NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

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www.newfoundlandpower.com

DELIVERED BY HAND

June 26, 2014

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 and Gentlemen:

Re: Newfoundland Power's 2015 Capital Budget Application

A. 2015 Capital Budget Application

Enclosed are the original and 12 copies of Newfoundland Power Inc.'s (the "Company") 2015 Capital Budget Application and supporting materials (the "Filing").

The Filing outlines a proposed 2015 Capital Budget totaling $94,211,000. There are also 5 multi-year projects involving future capital expenditures totaling $19,804,000. In addition, the Filing seeks approval of a 2013 rate base in the amount of $915,820,000.

B. Compliance Matters

B.1 Board Orders

In Order No. P.U. 27 (2013) (the "2014 Capital Order"), the Board required a progress report on 2014 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. *2014 Capital Expenditure Status Report*: this meets the requirements of the 2014 Capital Order;

2. *2015 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 *2015 Capital Plan* provides a breakdown of the overall 2015 Capital Budget by definition, classification, and materiality segmentation as described in the Guidelines. Pages ii through ix 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.

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. Thomas Johnson, 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,

Gerard M. Hayes
Senior Counsel

Enclosures

c. Geoffrey Young
Newfoundland and Labrador Hydro

Thomas Johnson
O'Dea Earle Law Offices

Newfoundland Power Inc.
2015 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 2015 Capital Budget of \$94,211,000;
(b) approving certain capital expenditures related to multi-year projects commencing in 2015; and
(c) fixing and determining a 2013 rate base of \$915,820,000

2015 Capital Budget Application

NEWFOUNDLAND POWER
A FORTIS COMPANY

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 2015 Capital Budget of $94,211,000;
(b) approving certain capital expenditures related to multi-year projects commencing in 2015; and
(c) fixing and determining a 2013 rate base of $915,820,000

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 2015 Capital Budget in the amount of $94,211,000, which includes an estimated amount of $1,500,000 in contributions in aid of construction that the Applicant intends to demand from its customers in 2015. 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 2015 Capital Budget are required.

4. Schedule C to this Application is a list of multi-year projects that will commence as part of the 2015 Capital Budget but will not be completed in 2015.

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 2013 of $915,820,000.

7. Communication with respect to this Application should be forwarded to the attention of Liam P. O'Brien and Gerard M. Hayes, 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 purchase and construction in 2015 of the improvements and additions to its property in the amount of $94,211,000 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 of improvements and additions to its property in the amount of $19,609,000 in 2016, as set out in Schedule C to the Application;

   (c) pursuant to Section 41 of the Act, approving Newfoundland Power's purchase and construction of improvements and additions to its property in the amount of $195,000 in 2017, as set out in Schedule C to the Application; and

   (d) pursuant to Section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2013 in the amount of $915,820,000 as set out in Schedule D to the Application.

DATED at St. John's, Newfoundland and Labrador, this 26th day of June, 2014.

NEWFOUNDLAND POWER INC.

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

Telephone: (709) 737-5609
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 2015 Capital Budget of $94,211,000;
(b) approving certain capital expenditures related to multi-year projects commencing in 2015; and
(c) fixing and determining a 2013 rate base of $915,820,000

AFFIDAVIT

I, Gary J. Smith 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 26th day of June, 2014:

Barrister

Gary J. Smith

2015 CAPITAL BUDGET SUMMARY

Asset Class	**Budget (000s)**
1. Generation - Hydro	$ 4,698
2. Generation - Thermal	216
3. Substations	22,478
4. Transmission	5,731
5. Distribution	42,473
6. General Property	3,224
7. Transportation	2,917
8. Telecommunications	123
9. Information Systems	7,501
10. Unforeseen Allowance	750
11. General Expenses Capitalized	4,100
Total	**$ 94,211**

2015 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
1. Generation – Hydro		
Facility Rehabilitation	$ 1,586	2
Public Safety Around Dams	429	4
Pierre's Brook Plant Penstock and Surge Tank [2]	750	6
Tors Cove Plant Refurbishment	1,777	8
Seal Cove Plant Refurbishment	156	10
Total Generation – Hydro	**$ 4,698**	
2. Generation – Thermal		
Facility Rehabilitation Thermal	$ 216	13
Total Generation – Thermal	**$ 216**	
3. Substations		
Substations Refurbishment and Modernization	$ 9,961	16
Replacements Due to In-Service Failures	3,110	18
Additions Due to Load Growth	8,935	20
Substation Feeder Termination	472	22
Total Substations	**$ 22,478**	
4. Transmission		
Transmission Line Rebuild[3]	$ 5,731	25
Total Transmission	**$ 5,731**	

1 Project descriptions can be found in Schedule B at the page indicated.
2 This is a multi-year project, with future commitments identified in Schedule C of this Application.
3 Includes the rebuild of 30L (Ridge Road to King's Bridge substations) and 400L (Bottom Brook to Wheelers substations) which are multi-year projects included in Schedule C to this Application.

2015 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[4]
5. Distribution		
Extensions	$ 12,314	29
Meters	3,146	31
Services	4,101	35
Street Lighting	2,469	38
Transformers	6,778	41
Reconstruction	3,964	43
Rebuild Distribution Lines	3,302	45
Relocate/Replace Distribution Lines for Third Parties	2,504	48
Trunk Feeders	991	50
Feeder Additions for Growth	1,684	53
Distribution Reliability Initiative	863	55
Distribution Feeder Automation	160	57
Allowance for Funds Used During Construction	197	59
Total Distribution	**$ 42,473**	
6. General Property		
Tools and Equipment	$ 467	62
Additions to Real Property	385	65
Standby and Emergency Power – Carbonear Office	304	67
Renovations to Company Buildings[5]	2,068	69
Total General Property	**$ 3,224**	
7. Transportation		
Purchase Vehicles and Aerial Devices	$ 2,917	72
Total Transportation	**$ 2,917**	

[4] Project descriptions can be found in Schedule B at the page indicated.
[5] This is a multi-year project, with future commitments identified in Schedule C of this Application.

2015 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[6]
8. Telecommunications		
Replace/Upgrade Communications Equipment	$ 123	76
Total Telecommunications	**$ 123**	
9. Information Systems		
Application Enhancements	$ 1,325	79
System Upgrades[7]	1,125	81
Personal Computer Infrastructure	487	83
Shared Server Infrastructure	970	86
Network Infrastructure	328	88
SCADA System Replacement[8]	2,833	90
Geographic Information System Improvements	433	92
Total Information Systems	**$ 7,501**	
10. Unforeseen Allowance		
Allowance for Unforeseen Items	$ 750	95
Total Unforeseen Allowance	**$ 750**	
11. General Expenses Capitalized		
General Expenses Capitalized	$ 4,100	97
Total General Expenses Capitalized	**$ 4,100**	

6 Project descriptions can be found in Schedule B at the page indicated.
7 Includes the Microsoft Enterprise Agreement included as a multi-year project in Schedule C of this Application.
8 This is a multi-year project, with future commitments identified in Schedule C of this Application.

2015 CAPITAL PROJECTS SUMMARY

2015 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 upon identified need or on a historical pattern of repair and replacement. Justifiable capital expenditures are those which are justified upon 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 2015 Capital Project Summary provides a summary of the planned capital expenditures contained in Newfoundland Power's 2015 Capital Budget Application by definition (pages iii to v), classification (pages vi to vii), and segmentation by materiality (pages viii to ix) 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
2015 Capital Projects by Definition
(000's)

Clustered	**$29,869**	**Page**
Distribution	**2,675**	
Feeder Additions for Growth	1,684	53
Trunk Feeders	991	50
Information Services	**2,095**	
Shared Server Infrastructure	970	86
System Upgrades	1,125	81
Substations	**19,368**	
Additions Due to Load Growth	8,935	20
Substations Refurbishment & Modernization	9,961	16
Substation Feeder Termination	472	22
Transmission	**5,731**	
Transmission Line Rebuild	5,731	25

Pooled	**$56,199**	**Page**
Distribution	**39,798**	
Distribution Reliability Initiative	863	55
Extensions	12,314	29
Meters	3,146	31
Rebuild Distribution Lines	3,302	45
Reconstruction	3,964	43
Relocate/Replace Distribution Lines for Third Parties	2,504	48
Services	4,101	35
Street Lighting	2,469	38
Transformers	6,778	41
AFUDC	197	59
Distribution Feeder Automation	160	57
General Property	**2,920**	
Additions to Real Property	385	65
Tools and Equipment	467	62
Company Building Renovations – Duffy Place	2,068	69
Generation	**4,758**	
Facility Rehabilitation	1,586	2
Facility Rehabilitation Thermal	216	13
PBK Plant Penstock & Surge Tank	750	6
TCV Plant Refurbishment	1,777	8
Public Safety Around Dams	429	4
Information Services	**2,573**	
Application Enhancements	1,325	79
Network Infrastructure	328	88
Personal Computer Infrastructure	487	83
Geographic Information System Improvements	433	92

Pooled (continued)		Page
Substations	**3,110**	
Replacement and In-Service Failures	3,110	18
Telecommunications	**123**	
Replace/Upgrade Communications Equipment	123	76
Transportation	**2,917**	
Purchase Vehicles and Aerial Devices	2,917	72

Other	$8,143	Page
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	95
General Expenses Capitalized	**4,100**	
General Expenses Capitalized	4,100	97
General Property	**304**	
Standby and Emergency Power – Carbonear Office	304	67
Generation-Hydro	**156**	
SCV Plant Refurbishment	156	10
Information Services	**2,833**	
SCADA System Replacement	2,833	90

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 2015 the following projects have expenditures which are clustered:

1. The *Trunk Feeders* Distribution project involving the relocation of distribution plant in St. John's has aspects which are clustered with the *Transmission Line Rebuild* project. Transmission lines 14L, 15L, 30L and 69L in St. John's share support structures with distribution lines. The replacement of the transmission line support structures necessitates the relocation and rebuilding of the distribution plant that shares those support structures. These items are inter-dependent, and are therefore clustered.

2. The *Substations Refurbishment and Modernization* Substations project has aspects which are clustered with the *Additions Due to Load Growth* Substations project. The refurbishment and modernization of Clarenville Substation is scheduled for 2015. In 2015, an additional transformer will be added to Clarenville Substation to accommodate customer load growth. Completing both projects in the same year will minimize the customer service interruptions associated with installing a portable substation and improve productivity by combining project planning and execution for both projects. These projects are related, and are therefore clustered.

3. The *Feeder Additions for Growth* Distribution project has aspects which are clustered with the *Additions Due to Load Growth* and *Substation Feeder Termination* Substations projects. In 2015, a new 50 MVA 66/25 kV transformer will replace an existing 25 MVA transformer at Kenmount Substation under the *Additions Due to Load Growth* Substations project to accommodate customer load growth. The addition of KEN-05 feeder to transfer load from 2 existing 25 kV feeders is necessary to service the growth in customer load. The new feeder will be constructed under the *Feeder Additions for Growth* Distribution project and terminated at Kenmount Substation under the *Substation Feeder Termination* Substations projects. These items are inter-dependent, and are therefore clustered.

4. The *Shared Server Infrastructure* and *System Upgrades* Information Services projects have aspects which are clustered. In 2015, the Company will continue to take steps to reduce the uncertainty regarding replacement of its Customer Service System ("CSS"), which has been in service since 1992. The server hardware (in *Shared Server Infrastructure*) and the software components (in *System Upgrades*) that support CSS and the external website will be upgraded to extend the life of CSS. These items are inter-dependent, and are therefore clustered.

Summary of 2015 Capital Projects by Classification (000's)

Normal Capital	**$92,024**	**Page**
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	95
Distribution	**42,473**	
Distribution Reliability Initiative	863	55
Extensions	12,314	29
Feeder Additions for Growth	1,684	53
Meters	3,146	31
Rebuild Distribution Lines	3,302	45
Reconstruction	3,964	43
Relocate/Replace Distribution Lines for 3rd Parties	2,504	48
Services	4,101	35
Street Lighting	2,469	38
Transformers	6,778	41
AFUDC	197	59
Trunk Feeders	991	50
Distribution Feeder Automation	160	57
General Expenses Capitalized	**4,100**	
General Expenses Capitalized	4,100	97
General Property	**3,224**	
Additions to Real Property	385	65
Tools and Equipment	467	62
Company Building Renovations – Duffy Place	2,068	69
Standby and Emergency Power – Carbonear Office	304	67
Generation	**4,485**	
Facility Rehabilitation	1,586	2
Thermal Plant Facility Rehabilitation	216	13
PBK Plant Penstock & Surge Tank	750	6
TCV Plant Refurbishment	1,777	8
SCV Plant Refurbishment	156	10
Information Systems	**5,743**	
Network Infrastructure	328	88
Personal Computer Infrastructure	487	83
Shared Server Infrastructure	970	86
System Upgrades	1,125	81
SCADA System Replacement	2,833	90
Substations	**22,478**	
Additions Due to Load Growth	8,935	20
Replacements and In-Service Failures	3,110	18
Substations Refurbishment & Modernization	9,961	16
Substation Feeder Termination	472	22

Summary of 2015 Capital Projects by Materiality (000's)

Large – Greater than $500	**$90,054**	**Page**
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	95
Distribution	**42,116**	
Distribution Reliability Initiative	863	55
Extensions	12,314	29
Feeder Additions for Growth	1,684	53
Meters	3,146	31
Rebuild Distribution Lines	3,302	45
Reconstruction	3,964	43
Relocate/Replace Distribution Lines for 3rd Parties	2,504	48
Services	4,101	35
Street Lighting	2,469	38
Transformers	6,778	41
Trunk Feeders	991	50
General Expenses Capitalized	**4,100**	
General Expenses Capitalized	4,100	97
Generation-Property	**2,068**	
Company Building Renovations – Duffy Place	2,068	69
Generation	**4,113**	
Facility Rehabilitation	1,586	2
PBK Plant Penstock & Surge Tank	750	6
TCV Plant Refurbishment	1,777	8
Information Systems	**6,253**	
Application Enhancements	1,325	79
Shared Server Infrastructure	970	86
System Upgrades	1,125	81
SCADA System Replacement	2,833	90
Substations	**22,006**	
Additions Due to Load Growth	8,935	20
Replacements and In-Service Failures	3,110	18
Substations Refurbishment & Modernization	9,961	16
Transmission	**5,731**	
Transmission Line Rebuild	5,731	25
Transportation	**2,917**	
Purchase Vehicles and Aerial Devices	2,917	72

Medium - Between $200 and $500	**$3,521**	**Page**
General Property	**1,156**	
Additions to Real Property	385	65
Tools and Equipment	467	62
Standby and Emergency Power – Carbonear Office	304	67
Generation	**645**	
Public Safety Around Dams	429	4
Thermal Plant Facility Rehabilitation	216	13
Information Systems	**1,248**	
Network Infrastructure	328	88
Personal Computer Infrastructure	487	83
Geographic Information System Improvements	433	92
Substations	**472**	
Substation Feeder Termination	472	22

Small – Under $200	**$636**	**Page**
Distribution	**357**	
AFUDC	197	59
Distribution Feeder Automation	160	57
Generation	**156**	
SCV Plant Refurbishment	156	10
Telecommunications	**123**	
Replace/Upgrade Communications Equipment	123	76

GENERATION - HYDRO

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

Project Cost: **$1,586,000**

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 2015 project includes the following items:

- Refurbishment of 4 hydro dams and spillways;
- Refurbishment of 1 turbine shaft; and
- Equipment replacements due to in-service failures.

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.

Details on 2015 proposed expenditures are included in ***1.1** 2015 Facility Rehabilitation*.

Justification

The Company's 23 hydroelectric plants range in age from 15 to 114 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 430.5 GWh. Replacing the energy produced by these facilities by increasing production at Newfoundland and Labrador Hydro's Holyrood thermal generation facility would require approximately 683,000 barrels of fuel annually. At an oil price of $105.60 per barrel, this translates into approximately $72 million in annual fuel savings.[1]

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

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[1] The price forecast per barrel of oil used at Holyrood as per letter regarding Rate Stabilization Plan - Fuel Price Projection dated April 30, 2014.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 1

Projected Expenditures (000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$1,051	-	-	-
Labour – Internal	277	-	-	-
Labour – Contract	-	-	-	-
Engineering	148	-	-	-
Other	110	-	-	-
Total	**$1,586**	**$1,470**	**$4,535**	**$7,591**

Costing Methodology

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

Table 2

Expenditure History (000s)

Year	2010	2011	2012	2013	2014F
Total	$1,301	$1,450	$1,616	$1,449	$1,610

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: **Public Safety Around Dams (Pooled)**

Project Cost: **$429,000**

Project Description

Newfoundland Power (the "Company") has over 150 dam structures throughout its 23 hydroelectric facilities. In 2011, the Canadian Dam Association ("CDA") published their *Guidelines for Public Safety Around Dams*.[2] These guidelines address the risk of accidents or incidents in which a member of the public is exposed to a hazard created by a hydroelectric development.

The Company currently plans to address public safety improvements for dams throughout its various hydroelectric developments over the next 3 years. It is estimated that expenditures of approximately $2.0 million will be necessary to implement public safety improvements at the Company's hydroelectric developments over this period.

The Company has completed detailed public safety assessments of 4 of its 23 hydroelectric developments consistent with the *Guidelines for Public Safety Around Dams*. Expenditures associated with the safety improvements identified through these 4 public safety assessments are included in this 2015 capital project. Expenditures in future years will be based upon detailed public safety assessments and presented in future capital budget applications.

Details on the proposed expenditures are included in ***1.5** Public Safety Around Dams.*

Justification

The Public Safety Around Dams project is justified on the basis of making reasonable effort to eliminate hazards and minimizes risk that have the potential to threaten the health and safety of employees, contractors and the general public.

Although the Company's dam portfolio consists of small dams, it is recognized that all dams pose a risk to public safety, regardless of size or impoundment. Low head and small dams may be equally or more hazardous than high dams as the hazards may not be as apparent and they may not command the same respect as high dams from the general public.

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[2] These guidelines are in addition to the *CDA Dam Safety Guidelines 2007*. Copies of these guidelines can be ordered online from www.cda.ca.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 1
Projected Expenditures (000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$300	-	-	-
Labour – Internal	39	-	-	-
Labour – Contract	-	-	-	-
Engineering	77	-	-	-
Other	13	-	-	-
Total	**$429**	**$880**	**$662**	**$1,971**

Costing Methodology

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

Future Commitments

This is not a multi-year project. Expenditures for projects in future years will be presented in future Capital Budget Applications.

Project Title: Pierre's Brook Plant Penstock and Surge Tank (Pooled, Multi-year)

Project Cost: $750,000

Project Description

This Generation Hydro project involves the replacement and refurbishment of the 2,533 metre long penstock at Pierre's Brook Plant consisting of 2,470 metres of woodstave construction and 63 metres of steel construction. The 2,470 metres long woodstave penstock, installed in 1965, requires replacement. The surge tank was reconstructed in 1991. Inspections completed in 2013 identified deterioration of the surge tank that requires refurbishment when the penstock is replaced.

The project is a multi-year project and will be executed over 2 years, with the engineering design and procurement work for the penstock and site preparation work including access roads completed in 2015. The installation of the replacement penstock and the refurbishment of the surge tank will take place in 2016.

Details on the proposed expenditures are included in ***1.2*** *Pierre's Brook Hydro Plant Penstock Replacement and Surge Tank Refurbishment*.

Justification

The Pierre's Brook Plant, located on the Avalon Peninsula near the community of Witless Bay, was commissioned in 1931 with a capacity of 3.4 MW.[3] The normal annual production at Pierre's Brook is 24.4 GWh or 5.7% of the total hydroelectric production of Newfoundland Power.

Engineering assessments of the woodstave penstock at this facility have revealed that it has reached the end of its useful life and requires replacement. The surge tank has deficiencies that will be addressed during the same plant outage as the penstock replacement.

A present worth feasibility analysis of projected capital and operating expenditures for the Pierre's Brook Plant has determined the levelized cost of energy from the plant over the next 50 years to be 4.87¢ per kWh, which is significantly less than the cost of replacement energy at the Holyrood Thermal Generating Station.[4]

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3 The plant was commissioned in 1931 and the original penstock was replaced in 1965.

4 The avoided cost of fuel at the Holyrood Thermal Generating Station is estimated at 16.76¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.60 per barrel for 2014 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan - Fuel Price Projection dated April 30, 2014.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 1
Multi-year Projected Expenditures (000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$546	$13,120	-	$13,666
Labour – Internal	12	22	-	34
Labour – Contract	-	-	-	-
Engineering	112	203	-	315
Other	80	185	-	265
Total	**$750**	**$13,530**	-	**$14,280**

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 which will be completed in 2015 and 2016.

Project Title: **Tors Cove Plant Refurbishment (Pooled)**

Project Cost: **$1,777,000**

Project Description

This Generation Hydro project involves a major refurbishment of civil, electrical and mechanical systems at Tors Cove Plant. The components requiring replacement or refurbishment include the overhead crane, turbine runner, main inlet valve, generator rotor and power cables. The project also includes the replacement of the penstock trestle with a section of reinforced steel penstock.

Details on the proposed expenditures for the refurbishment of the electrical and mechanical systems are included in ***1.4** Tors Cove Hydro Plant Refurbishment*.

Justification

The Tors Cove Plant, located on the Avalon Peninsula near the community of Tor's Cove, was commissioned in 1941 with a capacity of 6.5 MW. The normal annual production at Tors Cove is 25.4 GWh or 5.9% of the total hydroelectric production of Newfoundland Power.

Engineering assessments of civil, electrical and mechanical systems at this facility have revealed these systems have reached the end of their useful lives and require replacement.

A present worth feasibility analysis of projected capital and operating expenditures for the Tors Cove Plant has determined the levelized cost of energy from the plant over the next 50 years to be 2.77¢ per kWh, which is significantly less than the cost of replacement energy at the Holyrood Thermal Generating Station.[5]

[5] The avoided cost of fuel at the Holyrood Thermal Generating Station is estimated at 16.76¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.60 per barrel for 2014 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan - Fuel Price Projection dated April 30, 2014.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 1

Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$1,420	-	-	-
Labour – Internal	173	-	-	-
Labour – Contract	-	-	-	-
Engineering	85	-	-	-
Other	99	-	-	-
Total	**$1,777**	**-**	-	**$1,777**

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 not a multi-year project.

Project Title: **Seal Cove Plant Refurbishment (Other)**

Project Cost: **$156,000**

Project Description

This Generation Hydro project involves the refurbishment of generator G1 rotor at Seal Cove Plant. Generator G1 was manufactured in 1924 by Allis Chalmers. The generator stator was rewound in 1988 but the rotor windings are original to the 90 year old unit. The condition and age of the rotor insulation necessitates the rewinding of the 16 rotor poles in 2015.

Details on the proposed expenditures for the generator rotor rewind are included in ***1.3*** *Seal Cove Hydro Plant Refurbishment*.

Justification

The Seal Cove Plant is located on the Avalon Peninsula near the community of Seal Cove, approximately 20 km west of the City of St. John's. The plant was commissioned in 1924 with 2 generators having a total capacity of 3.3 MW. The normal annual production at Seal Cove is 9.4 GWh or 2.2% of the total hydroelectric production of Newfoundland Power.

Engineering assessment of rotor has revealed it has reached the end of its useful life and requires refurbishment.

A present worth feasibility analysis of projected capital and operating expenditures for the Seal Cove Plant has determined the levelized cost of energy from the plant over the next 50 years to be 1.93¢ per kWh, which is significantly less than the cost of replacement energy at the Holyrood Thermal Generating Station.[6]

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[6] The avoided cost of fuel at the Holyrood Thermal Generating Station is estimated at 16.76¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.60 per barrel for 2014 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan - Fuel Price Projection dated April 30, 2014.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 1

Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$89	-	-	-
Labour – Internal	54	-	-	-
Labour – Contract	-	-	-	-
Engineering	6	-	-	-
Other	7	-	-	-
Total	**$156**	**-**	**-**	**$156**

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 not a multi-year project.

GENERATION - THERMAL

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

Project Cost: **$216,000**

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 2015 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 upon historical information $216,000 is estimated to be the cost of refurbishment or replacement of thermal plant structures in 2015.

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. 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 2015 and a projection of expenditures through 2019.

Table 1

Projected Expenditures (000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$138	-	-	-
Labour – Internal	31	-	-	-
Labour – Contract	-	-	-	-
Engineering	31	-	-	-
Other	16	-	-	-
Total	**$216**	**$220**	**$684**	**$1,120**

Costing Methodology

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

Table 2

Expenditure History (000s)

Year	2010	2011	2012	2013	2014F
Total	$196	$252	$117	$201	$412

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.

SUBSTATIONS

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

Project Cost: **$9,961,000**

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** 2015 Substation Refurbishment and Modernization*.

The Company has 130 substations ranging in age from 12 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 and support structures, equipment foundations, switches and fencing. Infrastructure to be replaced is identified as a result of inspections, engineering assessments and operating experience.

In 2015, this project will refurbish and modernize the following substations:

- Clarenville Substation[7]
- Colliers Substation
- Gander Substation
- Ridge Road Substation
- Springfield Substation

In addition to the substations listed above, the 2015 project includes the refurbishment and modernization of Portable Substation P4 along with the upgrading of automation equipment in substations, including the automation of distribution feeder breakers and reclosers.[8]

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.

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[7] The Clarenville Substation refurbishment and modernization is clustered with the installation of a new substation transformer required at Clarenville which is included in the *Additions Due To Load Growth* project.

[8] At the end of 2013 approximately 60% of distribution feeder breakers and reclosers located in Company substations were automated through the SCADA system. By the end of 2014 there will be 206 distribution feeders automated representing approximately 67% of all distribution feeders. By the end of 2015 there will be 231 distribution feeders automated representing approximately 76% of all distribution feeders.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019. Appendix A of ***2.1*** *2015 Substation Refurbishment and Modernization* details the work planned for each year.

Table 1
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$7,796	-	-	-
Labour – Internal	172	-	-	-
Labour – Contract	679	-	-	-
Engineering	1,077	-	-	-
Other	237	-	-	-
Total	**$9,961**	**$4,927**	**$24,891**	**$39,779**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2010	2011	2012	2013	2014F
Total	$4,101	$2,208	$2,279	$3,570	$7,328

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: **$3,110,000**

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 2015 and a projection of expenditures through 2019.

