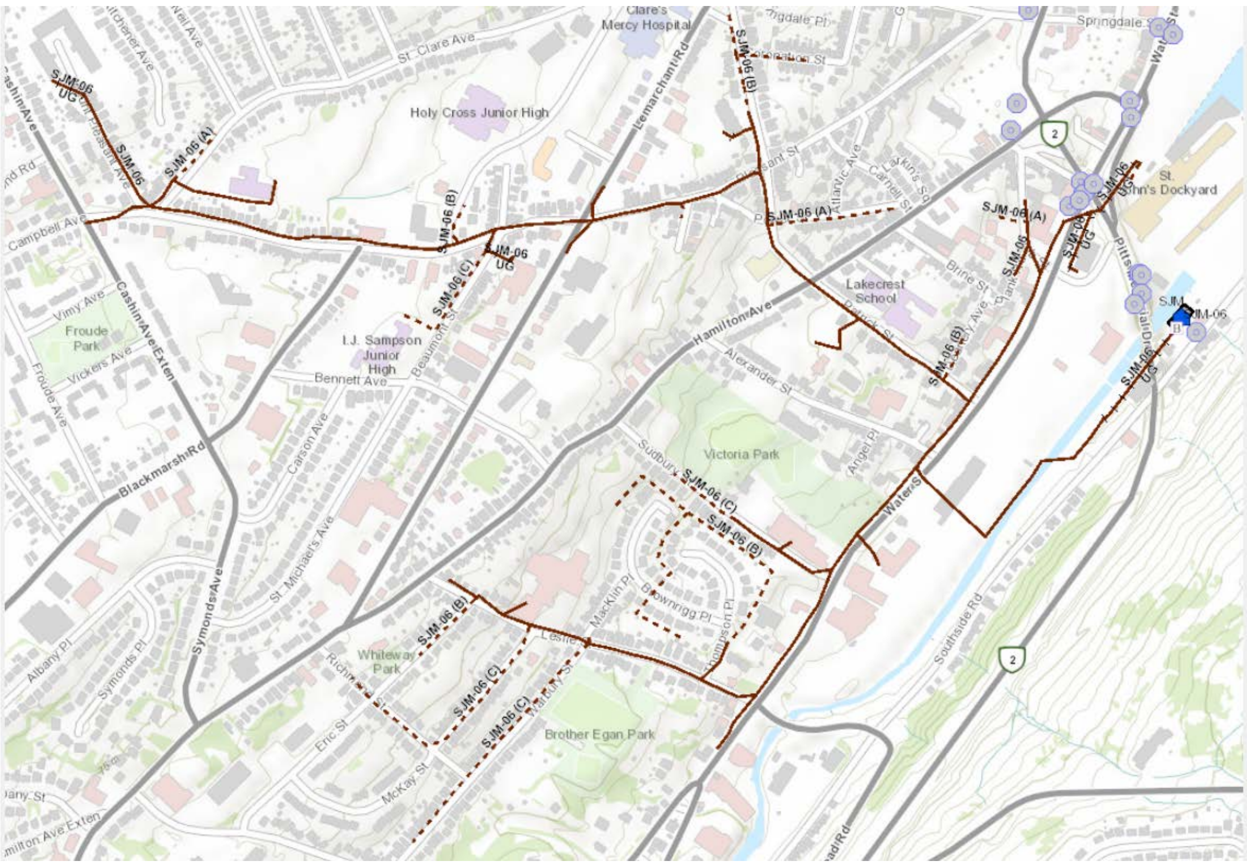


Figure 1 – Map of SJM-06

Attachment E-2
Photographs of SJM-06 Feeder

Figure 1 –Sleeved conductor

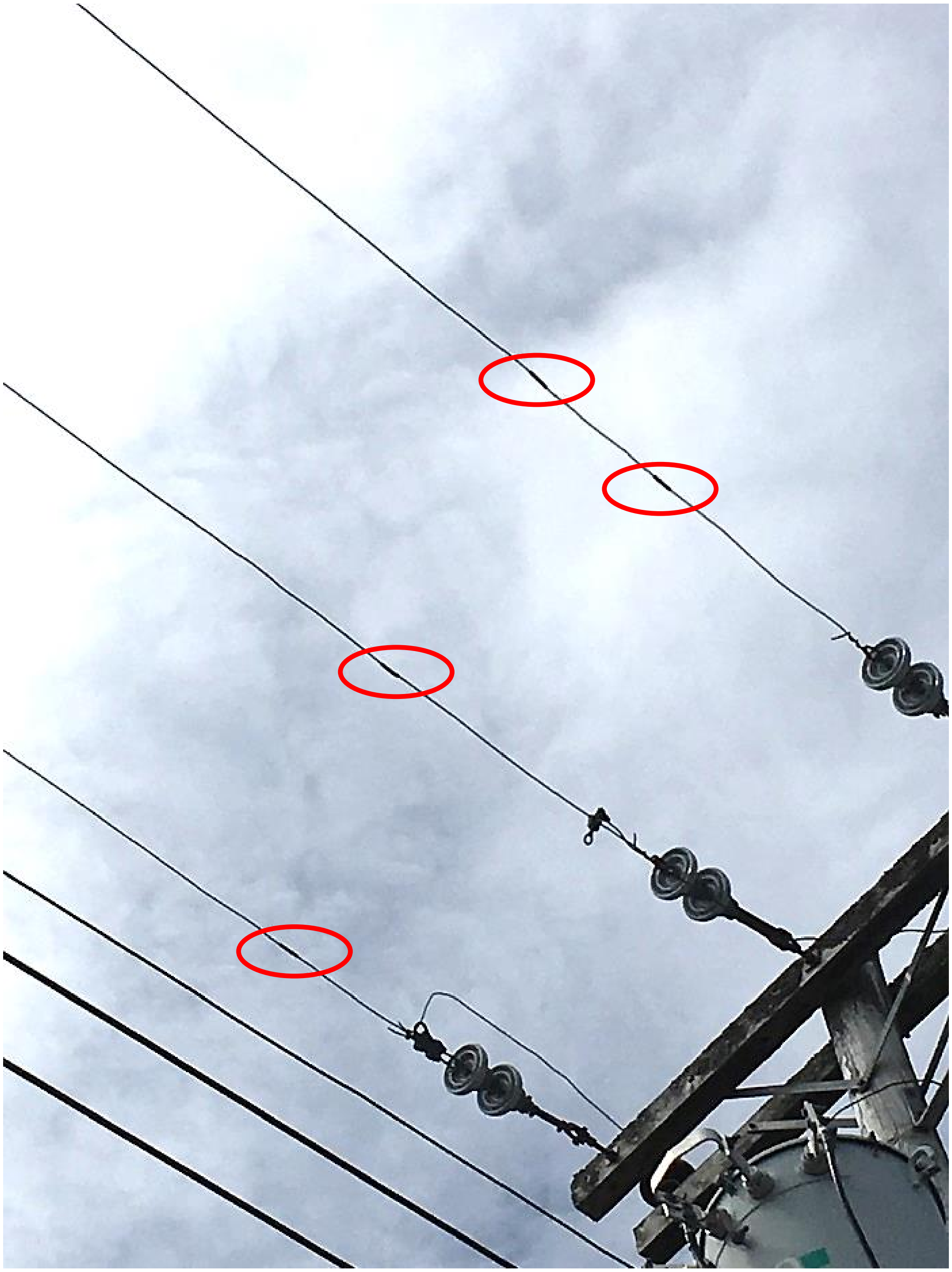


Figure 2 – #6 CU conductor with multiple sleeves

Figure 3 – Deteriorated pole with vehicular damage

Figure 4 – Deteriorated pole with vehicular damage

Figure 5 –#6 CU conductor

Figure 6 – #6 CU Conductor, deteriorated pole top and 2-piece Insulators

Figure 7 – Pole leaning into traffic

Feeder Additions for Load Growth

July 2018

Prepared by:

M. R. Murphy, P.Eng.
Robert Cahill, Eng. L.

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
PROFESSIONAL ENGINEERS AND GEOSCIENTISTS
M. R. MURPHY
M Murphy
SIGNATURE
6 July 2018
DATE
NEWFOUNDLAND & LABRADOR

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 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 complete a load transfer.

The overload conditions described in this report can each be attributed to commercial and residential customer growth in Newfoundland Power's (the "Company") 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 customer 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 ultimately, the conductor breaking, causing a fault and subsequent power interruption. Conductor overloads can also have a negative impact on customer outage durations during restoration due to increased conductor loading associated with cold load.

The Company undertakes analysis of distribution feeders using a distribution feeder computer modelling application to identify sections of feeders that may be overloaded. Overload conditions that are identified using the computer modelling application are followed up with field visits to ensure the accuracy of information.[2]

2.2 Alternatives for Overloaded Conductor

There are several alternatives for dealing with a conductor overload condition. Each alternative may not be applicable to every overload condition. They are dependent on factors such as: available tie points to surrounding feeders, the amount of conductor overload, physical limitations of line construction, or the effect on offloading strategies for surrounding feeders.

---

[1] Feeder balancing involves transferring load from one phase to another on a 3-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 modeling. The analysis uses conductor capacity ratings based on Newfoundland Power's Distribution Planning Guidelines. These ratings are shown in Appendix A.

Alternative #1 – Feeder Balancing
In some cases, conductor may be overloaded on only one phase of a 3-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 3-phase trunk of the feeder. This is only applicable in situations where all 3 phases are not overloaded.

Alternative #2 – 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.

Alternative #3 – Upgrade Conductor
The overload condition can be eliminated by increasing the conductor size on the overloaded section. This will improve load transfer capabilities for the feeder, and will not add to the total load or cause an overload condition on an adjacent feeder.

Alternative #4 – 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, then the addition of a new feeder from the substation is required to transfer a portion of load from the overloaded conductor.

2.3 Overloaded Feeders

SCV-01 Feeder Upgrade ($650,000)

Seal Cove ("SCV") Substation is located on the Conception Bay Highway in the community of Seal Cove. There are two 12.5 kV distribution feeders terminated at SCV Substation, serving approximately 2,200 customers. SCV-01 feeder leaves SCV Substation and extends northward along the Conception Bay Highway (Route 60) serving approximately 1,600 primarily residential customers in the communities of Seal Cove and Upper Gullies.

A 1.5 km section of the feeder is overloaded. The overloaded section is the main 3-phase trunk of SCV-01 leaving SCV Substation and extending to Seal Cove Road. This overloaded section was evaluated using the alternatives discussed in section 2.2. The conductor on this section is 4/0 AASC, which is rated for 356 amps per phase. The balanced 2018 forecasted peak load on each of the phases in this section is 374 amps per phase.

The overload condition on SCV-01 can be attributed to residential growth in the community of Conception Bay South ("CBS"), as well as infrastructure upgrades including lift stations installed by the Town of CBS. Continued load growth is expected as development in this area has been increasing with the completion of the CBS bypass road Peacekeepers Way.

Feeder balancing is not an option for this overload condition due to the fact that the combined forecasted peak currents exceed the total capacity of the 3 phase conductors. There is an existing tie point to a 2nd distribution feeder from SCV Substation, SCV-02, however the tie point is located at the very beginning of the feeder and only allows for backup of the entire SCV-01 feeder in the event of an unplanned outage or planned maintenance.[3] A second existing tie point to an adjacent distribution feeder originating at Kelligrews ("KEL") Substation, KEL-01, cannot be used to alleviate the overload condition due to the lack of additional capacity on KEL-01.

Increasing the conductor size on the 1.5 km section to 477 ASC would solve the overloaded condition. However, completing this work while maintaining customer interruptions at an acceptable level would involve using live line techniques, which are weather dependent, time consuming and costly. The least cost alternative would involve construction of a new 2.5 km section of trunk feeder along the new bypass road and tying in to SCV-01 at Lawrence Pond Road. This will effectively transfer the customer load beyond Lawrence Pond Road away from the overloaded 1.5 km section of SCV-01. Construction of this section of line adjacent to the highway is least cost due to the ability to construct away from energized lines, eliminating weather dependency and minimizing work to occur on private properties which may require new or additional easements.

Therefore, it is recommended that a 2.5 km section of new distribution line be constructed using 477 ASC conductor, which has a rating of 590 amps per phase.

SLA-05 Feeder Upgrade ($400,000)

Stamps Lane ("SLA") Substation is located on Stamps Lane in central St. John's. There are four 4.16 kV distribution feeders and six 12.5 kV distribution feeders terminated at SLA Substation, serving approximately 9,400 customers. SLA-05 feeder leaves SLA substation and extends northward underground, before going aerial at Oxen Pond Road north of Freshwater Road. SLA-05 services approximately 730 customers in the University Avenue and Larkhall Street area.

The main trunk cable of SLA-05 is overloaded. This cable is 750 MCM PILC in a 4-ductbank configuration which has a maximum rating of 430 amps. The balanced 2018 forecasted peak load on this cable is 438 amps. This cable was evaluated using the alternatives discussed in section 2.2.

The overload condition on SLA-05 can be attributed to residential upgrades and renovations in the mature central City area serviced by the distribution feeder. SLA-05 is a 4.16 kV feeder, which means that small changes in connected load can have a large effect on conductor loading, comparatively to higher voltage feeders.[4]

Feeder balancing is not an option for this overload condition due to the fact that the combined forecasted peak currents exceed the total capacity of the trunk cable. There is an existing tie point to a 2nd distribution feeder from SLA Substation, SLA-03, however the tie point is located

[3] The location of the tie point near the start of the feeder provides no opportunity to transfer small to medium amounts of customer load to the adjacent feeder thereby relieving the overload condition.