Table 1
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$2,109	-	-	-
Labour – Internal	649	-	-	-
Labour – Contract	-	-	-	-
Engineering	262	-	-	-
Other	90	-	-	-
Total	**$3,110**	**$3,182**	**$9,991**	**$16,283**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	**2010**	**2011**	**2012**	**2013**	**2014F**
Total	$2,388	$2,689	$3,327	$3,485	$2,859

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 190 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 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: **Additions Due To Load Growth (Clustered)**

Project Cost: **$8,935,000**

Project Description

This Substations project includes:

1. The replacement of the existing 66/25 kV 6.7 MVA substation transformer at Lethbridge Substation with a new 66/25 kV 16.7 MVA substation transformer to accommodate load growth in the Lethbridge area on the Bonavista Peninsula. ($3,029,000)

2. The installation of a new 66/12.5 kV 25 MVA substation transformer at Clarenville Substation to accommodate load growth in the Clarenville area. This area includes customers served from Clarenville (CLV) and Milton (MIL) substations. This item is clustered with the Clarenville Substation item in the *Substations Refurbishment and Modernization* Substations project. ($2,727,000)

3. The replacement of the existing 66/25 kV 25 MVA substation transformer at Kenmount Substation with a new 66/25 kV 50 MVA substation transformer to accommodate load growth in the Kenmount Road and Paradise area. This area includes customers served from Hardwoods (HWD) and Kenmount (KEN) substations. This item is clustered with the KEN-05 item in the *Substation Feeder Terminations* Substations project (Schedule B, page 22 of 98) and the KEN-05 item in *Feeder Additions for Growth* Distribution project (Schedule B, page 53 of 98). ($1,700,000)

4. The installation of an existing 66/12.5 kV 25 MVA substation transformer at St. John's Main Substation to accommodate load growth in the downtown core of the City of St. John's. This area includes customers served from St. John's Main (SJM) and Molloy's Lane (MOL) substations. ($1,479,000)

Details on the proposed expenditures are contained in ***2.2*** *2015 Additions Due to Load Growth*.

The individual requirements for additions to substations due to load growth included in this project 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

A 20-year load forecast has projected electrical demand for the Lethbridge, Clarenville, Paradise and St. John's areas. The development and analysis of alternatives has established a recommended expansion plan to meet that demand.

The least cost alternative that meets all of the technical criteria requires the installation of (i) a new 16.7 MVA substation transformers at Lethbridge Substation to replace the existing 6.7 MVA substation transformer (ii) a new 25 MVA substation transformer at Clarenville Substation, (iii) a new 50 MVA substation transformer at Kenmount Substation to replace an existing 25 MVA substation transformer, and (iv) the relocation of an existing 25 MVA substation transformer to St. John's Main Substation.

The project is justified on the basis of accommodating customer load growth. The proper sizing of equipment is necessary to avoid overloading equipment and to maintain safe, reliable electrical service.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 1
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$7,995	-	-	-
Labour – Internal	91	-	-	-
Labour – Contract	-	-	-	-
Engineering	627	-	-	-
Other	222	-	-	-
Total	**$8,935**	**$8,565**	**$10,715**	**$28,215**

Costing Methodology

The budget estimate for this project is based on engineering estimates of 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: **Substation Feeder Termination (Clustered)**

Project Cost: **$472,000**

Project Description

This Substations project involves the termination of a new 25 kV feeder at the Kenmount Substation and a new 12.5 kV feeder at Cobbs Pond Substation.

The termination at the Kenmount Substation is clustered with the *Feeder Additions for Growth* Distribution project to install a new 25 kV feeder at the Kenmount Substation (Schedule B, page 53 of 98) and the *Additions due to Load Growth* Substation project to install a new 25 MVA transformer at the Kenmount Substation (Schedule B, page 20 of 98).

Justification

The project is justified on the basis of accommodating customer load growth and 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 reliability of the electrical system.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 1
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$388	-	-	-
Labour – Internal	20	-	-	-
Labour – Contract	-	-	-	-
Engineering	54	-	-	-
Other	10	-	-	-
Total	**$472**	**$525**	**$469**	**$1,466**

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.

TRANSMISSION

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

Project Cost: **$5,731,000**

Project Description

This Transmission 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 2015 transmission line rebuild work will take place on transmission lines 14L, 15L, 30L, 69L and 400L. Transmission line 14L operates between Stamp's Lane Substation and Memorial University Substation in St. John's. Transmission line 15L operates between Molloy's Lane Substation and Stamp's Lane Substation in St. John's. Transmission line 30L operates between Ridge Road Substation and Kings Bridge Substation in St. John's. Transmission line 69L operates between Kenmount Substation and Stamp's Lane Substation in St. John's. Transmission line 400L operates between Newfoundland & Labrador Hydro's terminal station at Bottom Brook and Wheeler's Substation in the Stephenville area.

   Details on the proposed 2015 rebuilds are included in ***3.1** 2015 Transmission Line Rebuild* ($3,830,000).

2. 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 ($1,901,000).

For 2015, a portion of the Transmission Line Rebuild project proposed for the St. John's area is clustered with the *Trunk Feeders* Distribution project. This is because relocation of the under-built trunk feeders is dependent upon the completion of the transmission line rebuilds for transmission lines 14L, 15L, 30L and 69L.

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.

Justification

Approximately 30% of the Company's 103 transmission lines are in excess of 40 years of age. Many of these lines are experiencing pole, crossarm, conductor, insulator and hardware deterioration. 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 2015 and a projection of expenditures through 2019. Appendix A of ***3.1** 2015 Transmission Line Rebuild* details the transmission line rebuilds planned for each year.

Table 1

Projected Expenditures (000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$1,848	-	-	-
Labour – Internal	644	-	-	-
Labour – Contract	2,494	-	-	-
Engineering	286	-	-	-
Other	459	-	-	-
Total	**$5,731**	**$6,061**	**$23,023**	**$34,815**

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	2010	2011	2012	2013	2014F
Total	$6,409[1]	$3,732	$4,694	$5,081	$5,469

[1] Includes actual expenditures of $3,161,000 approved in Order No. P.U. 17 (2010) for work associated with the March 2010 ice storm, and $109,000 approved in Order No. P.U. 35 (2010) for work associated with Hurricane Igor.

The budget estimates for rebuilding and upgrade projects are based on engineering cost estimates. The budget estimates for replacements projects 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 lines 30L and 400L are multi-year projects. Table 3 details the complete multi-year project expenditure for these multi-year projects.

Table 3
Multi-Year Projected Expenditures
(000s)

Cost Category	**2015**	**2016**	**Total**
Material	$743	$653	$1,396
Labour – Internal	238	225	463
Labour – Contract	1,154	1,055	2,209
Engineering	110	142	252
Other	265	243	508
Total	**$2,510**	**$2,318**	**$4,828**

DISTRIBUTION

Project Title: **Extensions (Pooled)**

Project Cost: **$12,314,000**

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 who increase their electrical load. 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 2015 and a projection of expenditures through 2019.

Table 1
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$3,844	-	-	-
Labour – Internal	3,622	-	-	-
Labour – Contract	2,899	-	-	-
Engineering	1,554	-	-	-
Other	395	-	-	-
Total	**$12,314**	**$12,592**	**$37,461**	**$62,367**

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 2015.

Table 2
Expenditure History and Unit Cost Projection

Year	2010	2011	2012	2013	2014F	2015B
Total (000s)	$ 14,616	$ 11,420	$ 11,321	$ 13,434	$ 12,061	$ 12,314
Adjusted Costs (000s)[1,2]	$ 14,572	$ 12,563	$ 12,045	$ 13,849	$ 11,738	-
New Customers	5,300	4,909	5,286	5,280	4,834	4,749
Unit Costs ($/customer)[2]	$ 2,749	$ 2,559	$ 2,279	$ 2,623	$ 2,428	$ 2,593

1 An adjustment has been made to the expenditure history to recognize the impact of the sale of 40% of joint use support structures to Bell Aliant in 2011.
2 2014 Dollars.

The project cost for the connection of new customers is calculated on the basis of historical data.[9] 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.

9 An adjustment has been made to the expenditure history to recognize the impact of the sale of 40% of joint use support structures to Bell Aliant.

Project Title: **Meters (Pooled)**

Project Cost: **$3,146,000**

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 2015.

Table 1
2015 Proposed Meter Acquisition

Program	Number of Meters
Energy Only Domestic Meters	29,200
Other Energy Only and Demand Meters	3,853

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.

Included in the 2015 meter budget is a specific AMR project for the Burin Peninsula operating area. This project involves the installation of approximately 4,000 new AMR meters to complete all 26 meter reading routes with AMR meters. Details on the proposed expenditure and project justification are included in ***4.4*** *Burin AMR Project*.

The 2013 Capital Budget Application included the report ***4.3*** *2013 Metering Strategy*. The main focus of the *2013 Metering Strategy* was to:

- Continue with the objectives outlined in the *2006 Metering Strategy* with respect to accuracy & timeliness, cost management, worker safety and ratemaking,
- Implement a transition strategy to comply with changes to Measurement Canada regulations,
- Proceed with purchasing only AMR meters for meter replacements and new installations; and
- Maintain focus on route optimization in order to achieve productivity improvements and reduced costs through use of AMR meters.

Proposed expenditures under this Distribution project are consistent with the *2013 Metering Strategy*.

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)*. The additional cost associated with expenditures on AMR meters is justified by both safety and economics.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 2

Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$2,769	-	-	-
Labour – Internal	322	-	-	-
Labour – Contract	55	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$3,146**	**$2,759**	**$7,397**	**$13,302**

Costing Methodology

Table 3 shows the annual expenditures for the most recent five-year period, as well as a projection for 2015.

Table 3
Expenditure History and Unit Cost Projection

Year	2010	2011	2012	2013	2014F	Avg	2015B
Meter Requirements							
New Connections	5,300	4,909	5,286	5,280	4,834		4,749
GROs/CSOs	10,284	13,671	15,257	18,805	19,271		17,631
Other	7,494	8,366	7,130	6,218	4,156		10,673
Total	23,078	26,946	27,673	30,303	28,261		33,053
Meter Costs							
Actual (000s)	$1,872	$1,763	$2,557	$3,109	$2,755		$3,146
Adjusted[1] (000s)	$2,058	$1,888	$2,652	$3,162	$2,755		
Unit Costs[1]	$ 89	$ 95[2]	$ 96[2]	$ 104	$ 97	$ 96	$ 95

1 2014 dollars.
2 Adjusted to exclude meters in inventory.

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 and the transition strategy outlined in the *2013 Metering Strategy* to comply with changes to compliance sampling regulations for electricity meters. 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: **$4,101,000**

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 load.

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 2015 and a projection of expenditures through 2019.

Table 1

Projected Expenditures (000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$1,234	-	-	-
Labour – Internal	2,275	-	-	-
Labour – Contract	200	-	-	-
Engineering	343	-	-	-
Other	49	-	-	-
Total	**$4,101**	**$4,198**	**$12,672**	**$20,971**

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 2015.

Table 2
Expenditure History and Unit Cost Projection
New Services

Year	2010	2011	2012	2013	2014F	2015B
Total (000s)	$3,255	$3,887	$3,351	$3,608	$3,248	$3,201
Adjusted Costs (000s)[1]	$3,689[2]	$4,283	$3,570	$3,722	$3,248	-
New Customers	5,300	4,909	5,286	5,280	4,834	4,749
Unit Costs ($/customer)[1]	$ 696	$ 872	$ 675	$ 705	$ 672	$ 674

1 2014 dollars.
2 Excludes cost associated with Hurricane Igor related damage in September 2010.

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 2015.

Table 3
Expenditure History and Average Cost Projection
Replacement Services
(000s)

Year	2010	2011	2012	2013	2014F	2015B
Total	$1,083	$795	$1,157	$672	$780	$900
Adjusted Costs[1]	$ 933[2]	$876	$1,233	$693	$780	-

1 2014 dollars.
2 Excludes costs associated with Hurricane Igor related damage in September 2010.

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: **$2,469,000**

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.

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 2015 and a projection of expenditures through 2019.

Table 1
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$1,338	-	-	-
Labour – Internal	879	-	-	-
Labour – Contract	191	-	-	-
Engineering	37	-	-	-
Other	24	-	-	-
Total	**$2,469**	**$2,523**	**$7,628**	**$12,620**

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 2015.

Table 2

Expenditure History and Unit Cost Projection
New Street Lights

Year	2010	2011	2012	2013	2014F	2015B
Total (000s)	$1,781	$1,461	$1,588	$1,889	$1,742	$1,644
Adjusted Costs (000s)[1]	$1,992	$1,590	$1,672	$1,937	$1,742	-
New Customers	5,300	4,909	5,286	5,280	4,834	4,749
Unit Costs ($/customer)[1]	$ 376	$ 324	$ 316	$ 367	$ 360	$ 346

[1] 2014 dollars.

The project cost for the connection of new customers 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. 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 2015.

Table 3

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

Year	2010	2011	2012	2013	2014F	2015B
Total	$797	$750	$776	$703	$785	$825
Adjusted Costs[1]	$890	$816	$818	$721	$785	-

[1] 2014 dollars.

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.

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: **$6,778,000**

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 2015 and a projection of expenditures through 2019.

Table 1

Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$6,778	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$6,778**	**$7,311**	**$22,837**	**$36,926**

Costing Methodology

Table 2 shows the annual expenditures for the most recent five-year period, as well as an estimate for 2015.

Table 2

Expenditure History and Budget Estimate (000s)

Year	**2010**	**2011**	**2012**	**2013**	**2014F**	**2015B**
Total	$6,588	$7,196	$6,565	$6,710	$6,995	$6,778[2]
Adjusted Costs[1]	$7,193	$7,658	$6,770	$ 6,804	$6,995	-

1 2014 Dollars.

2 2015 budget reduced by $435,000 to reflect (i) reduction in replacement transformer requirements and (ii) inventory levels.

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: **$3,964,000**

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 to the next budget year.

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

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.

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 2015 and a projection of expenditures through 2019.

Table 1

Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$938	-	-	-
Labour – Internal	1,596	-	-	-
Labour – Contract	895	-	-	-
Engineering	401	-	-	-
Other	134	-	-	-
Total	**$3,964**	**$4,069**	**$12,864**	**$20,897**

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 2015.

Table 2
Expenditure History and Budget Estimate
(000s)

Year	**2010**	**2011**	**2012**	**2013**	**2014F**	**2015B**
Total	$5,202[2]	$3,967	$3,463	$4,643	$3,787	$3,964
Adjusted Costs[1]	$2,986[3]	$4,364	$3,685	$4,786	$3,787	-

1 2014 dollars.
2 Includes actual expenditures of $996,000 approved under Order No. P.U. 17 (2010) for work associated with the March 2010 ice storm and $1,167,000 approved under Order No. P.U. 35 (2010) for work associated with Hurricane Igor. These expenditures are excluded from Adjusted Cost.
3 The adjusted cost excludes costs associated with the March 2010 ice storm and Hurricane Igor referred to in Note 2.

The process of estimating the budget requirement for Reconstruction is based on a historical average.[10] 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.

10 An adjustment has been made to the expenditure history to recognize the impact of the sale of 40% of joint use support structures to Bell Aliant.

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

Project Cost: **$3,302,000**

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 which consist of either the complete rebuilding of deteriorated distribution lines, 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 2015 will be performed on the following 43 of the Company's 305 feeders:

BCV-03	CHA-03	HUM-09	OPL-01	SPR-03	VIR-02
BIG-01	GBE-01	JON-01	OPL-02	SPR-04	VIR-03
BLK-01	GDL-01	LAU-01	OPL-03	SUM-02	VIR-04
BRB-04	GDL-07	LEW-02	SJM-02	TNS-01	VIR-05
BVA-01	HAR-01	LGL-02	SJM-03	VIC-01	VIR-06
BVA-02	HOW-01	MIL-01	SJM-10	VIC-02	WBC-01
BVA-03	HUM-08	NCH-03	SJM-12	VIR-01	WES-01
CHA-01					

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 9,600 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 2015 and a projection of expenditures through 2019.

Table 1
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$1,387	-	-	-
Labour – Internal	1,519	-	-	-
Labour – Contract	198	-	-	-
Engineering	33	-	-	-
Other	165	-	-	-
Total	**$3,302**	**$3,384**	**$10,660**	**$17,346**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2010	2011	2012	2013	2014F
Actual	$1,268	$2,413	$3,723	$2,958	$3,462
Adjusted[1,2]	$1,359	$2,548	$3,866	$3,014	$3,462

1 An adjustment has been made to the expenditure history to recognize the impact of the sale of 40% of joint use support structures to Bell Aliant. The lower 2010 expenditures reflect higher customer-driven, third party and storm-related work in those years.

2 2014 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;

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.

The 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 upon which work is to take place in 2015 are ongoing throughout 2014. Complete inspection data will not be available until late 2014; therefore the 2015 budget estimate is based on average historical expenditures over the previous 3 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: **$2,504,000**

Project Description

This Distribution project is necessary to accommodate third party requests for the relocation or replacement of distribution lines. The relocation or replacement of distribution lines results from (1) work initiated by municipal, provincial and federal governments, (2) work initiated by other utilities such as Bell Aliant, Eastlink and Rogers Cable, or (3) requests from customers.

The Company's response to requests for relocation and replacement of distribution facilities by governments and other utility service providers is governed by the provisions of agreements in place with the requesting parties. Relocation or replacement of facilities by customers may be 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 2015 and a projection of expenditures through 2019.

Table 1

Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$877	-	-	-
Labour – Internal	800	-	-	-
Labour – Contract	526	-	-	-
Engineering	256	-	-	-
Other	45	-	-	-
Total	**$2,504**	**$2,566**	**$8,087**	**$13,157**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	**2010**	**2011**	**2012**	**2013**	**2014F**
Total	\$2,363	\$2,863	\$2,195	\$2,586	\$2,616
Adjusted Costs[1]	\$2,652	\$3,126	\$2,319	\$2,656	\$2,616

[1] 2014 dollars.

The budget estimate is based on historical expenditures. Generally, these expenditures are associated with a number of small projects that are not 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: **$991,000**

Project Description

This Distribution project includes:

1. The relocation of distribution plant from structures shared with transmission line 14L. Transmission line 14L is a 66 kV line running between Stamp's Lane Substation on Stamp's Lane and Memorial University Substation in St. John's. Constructed in 1950, 14L runs alongside Stamp's Lane and University Avenue where it goes underground and follows the Prince Philip Parkway to just east of the Chemistry Building at Memorial University. The transmission line rebuild project consists of 22 single-pole structures along University Avenue, *all* of which have distribution plant sharing the same poles.[11] The rebuild of the aerial section of transmission line 14L along University Avenue is planned for completion in 2015. The distribution plant sharing the poles with transmission line 14L will be relocated at the same time as the support structures are replaced on transmission line 14L. ($150,000)

2. The relocation of distribution plant from structures shared with transmission line 15L. Transmission line 15L is a 66 kV transmission line running between Molloy's Lane Substation on Topsail Road and Stamp's Lane Substation in St. John's. Constructed in 1958, 15L runs through residential areas in St. John's. The transmission line consists of 73 single-pole structures, *most* of which have distribution plant sharing the same poles.[12] The rebuild of transmission line 15L is planned for completion in 2015. The distribution plant sharing the poles with transmission line 15L will be relocated at the same time as the support structures are replaced on transmission line 15L. ($65,000)

3. The relocation of distribution plant from structures shared with transmission line 30L. Transmission line 30L is a 66 kV line running between King's Bridge Substation and Ridge Road Substation in St. John's. Constructed in 1959, 30L runs alongside New Cove Road, Portugal Cove Road and London Road. The transmission line consists of 87 single-pole structures, *all* of which have distribution plant sharing the same poles.[13] The rebuild of the aerial section of transmission line 30L is planned for completion in 2015 and 2016. The distribution plant sharing the poles with transmission line 30L will be relocated at the same time as the support structures are replaced on transmission line 30L. ($224,000)

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[11] A description of the project to refurbish transmission line 14L can be found in ***3.1** 2015 Transmission Line Rebuild.*

[12] A description of the project to refurbish transmission line 15L can be found in ***3.1** 2015 Transmission Line Rebuild.*

[13] A description of the project to refurbish transmission line 30L can be found in ***3.1** 2015 Transmission Line Rebuild.*

4. The relocation of distribution plant from structures shared with transmission line 69L. Transmission line 69L is a 66 kV transmission line running between Kenmount Substation and Stamp's Lane Substation in St. John's. Constructed in 1959, 69L runs through residential areas in St. John's. The transmission line rebuild project involves 48 single-pole structures, approximately one third of which have distribution plant sharing the same poles.[14] The rebuild of transmission line 69L is planned for completion in 2015. The distribution plant sharing the poles with transmission line 69L will be relocated at the same time as the support structures are replaced on transmission line 69L. ($79,000)

5. The refurbishment and modernization of 3 vaults in the St. John's underground distribution system. These vaults contain high voltage equipment supplying customers utilizing special underground arrangements. Details on the proposed expenditures are included in ***4.3*** *Vault Refurbishment and Modernization.* ($473,000)

For 2015, portions of the *Trunk Feeders* project is clustered with the *2015 Transmission Line Rebuild* Transmission project, since the relocation of the under-built distribution feeders is dependent upon the completion of the transmission line rebuilds for transmission lines 14L, 15L, 30L and 69L.

Justification

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

Inspections of transmission lines 14L, 15L, 30L and 69L have identified deterioration due to decay and vehicular damage, splits and checks in the poles, substandard crossarms and other hardware deficiencies. Many of these components are in advanced stages of deterioration and require replacement. As these transmission lines support distribution lines, it is necessary to relocate and rebuilt those distribution lines when the transmission line support structures are replaced.

The refurbishment and modernization of the underground vaults will bring this infrastructure into compliance with current standards.

[14] A description of the project to refurbish transmission line 69L can be found in ***3.1*** *2014 Transmission Line Rebuild.*

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 1
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$438	-	-	-
Labour – Internal	66	-	-	-
Labour – Contract	188	-	-	-
Engineering	153	-	-	-
Other	146	-	-	-
Total	**$991**	**$2,185**	**$9,311**	**$12,487**

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 Growth (Clustered)**

Project Cost: **$1,684,000**

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 2015, the following proposed expenditures are required:

1. The upgrading of conductor on Mobile Substation feeder MOB-01 to address overloaded conductor on this distribution feeder. ($785,000)

2. The upgrading of 2 sections of Seal Cove Substation feeder SCV-01 serving Scott's Road South and Lawrence Pond Road from single-phase to 3-phase in order to address an unbalanced condition that has developed as a result of customer load growth over time. ($259,000).

3. The upgrading of Rattling Brook Substation feeder RBK-01 from single-phase to 3-phase in order to address an unbalanced condition that has developed as a result of customer load growth in the Sandy Point area. ($386,000)

4. The construction of a new feeder originating at Kenmount Substation to accommodate growth in customers and load in the Kenmount Terrace neighborhood, including new phases of existing subdivisions. ($254,000)

For 2015, a portion of the *Feeder Additions for Growth* Distribution project is clustered with the *Additions Due to Load Growth* Substations project, since the installation of a new 25 kV feeder at Kenmount Substation is dependent upon the additional transformer capacity being added to Kenmount Substation (Schedule B, page 20 of 97). In addition, a portion of the *Feeder Additions for Growth* Distribution project is clustered with the *Substation Feeder Terminations* Substations project, since the installation of a new 25 kV feeder at Kenmount Substation is dependent upon the additional substation work to terminate the new distribution feeder (Schedule B, page 22 of 97).

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

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 2015 and a projection of expenditures through 2019.

Table 1

Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$422	-	-	-
Labour – Internal	616	-	-	-
Labour – Contract	404	-	-	-
Engineering	72	-	-	-
Other	170	-	-	-
Total	**$1,684**	**$3,527**	**$8,598**	**$13,809**

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: **Distribution Reliability Initiative (Pooled)**

Project Cost: **$863,000**

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.[15] The nature of the upgrading work follows from a detailed assessment of past service problems, knowledge of local environmental conditions (such as salt contamination and wind and ice loading), and engineering knowledge to apply location specific design and construction standards.

In the past Newfoundland Power identified worst performing feeders on the basis of SAIDI, SAIFI and customer minutes.[16] These indices ranked reliability performance based on the customer impact of the outages. In 2012, the Canadian Electricity Association began capturing and reporting on 2 additional indices; CIKM and CHIKM.[17] These indices rank reliability performance based on the length of line experiencing outages and tend to be more reflective of asset condition. Newfoundland Power has incorporated CIKM and CHIKM into its reliability analysis.

The 2015 project involves work on feeder KBR-10 and MOL–09. Table 1 shows the number of customers affected and the average unscheduled distribution interruption statistics for the 5-year period ending December 31, 2013 for these 2 distribution feeders. These statistics exclude planned power interruptions and interruptions due to all causes other than distribution system failure. An analysis of these feeders is contained in report ***4.1*** *Distribution Reliability Initiative*.

Table 1
Distribution Interruption Statistics
5-Years to December 31, 2013

Feeder	Customers	SAIFI	SAIDI	CHIKM	CIKM
KBR-10	950	1.21	2.20	313.0	172.3
MOL-09	1,930	1.73	2.13	403.4	327.2
Company Average	**-**	**1.12**	**1.68**	**57.3**	**44.5**

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

16 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.

17 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 these worst performing feeders experience power interruptions more often, or of longer duration, than the Company average, or experience power interruptions 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.[18]

Projected Expenditures

Table 2 provides the breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 2
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$140	-	-	-
Labour – Internal	194	-	-	-
Labour – Contract	267	-	-	-
Engineering	58	-	-	-
Other	204	-	-	-
Total	**$863**	**$820**	**$2,580**	**$4,263**

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.

[18] Chart 7 of the 2015 Capital Plan shows a 61% improvement in SAIDI and 64% improvement in SAIFI over the period from 1999 to 2013.

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

Project Cost: **$160,000**

Project Description

This Distribution project consists of expenditures to address some electrical system control limitations in the distribution system. Increasing the level of automation in the distribution system will improve the Company's capability to deal with cold load pickup and improved efficiency of restoration following both local and system wide outages.

Increasing automation of distribution feeders will involve the addition of new equipment to the distribution system and the replacement of some older generation equipment in service with modern communications capable equipment.

The following projects have been identified for 2015:

1. The installation of a downline automated distribution feeder 3-phase sectionalizing recloser on distribution feeder PUL-02 from Pulpit Rock Substation supplying customers in the Flatrock and Pouch Cove areas of the Northeast Avalon Peninsula. ($80,000), and

2. The installation of a downline automated distribution feeder 3-phase sectionalizing recloser on distribution feeder RRD-09 from Ridge Road Substation supplying customers in the Airport Heights area of the City of St. John's. ($80,000)

Justification

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

Installing automated reclosers to sectionalize heavily loaded distribution feeders and taps provides customers with a greater degree of reliability in all operating conditions.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 1

**Projected Expenditures
(000s)**

Cost Category	**2015**	**2016**	**2017 - 2019**	**Total**
Material	$12	-	-	-
Labour – Internal	92	-	-	-
Labour – Contract	48	-	-	-
Engineering	4	-	-	-
Other	4	-	-	-
Total	**$160**	**$250**	**$865**	**$1,275**

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: **$197,000**

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 2015 and a projection of expenditures through 2019.

Table 1
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	-	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering		-	-	-
Other	$197	-	-	-
Total	**$197**	**$201**	**$627**	**$1,025**

Costing Methodology

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

Table 2
Expenditure History and Budget Estimate
(000s)

Year	**2010**	**2011**	**2012**	**2013**	**2014F**
Total	$172	$181	$192	$196	$193

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 required to add or replace tools and equipment used in providing safe, reliable electrical service. Users of tools and equipment include 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.

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.

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

1. *Operations Tools and Equipment ($120,000)*: 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 ($200,000)*: 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 ($123,000)*: This item is 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.

4. *Substation Grounding Sticks ($24,000):* This item involves the purchase of grounding sticks for approximately 8 substations. Grounding sticks are required for the safe isolation of equipment to allow for maintenance, testing and troubleshooting. Multiple sets of grounding sticks are required at each substation.[19]

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[19] A set of grounding sticks includes 3 individual grounding sticks, one for each of the 3 phases. Estimated cost per set is $3,000.

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 2015 and a projection of expenditures through 2019.

Table 1
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$467	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$467**	**$477**	**$1,483**	**$2,427**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2010	2011	2012	2013	2014F
Total	$383	$428	$449	$443	$458

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. The budget for the substation grounding sticks is based on an engineering estimate. 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: **Additions to Real Property (Pooled)**

Project Cost: **$385,000**

Project Description

This General Property project is required 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 2015 project consists of the upgrading, refurbishment or replacement of equipment and facilities due to organizational changes, damage, deterioration, corrosion and in-service failure. Based upon recent historical information $285,000 is required for 2015. This project also includes corporate security upgrades to the Company's security infrastructure, including improvements in surveillance, fencing and lighting of Company facilities. Based upon an engineering estimate, $100,000 is required for corporate security upgrades in 2015. 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 buildings and support facilities and to operate them in a safe and efficient manner.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 1
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$324	-	-	-
Labour – Internal	4	-	-	-
Labour – Contract	-	-	-	-
Engineering	41	-	-	-
Other	16	-	-	-
Total	**$385**	**$391**	**$1,106**	**$1,882**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2010	2011	2012	2013	2014F
Total	$219	$311[1]	$300	$401[2]	$279[3]

[1] Excludes cost of security camera upgrades ($49,000) and Duffy Place office renovations ($63,000).
[2] Excludes cost of parking lot resurfacing ($40,000) and Duffy Place truck bay doors replacement ($47,000)
[3] Excludes corporate security upgrades ($100,000)

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: **Standby and Emergency Power – Carbonear Office (Other)**

Project Cost: **$304,000**

Project Description

This General Property project consists of the installation of a new diesel generating unit to provide a back-up power supply to the Company's Carbonear area operations building.

The 2006 Capital Budget Application included the report *Standby Generation at Newfoundland Power Facilities*. This report identified the need for standby generation at the Company's area operations buildings across the province. The 2014 Capital Budget Application included the report ***5.1** Standby and Emergency Power – Gander Office* which includes a review of the progress to date for the 2006 initiative, and Company plans to undertake the installation of standby generation in the 3 remaining area operations buildings.

For a major storm and power outage situation, full power restoration could take several days depending on the severity of the event. In such a situation, a response would involve teams working around the clock, that consists of field employees (involved in the physical restoration work) and support employees (involved in customer service, communications, information services, materials management, engineering, and operational support). Essentially, the Company has to provide essential services during such emergency situations.

During a major storm and power outage situation, restoration teams on the Avalon Peninsula, excluding St. John's and surrounding area, would require technology and communications infrastructure located in the Carbonear area operations building. The uninterruptible power supply ("UPS") system that is currently located at the Carbonear area operations building is only sufficient to sustain SCADA communications for a short duration (several hours). This limited UPS system would not support operating conditions required during a major outage event.

Justification

This project is necessary to ensure electrical service at the Company's Carbonear area operations building is not interrupted during a widespread power outage. This will permit the Company to facilitate the restoration of electrical service to customers during extended power outages as quickly as possible.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 1
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$260	-	-	-
Labour – Internal	10	-	-	-
Labour – Contract	-	-	-	-
Engineering	24	-	-	-
Other	10	-	-	-
Total	**$304**	**$175**	**-**	**$479**

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.

Project Title: **Company Building Renovations – Duffy Place (Pooled, Multi-year)**

Project Cost: **$2,068,000**

Project Description

This General Property project includes the renovation of the Company's Duffy Place facility.[20] The renovations are required to replace deteriorated building components necessary to ensure the continued safe operation of the facility, workplaces and surrounding property.

The Duffy Place facility is now 26 years old and has reached an age where capital improvements are necessary to ensure it continues to provide safe and reliable service to employees and the public. Improvements are required in 2015 and 2016 to replace building components that have reached the end of their useful service life.

A condition assessment has identified the following items to be included in this project:

1. *HVAC Replacement (2015 - $1,000,000, 2016 - $600,000).* Replacement of the existing Heating Ventilation and Air Conditioning ("HVAC") system with an energy efficient ground source heat pump is planned for 2015 and 2016. The duration of the project including engineering, procurement and installation requires it take place over 2 years.

2. *Building Interior (2015 - $182,000, 2016 - $124,000).* In advance of the HVAC project, interior reconfiguration focused on improving the functionally of space will be completed in 2015. The carpet in the office areas is original to the 1988 building construction and is in poor condition. Window treatment and wall coverings in many areas are also deteriorated. Upgrade of both is planned for 2016.

3. *Lighting Upgrade (2015 - $177,000).* Replacement of the metal halide truck bay lights as well as the replacement and retrofitting of various other lights throughout the facility is required to address low and shadowy light conditions. A lighting control system replacement is required as the current system is obsolete. Lighting upgrades are planned for 2015.

4. *Warehouse Improvements (2015 - $55,000).* Warehouse improvements are required in 2015 including replacement of damaged sections of the pallet racking system along with improvements to the dock-levelers.

[20] The Facility houses approximately 233 employees and equipment necessary to support operations throughout St. John's Region's service territory. This includes line crews, line inspectors, work dispatchers, regional engineering, meter reading and associated support and management staff. In addition, the Facility houses corporate functions such as stores warehouse, metering, customer service, information services, production center, generation maintenance, transportation and dispatch functions.

5. *Parking Lot Improvements (2015 - $366,000).* The Mews Place parking lot is in poor condition and resurfacing is required in 2015. This includes addressing curb and sidewalk deficiencies as adjacent section of pavement is replaced.

Details on the proposed expenditures are included in ***5.1** Company Building Renovations–Duffy Place Facility*.

Justification

The project is justified on the age and the deterioration of the existing Company buildings. Justification for individual projects is based upon inspections completed by professional engineers or independent experts. The least cost justification for selecting the ground source heat pump alternative can be found in Appendix B of the report ***5.1** Company Building Renovations–Duffy Place Facility*.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2015 and 2016 for this multi-year project. There are no expenditures projected beyond 2016.

Table 1
Multi-year Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$1,824	$601	-	$2,425
Labour – Internal	10	10	-	20
Labour – Contract	-	-	-	-
Engineering	112	58	-	170
Other	122	55	-	177
Total	**$2,068**	**$724**	-	**$2,792**

Costing Methodology

The budget estimate for this project is comprised of 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 a multi-year projected to be completed in 2015 and 2016.

TRANSPORTATION

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

Project Cost: **$2,917,000**

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 lives.

Table 1 summarizes the units to be acquired in 2015.

Table 1
2015 Proposed Vehicle Replacements

Category	No. of Units
Heavy fleet vehicles	6
Passenger vehicles[1]	35
Off-road vehicles[2]	9
Total	**50**

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.

The Company has 71 heavy fleet vehicles. An average replacement rate of approximately 7 vehicles per year would be required to replace the heavy fleet over a 10-year cycle. Mileage and overall vehicle condition are also considered in deciding whether to replace a vehicle. Over the period 2010 to 2014, the Company replaced 34 heavy fleet vehicles, an average of 7 heavy fleet vehicles per year. In 2015, there are 6 heavy fleet vehicles that meet the age, mileage and condition parameters which indicate replacement is necessary.

The Company has approximately 200 passenger vehicles. An average replacement rate of approximately 40 vehicles per year would be required to replace the passenger fleet over a 5-year cycle. Over the period 2010 to 2014, the Company replaced 130 passenger vehicles, an average of approximately 26 passenger vehicles per year. In 2015, the Company has identified 35 passenger vehicles for replacement.

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 2015 and a projection of expenditures through 2019.

Table 2
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$2,917	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$2,917**	**$2,955**	**$10,060**	**$15,932**

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

Table 3
Expenditure History
(000s)

Year	2010	2011	2012	2013	2014F
Total	$2,287	$2,272	$2,514	$3,220	$2,570

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 five 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 life and require replacement in 2015.

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: **$123,000**

Project Description

This Telecommunications project involves the replacement and/or upgrade of communications equipment, including radio communication equipment and communications equipment associated with electrical system control.

The Company has approximately 340 pieces of mobile radio equipment in service. Each year approximately 20 units break down and where practical, equipment is repaired and deficiencies rectified. However, where it is not feasible to repair equipment or correct deficiencies, replacement is required.

Newfoundland Power engages an engineering consultant to inspect radio towers. Deficiencies identified through these inspections are addressed through this project.

Justification

Reliable communications equipment is essential to the provision of safe, reliable electrical service. Communications towers must comply with safety codes and standards to ensure employee and public safety.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 1

Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$108	-	-	-
Labour – Internal	3	-	-	-
Labour – Contract	-	-	-	-
Engineering	9	-	-	-
Other	3	-	-	-
Total	**$123**	**$126**	**$392**	**$641**

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	2010	2011	2012	2013	2014F
Total	$149	$88	$100	$82	$99
Adjusted Cost	$162	$93	$104	$84	$99

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, 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.

Throughout 2013 and 2014, the Company is replacing its mobile radio system. Expenditures for the years 2013 and 2014 shown in Table 2 reduced to reflect lower mobile radio cost due to reduced replacements during the transition to the new system.

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.

INFORMATION SYSTEMS

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

Project Cost: **$1,325,000**

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 provision of service to customers, ensuring the effective operation of the electrical system and compliance with regulatory and financial reporting requirements.

The application enhancements proposed in 2015 include enhancements to the Company's inventory management, property management, customer outage communication and notification applications and Customer Service Internet, mobile website and energy conservation website enhancements.

The application enhancements proposed for 2015 are not inter-dependent. But, 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 ***6.1*** *2015 Application Enhancements*.

Justification

The proposed enhancements included in this project are justified on the basis of improving customer service and operational efficiencies.

Cost benefit analyses, where appropriate, are provided in ***6.1*** *2015 Application Enhancements*.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 1

Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$254	-	-	-
Labour – Internal	769	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	302	-	-	-
Total	**$1,325**	**$1,250**	**$4,550**	**$7,125**

Costing Methodology

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

Table 2

Expenditure History
(000s)

Year	2010	2011	2012	2013	2014F
Total	$945	$1,003	$1,102	$1,473	$1,372

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 a sole-source supplier to ensure least cost.

Future Commitments

This is not a multi-year project.

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

Project Cost: **$1,125,000**

Project Description

This Information Systems project involves necessary upgrades to the computer software underlying the Company's business applications. Most upgrades are required to address known software issues, to facilitate infrastructure upgrades or to maintain vendor support.

For 2015, the project includes upgrades to the Company's business applications including the employee self-serve application, access control application and an upgrade of the software components used to operate and maintain the Company's Customer Service System and external website.

This project also includes the Microsoft Enterprise Agreement. This Agreement covers the purchase of Microsoft software and provides access to the latest versions of each software product purchased under this agreement. Details on Microsoft Enterprise Agreement are included in *Schedule C* to this Application.

This project is clustered with the *Shared Server Infrastructure* Information Systems project to upgrade the CSS and external website server infrastructure. (Schedule B, page 86 of 97).

Details on proposed expenditures are included in ***6.2*** *2015 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 2015 and a projection of expenditures through 2019.

Table 1
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$370	-	-	-
Labour – Internal	590	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	165	-	-	-
Total	**$1,125**	**$1,695**	**$4,585**	**$7,405**

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	2010	2011	2012	2013	2014F
Total	$1,000	$853	$1,363	$1,269	$1,059

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 a sole-source supplier to ensure least cost.

Future Commitments

This project includes provision in 2015 for the renewal of the Microsoft Enterprise Agreement, which is included in Schedule C. This is not otherwise a multi-year project.

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

Project Cost: **$487,000**

Project Description

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

In 2015, a total of 165 PCs will be purchased, consisting of 95 desktop computers and 70 mobile computers. This project also includes the purchase of peripheral equipment such as monitors, mobile devices, and 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 5-year life cycle for its PCs before they require replacement.

Table 1 outlines the PC additions and retirements for 2013 and 2014, as well as the proposed additions and retirements for 2015.

Table 1
PC Additions and Retirements
2013 – 2015

	2013			**2014F**			**2015B**		
	Add	**Retire**	**Total**	**Add**	**Retire**	**Total**	**Add**	**Retire**	**Total**
Desktop	33	38	453	79	79	453	95	95	453
Mobile	53	48	308	64	64	308	70	70	308
Total	**86**	**86**	**761**	**143**	**143**	**761**	**165**	**165**	**761**

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 life.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 2
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$325	-	-	-
Labour – Internal	97	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	65	-	-	-
Total	**$487**	**$500**	**$1,500**	**$2,487**

Costing Methodology

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

Table 3
Expenditure History
(000s)

Year	2010	2011	2012	2013	2014F
Total	$449	$423	$401	$411	$420

The project 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, 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 (Clustered)**

Project Cost: **$970,000**

Project Description

This Information Systems project includes the procurement, implementation, and management of the hardware and software relating to the operation of shared servers. Shared servers are computers that support applications used by multiple employees. Management of these shared servers, and their components, is critical to ensuring that these applications operate effectively at all times.

This project is necessary to maintain current performance of the Company's shared servers and to provide the additional infrastructure needed to accommodate new and existing applications. This involves the replacement and upgrade of servers, disk storage, as well as security upgrades.

For 2015, the project includes the replacement of technology infrastructure that has reached the end of their useful life, as well as infrastructure required to ensure the security of customer and corporate information.

Projects proposed for 2015 include:

1. The replacement of shared server infrastructure that hosts the Company's Customer Service System;
2. The replacement of shared server infrastructure that hosts the Company's external website;
3. The replacement of shared server infrastructure that has reached the end of life;
4. The replacement of security infrastructure that that has reached the end of life; and
5. The replacement of security management software to consolidate reporting of security alerts.

The shared server infrastructure requirements for 2015 are not inter-dependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

This project is clustered with the *System Upgrades* Information Systems project to upgrade software components used to operate and maintain the Company's Customer Service System and external website. (Schedule B, page 81 of 97).

Details on proposed expenditures are included in ***6.3*** *2015 Shared Server Infrastructure*.

Justification

This project is justified on the basis of maintaining current levels of customer service and operational efficiencies that are supported by the Company's shared server infrastructure.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 1
Projected Expenditures (000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$540	-	-	-
Labour – Internal	285	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	145	-	-	-
Total	**$970**	**$650**	**$2,000**	**$3,620**

Costing Methodology

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

Table 2
Expenditure History (000s)

Year	2010	2011	2012	2013	2014F
Total	$577	$941	$687	$941	$833

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 a sole-source supplier to ensure least cost.

Future Commitments

This is not a multi-year project.

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

Project Cost: **$328,000**

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 across the Company, enabling the transport of SCADA data, corporate and customer service data. The Company has increased its use of wireless communications technologies in recent years.

For 2015, 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 2015 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 2015 and a projection of expenditures through 2019.

Table 1
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$220	-	-	-
Labour – Internal	73	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	35	-	-	-
Total	**$328**	**$175**	**$850**	**$1,353**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2010	2011	2012	2013	2014F
Total	$148	$158	$429	$218	$321

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 a sole-source supplier to ensure least cost.

Future Commitments

This is not a multi-year project.

Project Title: SCADA System Replacement (Other, Multi-year)

Project Cost: $2,833,000

Project Description

The Supervisory Control and Data Acquisition ("SCADA") System remotely monitors and controls the electricity system from a central location operated 24 hours a day.[21] The replacement of the SCADA System is being undertaken at this time due to the technical obsolescence of the operating system and server hardware platform on which the SCADA application operates. Also, the existing SCADA application will not be upgraded by the vendor to operate on a supported operating system and server hardware platform. Therefore the Company must proceed to replace the existing SCADA system.

The Company proposes to replace the SCADA system as a multi-year project starting in 2015. The project will be completed in 2 years at an estimated cost of $5.7 million. The project will involve the acquisition, installation, configuration, testing and deployment of an upgraded SCADA application to ensure the system continues to support Company operations. This includes the conversion and migration of SCADA components such as databases, operator displays, reporting environment and custom applications to the new platform

Details on proposed expenditures are included in ***6.4*** *SCADA System Replacement*.

Justification

The SCADA system is a critical operational technology necessary to provide reliable least cost service to customers. This project is necessary to ensure the continued integrity of the Company's remote monitoring and control capabilities. This, in turn, allows the maintenance of acceptable levels of customer service and operational efficiency.

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[21] The SCADA system remotely monitors and controls 71 substations, 25 hydro generators, 2 gas turbines, 187 distribution feeders and 78 power transformers. In total there are approximately 40,000 individual data points monitored and controlled through the SCADA system.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 1

Multi-year Projected Expenditures (000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$2,338	$2,309	-	$4,647
Labour – Internal	158	156	-	314
Labour – Contract	-	-	-	-
Engineering	294	332	-	626
Other	43	45	-	88
Total	**$2,833**	**$2,842**	**-**	**$5,675**

Costing Methodology

The budget for this project is based on cost estimates for the individual budget items based on an engineering assessment completed by an expert in SCADA system replacement. 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 to be completed in 2015 and 2016.

Project Title: **Geographic Information System Improvements (Pooled)**

Project Cost: **$433,000**

Project Description

Newfoundland Power operates approximately 300 distribution feeders, representing over 9,500 kilometres of distribution lines. It is important that accurate records of the current state of the electrical system be made available to field and technical employees at all times.

The Company's geographical information system (GIS) provides a central database for storage of distribution asset information. This enables information to be updated and available in a more efficient and timely manner, and also reduces the inherent inefficiencies that exist with maintaining multiple systems.

This Information Systems project involves:

(i) Improvements in how electrical system information is distributed and presented to crews in the field, and
(ii) Expanding the GIS database to include information about customer location and electrical connectivity.

The individual project requirements for 2015 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 ***6.5*** *Geographic Information System Improvements.*

Justification

GIS technology is an important tool in improving customer service and overall efficiency in the Company's field operations. Providing improved functionality to crews in the field, and integrating the GIS with other key systems such as the customer service system, will help improve data management, eliminate redundancies and enhance decision making abilities.

The proposed improvements included in this project are justified on the basis of improving customer service and operational efficiencies. Net Present Value analysis for the proposed improvements can be found in Appendix B of the report ***6.5*** *Geographical Information System Improvements*.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2015 and a projection of expenditures through 2019.

Table 1
Projected Expenditures
(000s)

Cost Category	2015	2016	2017 - 2019	Total
Material	$15	-	-	-
Labour – Internal	258	-	-	-
Labour – Contract	-	-	-	-
Engineering	50	-	-	-
Other	110	-	-	-
Total	**$433**	**$460**	**$720**	**$1,613**

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.

Future Commitments

This is not a multi-year project. Expenditures for projects in future years will be presented in future Capital Budget Applications.

UNFORESEEN ALLOWANCE

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

Project Cost: **$750,000**

Project Description

This Allowance for Unforeseen Items project is necessary to cover any unforeseen capital expenditures which have not been budgeted elsewhere. The purpose of the account is to permit the Company to act expeditiously to deal with 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: $4,100,000

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.
2015 Capital Budget
Multi-Year Projects

Class	Project Description	CBA Board Order		Expenditure (000s) 2013	2014	2015	2016	Total
Substations	Additions Due To Load Growth[1]	2012 CBA P.U. 26 (2011)	Budget	$3,974				$5,130
			Actual/Forecast	$2,705				$3,900
Substations	Substation Additions Portable Substation[2]	2012 CBA P.U. 26 (2011)	Budget	$3,621				$4,500
			Actual/Forecast	$3,238				$3,430
Generation	Heart's Content Plant Refurbishment[3]	2013 CBA P.U. 31 (2012)	Budget	$200	$3,495			$3,695
			Actual/Forecast	$144	$3,495			$3,695
Transmission	Transmission Line Rebuild[4]	2013 CBA P.U. 31 (2012)	Budget	$380	$358			$738
			Actual/Forecast	$363	$370			$750
Information Systems	Microsoft Enterprise Agreement[5]	2012 CBA P.U. 26 (2011)	Budget	$169	$170			$339
			Actual/Forecast	$171	$171			$342

[1] A detailed project description can be found in the 2012 Capital Budget Application, Schedule B pages 18 and 19, and report ***2.2*** *2012 Additions due to Load Growth*.
[2] A detailed project description can be found in the 2012 Capital Budget Application, Schedule B pages 22 and 23, and report ***2.4*** *2012 Portable Substation Study*.
[3] A detailed project description can be found in the 2013 Capital Budget Application, Schedule B pages 11 and 12, and report ***1.2*** *Heart's Content Hydro Plant Penstock Replacement*.
[4] A detailed project description can be found in the 2013 Capital Budget Application, Schedule B pages 29 to 31, and report ***3.1*** *2013 Transmission Line Rebuild*.
[5] A detailed project description can be found in the 2012 Capital Budget Application, Schedule B pages 78 and 79, and report 6***.2*** *2012 System Upgrades*.

Newfoundland Power Inc.
2015 Capital Budget
Multi-Year Projects

Class	Project Description	CBA Board Order		Expenditure (000s) 2014	2015	2016	2017	Total
Generation	Pierre's Brook Plant Penstock and Surge Tank [6]	2015 CBA	Budget		$750	$13,530		$14,280
			Actual/Forecast					
Transmission	Transmission Line Rebuild[7]	2015 CBA	Budget		$2,510	$2,318		$4,828
			Actual/Forecast					
General Property	Company Building Renovations Duffy Place Building[8]	2015 CBA	Budget		$2,068	$724		$2,792
			Actual/Forecast					
Information Systems	SCADA System Replacement[9]	2015 CBA	Budget		$2,833	$2,842		$5,675
			Actual/Forecast					
Information Systems	Microsoft Enterprise Agreement[10]	2015 CBA	Budget		$195	$195	$195	$585
			Actual/Forecast					

[6] A detailed project description can be found in the 2015 Capital Budget Application, Schedule B pages 6 and 7, and report ***1.2*** *Pierre's Brook Hydro Plant Penstock Replacement and Surge Tank Refurbishment*.
[7] A detailed project description can be found in the 2013 Capital Budget Application, Schedule B pages 25 to 27, and report ***3.1*** *2015 Transmission Line Rebuild*.
[8] A detailed project description can be found in the 2015 Capital Budget Application, Schedule B pages 69 and 70, and report ***5.1*** *2012 Company Building Renovations – Duffy Place Facility*.
[9] A detailed project description can be found in the 2015 Capital Budget Application, Schedule B pages 90 and 91, and report ***6.4*** *SCADA System Replacement*.
[10] A detailed project description can be found in the 2015 Capital Budget Application, Schedule B pages 81 and 82, and report ***6.2*** *System Upgrades*

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

	2013	2012
Net Plant Investment		
Plant Investment	1,501,729	1,439,646
Accumulated Amortization	(623,645)	(602,616)
Contributions in Aid of Construction	(31,911)	(31,006)
	846,173	806,024
Additions to Rate Base		
Deferred Pension Costs	101,159	100,113
Credit Facility Costs[1]	-	239
Cost Recovery Deferral – Seasonal/TOD Rates	95	93
Cost Recovery Deferral – Hearing Costs	644	-
Cost Recovery Deferral – Regulatory Amortizations	2,214	3,320
Cost Recovery Deferral – 2012 Cost of Capital	1,177	1,766
Cost Recovery Deferral – 2013 Revenue Shortfall	2,252	-
Cost Recovery Deferral – Conservation	2,085	227
Customer Finance Programs	1,363	1,446
	110,989	107,204
Deductions from Rate Base		
Weather Normalization Reserve	5,058	4,804
Other Post Employment Benefits	23,515	14,617
Customer Security Deposits	840	851
Accrued Pension Obligation	4,325	4,020
Accumulated Deferred Income Taxes	1,872	2,504
Demand Management Incentive Account	(272)	558
	35,338	27,354
Year End Rate Base	921,824	885,874
Average Rate Base Before Allowances	903,849	867,902
Rate Base Allowances		
Materials and Supplies Allowance[2]	5,445	5,332
Cash Working Capital Allowance	6,526	9,811
Average Rate Base at Year End	915,820	883,045

1 For 2013, the unamortized credit facility costs are included as a component of the Company's weighted average cost of capital and are therefore excluded from the calculation of average rate base. The exclusion of deferred credit facility costs adjusts the 2013 calculation of average rate base filed in Return 3 of Newfoundland Power's 2013 Annual Report to the Board.

2 This differs from the materials and supplies allowance included in the 2013 calculation of average rate base as filed in Return 3 of Newfoundland Power's 2013 Annual Report to the Board. The materials and supplies allowance included in Return 3 of the 2013 Annual Report understated the final materials and supplies costs for 2013.

2015 Capital Plan

June 2014

Table of Contents

1.0 Introduction

Newfoundland Power's 2015 Capital Plan provides an overview of the Company's 2015 Capital Budget together with an outlook for capital expenditure through 2019.

Newfoundland Power's 2015 Capital Budget totals $94,211,000.

The Company's 2015 Capital Budget is part of a series of stable and predictable annual capital budgets which the Board has recognized assists in fostering stable and predictable rates for consumers.[1] Newfoundland Power's annual capital expenditure for the next 5 years is forecast to average approximately $97 million. This level of annual expenditure is broadly consistent on an inflation adjusted basis with the annual capital expenditures in the period 2010 through 2014.[2]

The Company's annual capital budgets continue to focus on (i) plant replacement and (ii) meeting customer and sales growth. Together, expenditures on plant replacement and growth combine to account for 83% of expenditures over the next 5 years. This composition is broadly consistent with Newfoundland Power's capital budgets over the previous 5 years.

Over the past 5 years there have been 5 major disturbances that have impacted the Company's ability to serve its customers. In March 2010 an ice storm on the Bonavista Peninsula left 10,246 customers without electricity, some for as long as 6 days. In September 2010 Hurricane Igor affected 106,000 customers, with some being without electricity for 5 days. In September 2012 Tropical Storm Leslie affected 129,000 customers, with some being without electricity for 5 days. In January 2013 a breaker failure at the Holyrood Thermal Generating Station and the subsequent damage to generating unit #1 resulted in 173,000 Newfoundland Power customers losing electrical service. Finally, a series of system events in January 2014 resulted in as many as 187,501 customers being without electricity at one time. The Company responds to these major disturbances through the timely deployment of human resources and equipment including portable substations and emergency generation. The ability to respond effectively is supported through the increased use of technology and the upgrading and maintaining of electricity system assets.