[4] For example, 1 MVA of load at 4.16 kV represents approximately 240 amps while the same 1 MVA of load at 12.5 kV represents 80 amps.

at the very beginning of the feeder and only allows for backup of the entire SLA-05 feeder in the event of an unplanned outage, cable failure or planned maintenance. Distribution feeder SLA-08 services the same general area and has sufficient capacity to alleviate the overload condition on SLA-05, but is a 12.5 kV feeder. These feeders are on a shared structure just north of Prince Philip Drive. A load transfer between these feeders will require a voltage conversion on the part of SLA-05 to be transferred. Upgrading the conductor would require replacement of the underground trunk cable and is not the least cost option. A new feeder from SLA Substation would be very difficult due to congestion in the area of the substation, and is also not least cost.

Therefore, it is recommended to convert the 4.16 kV load on SLA-05 north of Prince Philip Drive and transfer this section to SLA-08. Completing this voltage conversion and transfer would remove approximately 1.26 MVA from SLA-05, alleviating the overload condition and leaving a peak balanced load of 262.5 amps on the SLA-05 cable.

BLK-02 Feeder Upgrade ($665,000)

In Order No. P.U. 037 (2017) the Board approved a multiyear project to upgrade BLK-02.[5] In 2018 the work is ongoing to upgrade the 2.0 km section of the existing single-phase line from Brigus Junction to Middle Gull Pond cabin area from 1-phase to 2-phase to resolve the overload condition on the existing single-phase line.

In 2019, the 11.5 km section of 2-phase line along the Trans-Canada Highway from Ocean Pond to Brigus Junction will be upgraded to 3-phase. This will permit balanced loading on all 3 phases of the entire distribution feeder and address the issue of high neutral current. Balancing the line across all 3 phases will allow for the implementation of standardized protection settings to provide safe and reliable service to customers on BLK-02.

3.0 Project Cost

Table 1 shows the estimated 2019 *Feeder Additions for Load Growth* project costs.

Table 1
2019 Project Costs

Description	Cost Estimate
SCV-01 Feeder Upgrade	$650,000
SLA-05 Voltage Conversion	$400,000
BLK-02 Extend 3-Phase Trunk	$665,000
Total	**$1,715,000**

[5] The multiyear project to upgrade BLK-02 feeder is described in the report ***4.2** 2018 Feeder Additions for Load Growth*, filed in Newfoundland Power's 2018 Capital Budget Application.

4.0 Concluding

The *Feeder Additions for Load Growth* project for 2019 includes distribution system upgrades to:

- Construct 2.5 km section of SCV-01 feeder,
- Complete voltage conversion and transfer of 1.26 MVA on SLA-05, and
- Upgrade 11.5 km of BLK-02 feeder.

The estimated cost to complete this work in 2019 is $1,715,000.

Appendix A
Distribution Planning Guidelines
Conductor Ampacity Ratings

Aerial Conductor Capacity 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
#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

PILC (Copper) Underground Conductor Continuous Capacity Ratings – [Amps]						
Size	Number of Cables in Ductbank					
	1	2	3	4	5	10
250 MCM	323	294	265	248	231	188
350 MCM	390	353	317	296	275	222
500 MCM	473	426	380	354	329	263
750 MCM	682	522	462	430	398	315

1 The winter rating is based on ambient conditions of 0ºC and 2ft/s wind speed.

2 The summer rating is based on ambient conditions of 25ºC and 2ft/s wind speed.

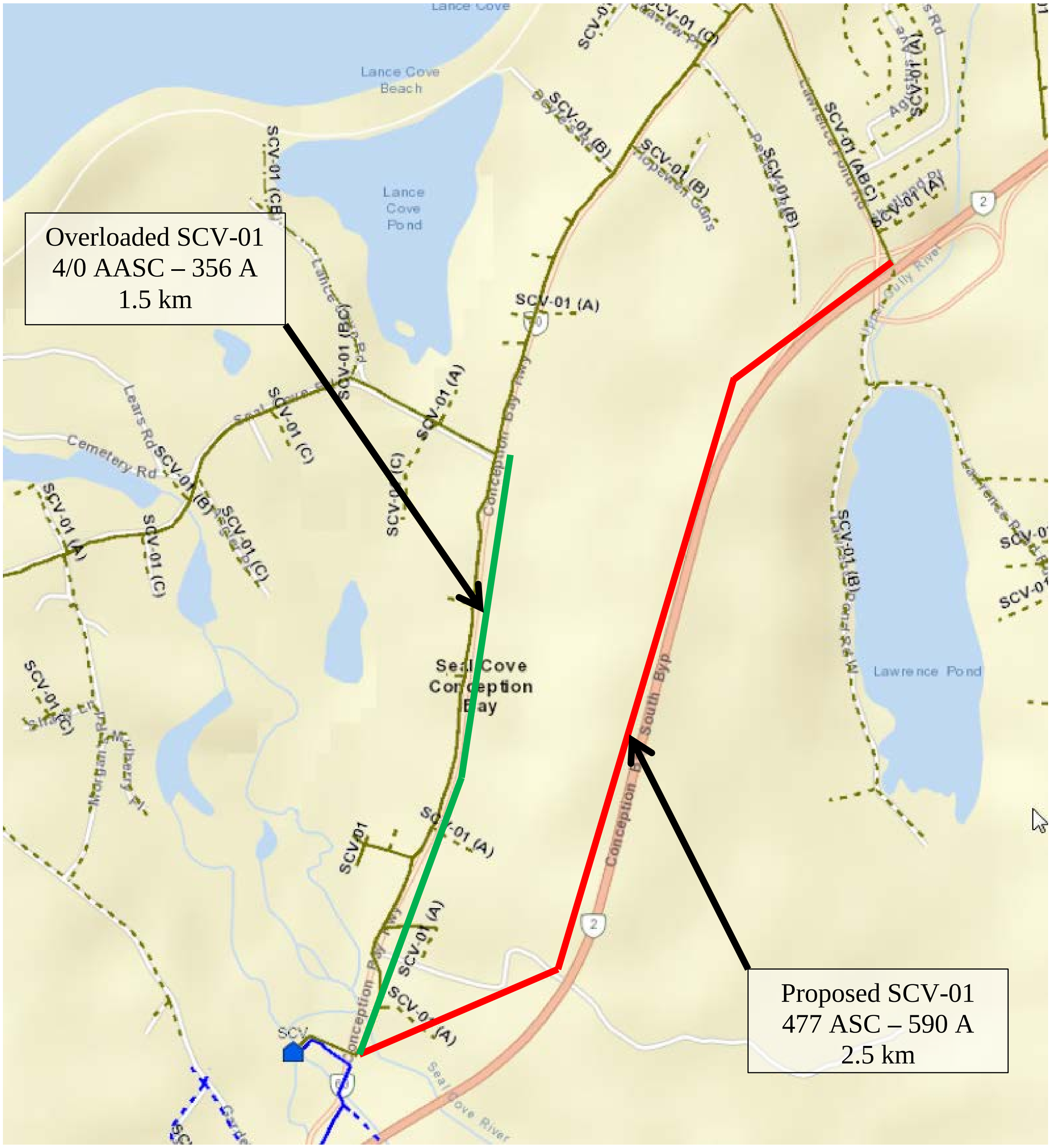
3 The planning rating is theoretically 75% of the winter conductor ampacity. In practice the actual percentage will be something less due to (i) the age and physical condition of the conductor, (ii) the number of customers on the feeder, (iii) the ability to transfer load to adjacent feeders and (iv) operational considerations including the geographic layout and the distribution of customers on the feeder.

4 Cold Load Pick Up: 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 1 hour.

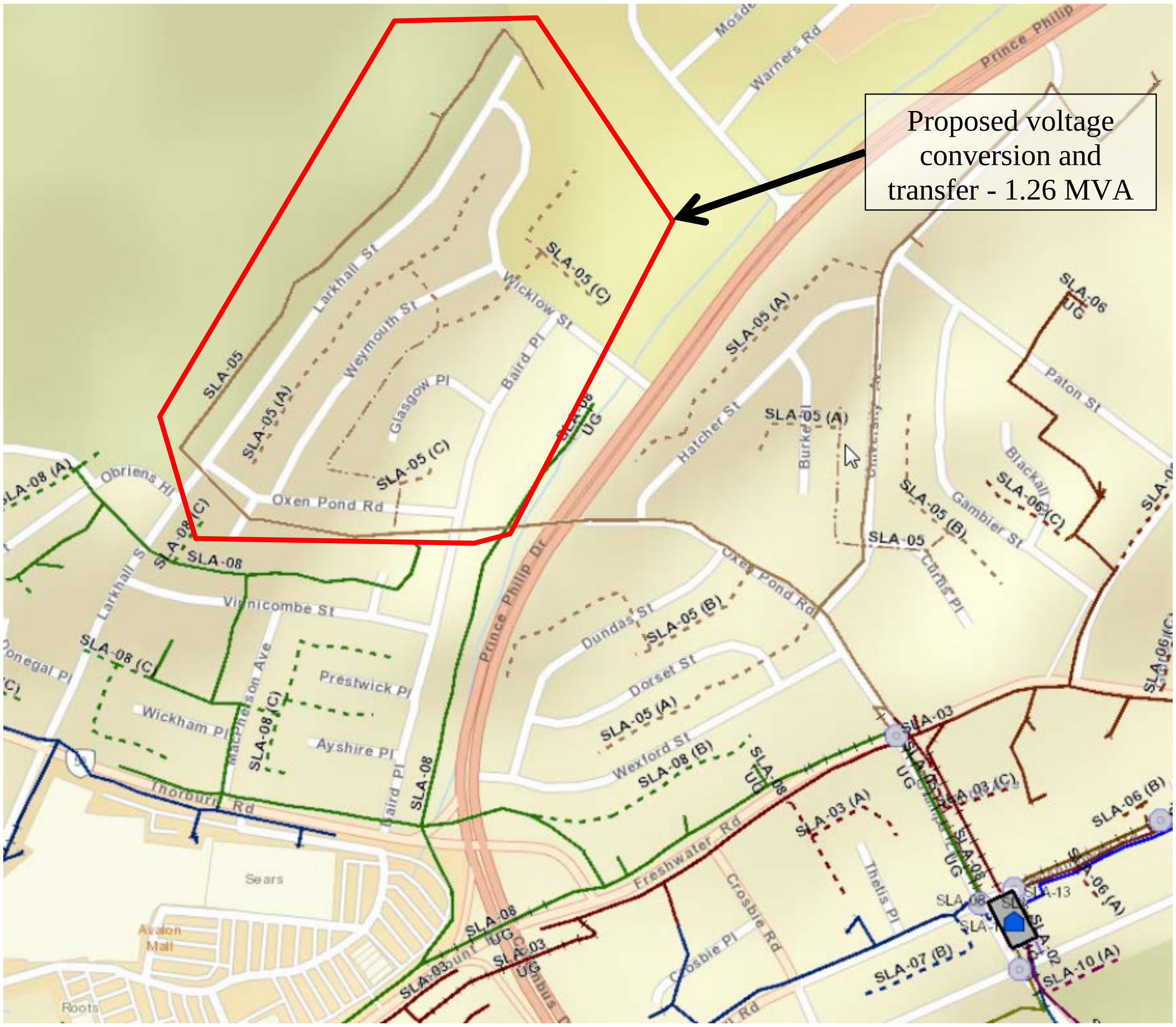
5 Sectionalizing factor: Two-stage sectionalizing is used during CLPU conditions to increase the Planning Rating of aerial conductors. Restoring power to one section of the feeder at a time reduces the overall effect of CLPU. The sectionalizing factor is the fraction of the load that is restored in the 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.

Appendix B
Distribution Feeder Diagrams

SCV-01 Distribution Feeder Upgrade



SLA-05 Voltage Conversion



Company Building Renovations
Salt Pond Facility

July 2018

Prepared by:

Monty Hunter, P.Eng.
Aaron Hayward

REGISTERED PROFESSIONAL ENGINEER
M. C. HUNTER
SIGNATURE
July 6, 2018
PROVINCE OF NEWFOUNDLAND

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

The Salt Pond Facility (the "Facility") is Newfoundland Power's (the "Company") primary operations facility for the Burin Peninsula Area (the "Area"). The Area's service territory encompasses the Burin Peninsula and serves approximately 12,000 customers, 4.6% of all customers served by the Company.

The Facility consists of adjacent office and service buildings.[1] The Facility currently houses 15 employees necessary to support operations throughout the Area's service territory. Staff working in the office building include engineering technologists, meter readers, area customer service representatives and management staff.[2] The office also houses meeting and video conference services utilized by both office and operations staff. All customer interactions are currently handled at the office building. The adjacent service building currently houses electrical maintenance and line staff as well as stores warehouse.

Many of the building systems at the Facility have reached an age where capital improvements are necessary to ensure it continues to provide safe and reliable service. The office building was originally constructed in 1969 and the service building constructed in 1974. In the years since construction both major and minor replacements, refurbishments and improvements have been made at both buildings. Improvements to the office included installation of an air conditioning system in 1987, interior refurbishment in 1995 and some interior and building envelope improvements in 2002. Work on the service building included parking lot improvements in 1987, interior reconfiguration in 1987 and 2004, and a roof replacement in 1993. An emergency generator shared by both buildings was installed in 2008.

Figure 1: Office Building

Figure 2: Service Building

Renovations are required in 2019 to replace some building systems that have reached the end of their useful service lives. This project includes $950,000 in estimated capital expenditures associated with the refurbishment of the interior and exterior of the service building and the

1 The office building is approximately 190 square metres, and primarily consists of office space. The service building is approximately 475 square metres, and is a combination of warehouse and workshop space with some individual offices. The Company's Salt Pond Substation is located on the same property.