Over the previous 5 year period the Company's use of technology in operations has expanded. Mobile computers were installed in Company line trucks over a 3 year period starting in 2009.[3] Annual expenditures in the Information Systems *Applications Enhancements* project have improved the Company's Internet presence, including the expanded use of social media for communicating with customers during major disturbances on the electricity system. Annual expenditures in the *Substations Refurbishment and Modernization* project have increased the amount of automation in the electricity system. Increased automation of substation equipment, particularly transmission line breakers and distribution feeder breakers and reclosers, has improved the electricity system's capability and flexibility to respond to both major disturbances and local system events.

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1 See Order No. P.U. 36 (2002-2003).

2 See Chart 3 on page 7 of this Capital Plan.

3 The initial justification was based on documentation management but the applications have expanded over time with mobile work dispatch and vehicle location currently improving overall operating efficiency of line crews.

The 2015 Capital Plan continues to expand the use of technology in operations. The *Substation Refurbishment and Modernization* project will complete the automation of substation based equipment. Over the 5-year plan the Company intends to automate all distribution feeders capable of communications back to the SCADA system. The Company is introducing a new project titled *Distribution Feeder Automation* to automate existing downline reclosers and to increase the presence of downline reclosers on heavily loaded distribution feeders. In 2015 and 2016 the Company will replace its 15 year old SCADA system with a new system that will be capable of integrating with geographic information and outage management systems. Following the completion of the SCADA replacement the 5-year capital plan includes the replacement of the Outage Management System ("OMS"). The combination of substation and feeder automation along with new SCADA and OMS technology has the potential to improve customer service delivery during normal operations and at times of major disturbances.

2.0 2015 Capital Budget

Newfoundland Power's 2015 capital budget is $94,211,000.

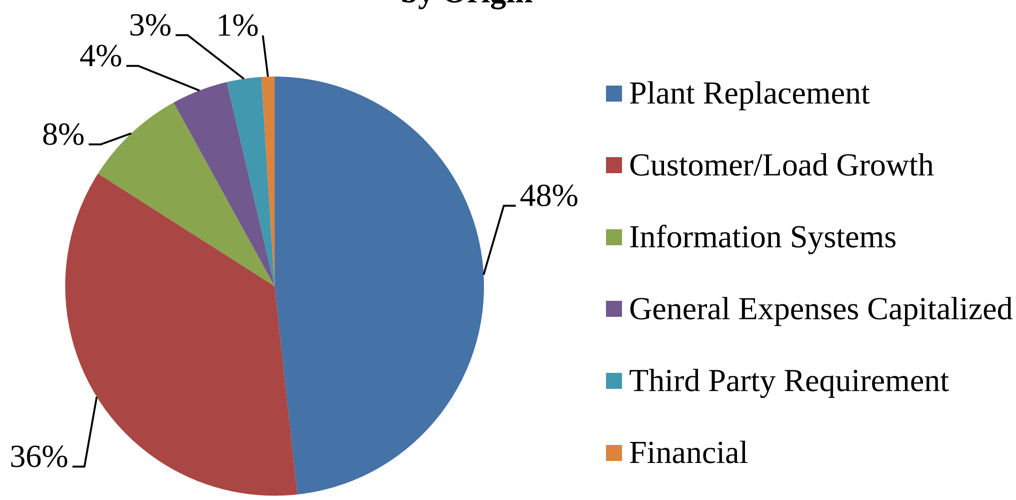
This section of the 2015 Capital Plan provides an overview of the 2015 capital budget by origin (root cause) and asset class. In addition, this section summarizes 2015 capital projects by the various categories set out in the Board's October 2007 Capital Budget Application Guidelines.

2.1 2015 Capital Budget Overview

Newfoundland Power's 2015 capital budget contains 39 projects totalling $94.2 million.

Chart 1 shows the 2015 capital budget by origin, or root cause.

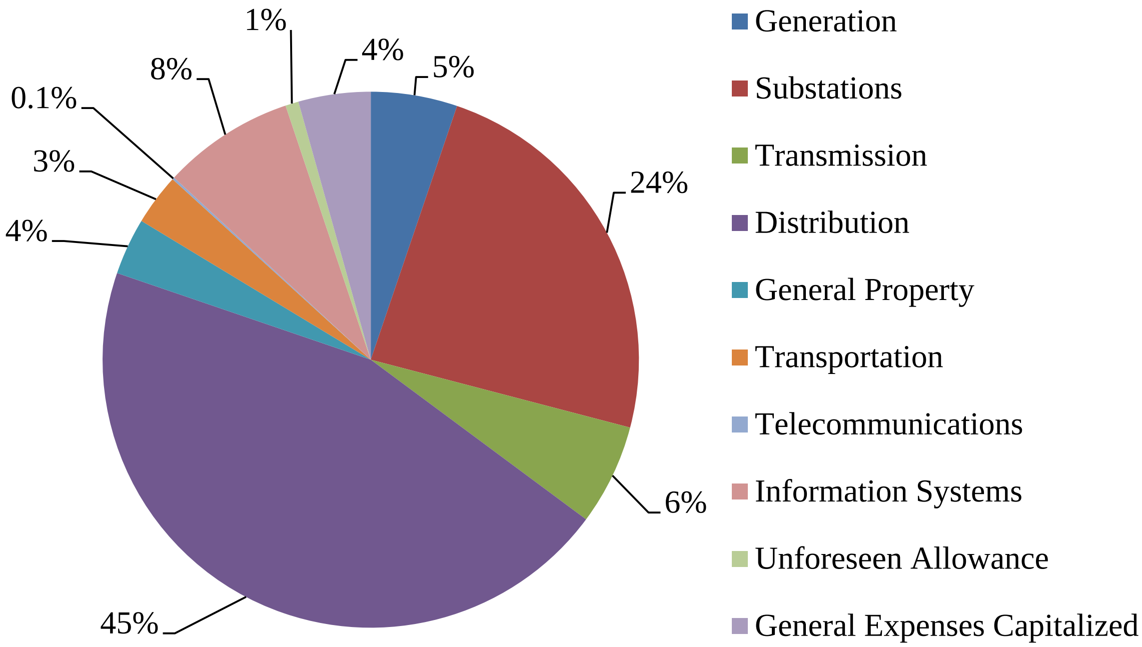
Chart 1
2015 Capital Expenditures
by Origin



Approximately 48% of proposed 2015 capital expenditure is related to the replacement of plant. A further 36% of proposed 2015 capital expenditure is required to meet the Company's obligation to serve new customers and meet the requirement for increased system capacity. The 8% of proposed 2015 capital expenditure associated with Information Systems includes the project to replace the Company's SCADA system. The remaining 8% of forecast capital expenditures for 2015 relate to general expenses capitalized, third party requirements and financial carrying costs (allowance for funds used during construction). The allocation of 2015 capital expenditures is broadly consistent with capital budgets for the past 5 years.

Chart 2 shows the 2015 capital budget by asset class.

Chart 2
2015 Capital Expenditures
by Asset Class



As in past years, Distribution capital expenditure accounts for the greatest percentage of overall expenditure at $42.5 million, or 45% of the 2015 capital budget. Substations capital expenditure accounts for $22.5 million, or 24% of the 2015 capital budget. Information Systems capital expenditure accounts for $7.5 million or 8% of the 2015 capital budget. Transmission capital expenditure accounts for $5.7 million, or 6% of the 2015 capital budget. Generation capital expenditure accounts for $4.9 million, or 5% of the 2015 capital budget. Together, expenditure for these 5 asset classes comprises 88% of the Company's 2015 capital budget.

Distribution capital expenditure is primarily driven by customer requests for new connections to the electrical system. While Distribution capital expenditures that address reliability have been reduced in recent years, in 2015 the Distribution Reliability Initiative will address reliability issues associated with 2 urban feeders. Otherwise expenditures in 2015 are expected to be similar to recent years.

In 2015, the Company plans to install new power transformers at Clarenville and Lethbridge substations in the Bonavista Peninsula area and Kenmount substation in the City of St. John's. Also in 2015, the Company will install a transformer from inventory at St. John's Main substation.[4] These projects are necessary to address growth in customer load in these areas.

Transmission lines proposed for rebuild in 2015 include 4 lines in the City of St. John's and one line in the Stephenville area.[5] Transmission line 14L operates between Memorial University and Stamp's Lane substations. Transmission line 15L operates between Molloy's Lane and Stamp's Lane substations. Transmission line 30L operates between Ridge Road and King's Bridge substations. Transmission line 69L operates between Kenmount and Stamp's Lane substations. Transmission line 400L operates between Newfoundland & Labrador Hydro's Bottom Brook terminal station and Wheeler's substation on the Hansen Highway outside of Stephenville.

In 2015, the Company plans to initiate a 2-year project to replace the penstock at the Pierre's Brook hydro plant. The Company will also complete projects to refurbish the Seal Cove and Tors Cove hydro plants in 2015.

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 2015 Capital Budget Application complies with the CBA Guidelines.

The 2015 Capital Budget Application includes 39 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 2015 Capital Budget, along with a summary of costs segmented by materiality.

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4 This substation transformer was last in service at Hardwoods substation. The transformer is planned to be replaced at Hardwoods substation by a new unit in 2014. The project was included in the 2014 Capital Budget Application and approved on Order No. P.U. 27 (2013).

5 These transmission lines are deteriorated and have reached a point where continued maintenance is no longer feasible.

2015 Capital Projects by Definition

Table 1 summarizes Newfoundland Power's proposed 2015 capital projects by definition as set out in the CBA Guidelines.

Table 1
2015 Capital Projects
By Definition

Definition	**Number of Projects**	**Budget (000s)**
Pooled	26	$56,199
Clustered[6]	8	29,869
Other	5	8,143
Total	**39**	**$94,211**

There are a total of 33 *pooled* or *clustered* projects accounting for 91% of total expenditures.

2015 Capital Projects by Classification

Table 2 summarizes Newfoundland Power's proposed 2015 capital projects by classification as set out in the CBA Guidelines.

Table 2
2015 Capital Projects
By Classification

Classification	**Number of Projects**	**Budget (000s)**
Normal	36	$92,024
Mandatory	1	429
Justifiable	2	1,758
Total	**39**	**$94,211**

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

[6] Projects that have some items that are defined as Clustered and some other items that are defined as either Pooled or Other are included as Clustered for the purpose of this table.

2015 Capital Projects Costing

Table 3 summarizes Newfoundland Power's proposed 2015 capital projects by costing method (i.e., identified need vs. historical pattern) as set out in the CBA Guidelines.

Table 3
2015 Capital Projects
By Costing Method

Method	Number of Projects	Budget (000s)
Identified Need	24	$48,230
Historical Pattern	15	45,981
Total	**39**	**$94,211**

Projects with costing method based on *identified need* account for 51% of total expenditures, while those based on *historical pattern* account for 49% of total expenditures.

2015 Capital Projects Materiality

Table 4 segments Newfoundland Power's proposed 2015 capital projects by materiality as set out in the CBA Guidelines.

Table 4
2015 Capital Projects
Segmentation by Materiality

Segment	Number of Projects	Budget (000s)
Under $200,000	4	$636
$200,000 - $500,000	9	3,521
Over $500,000	26	90,054
Total	**39**	**$94,211**

There are 26 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 2015 through 2019 includes forecast average annual capital expenditure of $97.3 million. Over the 5 year period 2010 through 2014, the average annual capital expenditure is expected to be $83.4 million.

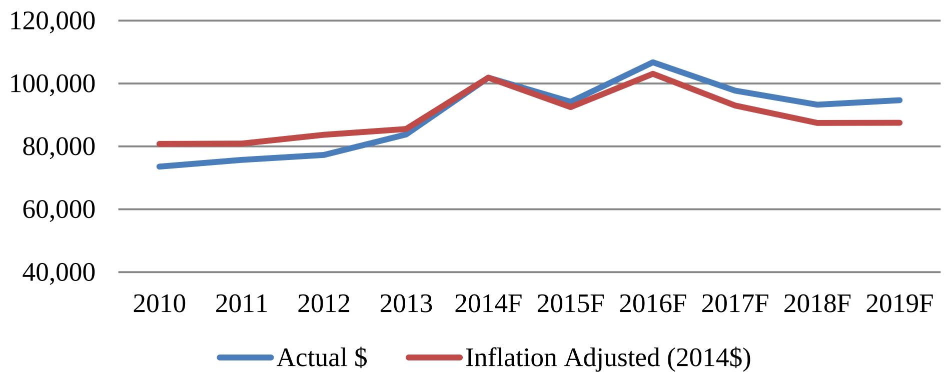
The increase in forecast annual capital expenditure reflects inflation and requirements for specific projects related to replacement of deteriorated facilities, meeting customer and load growth, replacing the Company's SCADA system, maintaining compliance with federal regulations and a new portable generator. Annual expenditure through the forecast period is broadly consistent on an inflation adjusted basis with that in the period 2010 through 2014.

3.1 Capital Expenditures: 2010-2019

The Company plans to invest $487 million in plant and equipment during the 2015 through 2019 period. On an annual basis, capital expenditures are expected to average approximately $97.3 million and range from a low of $93.3 million in 2018 to a high of $106.8 million in 2016.[7]

Chart 3 shows actual capital expenditures for the period 2010 through 2013 and forecast capital expenditures for the period 2014 through 2019.[8] For comparison purposes, the annual capital expenditures are also expressed in 2014 dollars to remove the effects of inflation.

Chart 3
Capital Expenditures
2010 to 2019F
($000s)



Overall planned capital expenditures for the 5-year period from 2015 through 2019 are expected to be greater than those in the 5-year period from 2010 through 2014. As shown in Chart 3 this

7 The Company plans to replace the Pierre's Brook penstock with a construction cost of $13.2 million in 2016.

8 The 2014 forecast capital expenditure includes supplemental capital expenditures for the Bell Island Submarine Cable Replacement and distribution feeder improvements and substation refurbishment application approved by Board Order Nos. P.U. 43 (2013) and P.U. 14 (2014) respectively.

is principally the result of inflation.[9] Forecast requirements for the 5-year period from 2015 through 2019 include additional power transformers due to load growth, changes in meter regulations, replacement of Pierre's Brook penstock, mobile generation and the SCADA system replacement.

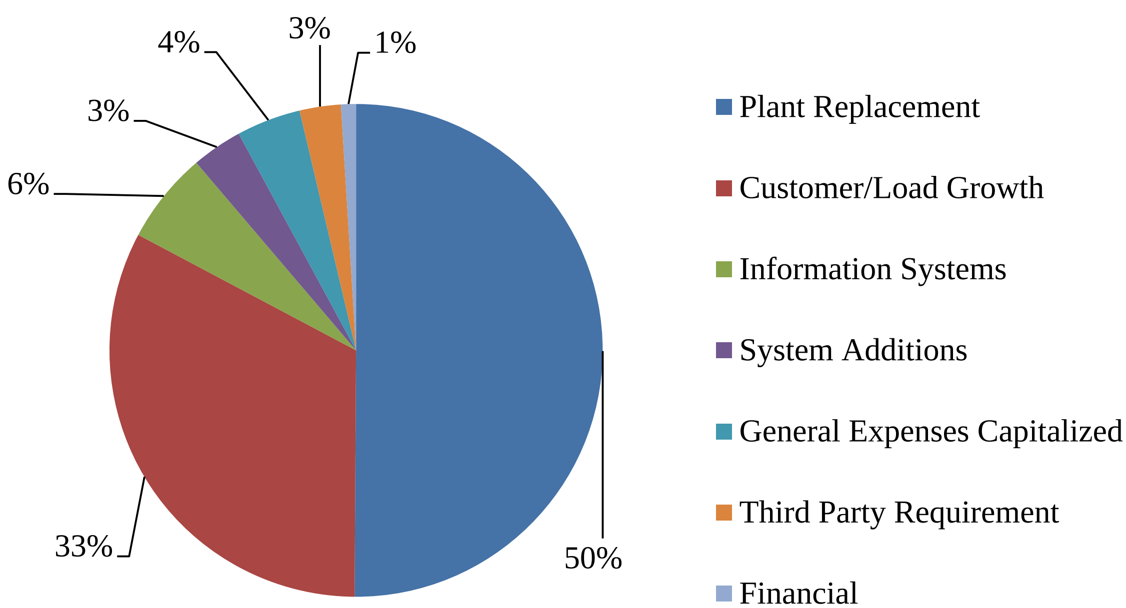
The replacement of plant has been, and will continue to be, the dominant driver of Newfoundland Power's capital budget, accounting for approximately 50% of total expenditure for the 10-year period from 2010 through 2019. Over the same 10-year period, capital expenditures to meet increased customer connections and electricity sales account for approximately 33% of total expenditures.

3.2 2015-2019 Capital Expenditures

3.2.1 Overview

Chart 4 shows aggregate forecast capital expenditures by origin for the period 2015 through 2019.

Chart 4
Capital Expenditures
by Origin
2015 to 2019

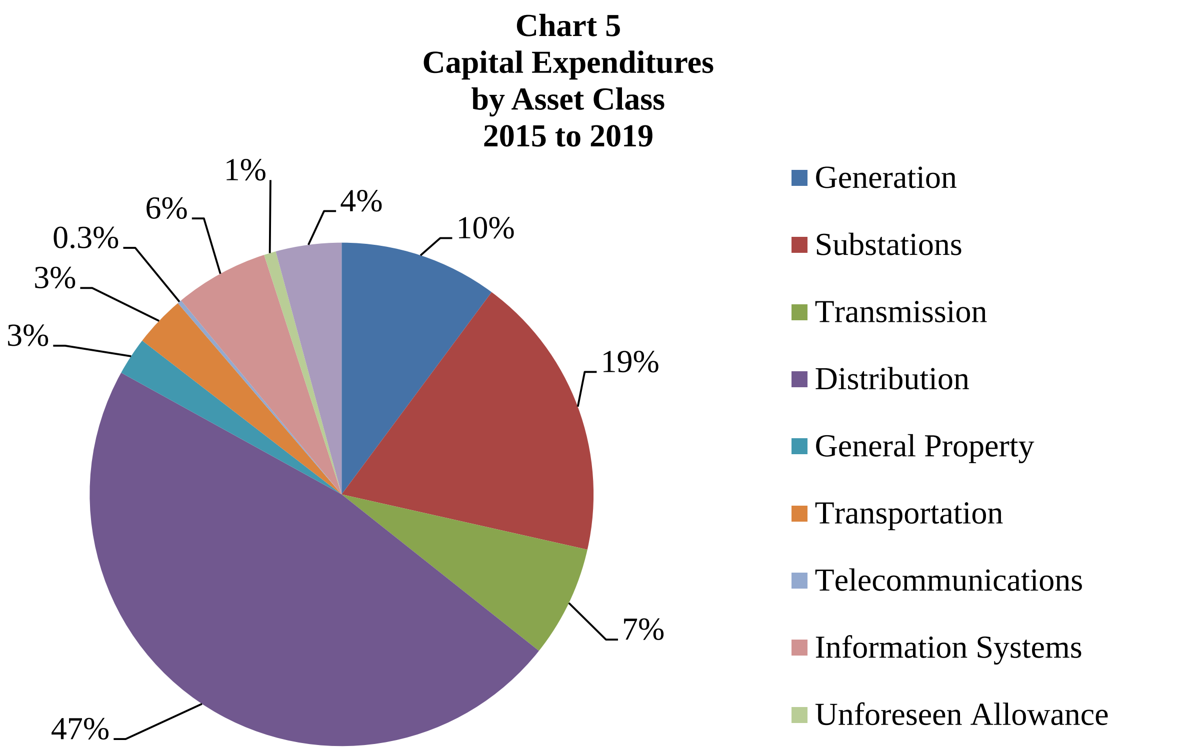


[9] With the exception of 2014 and 2016, the inflation adjusted curve is relatively flat. The increase in forecast capital expenditure in 2014 is attributable to the $15 million project to replace the Bell Island submarine cable. The increase in forecast capital expenditure in 2016 is attributable to the $13 million project to replace the Pierre's Brook penstock.

Plant replacement accounts for 50% of all planned expenditures over the 5-year period from 2015 through 2019. This is the same as the average of 50% in the previous 5-year period from 2010 through 2014. Capital expenditure related to customer and load growth accounts for 33% of planned expenditures for this period. This is practically the same as the average of 34% in the previous 5-year period from 2010 through 2014.

The remaining 17% of total capital expenditures for the 2015 through 2019 period relate to a variety of origins including information systems, system additions, general expenses capitalized, third party requirements and financial costs.

Chart 5 shows aggregate forecast capital expenditures for the period 2015 through 2019 by asset class.



The Distribution asset class accounts for 47% of all planned expenditures over the next 5 years, followed by Substations (19%), Generation (10%) and Transmission (7%). The remaining six asset classes account for 17% of total capital expenditures for the 2015 through 2019 period.

Overall, planned expenditures for the period 2015 through 2019 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 portable generation over the forecast period.

A summary of planned capital expenditures by asset class and by project for 2015 to 2019 is provided in Appendix A.

3.2.2 Generation

Generation capital expenditures will average approximately $9.9 million per year from 2015 through 2019, which is greater than the annual average of $7.3 million from 2010 through 2014.

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

- breakdown capital maintenance;
- generation preventive capital maintenance; and
- specific capital project initiatives, such as plant refurbishment.

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. Specifically, the following major capital projects are planned:

- In 2015 and 2016, the Company plans to replace the Pierre's Brook woodstave penstock, refurbish the existing surge tank and upgrade the plant controls at an estimated cost of $15.8 million. Work in 2015 will involve upfront engineering as well as necessary work required for the plant access road. The penstock replacement, surge tank refurbishment and plant controls upgrade are planned for 2016.

- In 2015, 2017 and 2018, the Company plans to refurbish the generators, turbines and wicket gates on all 3 generators along with the automation of G1 at the 76 year old Tors Cove hydroelectric plant at an estimated total cost of $5.2 million.

- In 2016 and 2017, the Company plans to purchase a 5 MW mobile generator at an estimated cost of $9.0 million. The mobile generator will be used for both emergency generation and to minimize customer outages during planned work.[10]

- In 2018, the Company plans to replace the runner at the Cape Broyle hydro plant to increase hydro production by 0.9 GWh at an estimated cost of $0.9 million.

- In 2019, the Company plans to replace the final section of woodstave penstock at the 108 year old Petty Harbour hydroelectric plant at an estimated cost of $2.1 million. The remaining section of woodstave penstock was replaced in 1999 with a steel penstock.

[10] The existing mobile gas turbine will be 43 years old in 2016.

Newfoundland Power's gas turbines range in age from 39 years to 45 years.[11] Historically, these thermal generators have been used to support system peaks for very limited periods of time each year, to allow for system maintenance in their local areas and to provide backup in the event of localized outages. Increased use of the gas turbines during the past 2 winter seasons is a significant change in usage.[12]

Newfoundland Power's 2014 Five Year Capital Plan included budgetary cost estimates for the overhaul of the Greenhill gas turbine in 2017 and the Wesleyville gas turbine in 2018. The timing, anticipated scope and cost estimates for these overhauls were based upon the historical level of usage for these units. Condition assessments for the Company's gas turbines are underway in light of potential increased use. The timing, scope and cost estimates for gas turbine equipment overhauls or complete system replacements will not be known until the condition assessments are completed. It is anticipated that the review will be completed in late 2014. No budgetary cost estimates associated with the overhaul of the Company's gas turbines are included in the 2015 Five Year Capital Plan.

3.2.3 Transmission

Transmission capital expenditures are expected to average $6.9 million annually from 2015 through 2019 compared with $4.8 million annually from 2010 through 2014.

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

- breakdown capital maintenance;
- transmission preventive capital maintenance; 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 10-year 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** Transmission Line Rebuild Strategy* included with the 2015 Capital Budget Application.

In 2018 the Company anticipates that a new transmission line will be required to supply substations in the area from Torbay to Portugal Cove at an estimated cost of approximately $1.6 million. In 2011 the Company installed a new 25 MVA transformer in Pulpit Rock substation

[11] The Greenhill gas turbine is 39 years old, the Wesleyville gas turbine is 45 years old and the mobile gas turbine is 40 years old.

[12] The rate of wear in a gas turbine is significantly affected by the number of times the turbine is stopped and started as each stop/start cycle involves extreme temperature changes and material expansion and contraction within the turbine. See, for example, *Technology Characterization: Gas Turbines* prepared for the Environmental Protection Agency, Washington DC, December 2008 at page 18.

and in 2017 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. 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 is required to provide redundancy of supply to this growing area.

3.2.4 Substations

Substations capital expenditures are expected to average $17.9 million annually from 2015 through 2019, a material increase from the average of $13.7 million annually from 2010 through 2014. The increase in expenditure is largely attributable to the requirement for additional system capacity to serve increased customer load and increasing the automation of transmission line breakers and distribution feeder breakers and reclosers.

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

- breakdown capital maintenance;
- substation preventive capital maintenance;
- Government regulations regarding the elimination of 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 10-year substation strategy 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 strategic plan is included in the report ***2.1** 2015 Substation Refurbishment and Modernization* filed with the 2015 Capital Budget Application.

The system events of January 2-8, 2014, particularly the lengthy customer outages and the successive rotating power outages revealed control limitations on the Company's transmission and distribution systems. SCADA control and monitoring has been implemented on approximately 91% of Newfoundland Power's transmission lines and approximately 60% of distribution feeders.[13] The 5-Year Capital Plan will include projects to complete the automation of the remaining distribution feeders. The *2015 Substation Refurbishment and Modernization* project includes the automation of 25 distribution feeders and 4 additional transmission line breakers.

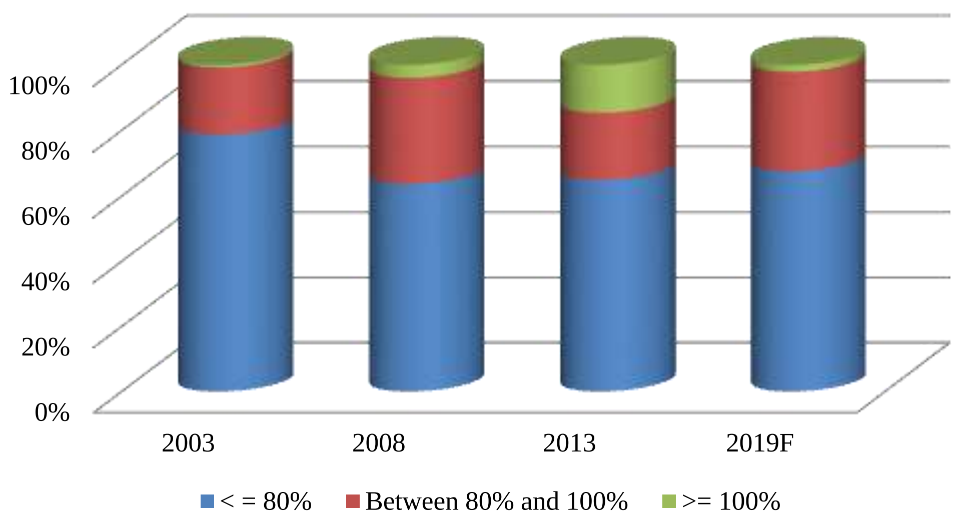
[13] The level of monitoring is dependent on the type of protection and communication equipment installed at the substation and ranges from monitoring equipment status to the ability to remotely control equipment and configure protection settings.