2 Area customer service representatives provide both walk-in customer service and answer calls remotely as part of the larger customer service call center.

construction of an extension to accommodate staff from the office building. After the office staff have been relocated to service building, the office building will be decommissioned.

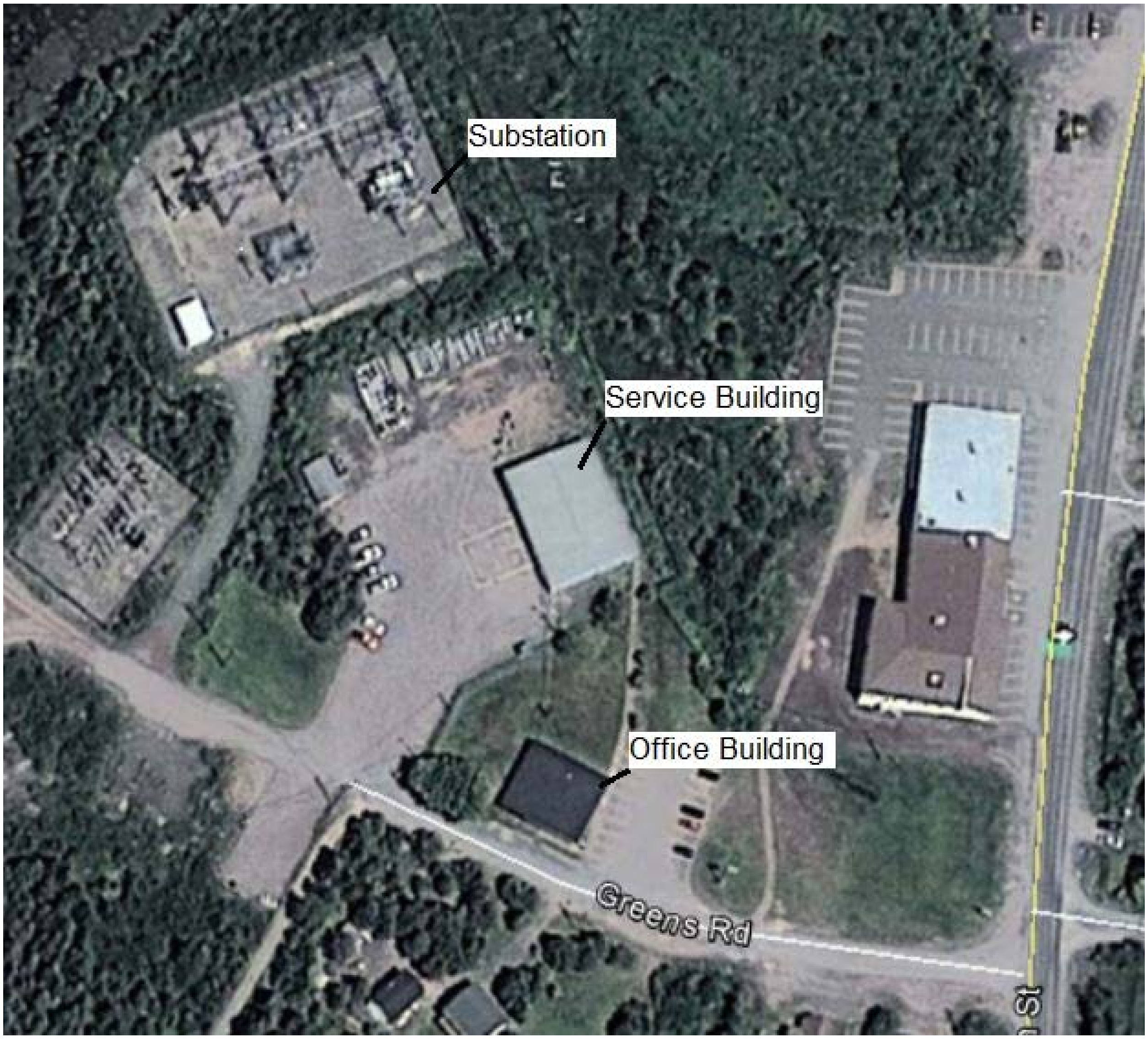


Figure 3: Salt Pond Facility

2.0 Condition Assessment

A condition assessment has been completed for the Facility's primary building components. Overall the buildings are in fair to poor condition with several components requiring capital improvements to ensure the Facility continues to provide safe and reliable service.

2.1 Office Building

Building Envelope

The roof is 16 years old. Heat loss through the ceiling space causes ice build-up along the eaves which creates a safety concern for both employees and the public.[3] Improvements to vapour barrier and insulation in the ceiling are required. The building's exterior is clad with vinyl siding and brick. The brick was part of the original construction. The mortar is failing and requires frequent repair. The vinyl siding and vinyl windows are approximately 16 years old. The vinyl siding and brick exterior would need to be replaced as part of a life extension to the office building.

The office building has 2 exterior personnel doors. The rear employee access door is corroded, including the door frame, due to exposure to de-icing salts. Corrosion is not as prevalent on the customer entrance, however it does not have motor operated doors to facilitate entrance by persons with physical or sensory disabilities. Both doors require replacement. The office building does not meet the requirements for barrier-free design as outlined in the current provincial Buildings Accessibility Regulations.

Figure 4: Re-grouted Brick

Figure 5: Customer Entrance

Building Interior

The interior finishes on the walls of the office building consist primarily of painted drywall. The drywall compound contains asbestos.[4] In early 2016 mold in the area of the kitchen was discovered on the exterior wall and remediated. It is likely that the deterioration of the exterior brick cladding contributed to the formation of the mold.

[3] The vapour barrier and insulation is no longer fully intact as a result disturbance over the building's life. The barrier is also of a lower grade than the currently accepted minimum standard. Currently the ceiling insulation provides an R-value of approximately 31 but due to disturbances is likely less. The recommended minimum R-value is 50.

[4] Hazardous Materials Assessment, Newfoundland Power, Salt Pond Office Building – Stantec – April 11, 2016. The asbestos is non-friable, meaning it cannot become airborne unless disturbed. Any future work on the walls will have be completed in compliance with provincial asbestos regulations.

Figure 6: Deteriorated Carpet

The floor coverings in the building are primarily carpet tile, with some ceramic tile and vinyl floor covering present. The flooring was replaced as part of the 1995 renovations. With over 25 years in service the floor coverings are at the end of their service life and require replacement.

In addition to not having a motor operated exterior door, the interior door leading from the porch to the customer service area is not motor operated. The customer walk-in counter does not meet the requirements for barrier free design. The washrooms are in fair condition however they also do not meet barrier free requirements. Improvements are required in these areas to provide an adequate level of service to customers and ensure accessibility for customers and employees.

Heating, Ventilation and Air Conditioning (HVAC) System

The HVAC system consists of electric baseboard heaters and a 30 year old air handler which provides fresh air and air conditioning. The cooling system currently uses R-22 refrigerant which is not environmentally friendly and will be phased out of commercial air conditioning equipment by 2020.[5] The cooling system is at the end of its useful life and requires replacement.

Electrical

Wiring in the building is a combination of the original fabric covered and modern insulation material styles. The fabric covered electrical wiring is 48 years old and should be replaced due to the effects of its extended time in service. The lighting fixtures are generally older and inefficient by today's standard. Future replacements should be with more energy efficient types.

[5] Hydro chlorofluorocarbons ("HCFC"), including R-22 are ozone-depleting refrigerants, and under the terms of the Montreal Protocol, will be 99.5% phased out by 2020. After 2020 R-22 refrigerant will no longer be imported or manufactured in Canada, although limited supplies of R-22 that have been recovered and recycled/reclaimed will be allowed until 2030 to service existing systems.

The building has smoke detectors however the system is not externally monitored. Access to the building is provided using the Company's electronic access card system.

Parking Areas
The customer parking area has isolated patches of deterioration and cracking of asphalt that require refurbishment. The concrete curbs have been damaged primarily as a result of snow clearing activities. The sidewalks and ramps do not meet the requirements for barrier-free design as outlined in the current provincial Buildings Accessibility Regulations. Some refurbishment and improvements are required, however the parking area does not need to be completely resurfaced.

2.2 Service Building

Building Envelope
The roof is 25 years old. Leaks are starting to become prevalent, indicating the roof is nearing the end of its service life. Flashing and trims have deteriorated and require refurbishment. The building's exterior is clad with 44 year old original metal siding. The aluminium framed windows are also original and have corroded and no longer seal properly. The roof, windows and metal siding need to be replaced.

The service building has 5 exterior personnel doors which vary in age, material and condition. None of the 5 personnel doors meet accessibility requirements. The building has one overhead garage style door to facilitate materials movement and storage. Door deficiencies should be addressed in the near future.

Figure 7: Corroded Door Assembly

Figure 8: Deteriorated Windows[6]

Building Interior
The interior finishes on the walls vary in age and condition. Finishes in the warehouse and workshop area consist of painted plywood or are unfinished. The remaining spaces which include offices, a lunch room and a washroom are finished with painted drywall. Refurbishment of the wall finishes should be undertaken in the near future.

6 Failed window seals result in trapped moisture between the panes.

The flooring in the warehouse and workshop areas is unfinished concrete while the office and support spaces are vinyl tile. The tile is in poor condition, with some having been removed in 2016 due to cracking and posing a safety hazard.

Only one washroom is present and it is original to the building construction. The plumbing fixtures have aged and are inefficient with respect to water consumption. The washroom is configured to be male only and does not meet barrier free requirements. The finishes in the kitchen are also original to the building construction and are in fair condition.

The ceiling is open to the roof trusses in the warehouse and workshops areas and is a suspended T-bar ceiling in the office and support areas.

Heating, Ventilation and Air Conditioning (HVAC) System
Heating is provided by electric and fan forced air heaters. The heaters are older styles, are inefficient, and have started to break down. There is no building-wide ventilation system with only local ventilation provided in spaces such as the washroom. There is no air conditioning in the building. The current heating and ventilation systems are not managed by a centralized building control system.

Figure 9: Incandescent Kitchen Fixtures

Figure 10: Incandescent Office Fixtures

Electrical
The building electrical wiring is largely original, with newer wiring being installed to accommodate modifications over the years. Lighting is provided by various types of fluorescent and incandescent fixtures. Lighting levels in the building are adequate however the fixtures are generally older, less efficient types. Future replacements should be with efficient types.

The building has smoke detectors however the system is not externally monitored. Access to the building is provided using the Company's electronic access card system.

Parking Areas
The employee parking area has some isolated patches of deterioration and cracking asphalt which require refurbishment. The concrete curbs exhibit damage primarily as a result of snow clearing activities. The sidewalks and ramps do not meet the requirements for barrier-free design as outlined in the current provincial Buildings Accessibility Regulations. Some refurbishment

and improvements are required, however the parking area does not need to be completely resurfaced.

2.3 Shared Systems

Site Services
Water service is provided by the municipality. Wastewater is handled by a septic tank, however it discharges directly to an estuary rather than a proper septic distribution field which would be the current requirement. Installation of a septic distribution field would be required as part of a major renovation to bring the system into compliance with current wastewater regulations.

Standby Generation
A 60 kW emergency standby generator was installed in 2008 and provides backup power for both the office and service building. The generator is in good condition and requires no refurbishment at this time.

3.0 Assessment of Alternatives

Both buildings currently meet the functional needs of the Area, however they both require capital improvements to ensure the Facility continues to provide safe and reliable service to employees and the public.

Since the buildings were constructed in the late 1960s and early 1970s, the manner in which the Company operates and serves customers on the Burin Peninsula has changed. When the buildings were constructed there were approximately 35 full time and 15 seasonal employees working out of these 2 buildings, and a 3rd building that housed an operating diesel plant. The operational changes over the past 40 years have resulted in a reduction in the facilities' work force by half, with approximately 15 fulltime employees currently based out of the Salt Pond facility.[7] As a result, there is an opportunity to evaluate a reduction in overall space required at the Facility.

To determine the least cost alternative, the Company has developed 3 alternatives which meet the operational needs of the Area and address the building deficiencies in order to provide safe, reliable service into the future.

3.1 Alternative 1: Renovate Both Buildings Independently ($1,015,000)

Components of both the office and service building have reached the end of their useful lives and require replacements. Upgrades are also required to meet current accessibility, efficiency, security and wastewater standards.

The office building requires approximately $490,000 of improvements in 2019, including refurbishment of the building envelope, interior refurbishment, replacement of the HVAC

[7] Examples of staff reduction include: fewer customer service staff due to the shift to more telephone and electronic communication and elimination of bill payments onsite, fewer meter readers due to the implementation of AMR technology, the introduction of contractors to complete pole setting in the early 1990s and the removal of the standby and emergency diesel generators and gas turbine from the Salt Pond site.

system, lighting and electrical improvements, and the installation of a modern security system. Interior work will include reconfiguration of the lobby and customer service areas to comply with accessibility standards and to improve employee security. To complete this work, abatement of the asbestos drywall compound will be required. Where possible, energy efficient materials in the building envelope and electrical fixtures will be used, and the installation of a modern security system. Improvements to the parking areas, curbs and sidewalks would be completed where required to address deficiencies and improve accessibility.

The service building requires $525,000 of improvements in 2019, including refurbishment of the building envelope, interior refurbishment in office and support areas, lighting, HVAC and electrical improvements and the installation of a modern security system. Where possible, energy efficient materials in the building envelope and electrical fixtures will be utilized. Improvements to the parking areas, curbs and sidewalks would be completed where required to address deficiencies and improve accessibility.

A new septic system and distribution field would also be required for both buildings.

3.2 Alternative 2: Renovate and Extend Service Building ($950,000)

To facilitate a reduction in overall footprint of the buildings to bring the size in line with current and future requirements, an estimate was prepared to refurbish the service building to address the same deficiencies as outlined in Alternative 1 and construct a 150 m^2 extension to allow the consolidation of all staff under one roof.[8] After completion of the consolidation, the office building would be decommissioned.

The extension would mainly house functions currently in the office as well as updated customer service spaces which would meet current accessibility and security standards. Some reconfiguration of the warehouse would also be undertaken to facilitate the integration. The consolidation allows for the elimination of duplicate spaces and systems if both buildings were to be maintained.[9]

A new septic system will be installed to service the renovated building.

3.3 Alternative 3: New Construction ($2,143,000)

An estimate was prepared for the construction of a new building on the same property. Similar to Alternative 2 in dimensions, the design of the new building would reduce the overall footprint of the facility to bring the size in line with current and future requirements. The building would house all functions of both the office and service buildings.

The new building would be fully completed prior to the relocation of staff and materials. After relocation, the office and service buildings would be decommissioned. It is likely that the

---

8 The current office building is approximately 192 m^2 and the service build is approximately 461 m^2 for a combine footprint of 653 m^2. The 150 m^2 extension of the service building to 611 m^2 results in an overall reduction in building footprint of 42 m^2.

9 Systems include access, security, communications and HVAC and spaces include lunch rooms and washrooms.

concrete floor of the existing warehouse would be reused to provide a storage area for materials such as cable reels at minimal cost.

As with the other alternatives, a new septic system will be required.

3.4 Analysis of Alternatives

When compared with Alternative 1, Alternative 2 provides a lower capital cost in 2019 and lower operating costs in the future as a result of an overall reduction in the building footprint and number of systems to maintain.[10] Consolidation also provides improved safety and security to staff.[11]

Although the new building suggested in Alternative 3 would have lower operating requirements in the short term, the significantly higher capital cost in 2019 outweighs any potential future savings.

Based upon the comprehensive assessment of the Facility, and comparison of alternatives, Alternative 2, renovation and extension of the service building in 2019, provides the least cost alternative for replacing building components that have reached the end of their service lives. As a result, it is recommended to proceed in 2019 with the project proposed as Alternative 2.

4.0 Project Description

The following sections describe in detail the project for 2019.

Building Extension

An extension to the existing service building totalling approximately 150 m^2 is required to combine both service and office building functions. Figure 11 shows the location of the building extension on the south end of the existing service building. The extension will be designed to meet accessibility regulations and will accommodate all Burin based employees and customer service walk in functions.

[10] For example, a single consolidated building would only require one security system and one HVAC to maintain.

[11] As most of the Burin based employees have field duties, the office staff in both buildings frequently work alone. Combining all functions into one building reduces the number of times employees are working alone.

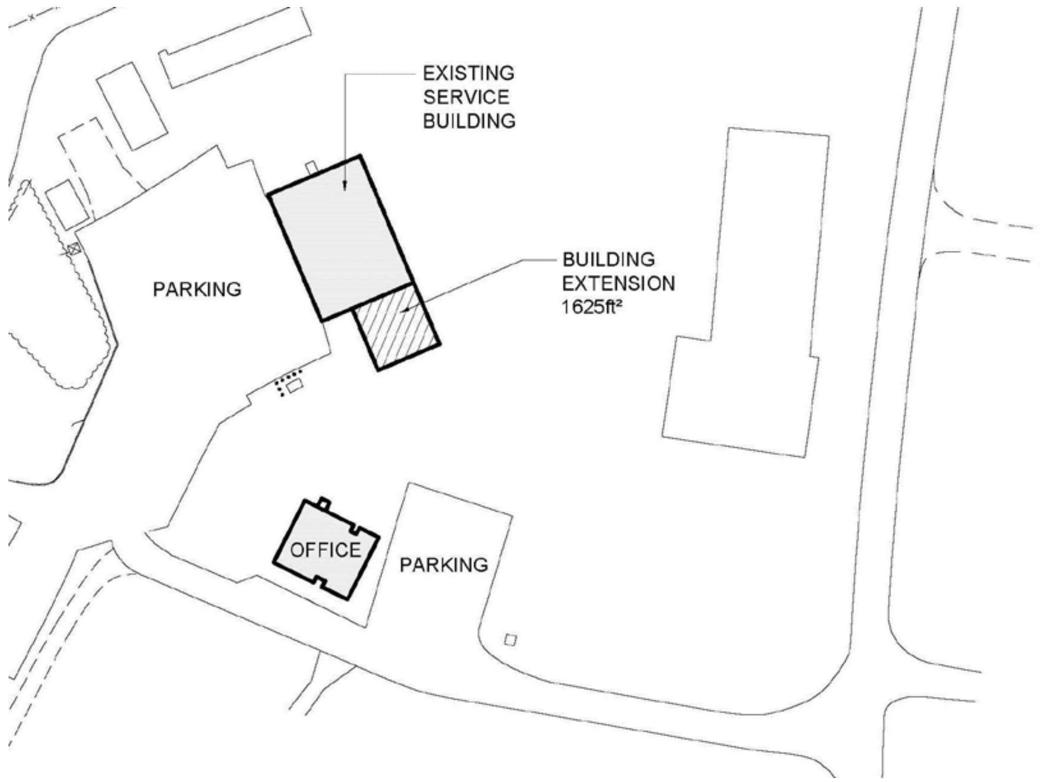


Figure 11

Building Envelope
Replacement of personnel doors, windows, exterior cladding and roof is required to ensure the building remains weather tight to prevent future ingress of water which could impact the structural integrity, energy efficiency, and air quality in the building.

Building Interior
The interior of the service building will be reconfigured as required to accommodate the integration of all Company employees. Accessible male and female washrooms will be constructed and the current lunchroom would be modified to provide a conference room and kitchen, separable by a divider. New interior finishes including flooring, wall coverings and ceilings will be required to facilitate the modifications.

Heating, Ventilation and Air Conditioning (HVAC) System
A new HVAC system will be installed to meet the needs of both the existing and extended spaces. The system will be optimized during detailed design however at a minimum will provide the necessary heating, ventilation and air conditioning for the combined facilities utilizing energy efficient solutions where practical, including the installation of a building-wide digital control system.

Electrical
The existing electrical service provides power for both the office and service buildings. The decommissioning of the office building and planned energy efficiency improvements are expected to offset the additional loading from the extension and new HVAC system. As a result

the existing building service should be sufficient. Replacement of original electrical wiring and other electrical modifications necessary to complete the extensions will be undertaken. Energy efficient lighting will be installed throughout the building. Security and fire alarm systems allowing external monitoring will be installed.

Site Improvements
Minor improvements are required to the existing asphalt parking lot, curb and sidewalks. Some site grading, fencing and additional parking lot work is required to facilitate the extension. A new septic system will be installed to service the facility.

Standby Generation
Although the standby generation is adequate to meet the needs of the combined facility, it will have to be relocated to facilitate the building extension.

5.0 2019 Project Costs

Table 1 provides a breakdown of the proposed expenditures for 2019 by cost category.

Table 1
2019 Projected Expenditures
(000s)

Cost Category	Amount
Material	$788
Labour – Internal	9
Labour – Contract	-
Engineering	61
Other	92
Total	**$950**

6.0 Conclusion

In 2019, capital improvements are necessary to replace deteriorated building components which range in age from 22 to 48 years, and to provide improvements to meet current standards to ensure the Facility continues to provide safe and reliable service. The Company assessed 3 alternatives and determined that combining both office and service building functions into one expanded building provided the least cost alternative when compared with renovating both buildings independently or constructing an entirely new building. The improvements will also provide an opportunity to increase energy efficiency and provide better service to our customers through increased accessibility. The planned improvements will also provide improved security to employees and materials.

Company Building Renovations
District and Other Buildings

July 2018

Prepared by:

Monty Hunter, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
M. C. HUNTER
SIGNATURE
July 6, 2018
PROVINCE OF NEWFOUNDLAND

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

Page

1.0 Introduction

Newfoundland Power (the "Company") maintains several offices across its service territory to support the operations and maintenance of the electricity system. Regional offices in St. John's, Carbonear and Corner Brook provide the local management, engineering, operational support, stores warehouse and customer service throughout each region. Within each of the 3 regions there are service buildings that provide local support, maintenance activities, customer service and storage of materials in areas remote from the regional offices. District buildings are located in outlying areas within the service territory and act as a base for work crews and the storage of materials.[1]

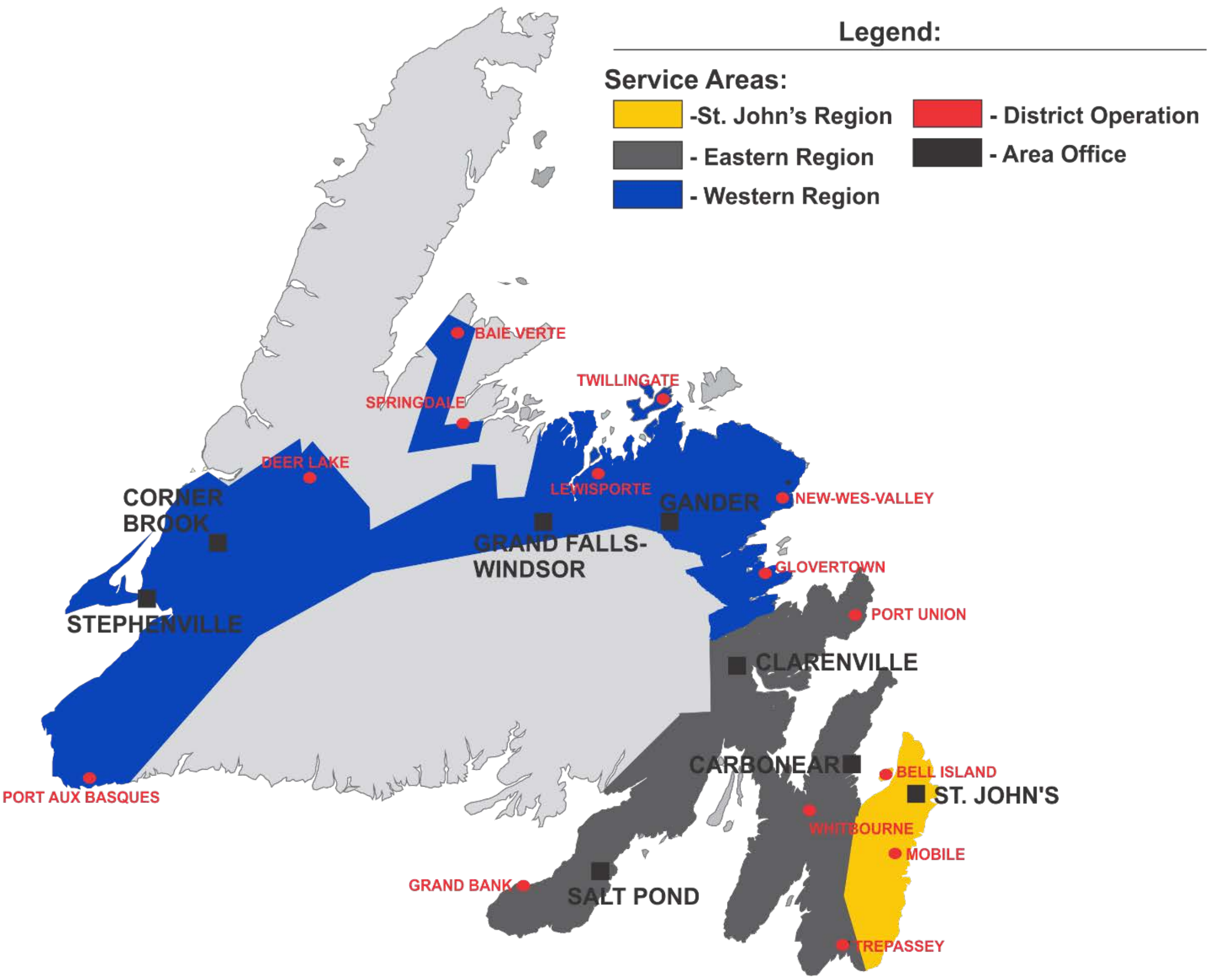


Figure 1 Service Territory

[1] To provide adequate response time for customer outages, more remote areas are provided with a line crew and materials (distribution transformers, cross-arms, wire, street lights and hardware). The Company standard is to provide a 2 hour response time to customer outages.

The Company periodically reviews the General Property assets to identify infrastructure that requires upgrade, refurbishment, additions or decommissioning. For 2019, the need was identified to rebuild the Glovertown district building and provide storage sheds at the Carbonear regional office and the Port Aux Basques district building.

This project includes $424,000 in estimated capital expenditures to construct a replacement district building in Glovertown ($178,000) and provide new storage sheds for the Carbonear and Port Aux Basques areas ($246,000). After the new construction is complete, the old district building and storage sheds will be decommissioned.

2.0 Condition Assessment

A condition and needs assessment has been completed for the 3 facilities to ensure the continued provision of safe and reliable service.

2.1 Glovertown District Building

The Glovertown District Building was originally constructed in 1967. The building envelope consists of timber framing with metal siding and asphalt shingles. The building was connected to the town's water and sewer systems in 1979. The storage yard adjacent to the building was fenced in 1975 and the fencing was upgraded in 2003.[2] Work was completed in 1988 to remove asbestos floor tiles.