The Company forecasts a number of significant substations projects will be required due to system load growth over the planning period. Capital expenditures will be required to increase system capacity, particularly power transformation capacity.

Over the 2015 to 2019 forecast period there is a requirement to install 11 substation transformers to accommodate load growth.[14] In 2015, as a result of customer and load growth experienced over the past decade new power transformers will be required at Clarenville, Lethbridge and Kenmount substations. Also in 2015 an existing substation transformer will be relocated to St. John's Main Substation.[15] Commencing in 2016 and continuing through 2019, 5 new substation transformers will be required for the Northeast Avalon Peninsula and Grand Falls areas.[16] The Company will also relocate 2 transformers to substations in St. John's and the Codroy Valley that will become available as a result of the 8 new transformer purchases.

Chart 6 shows substation transformer capacity utilization on peak for substations located across the Company's service territory.

Chart 6
Substation Transformer Capacity Utilization on Peak
2003, 2008, 2013 and 2019F



[14] By comparison, in the period 2010 through 2014, Newfoundland Power has purchased 7 new power transformers and relocated 2 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] Planning studies for the Lethbridge, Clarenville, Kenmount and St. John's Main service areas are included in the 2015 Capital Budget Application report ***2.2** 2015 Additions Due To Load Growth*.

[16] 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.

In 2003, approximately 21% of substation transformers had capacity utilization on peak of 80% or greater. By 2013, the proportion of substation transformers with capacity utilization on peak of 80% or greater had increased to 36%. This reflects the impact of customer load growth on substation transformer capacity utilization. With load growth forecast to be in the 1% to 2% range through the planning period, the capacity utilization on peak of substation transformers will continue to increase. The addition of 8 new substation transformers and relocation of 3 other substation transformers forecast in this 5-year capital plan will not materially change the proportion of substation transformers with capacity utilization on peak of 80% or greater. It does however reduce significantly the number of transformers at or above 100% utilization on peak.[17] The Company's annual capital budget applications will include engineering studies detailing the requirements for additional substation transformers in the years in which they are required.

The Company will meet the Government of Canada's regulatory requirement to remove from service all bushings and instrument transformer equipment containing oil at or above 500 mg/kg by December 31, 2014.[18] 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 $3.6 million to address PCB concentrations greater than 50 mg/kg and less than 500 mg/kg in advance of the 2025 deadline.

3.2.5 Distribution

Distribution capital expenditures from 2015 through 2019 are expected to increase to an average of approximately $46.1 million annually, compared to an average of $43.9 million annually from 2010 through 2014.

The Company operates approximately 9,500 km of distribution lines serving approximately 257,000 customers. Distribution capital expenditures are primarily driven by:

- new customers;
- third party requests;
- breakdown capital maintenance;
- distribution preventive capital maintenance;
- system load growth; and
- specific capital project initiatives, such as trunk feeder rebuilds.

The number of new customer connections is forecast to decrease towards the end of the planning period. Over the 5-year period from 2015 to 2019 the number of new customer connections will decrease by 7.3 %. Over the same 5-year period capital expenditures associated with new customer connections is forecast to increase by 3.8%. This increase in capital expenditures is primarily due to inflation. The costs to connect new customers to the electricity system are included in several distribution projects including *Extensions*, *Transformers*, *Services*, *Meters* and *Street Lighting*.

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17 The reduction in the number of transformers at or above 100% utilization on peak is reflected in the distribution of transformer additions over the 2015 to 2019 period. For example, 8 of the 11 transformer additions will occur in the first 2 years of the 5-year plan.

18 Newfoundland Power has been granted a permit extending the deadline to remove from service equipment containing oil at or above 500 mg/kg to December 31, 2014.

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

	2015	2016	2017	2018	2019
New Customer Connections	4,749	4,731	4,549	4,410	4,402
Average Cost/Connection	$4,724	$4,847	$5,005	$5,169	$5,291
Capital Expenditure (000s)	$22,436	$22,929	$22,770	$22,795	$23,289

Over the period 2015 to 2019, the expenditure associated with new customer connections is forecast to be within the range of $22 million to $23 million, or approximately 24% of the annual capital expenditures.

Distribution capital expenditures are required to relocate or replace distribution lines to meet third party requests from governments, telecommunications companies and individual customers. In 2015, the expenditures associated with third party requests are estimated at $2.5 million. Over the remainder of the 5-year period, these expenditures are forecast to remain stable and approximate an average of $2.6 million.

Capital expenditures associated with the replacement of meters are typically based upon historical expenditures. 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 report ***4.3*** *2013 Meter Strategy* filed with the 2013 Capital Budget Application. In 2015, the Company has included a project to replace all existing non-AMR meters on the Burin Peninsula. The Company will pilot new technology to reduce the number of meter reading days to read the approximate 11,000 meters on the Burin Peninsula from 26 days to possibly 4 days. The report ***4.4*** *Burin AMR Project* filed with the 2015 Capital Budget Application provides the details on the savings achieved by converting all meters to AMR technology.

The Company has a preventive capital maintenance program in place for its Distribution assets. However, in-service failures of distribution plant and equipment are unavoidable. The Company expects its efforts in preventive maintenance will counter the continuous aging of its distribution assets such that the capital expenditure due to distribution plant and equipment failures will approximate the historical average cost and while there will be fluctuations, costs are forecast to remain relatively stable over the next 5 years.

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.

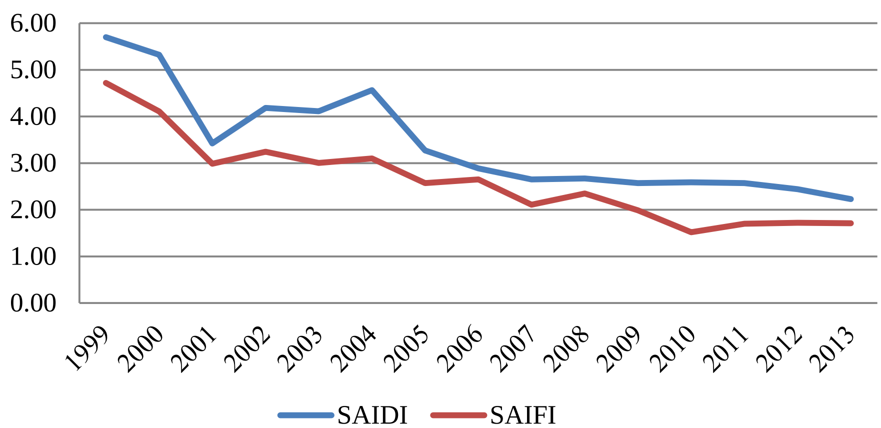
The Distribution *Reconstruction* project involves the replacement of deteriorated or damaged distribution structures and electrical equipment. The project is comprised of small unplanned projects and is estimated using the historical average of the most recent 5-year period.

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. Expenditure for feeder modifications and additions due to system load growth from 2015 through 2019 is expected increase over the next 5 years.[19]

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 a project titled *Distribution Reliability Initiative*.

Chart 7 shows SAIDI, or system average interruption duration index, and SAIFI, or system average interruption frequency index, for the years 1999 through 2013. Chart 7 has been adjusted to remove the effects of severe weather and system events.[20]

Chart 7
SAIDI and SAIFI
1999 - 2013



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[19] Capital expenditures for the Feeder Additions for Load Growth project for the 5-year period 2010 to 2014 were approximately $6.6 million

[20] 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 January 11th 2013 system disturbance and the Central Newfoundland winter storm in November 2013. These exclusions are consistent with the Canadian Electricity Association approved definitions. If these severe weather events were included, 2007 SAIDI and SAIFI would be 5.94 and 2.46, respectively, 2010 SAIDI and SAIFI would be 13.82 and 2.69 respectively, 2011 SAIDI and SAIFI would be 4.03 and 1.95, respectively, 2012 SAIDI and SAIFI would be 5.85 and 2.12 respectively and 2013 SAIDI and SAIFI would be 3.04 and 1.82 respectively .

Newfoundland Power considers current levels of service reliability on a system wide basis to be satisfactory. This primarily reflects the current condition of Newfoundland Power's distribution system assets. As a result, capital expenditures in the *Distribution Reliability Initiative* project were reduced in recent years.[21]

Commencing in 2014, Newfoundland Power has incorporated additional reliability indices, CIKM and CHIKM into its reliability analysis.[22] This has resulted in 2 distribution feeders being identified for work in 2015. These distribution feeders, KBR-10 and MOL-09 are located in the east and west ends of the City of St. John's respectively.[23] Details on the project expenditure can be found in the report ***4.1*** *Distribution Reliability Initiative* filed with the 2015 Capital Budget Application.

Newfoundland Power has equipment located in electrical vaults in the St. John's downtown area that were constructed as part of the Water Street underground electrical distribution system in the late 1960's. These vaults are typically located in the basement of buildings and contain high voltage electrical equipment that converts primary voltages from the existing underground distribution system to secondary voltages. The majority of the vaults in the St. John's downtown area contain exposed high voltage electrical conductor and equipment. In 2015, the Company will refurbish and modernize 3 of the 19 vaults in the St. John's downtown area.[24] Details on the refurbishment and modernization of the vaults are found in report ***4.3*** *Vault Refurbishment and Modernization* filed with the 2015 Capital Budget Application.

The Company continues to assess whether the replacement rate of older Distribution assets is sufficient to ensure both (i) continued safe and reliable service and (ii) long-term stability and predictability in capital expenditures.

The system events of January 2-8, 2014 revealed capacity and control limitations on the Company's distribution systems.[25] To address some of these limitations the Company filed a 2014 supplemental capital application to install 14 downline automated distribution feeder sectionalizing reclosers on heavily loaded distribution feeders on the Northeast Avalon Peninsula. Nine distribution feeders and 5 single-phase taps have been identified for the installation of remotely controlled reclosers to improve flexibility in the operation of Newfoundland Power's distribution feeders.[26] The 2015 Capital Plan has included a distribution

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[21] Over the period from 1999 to 2011, expenditures for the Distribution Reliability Initiative project totalled approximately $17.5 million. In the 3 years since, the Company has not had a Distribution Reliability Initiative capital project.

[22] In 2012 the Canadian Electricity Association began capturing and reporting on 2 additional indices; customer hours of interruption per kilometer "CHIKM" and customers interrupted per kilometer "CIKM".

[23] 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 issues with older poles and associated infrastructure.

[24] In 2014 work is underway to refurbish and modernize 3 of the 19 vaults in the St. John's downtown area as approved in Order No. P.U. 27 (2013).

[25] Cold load pickup was experienced following the sometimes lengthy successive customer outages during the period. These conditions tended to extend customer outages beyond what they would have been, absent the overloads.

[26] These 14 remotely controlled reclosers are in addition to 26 other reclosers that were previously identified in the 2014 Capital Budget. The 2014 capital budget supplement was approved by the Board in Order No. P.U. 14 (2014).

project titled *Distribution Feeder Automation* that increases the automation of the Company's distribution feeders.

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
- backup electricity generation at Company buildings.

General Property capital expenditures are expected to average $2.4 million annually from 2015 through 2019 which is an increase from an average of $1.9 million for the period from 2010 through 2014. The increase is attributable to inflation and renovations to Company buildings across the province including Duffy Place, which serves the Northeast Avalon area, over the period.

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.

Transportation capital expenditures from 2015 through 2019 are expected to increase to an average of approximately $3.2 million annually, compared to an average of $2.6 million annually from 2010 through 2014. The Company operates 72 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 2015 through 2019 is principally reflective of inflation and the number of heavy fleet and passenger vehicles expected to meet the replacement parameters over the period. Also, commencing in 2016 and continuing through 2019, the Company plans to increase the heavy fleet from 72 units to 79 units to accommodate the increase in the number of journeyperson powerline technicians resulting from the advancement of apprentices. This will reduce the number of 3 person crews and increase the number of 2 person crews, which, in turn, will improve efficiency.

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 decrease to an average of approximately $261,000 annually from 2015 through 2019 compared to the annual average of $304,000 from 2010 through 2014. The difference is attributable to the reduced cost associated with replacing new mobile equipment in the early years of operation for the new VHF mobile radio system.[27]

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 2015 through 2019 are expected to increase to an average of approximately $5.9 million annually, compared to an average of $3.9 million annually from 2010 through 2014. The increase is largely driven by the SCADA system replacement and operational technology upgrades for the Company's Geographic Information System ("GIS") and Outage Management System.[28]

In 2013, the Company undertook comprehensive assessments of both the Customer Service System ("CSS") and SCADA system as a result of the technical obsolescence of the Hewlett Packard AlphaServer hardware and associated operating systems. The AlphaServer hardware became available in 1992 and was last manufactured in 2008. Hewlett Packard has continued to service the AlphaServer hardware and associated operating systems through 2012. The assessments concluded that the SCADA system replacement should proceed in 2015 and the CSS system replacement could be deferred.[29]

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 2015 through 2019.

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[27] The 2013 capital budget included the replacement of the Company's VHF mobile radio system with a system shared with other users including Newfoundland & Labrador Hydro.

[28] A detailed report on the SCADA system replacement is included with the Application as **6.4** *SCADA System Replacement*. A report on the improvements being made with the GIS system is included with the Application as **6.5** *Geographic System Replacemen*t.

[29] The justification for the SCADA system replacement can be found in the report ***6.4*** *SCADA System Replacement*. The justification for the deferral of the CSS replacement can be found in the report ***6.2*** *System Upgrades*.

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 $4.1 million is reflected in each year's capital budget from 2015 through 2019.

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 some circumstances, necessarily facilitate such stability. The Company has identified some risks to such stability in the period 2015 through 2019.

Newfoundland Power has an obligation to serve customers in its service territory. 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 vary from forecast, the capital expenditure for the required transformers (each in the order of $2-$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, like the losses of the Kenmount, Horsechops, Pierre's Brook and Salt Pond power transformers, will necessitate capital expenditures.[30]

Newfoundland Power's gas turbines range in age from 39 years to 45 years. These gas turbines had a significant increase in usage during the December 2013 and January 2014 system supply shortage and blackout event. Condition assessments were completed following the 2013/2014 winter season identifying necessary refurbishment work to be completed prior to the 2014/2015 winter season. A broader review of the Company's gas turbines is underway in light of potential increased use. The timing, scope and cost estimates for major gas turbine equipment overhauls or complete system replacements will not be known until the broader review is completed. It is anticipated that the review will be completed in the 3rd quarter of 2014 and necessary capital expenditures will be identified in future capital plans.

Population growth on the Northeast Avalon Peninsula and new home construction continues to be strong. However, the current forecast for new customer connections indicates a decline in new customer connections in the Company's service territory. The extent of change in new customer connections required over the course of this 5-year capital plan can have a material impact on capital expenditures.

[30] 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 Muskrat Falls development will have an impact upon Newfoundland Power's capital expenditures. The Company will be involved in supplying construction power to sites within its service territory and potential rerouting of existing transmission and distribution lines to accommodate the Nalcor DC transmission line. There may be other impacts associated with integrating the new DC infeed with the existing power system. This capital plan has not envisioned material capital expenditures resulting from the Muskrat Falls development.

The Company has taken steps to reduce the uncertainty regarding replacement of its CSS, which has been in service since 1991.[31] These steps have included upgrades of hardware and software components and removal of technology components that posed the highest risk. The current versions of hardware, software and database should be supported throughout this capital plan period. 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 5th and 6th, 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's investigation into supply issues and power outages on the Island Interconnected System may result in Newfoundland Power undertaking capital expenditures to address gaps as identified by the Board or its consultant.[32]

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[31] The CSS originally cost in excess of $10 million.

[32] The 2015 Capital Plan has included projects to increase automation of transmission lines and distribution feeders.

Appendix A
2015-2019 Capital Plan

Newfoundland Power Inc.
2015-2019 Capital Plan
(000s)

Asset Class	2015	2016	2017	2018	2019
Generation	$4,914	$19,243	$10,976	$6,604	$7,670
Substations	$22,478	$17,199	$16,540	$15,426	$17,755
Transmission	$5,731	$6,061	$8,042	$8,380	$6,601
Distribution	$42,473	$46,385	$46,877	$47,702	$47,008
General Property	$3,224	$2,167	$1,867	$2,154	$2,411
Transportation	$2,917	$2,955	$3,194	$3,355	$3,511
Telecommunications	$123	$323	$340	$386	$133
Information Systems	$7,501	$7,572	$5,065	$4,395	$4,745
Unforeseen Allowance	750	750	750	750	750
General Expenses Capitalized	4,100	4,100	4,100	4,100	4,100
Total	**$94,211**	**$106,755**	**$97,751**	**$93,252**	**$94,684**

Newfoundland Power Inc.
2015-2019 Capital Plan
(000s)

GENERATION

Project	2015	2016	2017	2018	2019
Facility Rehabilitation – Hydro	$1,586	$1,470	$1,490	$1,512	$1,533
Facility Rehabilitation - Thermal	$216	$370	$524	$228	$232
Hydro Plant Production Increase	$0	$0	$0	$1,727	$820
Public Safety Around Dams	$429	$880	$662	$0	$0
Pierre’s Brook Penstock	$750	$15,013	$0	$0	$0
Tors Cove Plant Refurbishment	$1,777	$10	$800	$2,615	$0
Seal Cove Plant Refurbishment	$156	$0	$0	$0	$0
Rattling Brook Plant Refurbishment	$0	$0	$0	$345	$350
Cape Broyle Plant Refurbishment	$0	$0	$0	$177	$0
Horsechops Plant Refurbishment	$0	$0	$0	$0	$675
Lookout Brook Plant Refurbishment	$0	$0	$0	$0	$610
Morris Plant Refurbishment	$0	$0	$0	$0	$510
Petty Harbour Plant Refurbishment	$0	$0	$0	$0	$2,940
Purchase Portable Generation	$0	$1,500	$7,500	$0	$0
Total - Generation	**$4,914**	**$19,243**	**$10,976**	**$6,604**	**$7,670**

Newfoundland Power Inc.
2015-2019 Capital Plan
(000s)

SUBSTATIONS

Project	2015	2016	2017	2018	2019
Substations Refurbishment & Modernization	$9,961	$4,927	$6,339	$7,256	$11,296
Replacements Due to In-Service Failure	$3,110	$3,182	$3,256	$3,331	$3,404
Additions Due to Load Growth	$9,407	$9,090	$5,754	$3,621	$1,809
PCB Bushing Phase-Out	$0	$0	$1,191	$1,218	$1,246
Total - Substations	**$22,478**	**$17,199**	**$16,540**	**$15,426**	**$17,755**

Newfoundland Power Inc.
2015-2019 Capital Plan
(000s)

TRANSMISSION

Project	**2015**	**2016**	**2017**	**2018**	**2019**
Rebuild Transmission Lines	$3,830	$4,161	$6,092	$4,880	$4,801
Transmission Line Reconstruction	$1,901	$1,900	$1,900	$1,900	$1,800
Transmission Line Additions	$0	$0	$50	$1,600	$0
Total – Transmission	**$5,731**	**$6,061**	**$8,042**	**$8,380**	**$6,601**

Newfoundland Power Inc.
2015-2019 Capital Plan
(000s)

DISTRIBUTION

Project	2015	2016	2017	2018	2019
Extensions	$12,314	$12,592	$12,429	$12,368	$12,664
Meters	$3,146	$2,759	$2,581	$2,632	$2,184
Services	$4,101	$4,198	$4,182	$4,193	$4,297
Street Lighting	$2,469	$2,523	$2,517	$2,528	$2,583
Transformers	$6,778	$7,311	$7,462	$7,617	$7,758
Reconstruction	$3,964	$4,069	$4,177	$4,288	$4,399
Rebuild Distribution Lines	$3,302	$3,384	$3,468	$3,554	$3,638
Relocations For Third Parties	$2,504	$2,566	$2,630	$2,696	$2,761
Distribution Reliability Initiative	$863	$820	$840	$860	$880
Distribution Feeder Automation	160	250	330	205	330
Feeder Additions for Load Growth	$1,684	$3,527	$3,774	$3,172	$1,652
Trunk Feeders	$991	$2,185	$2,282	$3,380	$3,649
Allowance for Funds Used During Construction	$197	$201	$205	$209	$213
Total – Distribution	**$42,473**	**$46,385**	**$46,877**	**$47,702**	**$47,008**

Newfoundland Power Inc.
2015-2019 Capital Plan
(000s)

GENERAL PROPERTY

Project	2015	2016	2017	2018	2019
Tools and Equipment	$467	$477	$485	$494	$504
Additions to Real Property	$385	$391	$397	$402	$307
Renovations Company Buildings	$2,068	$1,124	$985	$1,258	$1,600
Standby Generators	$304	$175	$0	$0	$0
Total - General Property	**$3,224**	**$2,167**	**$1,867**	**$2,154**	**$2,411**

Newfoundland Power Inc.
2015-2019 Capital Plan
(000s)

TRANSPORTATION

Project	2015	2016	2017	2018	2019
Purchase Vehicles and Aerial Devices	$2,917	$2,955	$3,194	$3,355	$3,511
Total - Transportation	**$2,917**	**$2,955**	**$3,194**	**$3,355**	**$3,511**

Newfoundland Power Inc.
2015-2019 Capital Plan
(000s)

TELECOMMUNICATIONS

Project	2015	2016	2017	2018	2019
Replace/Upgrade Communications Equipment	$123	$126	$128	$131	$133
Fibre Optic Cable	0	197	212	255	0
Total - Telecommunications	**$123**	**$323**	**$340**	**$386**	**$133**

Newfoundland Power Inc.
2015-2019 Capital Plan
(000s)

INFORMATION SYSTEMS

Project	**2015**	**2016**	**2017**	**2018**	**2019**
Application Enhancements	$1,325	$1,250	$1,450	$1,500	$1,600
System Upgrades	$1,125	$1,695	$1,495	$1,495	$1,595
Personal Computer Infrastructure	$487	$500	$500	$500	$500
Shared Server Infrastructure	$970	$650	$600	$650	$750
Network Infrastructure	$328	$175	$300	$250	$300
SCADA System Replacement	$2,833	$2,842	$0	$0	$0
Operations Technology Improvement	$433	$460	$720	$0	$0
Total – Information Systems	**$7,501**	**$7,572**	**$5,065**	**$4,395**	**$4,745**

Newfoundland Power Inc.
2015-2019 Capital Plan
(000s)

UNFORESEEN ALLOWANCE

Project	2015	2016	2017	2018	2019
Allowance for Unforeseen Items	$750	$750	$750	$750	$750
Total - Unforeseen Allowance	**$750**	**$750**	**$750**	**$750**	**$750**

Newfoundland Power Inc.
2015-2019 Capital Plan
(000s)

GENERAL EXPENSES CAPITALIZED

Project	2015	2016	2017	2018	2019
General Expenses Capitalized	$4,100	$4,100	$4,100	$4,100	$4,100
Total - General Expenses Capitalized	**$4,100**	**$4,100**	**$4,100**	**$4,100**	**$4,100**

2014 Capital Expenditure Status Report

June 2014

Newfoundland Power Inc.

2014 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 5 of Order No. P.U. 27 (2013).

Page 1 of the 2014 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 2014, which were approved in Order Nos. P.U. 27 (2013), P.U. 43 (2013) and P.U. 14 (2014). The detailed tables also include information on those capital projects approved for 2012 and 2013 (and approved in Order Nos. P.U. 26 (2011) and P.U. 31 (2012)) that were not completed prior to 2014.

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 the blue page at the conclusion of the 2014 Capital Expenditure Status Report. These variance criteria are as outlined in the *Capital Budget Application Guidelines*.

Newfoundland Power Inc.

2014 Capital Budget Variances
(000s)

	Approved by Order Nos. P.U.27 (2013) P.U.43 (2013) P.U.14 (2014)	Forecast	Variance
Generation – Hydro	$9,010	$9,010	$ -
Generation - Thermal	312	412	100
Substations[1]	18,170	18,170	-
Transmission	5,469	5,469	-
Distribution[2,3]	56,377	56,894	517
General Property	1,112	1,112	-
Transportation	2,570	2,570	-
Telecommunications	99	99	-
Information Systems	4,005	4,005	-
Unforeseen Items	750	750	-
General Expenses Capitalized	4,000	4,200	200
Total	$101,874	$102,691	817
Projects carried forward from 2012 and 2013		$4,410	

[1] Includes $1,305,000 in estimated costs associated with substation refurbishment and automation in preparation for the 2014/2015 winter season as approved in Order No. P.U. 14 (2014).

[2] Includes $1,587,000 in estimated costs associated with distribution system automation in preparation for the 2014/2015 winter season as approved in Order No. P.U. 14 (2014).

[3] Includes $14,520,000 in estimated costs associated with the replacement of the Bell Island Submarine Cable as approved in Order No. P.U. 43 (2013).

2014 Capital Expenditure Status Report
(000s)

	Capital Budget				Actual Expenditures				Forecast			
	2012	2013	2014	Total	2012	2013	2014	Total To Date	Remainder 2014	Total 2014	Overall Total	Variance
	A	B	C	D	E	F	G	H	I	J	K	L
2014 Projects	$ -	$ -	$ 101,874	$ 101,874	$ -	$ -	$ 30,950	$ 30,950	$ 71,741	$ 102,691	102,691	$ 817
2013 Projects	-	6,312	-	$ 6,312	-	4,539	-	4,539	1,531	$ 1,531	6,070	(242)
2012 Projects	5,879	3,121	-	$ 9,000	2,936	851	1,072	4,859	1,803	$ 2,875	6,662	(2,338)
Grand Total	**$ 5,879**	**$ 9,433**	**$ 101,874**	**$ 117,186**	**$ 2,936**	**$ 5,390**	**$ 32,022**	**$ 40,348**	**$ 75,075**	**$ 107,097**	**$ 115,423**	**$ (1,763)**

Column A	Approved Capital Budget for 2012
Column B	Approved Capital Budget for 2013
Column C	Approved Capital Budget for 2014
Column D	Total of Columns A,B and C
Column E	Actual Capital Expenditures for 2012
Column F	Actual Capital Expenditures for 2013
Column G	Actual Capital Expenditures for 2014
Column H	Total of Columns E,F and G
Column I	Forecast for Remainder of 2014
Column J	Total of Columns G and I
Column K	Total of Columns H and I
Column L	Column K less Column D

2014 Capital Expenditure Status Report
(000s)

Category: Generation - Hydro

Project	Capital Budget 2012	Capital Budget 2013	Capital Budget 2014	Capital Budget Total	Actual Expenditures 2012	Actual Expenditures 2013	Actual Expenditures 2014	Actual Expenditures Total To Date	Forecast Remainder 2014	Forecast Total 2014	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	K	L	
2014 Projects													
Hydro Plants - Facility Rehabilitation	$ -	$ -	$ 1,610	$ 1,610	$ -	$ -	$ 392	$ 392	$ 1,218	$ 1,610	$ 1,610	$ -	
Hydro Plant Production Increase	-	-	1,665	1,665	-	-	48	48	1,617	1,665	1,665	-	
Hearts Content Plant Refurbishment	-	-	5,735	5,735	-	-	378	378	5,357	5,735	5,735	-	
Total - 2014 Generation Hydro	**$ -**	**$ -**	**$ 9,010**	**$ 9,010**	**$ -**	**$ -**	**$ 818**	**$ 818**	**$ 8,192**	**$ 9,010**	**$ 9,010**	**$ -**	
2012 Projects													
Rattling Brook Dam Refurbishment	$ 5,000	$ -	$ -	$ 5,000	2,744	213	$ 9	$ 2,966	$ 266	$ 275	$ 3,232	$ (1,768)	1
Total - Generation Hydro	**$ 5,000**	**$ -**	**$ 9,010**	**$ 14,010**	**$ 2,744**	**$ 213**	**$ 827**	**$ 3,784**	**$ 8,458**	**$ 9,285**	**$ 12,242**	**$ (1,768)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2012
Column B	Approved Capital Budget for 2013
Column C	Approved Capital Budget for 2014
Column D	Total of Columns A,B and C
Column E	Actual Capital Expenditures for 2012
Column F	Actual Capital Expenditures for 2013
Column G	Actual Capital Expenditures for 2014
Column H	Total of Columns E,F and G
Column I	Forecast for Remainder of 2014
Column J	Total of Columns G and I
Column K	Total of Columns H and I
Column L	Column K less Column D

2014 Capital Expenditure Status Report
(000s)

Category: Generation - Thermal

Project	Capital Budget 2014	Capital Budget Total	Actual Expenditures 2014	Actual Expenditures Total To Date	Forecast Remainder 2014	Forecast Total 2014	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2014 Projects									
Thermal Plants - Facility Rehabilitation	$ 312	$ 312	$ 354	$ 354	$ 58	$ 412	$ 412	$ 100	2
Total - Generation Thermal	**$ 312**	**$ 312**	**$ 354**	**$ 354**	**$ 58**	**$ 412**	**$ 412**	$ 100	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2014
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2014
Column D	Total of Column C
Column E	Forecast for Remainder of 2014
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2014 Capital Expenditure Status Report
(000s)

Category: Substations

Project	Capital Budget 2012 A	Capital Budget 2013 B	Capital Budget 2014 C	Capital Budget Total D	Actual Expenditures 2012 E	Actual Expenditures 2013 F	Actual Expenditures 2014 G	Actual Expenditures Total To Date H	Forecast Remainder 2014 I	Forecast Total 2014 J	Forecast Overall Total K	Variance L	Notes*
2014 Projects													
Substation Refurbishment and Modernization	$ -	$ -	$ 7,328	$ 7,328	$ -	$ -	$ 1,074	$ 1,074	$ 6,254	$ 7,328	$ 7,328	$ -	
Replacements Due to In-Service Failures	-	-	2,859	2,859	-	-	1,755	1,755	1,104	2,859	2,859	-	
Additions Due to Load Growth	-	-	5,004	5,004	-	-	344	344	4,660	5,004	5,004	-	
PCB Bushing Phase-out	-	-	2,733	2,733	-	-	1,274	1,274	1,459	2,733	2,733	-	
Hardwoods Substation Feeder Termination	-	-	246	246	-	-	-	-	246	246	246	-	
	$ -	$ -	$ 18,170	$ 18,170	$ -	$ -	$ 4,447	$ 4,447	$ 13,723	$ 18,170	$ 18,170	$ -	
2013 Projects													
Substation Refurbishment and Modernization	$ -	$ 4,452	$ -	$ 4,452	$ -	$ 3,495	$ -	$ 3,495	$ 75	$ 75	$ 3,570	$ (882)	3
2012 - 2013 Projects													
Substation Additions - Portable Substation	$ 879	$ 3,121	$ -	$ 4,000	$ 192	$ 638	$ 1,063	$ 1,893	$ 1,537	$ 2,600	$ 3,430	$ (570)	4
Total - Substations	**879**	**7,573**	**18,170**	**26,622**	**192**	**4,133**	**5,510**	**9,835**	**15,335**	**20,845**	**25,170**	**(1,452)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2012
Column B	Approved Capital Budget for 2013
Column C	Approved Capital Budget for 2014
Column D	Total of Columns A,B and C
Column E	Actual Capital Expenditures for 2012
Column F	Actual Capital Expenditures for 2013
Column G	Actual Capital Expenditures for 2014
Column H	Total of Columns E,F and G
Column I	Forecast for Remainder of 2014
Column J	Total of Columns G and I
Column K	Total of Columns H and I
Column L	Column K less Column D

2014 Capital Expenditure Status Report
(000s)

Category: Transmission

Project	Capital Budget 2014 A	Capital Budget Total B	Actual Expenditures 2014 C	Actual Expenditures Total To Date D	Forecast Remainder 2014 E	Forecast Total 2014 F	Forecast Overall Total G	Variance H	Notes*
2014 Projects									
Rebuild Transmission Lines	$ 5,469	$ 5,469	$ 697	$ 697	$ 4,772	$ 5,469	$ 5,469	$ -	
Total - Transmission	**$ 5,469**	**$ 5,469**	**$ 697**	**$ 697**	**$ 4,772**	**$ 5,469**	**$ 5,469**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2014
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2014
Column D	Total of Column C
Column E	Forecast for Remainder of 2014
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2014 Capital Expenditure Status Report
(000s)

Category: Distribution

Project	Capital Budget 2014 A	Capital Budget Total B	Actual Expenditures 2014 C	Actual Expenditures Total To Date D	Forecast Remainder 2014 E	Forecast Total 2014 F	Forecast Overall Total G	Variance H	Notes*
2014 Projects									
Extensions	$ 11,689	$ 11,689	$ 5,318	$ 5,318	$ 6,743	$ 12,061	$ 12,061	$ 372	
Meters	2,755	2,755	1,120	1,120	1,635	2,755	2,755	-	
Services	3,930	3,930	1,391	1,391	2,637	4,028	4,028	98	
Street Lighting	2,480	2,480	868	868	1,659	2,527	2,527	47	
Transformers	6,995	6,995	4,318	4,318	2,677	6,995	6,995	-	
Reconstruction	3,787	3,787	2,041	2,041	1,746	3,787	3,787	-	
Rebuild Distribution Lines	3,462	3,462	1,021	1,021	2,441	3,462	3,462	-	
Relocate/Replace Distribution Lines For Third Parties	2,616	2,616	776	776	1,840	2,616	2,616	-	
Trunk Feeders	1,261	1,261	174	174	1,087	1,261	1,261	-	
Feeder Additions for Growth	1,102	1,102	607	607	495	1,102	1,102	-	
Allowance for Funds Used During Construction	193	193	87	87	106	193	193	-	
Bell Island Cable Replacement	14,520	14,520	2,151	2,151	12,369	14,520	14,520	-	
2014 Distribution Feeder Improvements	1,587	1,587	10	10	1,577	1,587	1,587	-	
Total Distribution	**$ 56,377**	**$ 56,377**	**$ 19,882**	**$ 19,882**	**$ 37,012**	**$ 56,894**	**$ 56,894**	**$ 517**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2014
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2014
Column D	Total of Column C
Column E	Forecast for Remainder of 2014
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2014 Capital Expenditure Status Report
(000s)

Category: General Property

Project	Capital Budget 2013 (A)	Capital Budget 2014 (B)	Capital Budget Total (C)	Actual Expenditures 2013 (D)	Actual Expenditures 2014 (E)	Actual Expenditures Total To Date (F)	Forecast Remainder 2014 (G)	Forecast Total 2014 (H)	Forecast Overall Total (I)	Variance (J)	Notes*
2014 Projects											
Tools and Equipment	$ -	$ 458	$ 458	$ -	$ 183	$ 183	$ 275	$ 458	$ 458	$ -	
Additions to Real Property	-	379	379	-	206	206	173	379	379	-	
Standby and Emergency Power - Gander Office	-	275	275	-	12	12	263	275	275	-	
Total - 2014 General Property	**$ -**	**$ 1,112**	**$ 1,112**	**$ -**	**$ 401**	**$ 401**	**$ 711**	**$ 1,112**	**$ 1,112**	**$ -**	
2013 Projects											
Standby and Emergency Power - Duffy Place	$ 160	$ -	$ 160	$ 4	$ -	$ 4	$ 156	$ 156	$ 160	$ -	
Company Building renovations	950	-	950	998	-	998	550	$ 550	1,548	598	5
Total General Property	**$ 1,110**	**$ 1,112**	**$ 2,222**	**$ 1,002**	**$ 401**	**$ 1,403**	**$ 1,417**	**$ 1,818**	**$ 2,820**	**$ 598**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2013
Column B	Approved Capital Budget for 2014
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2013
Column E	Actual Capital Expenditures for 2014
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2014
Column H	Total of Columns E and G
Column I	Total of Columns F and G
Column J	Column I less Column C

2014 Capital Expenditure Status Report
(000s)

Category: Transportation

	Capital Budget		Actual Expenditures		Forecast				
Project	**2014**	**Total**	**2014**	**Total To Date**	**Remainder 2014**	**Total 2014**	**Overall Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
2014 Projects									
Purchase Vehicles and Aerial Devices	$ 2,570	$ 2,570	$ 922	$ 922	$ 1,648	$ 2,570	$ 2,570	$ -	
Total - Transportation	**$ 2,570**	**$ 2,570**	**$ 922**	**$ 922**	**$ 1,648**	**$ 2,570**	**$ 2,570**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2014
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2014
Column D	Total of Column C
Column E	Forecast for Remainder of 2014
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2014 Capital Expenditure Status Report
(000s)

Category: Telecommunications

Project	Capital Budget 2013	Capital Budget 2014	Capital Budget Total	Actual Expenditures 2013	Actual Expenditures 2014	Actual Expenditures Total To Date	Forecast Remainder 2014	Forecast Total 2014	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2014 Projects											
Replace/Upgrade Communications Equipment	$ -	$ 99	$ 99	$ -	$ 37	$ 37	$ 62	$ 99	$ 99	$ -	
2013 Projects											
Mobile Radio System Replacement	$ 750	$ -	$ 750	$ 42	$ -	$ 42	$ 708	$ 750	$ 792	$ 42	
Total - Telecommunications	**$ 750**	**$ 99**	**$ 849**	**$ 42**	**$ 37**	**$ 79**	**$ 770**	**$ 849**	**$ 891**	**$ 42**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2014
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2014
Column D	Total of Column C
Column E	Forecast for Remainder of 2014
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B
Column I	Total of Columns F and G
Column J	Column I less Column C

2014 Capital Expenditure Status Report
(000s)

Category: Information Systems

	Capital Budget		Actual Expenditures		Forecast				
Project	**2014**	**Total**	**2014**	**Total To Date**	**Remainder 2014**	**Total 2014**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2014 Projects									
Application Enhancements	$ 1,372	$ 1,372	$ 603	$ 603	$ 769	$ 1,372	$ 1,372	$ -	
System Upgrades	1,059	1,059	314	314	745	1,059	1,059	-	
Personal Computer Infrastructure	420	420	183	183	237	420	420	-	
Shared Server Infrastructure	833	833	268	268	565	833	833	-	
Network Infrastructure	321	321	125	125	196	321	321	-	
Total - Information Systems	**$ 4,005**	**$ 4,005**	**$ 1,493**	**$ 1,493**	**$ 2,512**	**$ 4,005**	**$ 4,005**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2014
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2014
Column D	Total of Column C
Column E	Forecast for Remainder of 2014
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2014 Capital Expenditure Status Report
(000s)

Category: Unforeseen Items

Project	**Capital Budget** 2014	**Capital Budget** Total	**Actual Expenditures** 2014	**Actual Expenditures** Total To Date	**Forecast** Remainder 2014	**Forecast** Total 2014	**Forecast** Overall Total	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2014 Projects									
Allowance for Unforeseen Items	$ 750	$ 750	$ -	$ -	$ 750	$ 750	$ 750	$ -	
Total - Unforeseen Items	**$ 750**	**$ 750**	**$ -**	**$ -**	**$ 750**	**$ 750**	**$ 750**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2014
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2014
Column D	Total of Column C
Column E	Forecast for Remainder of 2014
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2014 Capital Expenditure Status Report
(000s)

Category: General Expenses Capitalized

Project	Capital Budget 2014 A	Capital Budget Total B	Actual Expenditures 2014 C	Actual Expenditures Total To Date D	Forecast Remainder 2014 E	Forecast Total 2014 F	Forecast Overall Total G	Variance H	Notes*
2014 Projects									
Allowance for General Expenses Capitalized	$ 4,000	$ 4,000	$ 1,899	$ 1,899	$ 2,301	$ 4,200	$ 4,200	$ 200	
Total - General Expenses Capitalized	**$ 4,000**	**$ 4,000**	**$ 1,899**	**$ 1,899**	**$ 2,301**	**$ 4,200**	**$ 4,200**	**$ 200**	

* See Appendix A for notes containing variance explanations.

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Column A	Approved Capital Budget for 2014
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2014
Column D	Total of Column C
Column E	Forecast for Remainder of 2014
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

Generation - Hydro

1. *Rattling Brook Dam Refurbishment (2012 Project):*

Budget: $5,000,000 Actual: $3,232,000 Variance: ($1,768,000)

In 2010, the Company received an order from Department of Fisheries and Oceans ("DFO") stating that, pursuant to section 20 of the Fisheries Act, fish passage must be in place on Rattling Brook to allow downstream migration of salmon kelts and smolts by May 1, 2013 and the upstream migration of grilse and adult salmon by June 2014.

The implementation plan as proposed in the 2012 Capital Budget Application involved completing all construction work in 2012. Subsequent to the project being approved, the Company engaged the necessary technical expertise to execute the project. As a result of this technical work, it was determined that the work should take place over a 5-year period from 2012 to 2016. The extended implementation period allows in-stream structures to be adapted to make them more suitable to migrating salmon. The revised implementation plan was submitted to DFO for review, and DFO confirmed its approval.[1]

2. *Thermal Plant – Facility Rehabilitation*

Budget: $312,000 Forecast: $412,000 Variance: $100,000

The project is necessary for the replacement or rehabilitation of deteriorated thermal plant components. During the 2013/2014 winter season there were 2 extraordinary rehabilitations to thermal plants required. In December 2013 the mobile diesel generator MD3 experienced a bearing failure while operating at Badger. The mobile diesel generator was sent to a repair facility to replace the bearing and the generator was returned to service in February 2014. During operations in December 2013 the Port Aux Basques diesel generator experienced a loss of coolant. Inspections of the diesel engine determined there were small coolant leaks in various cylinders requiring a tear-down and rebuild of the engine. The total cost for the rehabilitation of the MD3 and Port aux Basques diesel generators was $274,000.

[1] The revised implementation plan meets the requirements and schedule of the original DFO order.

Substations

3. Substation Refurbishment and Modernization (2013 Project):

Budget: $4,452,000 Forecast: $3,570,000 Variance: ($882,000)

The *Substation Refurbishment and Modernization* project budget included an estimate for the planned refurbishment of portable substation P4. However, due to the increased use of the portable substation associated with completion of the *PCB Bushing Phase-out* project, the unit was unavailable for refurbishment in 2013. The P4 refurbishment has been resubmitted for approval in the 2015 Capital Budget Application.

4. Substation Additions- Portable Substation (2012-2013 Project):

Budget: $4,000,000 Forecast: $3,430,000 Variance: ($570,000)

This is a multi-year project to purchase a new 50 MVA portable substation. The Capital Budget Application estimated an expenditure of $879,000 in 2012 and $3,621,000 in 2013 for a total project estimate of $4,500,000. In the 2013 Capital Budget Application, the budget for 2013 was reduced to $3,121,000, lowering the total project budget estimate to $4,000,000.

The order for the portable substation was placed in 2012 with delivery now expected in June 2014. The purchase of the new portable substation is $570,000 below the budget estimate. This reduction in project cost was the result of the tendered supply contract being lower than the original engineering estimate.

General Property

5. *Company Building Renovations (2013 Project):*

Budget: $950,000 Forecast: $1,548,000 Variance: $598,000

The variance is principally due to issues encountered during the Carbonear service building refurbishment, which was initially budgeted at $375,000.

During the office refurbishment at Carbonear service building, mould was discovered inside the walls. The project consultant completed an assessment that determined a mould abatement program was required. It was also determined that the drywall plaster contained asbestos, necessitating an asbestos abatement plan.

The actual expenditure figure includes an estimated additional $550,000 to complete the building refurbishment in 2014.

2015 Facility Rehabilitation

June 2014

Prepared by:

David Ball, P.Eng.

NEWFOUNDLAND POWER
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1.0 Introduction

The 2015 Facility Rehabilitation project is necessary for the replacement or rehabilitation of deteriorated plant components that have been identified through routine inspections, operating experience and engineering studies. The project includes expenditures necessary to improve the efficiency and reliability of various hydro plants or to replace plant due to in-service failures.

Newfoundland Power (the "Company") has 23 hydroelectric plants that provide energy to the Island Interconnected System. Maintaining these generating facilities reduces the need for additional, more expensive, generation.

Items involving replacement and rehabilitation work, which are identified during inspections and maintenance activities, are necessary for the continued operation of these generation facilities in a safe, reliable and environmentally compliant manner. The Company's hydro generation facilities produce a combined normal annual production of 430.5 GWh.[1] The alternative to maintaining these facilities is to retire them.

The 2015 Facility Rehabilitation project totalling $1,586,000 is comprised of Hydro Dam and Spillway Rehabilitation, Rocky Pond Turbine Shaft Rehabilitation and Generation Equipment Replacements Due to In-Service Failures.

2.0 Hydro Dam and Spillway Rehabilitation

Cost: $858,000

The Company has over 150 dam structures throughout its 23 hydroelectric facilities. Based on the age of structures in the Newfoundland Power system, deterioration of embankment, timber crib and concrete dams is to be expected. Refurbishment is required to ensure integrity of the structures is maintained to an appropriate level of dam safety as per the guidelines established by the Canadian Dam Association.[2] The cost of the projects is justified based on the need to restore the structures to an appropriate safety level based on the site design conditions and to allow for future operation of the hydro system in a safe and reliable manner.

This item involves the refurbishment of deteriorated components at various dam structures.

Specific work to be completed in 2015 includes:

1. *Horse Chops Spillway ($493,000)*
   The Horse Chops Spillway was constructed in 1953 as part of the original hydro development. This project involves replacement of the existing stop log spillway

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[1] Normal annual production was established as 430.5 GWh in the Normal Production Review, Newfoundland Power Inc., December 2010.

[2] The guidelines established by the Canadian Dam Association ("CDA") applicable to the Hydro Dam Rehabilitation projects are *CDA Dam Safety Guidelines 2007*, *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.

with a new concrete structure. Overturning stability analysis indicates that under the loads associated with ice thrust, the spillway does not meet current requirements as a result of its original slender design.[3]

One large stop log bay and 11 smaller bays are present on the spillway.[4] The 150 mm high stop logs are removed manually using hooks from the smaller bays while the 300 mm high stop logs are removed from the large bay using a mechanical lift. The mechanical lift is in poor condition and no longer functions as designed.[5]

With stop logs in place, the required flood carrying capacity of the spillway is marginally met.[6] Removal of stop logs during extreme flood conditions is therefore critical to dam safety. The only access to this site is along the Horse Chops Canal embankment, an earthfill dam with minimal erosion protection. Extreme weather and water levels could render this access route unsafe, limiting the Company's ability to reach the site to remove stop logs or to monitor and address changing conditions including debris buildup. Operation of this type of spillway is very labour intensive and during extreme flood conditions presents a safety hazard for operators.

In addition to dam safety deficiencies, the spillway does not meet public safety requirements.[7] The current railing was constructed without toe boards and does not extend all the way to the end of the narrow concrete abutment. The spillway walking surface has an opening in the center to facilitate stop log removal which is a significant tripping hazard.[8]

The significant flow through the spillway as shown in Figure 1 is a direct result of leakage from deteriorated stop logs which no longer provide an adequate seal. This condition is expected to worsen over time. Based on field measurements, it is estimated that approximately 0.78 GWh of energy is lost annually as a direct result of the leakage.[9] Addressing the leakage as part of the construction of a new concrete structure will save approximately $131,000 in annual avoided fuel cost at the Holyrood generating station.[10]

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3 The overturning analysis involved using an ice load of 75 kN/m applied 300 mm below the full supply level.

4 See Figure 1. The stop logs are supported by steel columns, which are supported by a narrow concrete footing.

5 See Figure 3.

6 Additional capacity is advisable as this type of spillway is prone to debris buildup during extreme floods due to its narrow openings, particularly with stop logs in place. The loss of capacity due to debris build up was not considered in the capacity analysis.

7 Section 4.2 of the *Guidelines for Public Safety Around Dams, 2011* outlines a risk assessment process. In its current configuration the Horse Chops spillway is considered high risk and therefore based on engineering judgment, requires improvements.

8 See Figure 2.

9 Reducing the leakage through the stoplogs has not been previously considered as a hydro production increase project. At the time of the *"Hydroelectric Systems Strategic Planning Study"* completed by Hatch in 2001, the leakage at the spillway would have been significantly less and therefore not investigated as a potential project.

10 The avoided cost of fuel at the Holyrood Thermal Generating Station is estimated based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.60 per barrel for 2014 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan - Fuel Price Projection dated April 30, 2014.

Replacing the stop log spillway with a concrete overflow spillway and replacing the access walkway will address dam safety deficiencies and remove a significant public and employee safety hazard as well as increase production at the Horse Chops and Cape Broyle hydro developments as a result of reduced leakage.

Figure 1 – Slender Structure, Significant Leakage

Figure 2 – Access Walkway

Figure 3 – Stop Log Lift

2. *Bay Bulls Big Pond Dam and Spillway ($185,000)*
   The Bay Bulls Big Pond dam and spillway structure are part of the Petty Harbour hydroelectric development watershed. The structure was reconstructed in 1988. This project involves refurbishment of the spillway, improvements to the spillway channel, grading of the dam crest and drainage improvements along the toe of the dam.

   The existing riprap material along the spillway crest does not provide adequate erosion protection as it has broken down over time and is now undersized for the design flood conditions.[11] As a result of this deterioration, the metal spillway core is exposed and has been damaged by all-terrain vehicle ("ATV") traffic. The exposed metal spillway core has become a tripping hazard.[12] The existing riprap will be replaced with a harder, more appropriately sized stone and the metal spillway core will be refurbished.

   Downstream of the spillway, the spill channel follows along a section of the toe of the dam. Some armour stone is present, however during recent spill events some displacement of this stone has occurred.[13] Larger sized armour stone is required to ensure erosion of the dam toe does not occur.

   In addition, ATV traffic has caused localized ponding of water on the dam crest and at the toe of the structure near the outlet. Minor grading of the crest is required to prevent erosion of the dam slopes. Drainage improvements at the toe of the dam are required to facilitate observation of seepage.[14]

Figure 4 –Undersized Riprap and Damaged Spillway Core

Figure 5 – Eroded Armour Stone

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[11] See Figure 4. The final riprap design will require stone size of 700-1,000 mm in diameter. The existing riprap has a maximum sizing of approximately 700 mm with a median size significantly lower.

[12] See Figure 4.

[13] The erosion in Figure 5 occurred at a flow condition well below the required design flood, indicating the current armor stone protection is inadequate to prevent erosion of the dam during the design event.

[14] The observation of seepage at the toe of the dam during routine inspections is an important factor in determining the health of a dam.

3. *Franks Canal Spillway ($180,000)*
   The Franks Canal Spillway is located on the Franks Pond Canal and is a part of the Tors Cove - Rocky Pond hydroelectric development. The Franks Canal Spillway was reconstructed in 1978. The purpose of this spillway is to protect the canal embankment from high water levels by releasing excess water during periods of high inflow. This project involves replacing the existing timber crib and rock fill spillway with a new timber structure.[15] Replacement of the timber crib structure is required as the structural timber and decking has deteriorated over time, particularly at the abutments. Replacement is required to maintain safe, reliable operation of this canal.

Figure 6 – Franks Canal Spillway

Figure 7 – Deteriorated Timber

Figure 8 – Downstream Side of Spillway

Figure 9 – Aerial View

[15] Newfoundland Power typically replaces timber spillways with alternate, longer lasting materials. Due to the remote location and site topography, timber is the only practical solution.

3.0 Rocky Pond Turbine Shaft Rehabilitation

Cost: $198,000

This project involves the rehabilitation of the turbine shaft to correct a generator alignment issue at Rocky Pond Plant.

Weir Canada ("Weir") was retained to investigate the alignment issue with the turbine shaft and provide recommendations to correct the run out.[16] Results of their investigation revealed that there was a perpendicular offset between the coupling face and the shaft center line. It was recommended by Weir to machine the turbine shaft coupling onsite to correct the offset. While the machining of the coupling did improve the perpendicular offset, shims were still required to be installed in the coupling to align the unit.[17] Customized tapered shims were fabricated by Weir to increase the level of adjustability to align the unit. This did reduce the amount of run out and allowed the unit to be returned to service however the run out measured at the turbine bearing remained higher than normal machine tolerances.[18]

Although the unit has been fully operational, accelerated wear of the turbine bearing and runner seals has recently become evident. In addition to the run out at the turbine bearing the surface finish of the turbine journal is rough and pitted and requires refurbishment.[19]

The excessive run out of the turbine shaft and the condition of the turbine bearing journal is causing premature wear on the turbine bearing. To correct the excessive run out at the turbine bearing it is recommended that the unit be dismantled and the turbine shaft removed and sent to a machine shop for true measurements and rework. During this time the turbine bearing journal will also be refurbished and a new bearing installed.

4.0 Generation Equipment Replacements Due to In-Service Failures

Cost: $530,000

Equipment and infrastructure at generating facilities routinely requires upgrading or replacement to extend the life of the asset.

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

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[16] Run out of the turbine shaft refers to the cone shaped motion that the shaft scribes around a center point as the unit rotates. The motion is caused by non-perpendicularity between the thrust runner and the shaft or non-perpendicularity within the shaft coupling.