The Glovertown district crew is based out of this building. The 2 person crew consists of a Power Line Technician Lead Hand and a Power Line Technician. They have a single axle material handler line truck and a yard to store small quantities of materials.

Glovertown is 65 km east of the Gander area office. The eastern boundary of the Gander area is Salvage on the Eastport Peninsula and the community of Terra Nova in Terra Nova Park. Both communities are approximately 100 km from Gander. The Glovertown district building is centrally located to service these communities as well as the approximately 2,700 customers in the Glovertown area.

The building includes a combined space for both an office and a workshop area. The ceiling height inside the building does not provide adequate headroom for employees. The interior paint in the district building is failing and beginning to peel. Material testing completed in 2017 confirmed that this paint is lead based. The metal exterior of the structure is damaged in areas and is deteriorating (see Figures 2, 3 and 4). The roof shingles require replacement.

The site of the existing building is adjacent to the Terra Nova River and the building's elevation is below that of the main road. The building is surrounded by 1:20 year and 1:100 year flood zones.[3] The district crew indicate that in times of high river flow water has backed up onto the

---

2 The building is currently located inside a 30 meter by 20 meter fenced storage yard.

3 Flood Information Map - Glovertown, Newfoundland, Newfoundland Department of Environment & Lands, Water Resources Division.

site and into the building. As a result of the condition of the 50 year old building and the risk of flooding it is recommended that the building be relocated.

Figure 2: District Building Exterior

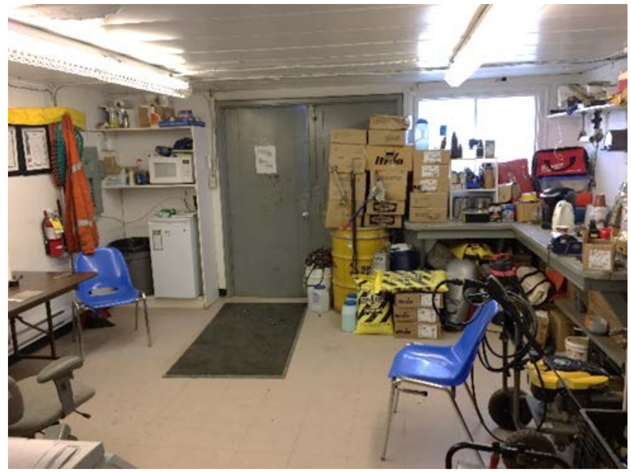


Figure 3: Interior

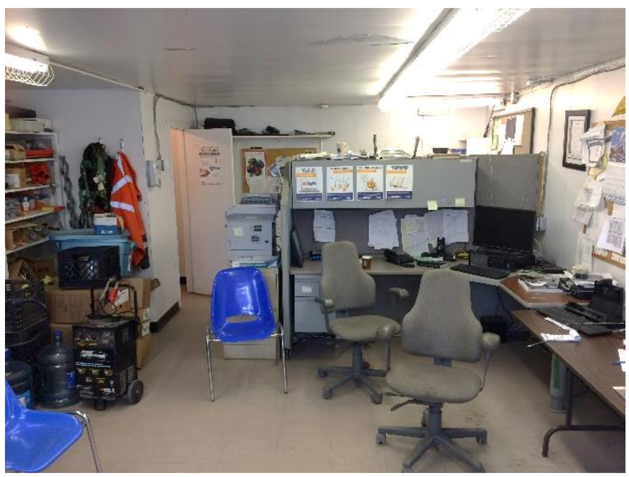


Figure 4: Interior

2.2 Carbonear Storage Shed

The Carbonear service building is the Company's main regional office facility for the Eastern region. The building provides support and maintenance for approximately 1,900 km of distribution lines and approximately 400 km of transmission lines, providing service to approximately 37,000 customers. Approximately 33 employees including 6 line crews operate from the Carbonear service building.

The existing 12'x 20' shed at the Carbonear site is insufficient for the required storage. Currently the majority of the area's equipment inventory is being stored outdoors. Items requiring indoor storage include automobile tires, snowmobiles, off road vehicles, spare parts, a cable reel trailer, materials for projects, specialty hotline tools, meters and hazardous materials awaiting pickup for proper disposal.[4] (see Figures 5, 6 and 7) Additional indoor storage is required at the Carbonear service building.

Figure 5: Off Road Vehicle

Figure 6: Off Road Vehicle Tracks

Figure 7: Cable Reel Trailer

[4] Hotline tools are used by power line technicians to perform electrical maintenance while the electrical system remains in operation.

2.3 Port Aux Basques Storage Building

The Port Aux Basques district building is the Company's main facility for the Port Aux Basques district operations. Existing storage is provided by a 20' x 30' approximately 50 year old prefab metal building that is not original to the property.[5] The building includes a concrete footing, without a frost wall, and a concrete floor.

In 2017, an inspection of the existing storage shed identified the following issues:

- Settlement and cracking of the concrete footing and floor,
- Door frame shifting due to frost so the doors can no longer be locked,
- Broken skylights in roof,
- Roof leaks,
- Corrosion of the exterior sheeting at the roof line base and around screw holes, and
- Garage door not seating and replacement required.

Items requiring storage include tires, snowmobiles, off road vehicles, materials for projects, specialty hotline tools, meters and hazardous materials awaiting pickup for proper disposal. This equipment is being stored outside much of the time leading to premature deterioration and a greater risk of theft. Due to the age and condition of the Port aux Basques storage shed it has reached the end of its service life. (see Figures 8, 9, 10, and 11)

Figure 8: Existing Storage Shed

Figure 9: Interior of Storage Shed

[5] This building was purchased used in the early 1980s, disassembled and transported to Port aux Basques for reassembly.

Figure 10: Deteriorated Siding

Figure 11: Deteriorated Roof and Eaves

The cost of repairing the storage shed, which would include foundation modifications to provide frost protection, structural modifications to repair misalignment caused by foundation shifting and building envelope modifications to insure the structure is weather tight, would result in renovation costs outweighing the replacement cost of the structure.

3.0 Project Descriptions

Glovertown District Building

This Glovertown project involves constructing a new 18' x 22' district building and gated storage yard adjacent to the Glovertown Substation located 3.5 kilometers from the site of the existing district building. The new district building will be constructed using timber frame with metal siding, asphalt shingles and will feature dedicated office, workshop and washroom facilities. The new storage yard will be adjacent to the existing substation and be of similar dimensions to the existing yard. The existing building and storage yard will be decommissioned and the site rehabilitated.

Carbonear Storage Shed

The Carbonear project involves constructing a new 24' x 30' storage shed located at Newfoundland Power's regional facility at 30 Goff Avenue in Carbonear. The primary use of the proposed building will be indoor storage for equipment and material. The new storage shed will be constructed using timber frame with metal siding, asphalt shingles and provided with basic heat and electrical service. The existing storage shed will remain in service.

Port Aux Basques Storage Shed

The Port Aux Basques project involves constructing a new 24’ x 30’ storage shed located at Newfoundland Power’s district facility in Port Aux Basques. The primary use of the proposed building will be indoor storage for equipment and material. The new storage shed will be constructed using timber frame with metal siding, asphalt shingles and provided with basic heat and electrical service. The existing storage shed will be dismantled following construction of the new storage shed.

4.0 2019 Project Costs

Table 1 provides a breakdown of the proposed expenditures for 2019 by cost category.

Table 1
2019 Projected Expenditures
($000s)

Cost Category	Glovertown	Carbonear	Port Aux Basques
Material	$138	$91	$91
Labour – Internal	2	2	2
Labour – Contract	-	-	-
Engineering	13	25	25
Other	25	5	5
Total	**$178**	**$123**	**$123**

5.0 Conclusion

In 2019, capital improvements are necessary to replace the existing deteriorated Glovertown district building, replace the existing Port Aux Basques storage shed and construct a new storage shed at the Carbonear service building location.

In 2017, inspections were completed on the Glovertown District Building and storage shed in Port aux Basques. Due to the deteriorated condition of both buildings, significant cost would be incurred in a thorough refurbishment and it is therefore recommended they both be replaced in 2019. There is insufficient indoor storage at the Carbonear service building and it is recommended that a new storage shed be constructed.

This project is justified on the requirement to replace deteriorated infrastructure and provide adequate storage facilities in order for the Company to provide safe, least-cost, and reliable electrical service to customers in these areas.

2019 Application Enhancements

July 2018

Table of Contents

Page

1.0 Introduction

Newfoundland Power (the "Company") operates and supports over 180 software applications. These include third-party software products, such as the Microsoft Dynamics Great Plains ("Dynamics GP") financial system, the ClickSoftware work scheduling and dispatch system, as well as internally developed software, such as the Customer Service System ("CSS") and the Technical Work Request ("TWR") system. These applications help employees work more effectively and efficiently in their daily duties.

The Company's *2019 Application Enhancements* fall into 4 categories: (i) Operations and Engineering Support System Enhancements; (ii) Business Support System Enhancements; (iii) CSS Enhancements; and (iv) Internet Enhancements. In addition, the Company budgets for various minor enhancements needed to respond to unforeseen requirements encountered during the course of each year.

Enhancing these applications, either through vendor-supplied functionality or internal software development, enables the Company to meet its obligation to serve its customers at least cost.

The following report describes the application enhancements planned for 2019.

2.0 Operations and Engineering Support System Enhancements

This category includes application enhancements necessary to support the Company's engineering and operations functions. The information technology in this category includes various applications used to engineer and maintain Company assets, respond to customer requests and manage work in a safe and environmentally responsible manner.

For 2019, enhancements are proposed to the Company's electronic tailboard application.

Table 1 summarizes the estimated cost associated with these enhancements.

Table 1
Operations and Engineering Support System Enhancements
2019 Project Expenditures
(000s)

Cost Category	**Amount**
Material	$55
Labour – Internal	128
Labour – Contract	-
Engineering	-
Other	30
Total	**$213**

2.1 Electronic Tailboard Enhancement ($213,000)

Description

The purpose of this item is to enhance the Company's Environment and Safety Management System ("E&SMS") to meet the requirements of Provincial Occupational Health and Safety legislation, the National Standard of Canada on Electric Utility Workplace Safety CAN-ULC-S801-14, the Occupational Health and Safety Assessment Series OHSAS 18001 standard, and the International Organization of Standards ISO 14001 management system which is an internationally recognized specification for health and safety management systems.

In 1997, a written job risk assessment process ("Tailboard") was implemented. A Tailboard requires a paper document be completed by medium/high risk work groups to ensure key safety procedures were considered before starting each job.[1]

In 2015, a limited implementation of an electronic Tailboard was undertaken. It consisted of an electronic form designed to replace the paper form for power line staff. In addition, it included functionality to record the audio from the discussion around the major job steps, associated hazards and physical barriers required for the safe completion of planned work.

In 2019, the Company will build on the 2015 implementation to include electronic tailboards for all employees who participate in medium and high risk work.

Operating Experience

The safety of the general public, employees and contractors is the top priority for the Company. The Company continually evaluates the effectiveness of its policies, procedures and systems to ensure a safe and healthy workplace.

The original 1997 Tailboard process, while effective, is due for updating. Documenting Tailboards with paper forms produced inconsistent results, required significant administrative effort and was time consuming to complete.

The limited implementation in 2015 of electronic Tailboards identified many opportunities for improvement including standardized scripts for hazard and barrier identification to ensure the correct information was being captured. Also, the electronic version resulted in reduced administration, and allowed supervisors to review the Tailboards for coaching and continual improvement purposes.

---

[1] Tailboards (referred to as "tool box" meetings in some industries) are safety meetings held at the job site with all workers involved. They are held before the work begins and as required during the course of the work to ensure that all workers understand the hazards, risks, and procedures associated with the job. Tailboards are industry best practice for worksite safety.

Justification

Enhancements to the Tailboard application for all staff completing medium to high risk work will enable the Company to better manage and comply with regulatory and legislative requirements, and will permit more effective and efficient management of Tailboards.

The expansion of electronic Tailboards to all employees who participate in medium and high risk work will allow the Company to continually improve employee safety while executing work functions.

3.0 Business Support System Enhancements

This category includes enhancements necessary to support the Company's business applications. Business Support System applications include the Dynamics GP financial management application and various other applications used to manage the financial, human resources, and inventory areas of the Company.

For 2019, enhancements to TWR billing are proposed.

Table 1 summarizes the estimated cost associated with these enhancements.

Table 2
Business Support System Enhancements
2019 Project Expenditures
(000s)

Cost Category	Amount
Material	$40
Labour – Internal	47
Labour – Contract	-
Engineering	-
Other	90
Total	**$177**

3.1 Technical Work Request (TWR) Billing Enhancements ($177,000)

Description

The Company undertakes distribution system work on behalf of third parties for which invoices are required to receive payment. In 2017, the Company undertook approximately 2,000 third-party requested jobs that required invoices. These third party jobs included individual customer requests such as moving a pole on their property, to large jobs for building line extensions for communication companies such as Bell or Rogers Communications.

In 2019, the Company will enhance the existing system for producing customer invoices associated with field work requested by third parties. This application enhancement will reduce manual effort by automating information flow between the TWR and Dynamics GP financial management systems to ensure accuracy and consistency in billing for third party requested work.

Operating Experience

In 2017, the Company produced approximately 2,000 invoices for third party requested work.

For smaller jobs, the cost is based on the work specifications and predefined pricing. These estimates are manually created per job and a quote is sent to the customer. The quote is then authorized by the customer prior to the work being approved for construction. The final cost is then submitted to the customer either through CSS or an invoice created in the Dynamics GP system. The method used to invoice the customer is determined based on the customer's account status and job cost. Once the invoice is paid there is a manual process to update the system.