[17] A shim is a piece of thin steel that is wedged between bolted joints to counteract the perpendicular offset flaw that causes run out of the turbine shaft. Shims are typically fabricated out of shim stock that is rolled steel in various thickness increments between 0.001 inches and 0.100 inches.

[18] The decision to return the unit to service with less than ideal alignment was made recognizing the importance of returning the generator to service in advance of the upcoming winter availability requirement.

[19] The journal is the part of the shaft that is in contact with the bearing surface.

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 one of two 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 2009.

Table 1
Expenditures Due to In-Service Failures
(000s)

Year	2010	2011	2012	2013	2014F
Total	$569[20]	$464	$523	$399	$585

Based upon this recent historical information and engineering judgement, $530,000 is estimated to be required in 2015 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 facilitate the continued operation of generating facilities in a safe and reliable manner.

5.0 Concluding

This project, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable generating plant operations. A 2015 budget of $1,586,000 for Facility Rehabilitation is recommended as follows:

- $858,000 for Hydro Dam Rehabilitation;
- $198,000 for Rehabilitation of Rocky Pond Turbine Shaft;
- $530,000 for Generation Equipment Replacements Due to In-Service Failures.

[20] Excludes Hurricane Igor related costs from 2010.

Pierre's Brook Hydro Plant
Penstock Replacement and Surge Tank Refurbishment

June 2014

Prepared by:

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NEWFOUNDLAND POWER
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1.0 Introduction

Newfoundland Power's Pierre's Brook hydroelectric development (the "Plant") is located on the Avalon Peninsula, near the community of Witless Bay, approximately 30 km south of the City of St. John's.

The Plant was placed into service in 1931 and contains one generating unit with a nameplate capacity of 3.4 MW and a rated net head of 80 m.[1] The normal annual production at Pierre's Brook is approximately 24.4 GWH or 5.7 % of the total hydroelectric production of Newfoundland Power. The development has provided 83 years of reliable energy production.

The penstock has reached the end of its useful life and requires replacement.[2] The penstock is primarily of woodstave construction with the lower section nearest the power house constructed from steel. The woodstave penstock was replaced in 1965 and is in poor condition. The materials making up the woodstave penstock are largely 49 years old however construction drawings indicate that 400 cradles on the lower section and a large number of bands on the upper section are now 83 years old as they were recycled from the original 1931 construction.

The steel section of the penstock is original to the 1931 construction. With the exception of the exterior penstock coating and the concrete foundations, the steel penstock is in good condition. The penstock coating has failed and requires replacement. The concrete foundations are showing signs of deterioration and require rehabilitation.

The surge tank located 273 m from the plant was re-constructed in 1991. Refurbishment of the exposed structural elements, ladder and cladding fasteners is required to prevent deterioration of the structure.

Engineering and procurement for the penstock will need to be completed in 2015 to allow for replacement in 2016. Completion of an access road along the length of the penstock will be completed in 2015 to allow access to complete the necessary geotechnical and environmental sampling as well as accelerate the construction schedule in 2016.

2.0 Background

This report provides an assessment of the Plant's penstock and surge tank to determine the project scope and project budget. Appendix B includes a feasibility analysis of the costs and benefits associated with the project. Figure 1 is a map outlining the lower reaches of the Pierre's Brook hydroelectric system. Water from upstream reservoirs entering Gull Pond/Pierre's Brook forebay is stored, spilled, or used for generation at the Pierre's Brook hydroelectric plant.

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[1] The Pierre's Brook site was originally developed to supply electricity to the Bell Island mines. Prior to the 1930's the mines were powered by steam produced from coal imported from Cape Breton, Nova Scotia.

[2] See Appendix C for the engineering assessment of Pierre's Brook penstock completed by AMEC.

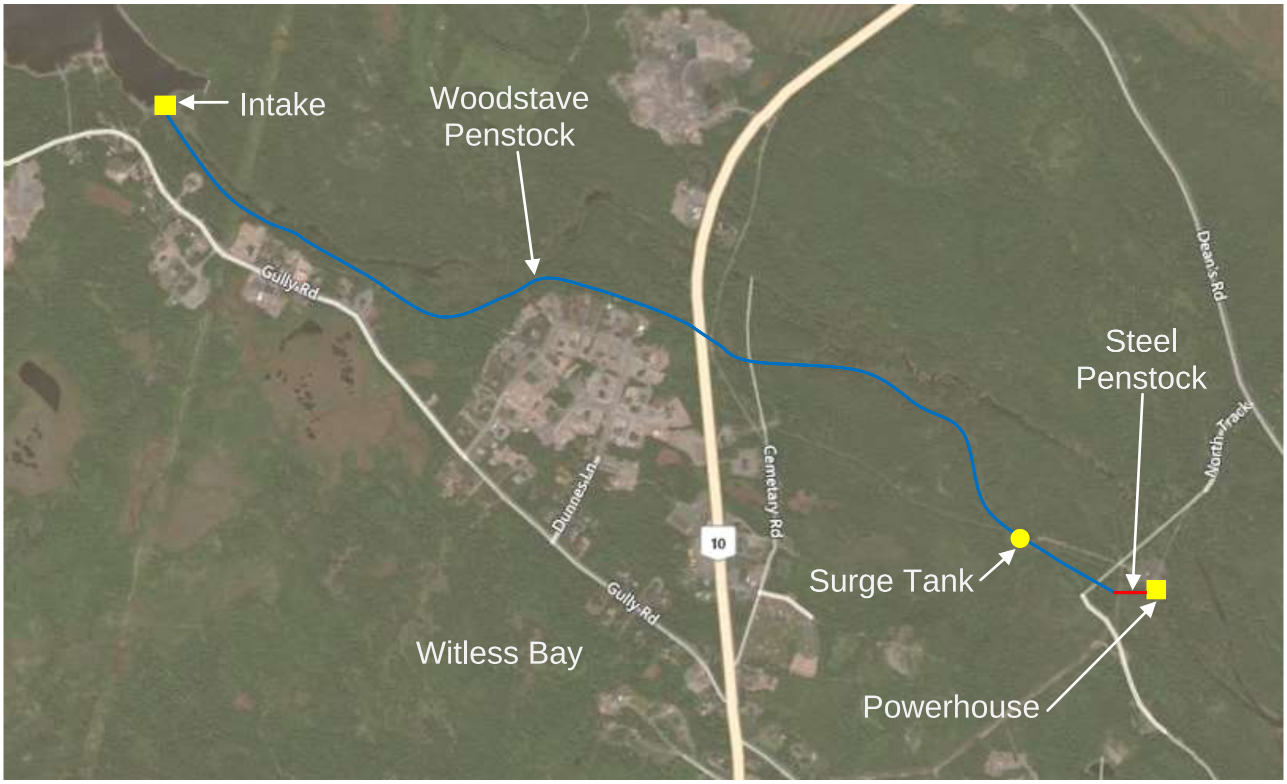

Figure 1 – Map of Pierre's Brook Penstock

The penstock is comprised of a woodstave section constructed in 1965 and a steel section built in 1931.[3] The steel section is constructed using riveted joints and was last refurbished in 1965. Concrete cradle foundations support the penstock and a single concrete anchor block is present at the steel/woodstave transition. The anchor block also acts as a bridge used by pedestrians and all-terrain vehicles ("ATV") travelling along the abandoned railway right of way.

The woodstave section of the penstock is constructed using timber staves contained within steel bands of varying sizes and is supported on timber cradles.[4] The timber staves and cradles were treated with creosote. Drawings from the 1965 construction indicate that a large number of support cradles and bands were salvaged and reused from the original 1931 construction.[5]

3 The woodstave section is 2,470 metres long and the steel section is 63 metres long. Both are 1,829 mm in diameter.

4 Staves are primarily 67mm changing to 92mm on the highest pressure section. Bands are primarily 19mm with some 22mm bands present in the vicinity of the surge tank. Band spacing varies as pressure increases, ranging from 250mm at the lowest pressure to 42mm at the highest pressure section. The cradles on the upper woodstave section are constructed out of 150 mm by 200 mm, 150 mm by 250 mm and 50 mm by 200 mm timber and support 190° of the pipe. The cradles on the lower woodstave section are constructed from 150 mm by 200 mm and 150 mm by 150mm timbers and support 120° of the pipe.

5 Construction drawings indicate that 400 of the original 1931 vintage 120° cradles were salvaged and reused in the 1965 penstock reconstruction. Drawings also indicate that bands were reused on over 80% of the penstock length.

The 43 m high surge tank located approximately 273 m upstream of the plant was re-constructed in 1991. A 1.8 m diameter internal riser conveys water to a 21 m high, 4.3 m diameter main steel tank sitting on top of a steel support structure. The tank and riser are covered with a frost casing.[6] The penstock connection is encased in a concrete anchor block and the structure legs are supported on concrete foundations.

3.0 Condition Assessment

In 2013 Newfoundland Power engaged AMEC Americas Limited ("AMEC") to complete a visual inspection and engineering assessment of the existing penstock and surge tank. Due to the specialized nature of surge tank inspection, Remote Access Technologies Limited ("RAT") were subcontracted to provide climbing inspection of the surge tank. Observations from both reports are summarized in the sections below. The detailed inspection reports can be found in Appendix C, *Pierre's Brook Penstock Inspection* and Appendix D, *Pierre's Brook Surge Tank Inspection*.

3.1 Steel Penstock Section

The 83 year old steel penstock section was refurbished in 1965. Overall, the steel penstock appears to be in generally good condition. Figure 2 shows how the exterior coating has failed over much of the steel penstock surface however no significant loss of wall thickness or pitting was observed. Rivet heads and riveted joints are in good condition. The access hatch in this section is in good condition. Some corrosion and minor leakage was identified on the single expansion joint. Based on the small amount of leakage, the joint is good condition and likely only requires re-packing.

Figure 2 - Steel Penstock

The concrete cradles are showing signs of surface deterioration. Similarly, the anchor block at the woodstave to steel transition has deteriorated at the outer layer. The anchor block, which is currently used as a bridge by pedestrians and ATV's travelling along the abandoned railway right of way does not have safety fencing or railing. The penstock bed has a significant amount of flowing water originating from the woodstave section of the penstock.

The exterior coating requires replacement to prevent further deterioration of the steel thereby extending the life of the steel penstock section. Refurbishment of the support cradles as well as the anchor block is required to prevent further deterioration as well as ensure the structural integrity of the penstock. Cost estimates have been prepared based on previous experience with remediating concrete of similar vintage and surface deterioration. Installation of safety railing on the anchor block and drainage improvements are also required.

[6] The frost casing consists of rigid insulation and an outer shell of aluminum cladding.

Due to the current condition of the woodstave section of the penstock, dewatering is no longer possible. As a result an internal inspection of the steel penstock to assess components such as the mechanical expansion joint and interior of the steel was not undertaken. Based on the Company's past experience, it is expected that the expansion joint and the interior of the steel will require some refurbishment.[7]

3.2 Woodstave Penstock Section

Overall the 49 year old woodstave penstock section is in poor condition with deterioration along its entire length. Issues have been noted with all components of the wooden section of penstock including cradles, staves, steel bands, bed and alignment.

Figure 3 - Deteriorated Cradle

Over the entire length of the penstock, the bedding is saturated due to leakage as well as the deterioration of the drainage system over time. In places, saturation of the penstock bedding has resulted in the localized rotting and settling of the support cradles which in turn has caused sagging and misalignment of the penstock.

Two distinct support cradle designs were used when the penstock was rebuilt in 1965. AMEC notes that 190° support is recommended for a woodstave pipe of this diameter. Cradles below the highway crossing only support 120° of the penstock. Approximately 400 or 82% of the cradles on this section were salvaged from the 1931 construction. Although some of these cradles were reinforced in the past with metal plates, the wood has now deteriorated beyond repair.[8] As a result, many of the support cradles are now cracked and no longer able to support the penstock as designed. This has caused localized sagging and misalignment of the penstock.

The support cradles on the upper section of the penstock were constructed in 1965 and appear to support 190° of the penstock.[9] The Pierre's Brook penstock was built without tension rods and field observation confirms that some cradles on the upper section are not supporting the full 190° as required. On the lower section 120° cradles are being used which also lack the necessary lateral support for the penstock. Some localized cracking of the 190° cradles is present as well as widespread leaching of the preservative treatment.

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[7] The original 1931 section of steel penstock comprises approximately 2.5% of the entire penstock length. The estimated cost to refurbish this section will be considered against the alternative of replacement to ensure it is more cost effective.

[8] See Figure 3 for a picture of a deteriorated cradle that was reinforced with a metal plate.

[9] Typically penstock cradles are built with inclined tension rods which prevent deformation of the cradle which in turn provides improved lateral support of the penstock.

Overall the steel bands, shoes and nuts are in good condition however localized corrosion exists near areas of heavy leakage. There is excessive corrosion of steel bands, shoes and nuts at the point where the penstock crosses under Route 10 as a result of road de-icing salt used during the winter.[10] The bands in the deteriorated areas cannot be tightened or adjusted to facilitate maintenance. Additional bands have been added in the past to ensure structural integrity in this area however they are also corroded.

Figure 4 - Bands at Route 10

Woodstaves are deteriorated along the entire length of the penstock. Crushing and delamination of the staves along with *brooming* of the stave ends are prevalent over the entire length.[11] The preservative treatment has deteriorated along the length of the penstock however it is especially prevalent upstream of the Route 10 crossing.

Figure 5 - Additional Support at Blowout

In the mid 1990's a blowout of the penstock occurred approximately 170 m upstream of the surge tank. AMEC notes that the blowout occurred near the area where the largest relative internal pressure swings occur during generator starts and stops. As a result, the penstock in this area would have the greatest tendency to ovalize.[12] AMEC attributes this tendency to ovalize along with the poor lateral support provided by the 120° cradles as the principal contributing factors of the blowout. As shown in Figure 5 additional timber supports were installed to provide the additional required lateral support, stabilizing the pipe in this area.

Leakage is significant over the entire penstock length and has been contained by various methods over the years, with repairs evident along the length of the penstock. Large leaks and end split outs are most often contained by placing large metal plates and rubber gaskets under the bands. Leaks along the springline are normally fixed with tapered wedges. The extent of wood deterioration is currently making repairs difficult to complete.

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[10] See Figure 4.

[11] Brooming is the severe splitting and fanning of the end of a wood stave. Brooming has occurred despite the presence of metal butt joints used in the 1965 construction.

[12] To ovalize means to deform from a circular shape to an oval shape. In a penstock this typically occurs when there is insufficient side support and when the internal pressure in the penstock is low.

Figure 6 - Ice Formations

As shown in Figure 6 the current amount of leakage causes significant ice buildup in winter months. Ice buildup can cause overloading of the cradles and foundations when the ground thaws and the ice structure collapses. Significant lateral forces can occur if the leakage and ice buildup is predominantly on one side. Jacking or lifting may also occur if ice builds up under the penstock. As the staves continue to deteriorate, the likelihood of a major ice related problem will increase.

Recent experience indicates that the Plant's penstock is increasingly unable to withstand de-watering without significant leakage upon re-watering.[13] As a result, every effort is made to avoid de-watering the penstock. Consequently, leaks that cannot be plugged without de-watering may remain unrepaired, as long as the escaping water does not imperil safety or the Plant infrastructure itself.[14] The inability to de-water the penstock for maintenance purposes constitutes a serious operating limitation on the plant.

The woodstave section of penstock has reached the end of its useful life and requires replacement. Delaying this work will increase the risk of catastrophic failure. Other civil works will be required to facilitate replacement of the penstock. The penstock right of way has creosote contamination that will require clean up and disposal. The existing penstock does not have an access road adjacent to it. To facilitate the removal and installation of the new penstock, an access road will be constructed.[15]

3.3 Surge Tank

The surge tank is 23 years old and some components are deteriorated and require refurbishment at this time.

The coating on the exposed steel components of the surge tank, including the legs, cross bracing, beams, ladder, roof, balcony and the surge tank tee at the base has deteriorated. With the exception of the lower section of the legs and isolated areas of the balcony rail, corrosion has not resulted in significant material loss to date.

A routine inspection in January 2013 revealed that approximately 5 m^2 of the frost casing had blown off the tank. Repairs and further inspection was completed in February 2013. The galvanized metal screws used in the original construction were found to have corroded through

13 The deteriorated condition of the woodstaves and deteriorated supports increase the potential need to de-water the penstock to address major leaks.

14 The condition of the penstock is such that de-watering during the winter months could make it impossible to return the penstock to service due to the extent of the leakage upon re-watering and the resultant ice build-up.

15 The penstock can be accessed at several locations however a single road does not follow the penstock route.

the cladding. The inspection by RAT confirmed that other areas of cladding are missing or have deteriorated fasteners. As cladding fasteners continue to deteriorate, future failures similar to the one experienced in 2013 are likely to occur.[16]

The frost casing is most likely to fail during high wind conditions. Failures in high wind conditions from high on the surge tank could potentially have debris travelling significant distances. This poses a safety hazard to the general public and energized power lines in the immediate area of the surge tank.

Figure 7 - Frost Casing Failure 2013

The upper section of the tank does not meet provincial occupational health and safety standards for ladder safety as the spacing from the cladding to the rungs is 125 mm where 178 mm is required.[17] The anchor block encapsulating the surge tank tee is in good condition however the leg foundations are showing some signs of deterioration on the surface.

Deterioration of the steel structure has occurred on the tank legs and balcony rail due to the accelerated rates of corrosion from the proximity to the ocean. Replacing failed coatings on all exposed steel surfaces is required to ensure structural deterioration does not continue. Re-fastening of the cladding with screws and gaskets is required to ensure the frost casing does not continue to fail. Modification to the ladder is required to comply with occupational health and safety standards and to facilitate future inspection and maintenance.

Due to the woodstave penstock condition, dewatering of the surge tank to complete an internal inspection could not be completed. Based on the age of the tank, Newfoundland Power does not expect significant deterioration on the inside of the tank.

4.0 Project Execution

The replacement of the woodstave section of penstock and the refurbishment of both the steel section of penstock and surge tank is necessary in 2016. The woodstave section of the penstock has reached the end of its useful life and requires replacement. The steel penstock section and surge tank require refurbishment to ensure their structural integrity is maintained. It is estimated that the Plant will be out of service for 28 weeks from May to November 2016. It is anticipated that the penstock replacement will take 26 weeks and the surge tank refurbishment 8 weeks. Both projects will be completed simultaneously. When the new penstock is re-watered, commissioning will commence and the Plant will be back in service within 2 weeks of re-watering.

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16 See Figure 7.

17 See Section 155 – Fixed Ladders of the Newfoundland & Labrador *Occupational Health and Safety Regulations, 2012*.

In order for the project to be completed on schedule, the penstock will be designed and tendered in 2015.[18] The detailed engineering for the project will be completed in the 2nd quarter of 2015 with the supply contracts for all items tendered and awarded early in the 4th quarter.

Table 1 shows the proposed preliminary high level schedule for the project.

Table 1
High-Level Project Schedule

Date	Description
Apr 2015	Complete survey.
Apr - May 2015	Complete access road construction.
May – June 2015	Complete geotechnical study and environmental review.
May – Aug 2015	Complete detailed engineering design and tender package.
Sep – Oct 2015	Tender and award penstock installation contract
May – Oct 2016	Complete penstock installation and surge tank refurbishment
Nov 2016	Test and commission systems, return to service

During the 28 week plant downtime it is estimated, based on normal inflows that spill at the Pierre's Brook plant will be 9.5 GWh.[19]

5.0 Additional Future Work

In addition to the penstock replacement and surge tank refurbishment, the following work at Pierre's Brook is planned for 2016:

- Switchgear Upgrades
- Protection and Control Upgrades
- Refurbishment of the Gull Pond Forebay Dam[20]

This work will be put forward as separate projects with justification included as part of Newfoundland Power's 2016 Capital Budget Application. The additional work in 2016 is scheduled to coincide with the extended plant outage associated with the replacement of the

[18] The construction material options that are being considered for the penstock replacement include steel, fibreglass and high density plastic. It is planned to tender all options to ensure competitive bidding and proceed with the least cost option that meets all technical and engineering requirements.

[19] This will result in approximately \$836,475 in increased purchased power costs (9.5 GWH × \$88,050/GWH = \$836,475).

[20] This project will be included as part of the 2016 Facility Rehabilitation Report.

penstock.[21] Coordinating the penstock replacement and the additional work in this manner ensures the minimum amount of lost production due to spill. A 2016 estimate of $1.48 million for the Switchgear and Protection and Control Upgrades and $100,000 for the refurbishment of the Gull Pond Forebay Dam has been included in the feasibility analysis.[22]

6.0 Project Cost

The total project cost is estimated at $14.28 million which includes $750,000 in 2015 to complete the access road, survey, environmental and geotechnical sampling, design and tendering, followed by $13.53 million in 2016 for penstock replacement and surge tank refurbishment. This does not include the cost associated with the additional future work outlined in Section 5.0.

Table 2 provides the project cost breakdown by year.

Table 2
Cost Estimate for Pierre's Brook Penstock and Surge Tank
(000s)

Description	2015	2016
Material	$546	$13,120
Labour - Internal	12	22
Labour - Contract	-	-
Engineering	112	203
Other	80	185
Total	**$750**	**$13,530**

7.0 Feasibility Analysis

Appendix B provides a feasibility analysis for the continued operation of the Pierre's Brook hydroelectric development assuming that the planned capital refurbishment is undertaken. The results of the feasibility analysis show that the continued operation of the facility is economical over the long term. Investing in the life extension of the Pierre's Brook hydroelectric development ensures the continued availability of 24.4 GWH of energy annually to the Island Interconnected System.

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[21] The Hearts Content penstock replacement (2013 CBA) and plant refurbishment (2014 CBA) projects were proposed in a manner similar to this Pierre's Brook project whereby approval was sought for the penstock replacement as a multiyear project and the approval of the plant refurbishment was sought as a separate project in year 2 of the multiyear project. Approval was granted for the multiyear penstock replacement project in Order No. P.U. 31 (2012) and for the plant refurbishment project in Order No. P.U. 27 (2013).

[22] A preliminary estimate of $1.48 million for the Switchgear and Protection and Control Upgrades and $100,000 for the refurbishment of the Gull Pond Forebay Dam has been included in the Company's 5-year capital plan. Additional engineering work is required to finalize estimates for the 2016 Capital Budget Application.

The estimated levelized cost of energy from the Plant over the next 50 years is 4.87¢ per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Pierre's 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.[23]

8.0 Concluding

Results of the feasibility analysis conclude that the continued operation of the Pierre's Brook plant, including the planned replacement and refurbishment project, is economically viable over the long term. This project will allow Newfoundland Power to continue to operate this facility into the future, maximizing the benefits of this renewable resource for its customers.

[23] The avoided cost of fuel at the Holyrood Thermal Generating Station is estimated at 16.76¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.60 per barrel for 2014 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan - Fuel Price Projection dated April 30, 2014.

Appendix A
Pictures of Pierre's Brook Penstock and Surge Tank

Steel Penstock

Figure 1: Steel Penstock – Coating Failure

Figure 2: Coating Failure and Surface Cracks on Cradle

Figure 3: Penstock Cradle

Figure 4: Water Flowing Along Penstock Bed

Figure 5: Deteriorated Anchor Block at Transition

Figure 6: Steel Expansion Joint

Woodstave Penstock

Figure 7: Deteriorated Cradle (Typical) and Saturated Penstock Bed

Figure 8: Corroded Bands and Nuts

Figure 9: Repair and Stabilization of Past Blowout

Figure 10: Crushed Stave

Figure 11: Deteriorated Cradle with Previous Steel Plate Reinforcement

Figure 12: Leak Repair along Springline

Figure 13: Leaks along Springline

Figure 14: Transition from 190° to 120° Cradles

Figure 15: Severely Corroded Bands (near Route 10 crossing)

Figure 16: Deteriorated Bridge across Penstock Right of Way

Figure 17: Typical 190 Degree Cradle (Note: Top of cradle not supporting pipe)

Figure 18: Deteriorated 190 Degree Cradle

Figure 19: Deteriorated Stave

Figure 20: Broomed Stave End (Note: absence of preservative)

Figure 21: Deteriorated Stave End

Figure 22: Previous Repairs

Figure 23: Leakage and Ice Buildup

Figure 24: Ice Buildup

Figure 25: Ice Towers

Surge Tank

Figure 26: Surge Tank

Figure 27: Frost Casing Failure – January 2013

Figure 28: Deteriorated Coating – Surge Tank Support

Figure 29: Deteriorated Coating – Deck

Figure 30: Screws Pulled Through Cladding

Figure 31: Corrosion at Fastener

Appendix B
Feasibility Analysis

Table of Contents

1.0 Introduction

This feasibility analysis examines the future viability of Newfoundland Power's Pierre's Brook hydroelectric development. The continued long-term operation of the Pierre's Brook hydroelectric development is reliant on the completion of capital improvement in 2015 and 2016. Planned work includes replacement of the woodstave penstock section and refurbishment of the steel penstock section and surge tank as contained in this application. It also includes switchgear, and protection and control upgrades that will be described in further detail in the 2016 capital budget application.

With substantial investment required in the near-term to permit the continued reliable operation of this 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 hydroelectric development over the next 50 years have been identified. The majority of these expenditures are planned for 2015 and 2016, with the largest amount being attributed to the penstock replacement. The capital expenditures required to maintain the safe and reliable operation of the facilities are summarized in Table 1.

Table 1
Hydroelectric Development
Capital Expenditures
(000s)

Year	Expenditure
2015-2019	$16,054
2020-2024	$20
2025-2029	$223
2030-2034	-
2035-2039	$320
Total	**$16,617**

The total capital expenditure of all of the projects listed above is $16.6 million. A more comprehensive breakdown of capital costs is provided in Attachment A.

3.0 Operating Costs

Operating costs for this hydroelectric system are estimated to be $80,641 per year. This estimate is based upon recent historical operating experience. The operating cost represents both direct charges for operations and maintenance at this 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.

The annual operating cost includes a water power rental rate of $0.80 per MWhr. This fee is paid annually to the Provincial Department of Environment and Conservation (Water Resources Management Division) based on yearly hydro plant production. This charge is reflected in the historical annual operating costs for the Pierre's Brook development.

Penstock maintenance have accounted for a large portion of the operating costs of this plant in recent years. Future operating costs have been reduced by $15,000 to reflect the penstock replacement project.

4.0 Lost Production

The downtime associated with the 2016 capital works at this plant will result in spill from the system. To minimize spill it has been determined that May to October 2016 would be the most economic time to complete the project. Spill from Pierre's Brook forebay is estimated to be 9.5 GWH which translates into approximately $836,475 in increased purchased power costs.[1]

5.0 Financial Analysis

An overall financial analysis of combined costs and benefits has been completed 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 Pierre's Brook plant over the next 50 years is 4.87¢ per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Pierre's 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.[2]

The future capacity benefits of the continued availability of Pierre's Brook hydro 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 Recommendation

The results of this feasibility analysis show that the continued operation of the Pierre's Brook hydroelectric development is economically viable. Investing in the life extension of facilities at Pierre's Brook guarantees the availability of low cost energy to the Province. Otherwise the

[1] Approximately $836,475 in increased purchased power costs is calculated as follows: (9.5 GWH × $88,050/GWH = $836,475).