Invoices for work completed for communications companies involve a time consuming manual process. These invoices may include costs for engineering labour, tree trimming, pole and line work. The estimated cost for these jobs is determined and approved prior to work being started. Once the work is completed the final invoice is created from information manually compiled from several information systems. These invoices are reviewed before being manually entered into the Company's financial system and submitted to the customer for payment. Once the invoice is paid a manual process is used to update the appropriate systems.

This enhancement will automatically identify work orders in TWR that are ready for invoicing and transfer the necessary information to the appropriate customer invoicing application without any manual effort to rekey the invoice data.

Benefits from this enhancement will allow automation between TWR and Dynamics GP that will reduce the amount of manual effort required to produce and process customer invoices.

Justification

Improvements to automate this process will result in a net present value of approximately $143,000 over an expected application life-cycle of 7 years.[2] The project will also enhance the accuracy and consistency of customer invoicing.

4.0 Customer Service System Enhancements

This category includes application enhancements necessary to support customer service delivery, including the various forms of communication used by customers to interact with the Company.

[2] The net present value calculation for this project can be found on page A-1 of Appendix A.

For 2019, enhancements are proposed to consolidate customers' contact history and to automate the collection of weather data for use within the Company's Weather Normalization System.

Table 3 summarizes the estimated cost associated with this item.

Table 3
Customer Service System Enhancements
2019 Project Expenditures
(000s)

Cost Category	**Amount**
Material	$50
Labour – Internal	255
Labour – Contract	-
Engineering	-
Other	65
Total	**$370**

4.1 Customer Contact Consolidation ($253,000)

Description

The purpose of this item is to improve the Company's response to customer inquiries.

In 2019, the Company will consolidate all types of customer contacts that are recorded in various operational systems, in a single application that will be readily available for review when a customer speaks with a Contact Centre Agent. This will allow Contact Center Agents to quickly review information provided in previous contacts to assist in responding to a customer's inquiry.

Operating Experience

The Company's Contact Center handles about 1,200 calls daily and there are over 140,000 emails, faxes, and walk-in contacts processed annually. For each of these contacts, activity is recorded in one or more of the Company's operational systems including the CSS, Outage Management System ("OMS") and TWR systems. When a customer contacts Newfoundland Power, they expect the agent is aware of all prior interactions with the Company. However, to help direct the agent to retrieve the relevant information from the appropriate system, a series of questions is often necessary to understand the customer's prior communications with the Company.

Linking all prior customer interactions with the Company, regardless of what system recorded the contact, is necessary to provide the customer's expected level of service. Enhancing the technology used to record and manage the Company's interactions with customers and the consolidation of customer notes and Company action items will streamline and improve the customer interaction experience.

Justification

This item is justified on improved customer service. This change will allow agents to view all correspondence with a customer from one central location. The enhancements will allow employees to be more effective when interacting with customers. The new customer contact application will integrate with the new OMS and in the future with the CSS replacement system to provide Contact Center Agents with a consolidated view of prior customer contacts.

4.2 Weather Normalization System (WNS) Enhancements ($117,000)

Description

The purpose of this enhancement is to replace the manual process of collecting weather data from the various provincial locations with an automated process.

In 2019, the Company will develop an automated process for collecting and storing weather data for use in the WNS system.

Operating Experience

Currently, daily temperature and hourly wind speed data are manually entered into Newfoundland Power's WNS. This data is used to normalize the Company's electricity sales by accounting for the impact extreme weather events have on sales. The data is also used to produce accurate electricity consumption estimates for customers when a meter reading cannot be obtained. For example, a meter reader may not be able to visit a customer's meter during extreme weather conditions. The electricity consumption estimate is also used to form the basis of many billing integrity edits to ensure accuracy of customer billing.

This project will automate the collection and input of weather data by receiving a file transfer from a third party service provider that captures the appropriate weather data and automatically imports it into the WNS application. This will remove the requirement to have information manually entered into the WNS for the 4 weather locations monitored in the province.

Justification

This item is justified on process accuracy and consistency by automating the input of weather data into the WNS. Automating the collection of weather data will eliminate the risk of human error when entering data manually.

5.0 Internet Enhancements

This category includes enhancements to the Company's web-based applications, which provide customers with convenient, self-service options. These options give customers the ability to interact with the Company 24 hours a day. Applications in this category include the Company's customer service website and the takeCHARGE website.[3]

For 2019, enhancements to the Company's self-service offerings and the takeCHARGE website are proposed in order to reflect planned changes in the Company's energy conservation initiatives.

Table 4 summarizes the estimated cost associated with this item.

Table 4
Internet Enhancements
2019 Project Expenditures
(000s)

Cost Category	**Amount**
Material	-
Labour – Internal	$148
Labour – Contract	-
Engineering	-
Other	25
Total	**$173**

5.1 Customer Website Equal Payment Plan Enhancements ($113,000)

Description

The purpose of this item is to enhance the Company's self-service offerings. In 2017, there were over 2.8 million visits to the Company's Customer Website. This reflects the broad trend that customers continue to utilize web self-service functionality on their personal computers and mobile devices.

In 2019, the Company will enhance the Customer Website by adding a new service option allowing customers to manage their Equal Payment Plan ("EPP") through their personal computer or smartphone.[4]

Operating Experience

There are approximately 43,000 customers using the EPP option, resulting in approximately 6,000 customer contacts annually. The EPP allows a customer to set a uniform bill amount each

---

[3] The takeCHARGE website supports the joint Newfoundland and Labrador Hydro and Newfoundland Power customer energy conservation initiative.

[4] Currently customers can enroll in the EPP payment option through the Customer Website. Changes to the EPP require the customer to contact the Company's Contact Centre.

month based on their estimated 12 month electricity consumption.[5] Currently, the EPP is reviewed every 3 months by the Company to determine if the equal billed amount is still valid based on the actual consumption to date. This review often requires contacting the customer to communicate the need for an increase or decrease in their monthly equal billed amount.

This enhancement will create a self-service option on the Customer Website to allow a customer to review and adjust their EPP at the 3 month intervals.[6] Making minor adjustments at the 3 month intervals may result in avoiding a large EPP change during the mandatory 6 month or annual reviews. Any changes made will automatically take effect on their next billing cycle. The interactive nature of the new service will provide additional information to help customers understand and manage their EPP option.

Justification

This item is justified on improved customer service. This change will expand the Company's self-service options and provide customers the opportunity to self-manage their EPP. Providing customers with the ability to modify their EPP details through a self-service option will reduce the need for customers to call the Company's Contact Centre directly.

5.2 Energy Conservation Website Enhancements ($60,000)

Description

The purpose of this item is to enhance the website which supports the Company's energy conservation initiatives under takeCHARGE.

In 2019, the takeCHARGE website enhancements are required to support the changes to customer energy conservation programs arising from the *5-Year Energy Conservation Plan: 2016-2020*. Specific enhancements anticipated include (i) expansion of educational content for residential and business customers, (ii) calculators and (iii) customer rebate tracking.

Operating Experience

In 2008, Newfoundland and Labrador Hydro and Newfoundland Power launched a joint energy conservation initiative which included the takeCHARGE website. This website is an integral part of the Company's customer energy conservation communications portfolio. It serves as the primary communication channel to which customers are directed for information regarding customer energy conservation programs, rebate and eligibility details, as well as energy efficiency education and awareness resources.

---

5 The Customer Website allows customers to enroll in the EPP, but subsequent management of the EPP requires the customer to communicate with the Company's Contact Centre.

6 Customers will be presented with their current EPP information and a revised EPP amount based on their most up-to-date electricity usage information. The customer can then choose if they want to accept the proposed adjustment to their plan without having to speak directly with a Company representative.

In 2017, there were over 300,000 visits to the takeCHARGE website. This is consistent with promotion of the takeCHARGE website as the primary resource for customer inquiries and information, and reflects ongoing promotion, program changes, and website enhancements implemented in 2017. It also reflects the broad trend toward increasing customer expectations for self-service options, particularly through mobile devices. In 2017, the proportion of *takeCHARGE* website visits using mobile devices was consistent with 2016 with almost 60% of customers accessing the website with a mobile device.

Justification

Website enhancements are justified based on improvements to customer service and promotion of energy conservation. As customer energy conservation programs and associated incentives and information evolve as proposed in the 5-year Energy Conservation Plan: 2016-2020, it is necessary that the takeCHARGE website and related tools are updated to ensure these new programs and information resources can be offered to customers.

These enhancements will expand customers' access to the energy conservation tools and information which are integral to the Company's customer energy conservation initiative, through their personal choice of a full or mobile website. This will enhance the customer's ability to access information on conservation opportunities independent of location, time of day or type of device used, and will support continued efficiency in the Company's response to customer expectations in this area.

6.0 Various Minor Enhancements ($319,000)

Description

Table 5 summarizes the estimated cost associated with this item.

Table 5
Various Minor Enhancements
Project Expenditures
(000s)

Cost Category	Amount
Material	$25
Labour – Internal	219
Labour – Contract	-
Engineering	-
Other	75
Total	**$319**

The purpose of this item is to complete enhancements to the Company's corporate applications in response to unforeseen requirements, such as legislative and compliance changes, vendor-driven changes, or employee-identified enhancements designed to improve customer service or operational efficiency. Based on recent expenditures, $319,000 is estimated to be required in 2019 to address various minor enhancements to Company applications.

Operating Experience

Examples of work that would be completed under this budget item include modifications to customer, operations and engineering applications. This work is often required as a result of unforeseen circumstances that occur throughout the year that cannot be deferred to future capital budget applications.

Some recent examples include net metering and customer billing enhancements. This allowed the Company to credit customers who generate electricity through the use of wind or solar power for use on the electric system. Other enhancements such as externally requested changes to how Newfoundland Power conducts business with third parties, such as Bell Aliant and Rogers are also completed as required.

Justification

Work completed as part of Various Minor Enhancements is justified on the basis of improved customer service, operating efficiencies, or compliance with regulatory and legislative requirements.

Appendix A
Net Present Value Analysis

NET PRESENT VALUE ANALYSIS

<u>Technical Work Request Billing</u>

		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 C	Residual CCA	Total	Labour D	Non-Lab	Labour E	Non-Lab	Net Operating Savings F	Income Tax G	After-Tax Cash Flow H
0	2019	($177)	$0	$89	$0		$89	$0	$0	$15,000	$0	$15,000	($4,473)	$10,350
1	2020	$0	$0	$89	$0		$89	$0	$0	$30,750	$0	$30,750	($9,198)	$21,552
2	2021	$0	$0	$0	$0		$0	$0	$0	$31,519	$0	$31,519	($9,456)	$22,063
3	2022	$0	$0	$0	$0		$0	$0	$0	$32,307	$0	$32,307	($9,692)	$22,615
4	2023	$0	$0	$0	$0		$0	$0	$0	$33,114	$0	$33,114	($9,934)	$23,180
5	2024	$0	$0	$0	$0		$0	$0	$0	$33,942	$0	$33,942	($10,183)	$23,760
6	2025	$0	$0	$0	$0		$0	$0	$0	$34,791	$0	$34,791	($10,437)	$24,354
7	2026	$0	$0	$0	$0	$0	$0	$0	$0	$35,661	$0	$35,661	($10,698)	$24,962
7 Yr	Present Value (See Note I)	@		5.29%										$142,574

NOTES: A is the sum of the software additions by year.

B is the sum of the computer network hardware additions by year.

C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.

D is any software maintenance fees and internal support costs associated with the project. The labour cost estimates are escalated to current year using the GDP Deflator Index. The non-labour costs are escalated by The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.

E is the reduced operating costs. The non-labour cost estimates are escalated to current year using the GDP Deflator Index. The labour costs are escalated by The cost estimate is 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.

2019 System Upgrades

July 2018

Table of Contents

1.0 Introduction

Newfoundland Power (the "Company") depends on the effective implementation and ongoing operation of its information systems in order to continue providing least-cost and reliable service to customers. Over time, these systems must be upgraded to ensure continued vendor support, to improve compatibility with software or hardware upgrades, or to take advantage of newly developed functionality and security improvements.

This project consists of system upgrades and continuation of the Microsoft Enterprise Agreement.

2.0 2019 System Upgrades ($1,258,000)

These upgrades involve third-party software products that comprise the Company's information systems. For 2019, upgrades are proposed for the Company's Supervisory Control and Data Acquisition system ("SCADA system"), Customer Outage Reporting System, Meter Data Collection System and various minor upgrades.

Table 1 summarizes the cost associated with these items.

Table 1
System Upgrades
2019 Project Expenditures
($000s)

Cost Category	**Amount**
Material	440
Labour – Internal	543
Labour – Contract	-
Engineering	-
Other	275
Total	**1,258**

2.1 Description

Upgrades to third-party software products ensure the Company's information systems continue to function in a stable and reliable manner with the appropriate level of vendor support. Each year, the Company's systems are reviewed to determine if upgrades are required.

For 2019, upgrades include:

Supervisory Control and Data Acquisition System Upgrade ($98,000)

This item involves upgrading the SCADA system to ensure system operations benefit from the latest enhancements and functionality and the system continues to be fully supported by the vendor.

This system was implemented in 2016. It is a critical information system used at the Company's System Control Centre that monitors and controls the electrical system on a real-time basis. Frequent functionality and security upgrades of SCADA systems have become industry best practice.

The proposed upgrade will ensure consistent and effective operation of the Company's SCADA system and apply the latest security updates and features available for the system. The upgrade will also ensure that integrations to other enterprise systems like the Company's new Outage Management System ("OMS") and Geographic Information System technology will continue to function properly.

Customer Outage Reporting System Upgrade ($510,000)

Newfoundland Power's customer outage reporting system was implemented in 1998 as a high volume voice announcer to provide customers with information on current outages in their neighborhood. While there have been upgrades to the system since 1998, the underlying 20-year old voice announcer technology remains the same. The system is comprised of an in-house developed computer application for outage message creation, along with call routing and voice message storage technology located at the local telephone company's facility in St. John's.[1] Locating the voice announcer at the telephone exchange provided enough line capacity to provide messaging to hundreds of customers in all 8 operating areas simultaneously. Customers calling the Company's outage reporting telephone number would hear location specific audio messaging based on the local area exchange that the telephone call was originating from.[2]

The high volume voice announcer and call routing system has reached the end of its useful life and is due for replacement. Additionally, with recent advancements in mobile phone technology and portability of telephone numbers, it is not always possible to use the first 3 digits of a 7-digit telephone number to determine where a customer is calling from. As a result, it is becoming increasingly more difficult to automatically relate a telephone call to a part of the Company's service territory experiencing an outage. This has resulted in customers receiving outage

[1] Components of the Company's customer outage reporting system include: (i) an in-house developed computer application, (ii) Bell Aliant 800 toll-free services, (iii) an Interalia XMU+ digital voice announcer appliance and, (iv) a Bell Aliant DMS-100 telephone exchange switch to provide connection to the public telephone network.

[2] The local area exchange information had historically been provided by the first 3 digits of the 7-digit telephone number. For example, telephone number 256-0000 and all other telephone numbers starting with 256 would be based out of the telephone exchange in Gander, NL.

message recordings in error leading to customer frustration and resulting in additional calls to the Company's Contact Centre or System Control Centre.

Upgrading to a modern high volume call handling system will allow integration with the Company's new OMS planned for 2019.[3] In the future, whenever a customer call is answered by the new OMS, customers who are associated with a current outage will be routed to the new high volume call handling system and played an outage messaging specific to the location of their electricity account. This OMS based functionality cannot be provided by the current high volume call handling system.

The proposed upgrade will ensure that customers continue to be provided with accurate automated outage messaging.

Meter Data Collection System Upgrade ($278,000)

This project involves upgrading the software and hardware used by employees to collect customer meter readings.

In 2017, the Company completed its metering initiative to be 100% Automatic Meter Reading ("AMR") meters for domestic and most general service customers. One of the benefits of being 100% AMR is that the Company is now able to use portable drive-by meter data collection solutions that use hardware and software to gather customer meter reading data. This allows employees to collect both walk-by and drive-by meter readings.

The current handheld meter reading technology has not been available for new purchase since July 2016. As such, the Company can no longer purchase replacement handheld units and replacement parts are only provided by the vendor on a best-efforts basis. As a result, the Company runs the risk of not being able to deliver services to its customers via the most cost effective method.

The proposed upgrade will ensure that the hardware and software are at the latest supported versions, and will allow the Company to take advantage of the latest functionality available in the upgraded system.[4]

Various Minor Upgrades ($127,000)

This item involves the upgrading of multiple software applications that have either reached the end of vendor support, require bug fixes, require security patches or require changes to comply with regulatory and legislative requirements.

The Company currently maintains a software portfolio consisting of over 180 applications used by employees in carrying out their daily work. The upgrading of these various applications is

---

[3] Replacement of the Outage Management System was approved in Order No. P.U.37 (2017).

[4] New handheld technology will enable employees to better utilize the capture of out-of-route meter reads, reducing the number of estimates, and reduce the number of field visits required to collect missing data.

routinely carried out to extend the useful life of the application, as well as to take advantage of new functionality available in newer versions of software.

Upgrades are required to maintain vendor support, and to obtain bug fixes available in the newest versions. Cybersecurity improvements are usually contained in new software versions. The Company assesses these security improvements to ensure the Company maintains a secure computing environment.

2.2 Operating Experience

System upgrades help ensure the reliability and effectiveness of the Company's information systems and mitigate risks associated with technology-related issues. The timing of the upgrades is based on a review of the risks and operational experience of the systems being considered for upgrade. New versions of third-party software products are generally designed to address known deficiencies, thereby improving performance, and allow the Company to take advantage of new functional or technical enhancements.

2.3 Justification

Investments in the SCADA, Customer Outage Reporting, and Meter Data Collection systems will ensure continued vendor support and compatibility with other systems. Unstable and unsupported software products can negatively impact operating efficiencies and customer service. Increasing cybersecurity risks have also resulted in software vendors releasing new versions of software to further enhance cybersecurity capabilities within the application and to also address known cyber vulnerabilities. Keeping current with these latest versions helps protect customer and Company information.

3.0 The Microsoft Enterprise Agreement ($245,000)

3.1 Description

This 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 least-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.[5]

Under this agreement, the Company distributes its purchasing costs for these licenses over 3 years, as outlined in Schedule C. This achieves overall cost savings.

[5] Personal computers include desktops, laptops, tablets and other mobile computing devices.

3.2 Operating Experience

The Company has had the Microsoft Enterprise Agreement in place providing access to the latest versions of software products for over 15 years.[6] The terms of the agreements are typically 3 years, with requirements reviewed and adjusted annually.[7]

3.3 Justification

The Microsoft Enterprise Agreement is the least-cost option to ensure access to current Microsoft software products.

[6] The agreement covers software products such as Microsoft Windows, Microsoft Office, Outlook, SharePoint, SQL Server, and other products used by employees in the completion of their normal duties.

[7] The Microsoft Enterprise Agreement was approved as a multiyear project in Order No. P.U. 37 (2017). The current agreement expires on May 31, 2021.

2019 Shared Server Infrastructure

July 2018

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

Page

1.0 Introduction

Newfoundland Power's (the "Company") shared server infrastructure consists of over 100 shared servers that are used for routine operation, testing, and disaster recovery of the Company's corporate applications. The Company relies on these shared servers to ensure the efficient operation and support of its systems and applications.[1]

Each year, an assessment is completed to determine shared server infrastructure requirements. This assessment involves identifying servers and peripherals to be replaced based on age and risk of failure. The assessment also determines new computing requirements for corporate applications and identifies security management equipment necessary for the protection of customer and corporate data.

2.0 Description

This project includes the addition, upgrade and replacement of computer hardware components and related technology associated with shared server infrastructure and peripheral equipment.

Table 1 summarizes the cost associated with these items.

Table 1
Shared Server Infrastructure Upgrades
2019 Project Expenditures
($000s)

Cost Category	**Amount**
Material	590
Labour – Internal	148
Labour – Contract	-
Engineering	-
Other	110
Total	**848**

For 2019, this project includes 4 items to enhance the operation of the Company's shared server infrastructure

1. Lifecycle replacement of the Company's email infrastructure used for efficient and secure internal and external email communications. The current infrastructure was installed in 2012 and has reached the end of its useful life.

[1] The Company's systems and applications fall into 4 categories: (i) Business Support Systems, (ii) Customer Service Systems, (iii) Internet, and (iv) Operations and Engineering Systems.

2. Lifecycle replacement of the Company's workforce management system infrastructure used to support the mobile dispatch of field work. The current infrastructure was installed in 2013 and has reached the end of its useful life. In 2019, the Company's new Outage Management System will become operational increasing the information flow to and from employees in the field. Server upgrades are required to support the increased information flow;

3. Lifecycle replacement of the Company's blade server chassis infrastructure. Blade server infrastructure is computing architecture that houses multiple server modules (blades) in a single chassis. This type of technology is widely used in datacenters to minimize space requirements and ensure efficient system management. Multiple applications used to provide customer service reside within this architecture including information systems such as the Avantis Asset Management System, the Dynamics GP Financial System, and the Company's Intranet. The current blade chassis infrastructure was installed in 2013, and has reached the end of its useful life.

4. Infrastructure upgrades to extend the existing infrastructures' useful life. Infrastructure upgrades for 2019 include additional components to increase disk storage, processor and memory capacity to various systems to accommodate information storage growth needs, and improve performance of various applications used to serve customers.

3.0 Operating Experience

The shared server infrastructure project includes the purchase, implementation and management of the hardware and software related to the operation of shared servers and peripheral equipment. Shared servers and peripheral equipment are critical to ensuring the efficient operation of the Company and the provision of service to customers.

Factors considered in determining when to upgrade, replace or add shared server components or peripheral equipment include:

(i) Level of support provided by the vendor;
(ii) Current performance of the components;
(iii) Ability of the components to meet future growth;
(iv) Cost of maintaining and operating the components;
(v) Cost of replacing or upgrading the components versus operating the current components;
(vi) Criticality of the equipment or the applications running on the shared servers; and
(vii) Business or customer impact, should the component fail.

Gartner Inc. has indicated that servers have a useful life of approximately 5 years.[2] By making appropriate investments in its shared server infrastructure, the Company's experience is that the average useful life of its servers is about 7 years.

[2] Gartner Inc. is a leading provider of research and analysis on the global information technology industry.

In order to ensure the high availability of its applications, and to minimize the vulnerability of its computer systems to external interference, the Company invests in system availability, proactive security monitoring and protection tools. These tools allow the Company to monitor and respond to problems that could impede the normal operation of applications or compromise customer and corporate information.

4.0 Justification

The need to replace, upgrade and modernize information technology infrastructure is fundamentally the same as the need to replace, upgrade and modernize the components of the Company's electrical system infrastructure as it deteriorates. Instability within shared server infrastructure and peripheral equipment has the potential to impact large numbers of employees and customers. Investments in shared server infrastructure and peripheral equipment are therefore critical to the Company's overall operations and the provision of least-cost service to customers.

Investments are based on evaluating the alternatives of modernizing or replacing technology components and selecting the least-cost alternative.

Rate Base:
Additions, Deductions & Allowances

July 2018

Table of Contents

1.0 Introduction

1.1 General

In the 2019 Capital Budget Application (the "Application"), Newfoundland Power seeks final approval of its 2017 average rate base. This is consistent with current regulatory practice before the Board.

Newfoundland Power's 2017 average rate base of $1,092,254,000 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. 32 (2007), the Board approved Newfoundland Power's calculation of rate base in accordance with the Asset Rate Base Method. That calculation included the additions to, deductions from, and allowances in rate base, which are more fully described in this report.

1.2 Compliance and Related Matters

In Order No. P.U. 19 (2003), the Board, in effect, ordered Newfoundland Power to file with its capital budget applications: (i) evidence related to changes in deferred charges, including pension costs, and (ii) a reconciliation of average rate base and average invested capital.

Commencing in 2008, Newfoundland Power's rate base is calculated in accordance with the Asset Rate Base Method. This includes provision for allowances calculated in accordance with accepted regulatory practice. The use of allowances versus average year-end balances results in permanent differences between Newfoundland Power's average rate base and average invested capital. Accordingly, they are, in effect, the principal reconciling items between the Company's average rate base and average invested capital.

This report provides evidence relating to: (i) changes in deferred charges, including pension costs; and (ii) the cash working capital allowance and materials and supplies allowance included in rate base. This complies with the requirements of Order No. P.U. 19 (2003).

To provide the Board with a comprehensive overview of those items in Newfoundland Power's rate base other than plant investment, this report reviews *all* additions, deductions and allowances included in rate base.

Four years of data are provided in this report. This includes two historical years, the current year and the following year. The 2018 and 2019 forecast rate base additions and deductions reflect the Company's most recent forecasts and estimates. The data presented is year-end data. This is consistent with past evidence submitted in compliance with Order No. P.U. 19 (2003).

2.0 Additions to Rate Base

2.1 Summary

Table 1 summarizes Newfoundland Power's additions to rate base for 2016 and 2017, and the forecast additions for 2018 and 2019.

Table 1
Additions to Rate Base
2016-2019F
($000s)

	2016	2017	2018F	2019F
Deferred Pension Costs	94,775	92,017	89,640	92,779
Deferred Credit Facility Issue Costs	94	110	82	54
Cost Recovery Deferral – Hearing Costs	682	341	-	-
Cost Recovery Deferral – Conservation	11,304	14,116	16,212	17,773
Weather Normalization Reserve	1,721	4,771	(272)	-
Customer Finance Programs	1,341	1,496	1,531	1,560
Demand Management Incentive Account	-	1,490	-	-
Total Additions	109,917	114,341	107,193	112,166

Additions to rate base were approximately $114.3 million in 2017. This is approximately $4.4 million higher than 2016. The higher additions to rate base in 2017 reflects an increase in the deferred recovery of annual customer energy conservation program costs and the balance in the weather normalization account. These increases are partially offset by a decrease in deferred pension 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).[1]

Table 2 shows details of changes in Newfoundland Power's deferred pension costs from 2016 through 2019F.

Table 2
Deferred Pension Costs
2016-2019F
($000s)

	2016	**2017**	**2018F**	**2019F**
Deferred Pension Costs, January 1st	98,829	94,775	92,017	89,640
Pension Plan Funding	3,249	3,378	2,784	2,993
Pension Plan Expense	(7,303)	(6,136)	(5,162)	145
Deferred Pension Costs, December 31st	94,775	92,017	89,640	92,779

2.3 Credit Facility Costs

In Order No. P.U. 1 (2005), the Board approved Newfoundland Power's issue of a $100 million committed revolving term credit facility.

In the 2016/2017 General Rate Application, the amortization of credit facility costs associated with the balance as of December 31, 2015 of $56,000 was included as a component of the Company's cost of capital for 2016 and 2017 for revenue requirement purposes. As these costs are reflected in customer rates, they are not included in rate base for those years.

In August 2016, the committed credit facility was renegotiated to extend its maturity date to August 2021. Costs related to this amendment totalled $101,000 and are being amortized over the 5-year life of the agreement, beginning in 2016. In August 2017, it was further extended to August 2022 at an additional cost of $40,000. The unamortized credit facility costs associated with this amount are included in rate base as these costs have not yet been reflected in the Company's revenue requirements.

1 Deferred pension costs were approved for inclusion in average rate base in Order No. P.U. 19 (2003).

Table 3 shows details of Newfoundland Power's amortization of deferred credit facility issue costs for 2016 through 2019F.

Table 3
Deferred Credit Facility Issue Costs
2016-2019F
($000s)

	2016	2017	2018F	2019F
Balance, January 1st	56	94	110	82
Cost – Reduction	(56)	-	-	-
Cost – Addition	101	40	-	-
Amortization	(7)	(24)	(28)	(28)
Balance, December 31st	94	110	82	54

2.4 Cost Recovery Deferral – Seasonal/Time-of-Day Rates

In Order No. P.U. 8 (2011), the Board approved Rate #1.1S Domestic Seasonal - Optional (the "Optional Seasonal Rate"), with effect from July 1, 2011. Order No. P.U. 8 (2011) also approved the Optional Seasonal Rate Revenue and Cost Recovery Account to provide for the deferral of annual costs and revenue effects associated with implementing the Optional Seasonal Rate and the operating costs associated with a two-year study to evaluate time-of-day rates.

Newfoundland Power is required to file an application with the Board no later than the 1st day of March each year for the disposition to the Rate Stabilization Account ("RSA") of any balance in this account.

In Order No. P.U. 13 (2013), the Board approved that Newfoundland Power would maintain the Account until its next general rate application. In the 2016/2017 General Rate Application, Newfoundland Power did not propose that the Optional Seasonal Rate Revenue and Cost Recovery Account be maintained beyond 2015. Accordingly, the disposition of the December 31, 2015 balance was the final disposition to the RSA.[2]

[2] The disposition of the December 31, 2015 balance in the Optional Seasonal Rate Revenue and Cost Recovery Account to the RSA as of March 31, 2016 was approved by the Board in Order No. P.U. 10 (2016).

Table 4 shows details of the Optional Seasonal Rate Revenue and Cost Recovery Account for 2016 through 2019F.

Table 4
Seasonal/TOD Rates
2016-2019F
($000s)

	2016	2017	2018F	2019F
Balance, January 1st	49	-	-	-
Additions	-	-	-	-
Reductions	(49)	-	-	-
Balance, December 31st	-	-	-	-

2.5 Cost Recovery Deferral – Hearing Costs

In Order No. P.U. 13 (2013), the Board approved the deferred recovery over a 3-year period, beginning in 2013, of external costs related to the Company's 2013 General Rate Application. The deferred hearing costs were fully amortized in 2015.

In Order No. P.U. 18 (2016), the Board approved hearing costs of up to $1.0 million related to the 2016/2017 General Rate Application be recovered in customer rates over the period July 1, 2016 through December 31, 2018.

Table 5 shows details of the changes in Newfoundland Power's deferred hearing costs from 2016 through 2019F.

Table 5
Deferred Hearing Costs
2016-2019F
($000s)

	2016	2017	2018F	2019F
Balance, January 1st	-	682	341	-
Cost	853	-	-	-
Amortization	(171)	(341)	(341)	-
Balance, December 31st	682	341	-	-

2.6 Cost Recovery Deferral – Conservation

Table 6 shows details of the forecast amortizations of the deferred cost recovery related to conservation for 2016 through 2019F.

Table 6
Cost Recovery Deferral – Conservation
2016-2019F
($000s)

	2016	**2017**	**2018F**	**2019F**
Balance, January 1st	7,463	11,304	14,116	16,212
Cost	5,040	4,731	4,691	4,826
Amortization	(1,199)	(1,919)	(2,595)	(3,265)
Balance, December 31st	11,304	14,116	16,212	17,773

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 7 years, beginning in 2014, with recovery through the RSA.

2.7 Weather Normalization Reserve

In Order No. P.U. 1 (1974), the Board approved that rate base be adjusted for the balance in the Weather Normalization Reserve.

Table 7 shows details of changes in the balance of the Weather Normalization Reserve from 2016 through 2019F.

Table 7
Weather Normalization Reserve
2016-2019F
($000s)

	2016	**2017**	**2018F**	**2019F**
Balance, January 1st	4,411	1,721	4,771	(272)
Operation of the reserve	1,721	4,771	(272)	-
Transfers to the RSA	(4,411)	(1,721)	(4,771)	272
Balance, December 31st	1,721	4,771	(272)	-

The disposition of the December 31, 2017 balance in the Weather Normalization Reserve Account to the RSA as of March 31, 2018, was approved by the Board in Order No. P.U. 11 (2018).

2.8 Customer Finance Programs

Customer finance programs are loans provided to customers for the purchase and installation of products and services related to conservation programs and contributions in aid of construction ("CIAC").

Table 8 shows details of changes to balances related to customer finance programs for 2016 through 2019F.

Table 8
Customer Finance Programs
2016-2019F
($000s)

	2016	2017	2018F	2019F
Balance, January 1st	1,211	1,341	1,496	1,531
Change	130	155	35	29
Balance, December 31st	1,341	1,496	1,531	1,560

2.9 Demand Management Incentive Account

In Order No. P.U. 32 (2007), the Board approved the Demand Management Incentive Account (the "DMI Account") to replace the Purchase Power Unit Cost Variance Reserve.

Table 9 shows details of the DMI Account from 2016 through 2019F.

Table 9
DMI Account
2016-2019F
($000s)

	2016	2017	2018F	2019F
Balance, January 1st	-	-	1,490	-
Transfers to the RSA	-	-	(1,490)	-
Operation of DMI	-	1,490	-	-
Balance, December 31st	-	1,490	-	-

The disposition of the December 31, 2017 balance in the Demand Management Incentive Account to the RSA as of March 31, 2018, was approved by the Board in Order No. P.U. 10 (2018).

3.0 Deductions from Rate Base

3.1 Summary

Table 10 summarizes Newfoundland Power's deductions from rate base for 2016 and 2017, and the Company's forecasts for 2018 and 2019.

Table 10
Deductions from Rate Base
2016-2019F
($000s)

	2016	2017	2018F	2019F
Other Post Employment Benefits ("OPEBs")	46,083	52,584	56,097	59,594
Customer Security Deposits	786	1,066	1,066	1,066
Accrued Pension Obligation	5,285	5,572	5,036	5,311
Accumulated Deferred Income Taxes	2,186	3,915	5,606	8,347
Cost Over Recovery – 2016 Revenue Surplus	1,445	723	-	-
Total Deductions	55,785	63,860	67,805	74,318

Deductions from rate base were approximately $63.9 million in 2017. Newfoundland Power's total deductions from rate base in 2017 were approximately $8.1 million higher than 2016 primarily due to the increase in the OPEBs liability from 2016. The increase in the OPEBs liability primarily reflects the amortization of the OPEBs regulatory asset[3] and amortization of the employee future benefits regulatory asset[4] related to OPEBs.

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.

[3] In Order No. PU. 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.

[4] In Order No. PU. 11 (2012), the Board approved the opening balances for regulatory assets and liabilities associated with employee future benefits to be recognized for regulatory purposes under U.S. GAAP as of January 1, 2012.

Table 11 shows details of the changes related to the net OPEBs liability from 2016 through 2019F.

Table 11
Other Post Employment Benefits
2016-2019F
($000s)

	2016	2017	2018F	2019F
Regulatory Asset	45,875	29,207	24,528	21,024
OPEBs Liability	91,958	81,791	80,625	80,618
Net OPEBs Liability	46,083	52,584	56,097	59,594

3.3 *Customer Security Deposits*

Customer security deposits are provided by customers in accordance with the Schedule of Rates, Rules and Regulations.

Table 12 shows details on the changes in customer security deposits from 2016 through 2019F.

Table 12
Customer Security Deposits
2016-2019F
($000s)

	2016	2017	2018F	2019F
Balance, January 1st	1,286	786	1,066	1,066
Change	(500)	280	-	-
Balance, December 31st	786	1,066	1,066	1,066

3.4 Accrued Pension Obligation

Accrued pension obligation is the cumulative costs of Newfoundland Power's unfunded pension plans net of associated benefit payments.

Table 13 shows details of changes related to accrued pension obligation for 2016 through 2019F.

Table 13
Accrued Pension Obligation
2016-2019F
($000s)

	2016	2017	2018F	2019F
Balance, January 1st	4,955	5,285	5,572	5,036
Change	330	287	(536)	275
Balance, December 31st	5,285	5,572	5,036	5,311

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 with respect to timing differences related to plant investment,[5] pension costs[6] and other employee future benefit costs.[7]

Table 14 shows details of changes in the accumulated deferred income taxes from 2016 through 2019F.

Table 14
Accumulated Deferred Income Taxes
2016-2019F
($000)

	2016	2017	2018F	2019F
Balance, January 1st	1,268	2,186	3,915	5,606
Change	918	1,729	1,691	2,741
Balance, December 31st	2,186	3,915	5,606	8,347

[5] 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.

[6] 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.

[7] In Order No. P.U. 31 (2010), the Board approved the use of Tax Accrual Accounting to recognize deferred income taxes related to timing differences between other employee future benefits recognized for tax purposes (cash payments) and other employee future benefit expense recognized for accounting purposes (accrual basis).

3.6 Cost Over Recovery – 2016 Revenue Surplus

The Board's determination on Newfoundland Power's 2016/2017 General Rate Application in Order No. P.U. 18 (2016) resulted in a $2.6 million ($1.8 million after-tax) surplus in the recovery of the revenue requirements for 2016 (the "2016 Revenue Surplus"). The order provided for credit of the 2016 Revenue Surplus through a regulatory amortization beginning on July 1, 2016 and concluding on December 31, 2018.

Table 15 shows the 2016 revenue surplus amortization for 2016 through 2019F.

Table 15
Cost Over Recovery – 2016 Revenue Surplus
2016-2019F
($000s)

	2016	**2017**	**2018F**	**2019F**
Balance, January 1st	-	1,445	723	-
Credit	1,806	-	-	-
Amortization	(361)	(722)	(723)	-
Balance, December 31st	1,445	723	-	-

3.7 Excess Earnings Account

In Order No. P.U. 23 (2013), the Board approved the definition of the Excess Earnings Account. In 2013, Newfoundland Power's regulated earnings exceeded the upper limit of allowed regulated earnings by $49,000.[8]

In the Company's 2016/2017 General Rate Application, the 2013 excess earnings amount was included in the Company's 2016 revenue requirement.[9] Accordingly, there is no balance in the excess earnings account as of December 31, 2016.

8 The allowed regulated earnings are based on a return on rate base of 7.92% plus 18 basis points approved in Order No. P.U. 23 (2013).
9 The Company's 2016 and 2017 revenue requirements were approved in Order No. P.U. 25 (2016).

Table 16 shows details of the Excess Earnings Account from 2016 through 2019F.

Table 16
Excess Earnings Account
2016-2019F
($000s)

	2016	2017	2018F	2019F
Balance, January 1st	49	-	-	-
Change	(49)	-	-	-
Balance, December 31st	-	-	-	-

4.0 Rate Base Allowances

4.1 Summary

The cash working capital allowance, together with the materials and supplies allowance, form the total allowances that are included in the Company's rate base. This represents the average amount of investor-supplied working capital necessary to provide service.

4.2 Cash Working Capital Allowance

The cash working capital allowance recognizes that a utility must finance the cost of its operations until it collects the revenues to recover those costs.

Table 17 shows details on changes in the cash working capital allowance from 2016 through 2019F.

Table 17
Rate Base Allowances
Cash Working Capital Allowance[10]
2016-2019F
($000s)

	2016	**2017**	**2018F**	**2019F**
Gross Operating Costs	513,878	507,434	505,884	505,703
Income Taxes	12,204	10,592	17,137	14,370
Municipal Taxes Paid	17,561	16,076	18,043	18,043
Non-Regulated Expenses	(2,379)	(2,462)	(2,286)	(2,139)
Total Operating Expenses	541,264	531,640	538,778	535,977
Cash Working Capital Factor	1.336%	1.353%	1.353%	1.353%
	7,231	7,193	7,290	7,252
HST Adjustment	1,087	960	960	960
Cash Working Capital Allowance	8,318	8,153	8,250	8,212

4.3 Materials and Supplies Allowance

Including a materials and supplies allowance in rate base provides a utility a means to reasonably recover the cost of financing its inventories that are not related to the expansion of the electrical system.[11]

[10] The cash working capital allowance for 2016 through 2019 is calculated based on the method used to calculate the 2016/2017 Test Year average rate base approved by the Board in Order No. P.U. 18 (2016).

[11] Financing costs for inventory related to the expansion of the electrical system are recovered through the use of an allowance for funds used during construction and are capitalized upon project completion.

Table 18 shows details on changes in the materials and supplies allowance from 2016 through 2019F.

Table 18
Rate Base Allowances
Materials and Supplies Allowance
2016-2019F
($000s)

	2016	**2017**	**2018F**	**2019F**
Average Materials and Supplies	8,142	7,730	7,332	7,463
Expansion Factor[12]	20.61%	20.61%	20.61%	20.61%
Expansion	1,678	1,593	1,511	1,538
Materials and Supplies Allowance	6,464	6,137	5,821	5,925

[12] The expansion factor is based on a review of actual inventories used for expansion projects. The calculation of the 2016 through 2019 rate base, including a materials and supplies allowance based upon an expansion factor of 20.61%, was approved by the Board in Order No. P.U. 18 (2016).