[2] The avoided cost of fuel at the Holyrood Thermal Generating Station is estimated at 16.76¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.60 per barrel for 2014 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan - Fuel Price Projection dated April 30, 2014.

annual production of 24.4 GWh would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood thermal generating station. Newfoundland Power should proceed with this project in 2015 and 2016. 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

Pierre's Brook Feasibility Analysis Summary of Capital Costs ($000s)						
Description	**2015**	**2016**	**2018**	**2021**	**2026**	**2036**
Civil						
Dam, Spillways and Gates		100	192			
Penstock	750	13,200				
Surge Tank		330				300
Power House		135				
Mechanical						
Governor		15			15	
Heat and Ventilation		60				
Electrical						
P&C		857			200	
Switchgear		375				
AC & DC Systems		40				
Battery/Charger				20	8	20
Annual Totals ($2014)	**$750**	**$15,112**	**$192**	**$20**	**$223**	**$320**

Attachment B
Summary of Operating Costs

Pierre's Brook Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs

Year	Amount
2009	$94,778
2010	$99,786
2011	$99,434
2012	$96,883
2013	$87,323
Average	**$95,641**

5-Year Average Operating Cost	$95,641
Reduced Future Penstock Maintenance	-15,000
Total Forecast Annual Operating Cost	$80,641

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted Average Incremental Cost of Capital	**6.85%**
Escalation Rate	**See following worksheet**
PW Year	**2014**

YEAR	Generation Hydro 64.4yrs 8% CCA	Generation Hydro 64.4yrs 50% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net benefit	Present Worth Benefit +ve	Cumulative Present Value Benefit +ve	Present Worth of Sunk Costs	Total Present Worth Benefit +ve	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2015	0	750,000	68,544	80,641	0	-149,185	-139,621	-139,621	-15,162,215	-15,301,836	0.611	4.8679
2016	1,951,260	13,464,000	1,483,540	82,253	0	-1,565,793	-1,371,467	-1,511,088	-13,862,793	-15,373,881	6.417	4.8679
2017	0	0	1,512,702	83,899	0	-1,596,601	-1,308,798	-2,819,886	-12,622,769	-15,442,656	6.543	4.8679
2018	203,752	0	1,413,133	85,576	0	-1,498,709	-1,149,792	-3,969,678	-11,538,631	-15,508,309	6.142	4.8679
2019	0	0	1,344,069	87,117	0	-1,431,186	-1,027,598	-4,997,277	-10,573,583	-15,570,859	5.866	4.8679
2020	0	0	1,296,970	88,752	0	-1,385,722	-931,170	-5,928,446	-9,702,052	-15,630,499	5.679	4.8679
2021	22,423	0	1,264,195	90,410	0	-1,354,605	-851,905	-6,780,351	-8,907,006	-15,687,357	5.552	4.8679
2022	0	0	1,235,708	92,067	0	-1,327,775	-781,499	-7,561,850	-8,179,695	-15,741,546	5.442	4.8679
2023	0	0	1,210,195	93,788	0	-1,303,983	-718,292	-8,280,142	-7,513,066	-15,793,208	5.344	4.8679
2024	0	0	1,186,387	95,560	0	-1,281,947	-660,883	-8,941,025	-6,901,447	-15,842,472	5.254	4.8679
2025	0	0	1,163,522	97,343	0	-1,260,864	-608,343	-9,549,369	-6,340,070	-15,889,438	5.167	4.8679
2026	274,224	0	1,166,979	99,164	0	-1,266,143	-571,727	-10,121,095	-5,813,121	-15,934,216	5.189	4.8679
2027	0	0	1,147,141	101,017	0	-1,248,158	-527,473	-10,648,569	-5,328,337	-15,976,906	5.115	4.8679
2028	0	0	1,124,598	102,907	0	-1,227,504	-485,489	-11,134,058	-4,883,548	-16,017,606	5.031	4.8679
2029	0	0	1,102,281	104,830	0	-1,207,111	-446,817	-11,580,874	-4,475,535	-16,056,409	4.947	4.8679
2030	0	0	1,080,153	106,809	0	-1,186,962	-411,192	-11,992,066	-4,101,344	-16,093,411	4.865	4.8679
2031	0	0	1,058,189	108,787	0	-1,166,976	-378,351	-12,370,417	-3,758,264	-16,128,681	4.783	4.8679
2032	0	0	1,036,370	110,836	0	-1,147,207	-348,097	-12,718,514	-3,443,798	-16,162,312	4.702	4.8679
2033	0	0	1,014,684	112,915	0	-1,127,598	-320,213	-13,038,727	-3,155,650	-16,194,377	4.621	4.8679
2034	0	0	993,117	115,042	0	-1,108,159	-294,518	-13,333,245	-2,891,708	-16,224,952	4.542	4.8679
2035	0	0	971,660	117,191	0	-1,088,851	-270,834	-13,604,079	-2,650,023	-16,254,101	4.463	4.8679
2036	473,747	0	994,823	119,385	0	-1,114,208	-259,374	-13,863,453	-2,418,440	-16,281,893	4.566	4.8679
2037	0	0	977,224	121,626	0	-1,098,850	-239,400	-14,102,853	-2,205,538	-16,308,391	4.503	4.8679
2038	0	0	954,614	123,908	0	-1,078,522	-219,908	-14,322,761	-2,010,895	-16,333,655	4.420	4.8679
2039	0	0	932,149	126,233	0	-1,058,383	-201,967	-14,524,727	-1,833,017	-16,357,744	4.338	4.8679
2040	0	0	909,820	128,602	0	-1,038,423	-185,454	-14,710,181	-1,670,530	-16,380,711	4.256	4.8679
2041	0	0	887,615	131,016	0	-1,018,631	-170,257	-14,880,438	-1,522,171	-16,402,610	4.175	4.8679
2042	0	0	865,525	133,474	0	-998,999	-156,271	-15,036,709	-1,386,779	-16,423,489	4.094	4.8679
2043	0	0	843,539	135,979	0	-979,518	-143,401	-15,180,110	-1,263,286	-16,443,396	4.014	4.8679
2044	0	0	821,650	138,531	0	-960,181	-131,558	-15,311,668	-1,150,708	-16,462,377	3.935	4.8679
2045	0	0	799,851	141,131	0	-940,981	-120,662	-15,432,330	-1,048,144	-16,480,474	3.856	4.8679
2046	820,163	0	855,204	143,779	0	-998,984	-119,887	-15,552,218	-945,511	-16,497,729	4.094	4.8679
2047	0	0	839,907	146,478	0	-986,385	-110,787	-15,663,004	-851,176	-16,514,180	4.043	4.8679
2048	0	0	815,855	149,226	0	-965,081	-101,445	-15,764,449	-765,417	-16,529,866	3.955	4.8679
2049	0	0	791,984	152,027	0	-944,011	-92,869	-15,857,318	-687,505	-16,544,822	3.869	4.8679
2050	0	0	768,282	154,880	0	-923,162	-84,995	-15,942,313	-616,769	-16,559,082	3.783	4.8679
2051	39,133	0	748,412	157,786	0	-906,198	-78,085	-16,020,398	-552,281	-16,572,678	3.714	4.8679
2052	0	0	725,309	160,747	0	-886,056	-71,454	-16,091,852	-493,789	-16,585,641	3.631	4.8679
2053	0	0	701,916	163,764	0	-865,680	-65,336	-16,157,188	-440,813	-16,598,001	3.548	4.8679
2054	0	0	678,649	166,837	0	-845,486	-59,721	-16,216,908	-392,877	-16,609,786	3.465	4.8679
2055	0	0	655,498	169,968	0	-825,466	-54,569	-16,271,477	-349,544	-16,621,022	3.383	4.8679
2056	0	0	632,453	173,158	0	-805,611	-49,842	-16,321,319	-310,415	-16,631,735	3.302	4.8679
2057	0	0	609,506	176,407	0	-785,914	-45,506	-16,366,825	-275,124	-16,641,949	3.221	4.8679
2058	0	0	586,650	179,718	0	-766,368	-41,530	-16,408,355	-243,333	-16,651,688	3.141	4.8679
2059	0	0	563,877	183,091	0	-746,967	-37,883	-16,446,238	-214,735	-16,660,974	3.061	4.8679
2060	0	0	541,180	186,526	0	-727,706	-34,540	-16,480,779	-189,048	-16,669,827	2.982	4.8679
2061	0	0	518,553	190,027	0	-708,580	-31,476	-16,512,255	-166,013	-16,678,268	2.904	4.8679
2062	0	0	495,991	193,593	0	-689,584	-28,669	-16,540,924	-145,393	-16,686,317	2.826	4.8679
2063	0	0	473,489	197,226	0	-670,715	-26,097	-16,567,021	-126,970	-16,693,991	2.749	4.8679
2064	0	0	451,041	200,927	0	-651,968	-23,741	-16,590,762	-110,545	-16,701,307	2.672	4.8679

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects a statutory income tax rate of 29%.

Operating Costs: Operating costs were assumed to be in 2014 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55.00%	5.250%	2.89%
Common Equity	45.00%	8.800%	3.96%
Total	**100.00%**		**6.85%**

CCA Rates:

Class	Rate	Details
17.1	8.00%	Expenditures related to the betterment of electrical generating facilities.
43.2	50.00%	Primary generating equipment, new or additions or alterations that increase the capacity of existing facilities.

Escalation Factors: Conference Board of Canada GDP deflator, February 6, 2014.

Appendix C
Pierre's Brook Penstock Inspection (AMEC)

Pierre's Brook Penstock Inspection

Work Authorization Number: 09-058-WA-011

To Newfoundland Power

Date: February 28, 2014

From: Ellis O'Neil, P.Eng., Senior Project Manager

Project: 176007

PIERRE’S BROOK PENSTOCK INSPECTION

February 28, 2014

Submitted by:

AMEC Americas Limited
29-31 Pippy Place
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AMEC #176007

28 February 2014

#176007

Mr. David Ball, P.Eng.
Civil Engineer
Newfoundland Power
55 Kenmount Road
P.O. Box 8910
St. John's NL
A1B 3P6

Email : dball@newfoundlandpower.com

Dear Mr. Ball:

Re: Pierre's Brook Penstock Inspection – Final Report

Please find attached two (2) paper copies of the Final Report for the Pierre's Brook Penstock Inspection.

Thank you for the opportunity to work with you and your staff on this project, and please contact us if you require any explanation or further discussion.

Yours truly,

Ellis O'Neil

Ellis O'Neil, P.Eng.
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EO/cz

Attachments (2)

NEWFOUNDLAND POWER
PIERRE'S BROOK PENSTOCK INSPECTION
PROJECT 176007

Prepared by

Date Feb 28/14

Checked by

Date 28 Feb 14

Approved by Project Manager

Date Feb 28/14

REV.	Description	Prepared by	Checked	Approved	Date
1	Draft Report	E. O'Neil	E. O'Neil	E. O'Neil	2014-02-24
2	Final Report	E.O.		E.O.	Feb 28/14

DISCLAIMER

This report is issued to Newfoundland Power for the sole purpose of evaluating the progress and future course of the project described in the report. AMEC disclaims all liability for damages arising from any use of this document by other persons or for other purposes. This disclaimer must appear on all complete or partial copies of this document.

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DISCLAIMER

This report is prepared for Newfoundland Power (the "Client") by AMEC (the "CONSULTANT") and is subject to the following limitations, qualifications and disclaimers:

1. The report is intended for the exclusive use of the Client and it may not be used or relied upon in any manner or for any purpose whatsoever by any other party.

2. The report is **Pierre's Brook Penstock Inspection** (the "Project"). Data required to support detailed engineering assessments have not always been available and in such cases engineering judgements have been made which may subsequently turn out to be inaccurate. There are, therefore, risks inherent in the Project which are outlined in the report. The CONSULTANT accepts no liability beyond using reasonable diligence, professional skill and care in preparing the report in accordance with the standard of care, skill, and diligence expected of professional engineering firms performing substantially similar work at the time such work is performed, based on the circumstances the CONSULTANT knew or ought to have known based on the information it had at the date the report was written and after due inquiry based on that information.

3. The CONSULTANT shall not be responsible or liable for any interpretation or recommendation made by others including any determination in respect of any sale by the Client or any purchase by any third party or any valuation in respect of the Project based in whole or in part on the data, interpretations and/or recommendations generated by the CONSULTANT in the report.

4. The investigation described in the report is based solely upon site visits carried out on February 18, 2014 by the CONSULTANT, and the information received from the Client.

5. The report speaks only as of its date and to conditions observed at that time, which conditions may change (or may have changed) by virtue of the passage of time or due to direct or indirect human intervention causing any one or more changes in plans or procedures or due to other factors.

6. The report does not extend to any latent defect or other deficiency in the Project which could not have been reasonably discoverable or discovered by such observation, with the exception of any latent defect or other such deficiency of which the CONSULTANT had actual knowledge.

7. The report is to be read in conjunction with all other data and information received and referenced throughout the report, and all correspondence between the Client and the CONSULTANT. Except as stated in the report, the CONSULTANT has not made any independent verification of such data and information and does not have responsibility for the accuracy or completeness thereof.

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APPENDICES

1.0 INTRODUCTION

In January, 2014, Newfoundland Power engaged AMEC to carry out a visual inspection and engineering assessment of the existing penstock at the Pierre's Brook Hydroelectric Development near Witless Bay, Newfoundland. The work was undertaken based on a proposal submitted by AMEC dated January 27, 2014. The condition assessment of the surge tank and its foundations is presented in a separate report.

1.1 Scope of Inspection and Report

The project scope consists of an external visual inspection of the 6'-0" diameter wood stave penstock section, and the 6-0" diameter steel penstock section. The project scope also includes an engineering assessment of the penstocks based on the results of the visual inspection, and to provide recommendations for any observed deficiencies. There was no independent field verification of the information shown on the design drawings.

1.2 Background

The Pierre's Brook Hydroelectric Development is a single unit 4.3 MW plant commissioned in 1931, with an average annual generation of 24.4 GW hrs. The plant typically operates under a head of approximately 278 ft. (120 psi), and a maximum unit flow of 230 cfs. The normal supply level in the headpond is El. 380 ft, while the tailwater level varies between El. 100 ft and 104 ft. The most recent load rejection testing conducted on September 17, 2012 showed the upsurge creating a head of 323 ft (140 psi) on the unit.

According to the Operating Procedure for the Pierre's Brook development (Bulletin POG100.03.02 – see Appendix A), the plant is operated 75 to 80% of the time, typically at its best efficiency of 180 cfs, unless there is heavy inflow, or insufficient water to operate at this flow rate. Newfoundland Power noted it is not uncommon for the plant to start and stop once or twice a day in the summer months.

The wood stave penstock was reportedly replaced in 1965, but the original bands were re-used on the upper 96% of its length, and the original cradles were re-used on approximately 3205 ft of its length from the highway crossing to 274 ft downstream of the surge tank.

Appendix B provides a list of the drawings reviewed as part of this assessment. As noted above, no independent field verification of the information shown on the design drawings was carried out. However, it was noted the foundations and support details for the steel penstock observed in the field differ from the information shown on the available drawings. In addition, the concrete anchor block observed in the field does not match the size, type and location shown on the drawings. The design drawings show the original steel penstock in the vicinity of the powerhouse as being replaced in 1959. Standard construction practice of that time period would have been welded steel, but the penstock in the field is riveted steel. Therefore, it is believed the steel penstock, foundations, cradles and anchor block in the field are the original 1931 construction, and the structures shown on the design drawings from 1959 were never constructed. This would explain the discrepancies. The poor condition of the concrete in the anchor block observed in the field supports this theory, as the level of deterioration indicates it to be significantly older than 50 years.

2.0 EXISTING CONDITIONS

The penstock consists of an 8097 ft length of 6'-0" internal wood stave pipe, and approximately 212 ft length of 6'-0" internal diameter riveted steel pipe near the powerhouse. According to the design drawings, the penstock profile has 9 separate grades along its length between the intake structure and the powerhouse, with the following configuration:

- The wood stave penstock starts at the intake structure at Chainage 0+18, and crosses under a highway bridge 4482 ft downstream at Chainage 45+00. This length of penstock was reconstructed in 1965 with all new timber cradles, spaced at 8'-0 ". Both the original and new cradles along this length of pipe theoretically provide 190 degrees of support, which is in line with the minimum recommended level of support of 180 degrees for wood stave penstocks with a diameter of 6'-0" or greater. The stave thickness along this length was a constant 2-5/8". The bands were salvaged from the original construction, and are ¾" diameter with spacing varying between 10" at the intake structure to 5¾" at the highway bridge.
- From the highway bridge, the penstock extends an additional 2931 ft downstream to the surge tank at Chainage 74+31. The timber cradles in this length were salvaged from the original construction, and provide only 120 degrees of support, which is less than recommended for a pipeline of this size. The stave thickness along this length was also a constant 2-5/8". The bands were salvaged from the original construction, and are ¾" diameter with spacing varying between 5¾" at the highway bridge to a 3" spacing 1704 ft downstream, changing to 7/8" diameter bands at 6.87" spacing varying to 3.9" spacing at the surge tank.
- At a distance of 274 ft downstream of the surge tank, the wood stave thickness changes from 2-5/8" to 3-5/8", at Chainage 77+05, and is constant for the remaining length of the wood stave penstock. Along this section of pipe, the bands change from 7/8" diameter salvaged bands at 3.9" spacing to new (in 1965) ¾" diameter Intermediate Grade bands at 2.76". The timber cradles in this length were salvaged from the original construction, and provide only 120 degrees of support.
- From the change in wood stave thickness at Chainage 77+05, the penstock extends an additional 410 ft downstream to Chainage 81+15 where it meets a concrete anchor block. Along this section of pipe, the spacing of the new (in 1965) ¾" diameter Intermediate Grade bands vary from 2.76" at the upstream end to 1.67" at the downstream end. The timber cradles in this section of pipe were replaced in 1965 with new cradles that only provide 120 degrees of support.
- A 6'-0" diameter riveted steel penstock extends approximately 212 ft from the concrete anchor block at Chainage 81+15 to the powerhouse wall at Chainage 83+27.3. This section of pipe was refurbished in 1965, and is supported on concrete cradle foundations. There is an expansion joint located just downstream of the concrete anchor block. The expansion joint is a mechanical expansion joint (as opposed to the bolted sleeve-type couplings which are typically used today). This style of joint originated in the 1920's, and allows for more longitudinal movement than the bolted sleeve-type couplings, but tend to bind and leak where shear or deflection conditions exist.

The wood stave penstock cradle and stave information is summarized in Table 1-1, while the steel band information is summarized in Table 1-2. The profile and other pertinent details of the penstock are provided in Appendix D.

Table 1-1: Summary of Penstock Cradles and Wood Staves

Station	Location	Cradles		Pipeline
		Type	Comments	Stave Thickness (inches)
0+18	Upstream end at dam			
		190 degrees (theoretical)	New in 1965	2-5/8"
45+00	Highway crossing			
		120 degrees	Salvaged	2-5/8"
74+31	Surge tank			
		120 degrees	Salvaged	2-5/8"
77+05	Change in wood stave thickness			
		120 degrees	New in 1965	3-5/8"
81+15	At anchor block / steel penstock interface			

Table 1-2: Summary of Penstock Steel Bands

Station	Band Size (Inches)	Band Spacing (Inches)	Comments
0+18	Upstream end at dam		
	3/4	10.00	Salvaged
10+00		9.90	
	3/4	10.00	Salvaged
20+00			
	3/4	8.20	Salvaged
30+00			
	3/4	6.75	Salvaged
40+00			
	3/4	6.35	Salvaged
44+50			
	3/4	5.75	Salvaged
45+00	Highway crossing		
	3/4	5.75	Salvaged
45+50			
	3/4	5.65	Salvaged
47+50			
	3/4	3.20	Salvaged
57+50			
	3/4	3.00	Salvaged
62+04			
	7/8	6.87	Salvaged
68+56			
	7/8	6.34	Salvaged
69+36			
	7/8	5.70	Salvaged
70+02			
	7/8	5.18	Salvaged
70+77			
	7/8	4.75	Salvaged
71+52			
	7/8	4.40	Salvaged
72+77			
	7/8	4.15	Salvaged
74+27			
	7/8	3.90	Salvaged
74+31	Surge tank		
	7/8	3.90	Salvaged
74+62			
	7/8	3.62	Salvaged
75+12			
	7/8	3.40	Salvaged
75+24			
	3/4 Int. Grade	3.40	New in 1965
75+61			
	3/4 Int. Grade	3.18	New in 1965
76+11			
	3/4 Int. Grade	3.00	New in 1965
76+61			
	3/4 Int. Grade	2.92	New in 1965
76+88			
	3/4 Int. Grade	2.76	New in 1965
77+05	Change in wood stave thickness		
	3/4 Int. Grade	2.76	New in 1965
77+28			
	3/4 Int. Grade	2.64	New in 1965
77+63			
	3/4 Int. Grade	2.54	New in 1965
77+88			
	3/4 Int. Grade	2.47	New in 1965
78+13			

	3/4 Int. Grade	2.35	New in 1965
78+55			
	3/4 Int. Grade	2.24	New in 1965
78+91			
	3/4 Int. Grade	2.16	New in 1965
79+17			
	3/4 Int. Grade	2.08	New in 1965
79+43			
	3/4 Int. Grade	2.02	New in 1965
79+69			
	3/4 Int. Grade	1.94	New in 1965
79+95			
	3/4 Int. Grade	1.89	New in 1965
80+21			
	3/4 Int. Grade	1.81	New in 1965
80+47			
	3/4 Int. Grade	1.72	New in 1965
80+73			
	3/4 Int. Grade	1.67	New in 1965
81+15	At anchor block / steel penstock interface		

3.0 COMMENTS ON DESIGN

The performance and lifespan of a wood stave penstock depends on a number of factors including the following:

- species and quality of wood used in the original construction
- quality of preservative treatment of the wood staves and cradles
- bed preparation for the cradles
- drainage of the bed
- the degree of support offered by the cradles to the penstock shell
- the type of shoe used as part of the band system
- the quality of construction
- the applied loads, in particular waterhammer
- the number of start / stops and load changes on the unit
- the number and duration of de-waterings
- the level of maintenance on the penstock
- vegetation management adjacent to the penstock

The performance and lifespan of a steel penstock depend on many of the same factors as a wood stave penstock, plus the quality and maintenance of the penstock coating, both on the interior and exterior of the penstock shell.

The following Sections provide comments on particular aspects of penstocks that are pertinent to the assessment of the penstock at the Pierre's Brook development.

3.1 Wood Stave Penstock

3.1.1 Cradles

With the exception of very small diameters, all pipes need support. Cradle spacing for wood stave pipe is typically 8 ft. Spacing greater than this tends to result in the penstock sagging, which reduces its lifespan. The cradle spacing in the Pierre's Brook penstock is 8 ft.

Ovalling of a penstock occurs when there is insufficient side support on the penstock to prevent the lateral deformation of the penstock at its springline due to the self weight of the penstock and water. This is especially critical when the internal pressure in the penstock is low. Penstocks with a diameter of 6 ft and larger, such as the Pierre's Brook penstock, require a minimum of 180 degrees of support to prevent ovalling. At Pierre's Brook, the upper 4,482 ft of penstock (i.e. upstream of the highway crossing) has cradles which, at first glance, appear to provide 190 degrees of support. However, those cradles are of a somewhat unusual design in that they do not have steel tie-rods which are typically present in such cradle configurations to help prevent deformation of the cradle. Consequently, the cradles in the upper half of the Pierre's Brook penstock likely do not provide a full 190 degrees of support, but they do provide significantly more support than the cradles on the penstock downstream of the highway crossing.

The cradles on the lower 3615 ft of penstock downstream of the highway provide only 120 degrees of support. When there is inadequate side support, the wood in the staves at the springline crush on the inside of the stave joint during each cycle of penstock ovalling and rounding out. Under such conditions, the wood eventually loses its ability to form a water tight joint, and leakage occurs at the springline. The cradle style is believed to be a significant contributing factor to the poorer condition of the lower 3,615 ft of the Pierre’s Brook penstock.

3.1.2 Bands

Bands are the single most important part of a wood stave pipe because their failure or disconnection can result in catastrophic failure. Disconnection of the band will most often occur because of pipe vibration, ovaling, drying out of the pipe, or excessive stress and resulting elongation of the bands. The more recent style of shoes securing the steel bands in position have “keepers” on them, which are narrow ridges or bumps cast into the shoe which serve to keep the washer and nut from slipping off the show which would result in the bands loosening. None of the shoes observed on the Pierre’s Brook penstock had keepers on them. However, disconnection of the bands is usually more of a concern with larger pipes i.e. larger than 6 ft diameter, due to the flatness of the bands. This may be part of the reason why no loose or missing bands were observed on the Pierre’s Brook penstock.

A common mode of failure of steel bands is corrosion of the forged button head on the upper half of the band. The button head corrodes to the point where its reduced head size slips through the opening in the top of the shoe, and the band fails. Corrosion of the button heads is difficult to see in the field because it is located directly behind the threaded end of the lower half of the band. This congested area also serves to trap dirt and moisture, resulting in conditions ideal to cause corrosion of the button head.

Proper steel bands have rolled threads on the bottom half of the band. These rolled threads have good corrosion resistance, and the threads are rolled proud of the band shank i.e. the root diameter of the thread is the same as or larger than the diameter of the band shank. Replacement bands are sometimes fabricated from steel rod, with a cut thread each end. The reduced area of the cut thread needs to be accounted when determining the size and spacing of these bands. The bands in the Pierre’s Brook penstock had proper rolled threads.

3.1.3 Shell

Prior to 1936, wood stave penstocks were constructed with untreated wood, with the preservative surface-applied at a later date. Creosote and pine pitch were typical preservative treatments during that time period. Typical maintenance cycles involved applying creosote on the exterior of penstocks every 5 to 10 years to compensate for its deterioration / leaching by the sun. The penstock at Pierre’s Brook appears to have been constructed with creosoted timber, with periodic surface application of creosote.

The ends of wood staves were typically installed with a minimum 2 ft stagger to the adjacent stave, and this appears to be the case at Pierre’s Brook. The Pierre’s Brook penstock has Kelsey Type Butt Joints joining the ends of the staves, as opposed to a double tenon or spline. A Kelsey Type Butt Joint is a cast metal (usually malleable iron, ductile iron, or aluminum alloy) device which is similar to a spline, and is forced into position on the end of each stave to form a water tight connection between the ends of the staves. It also prevents the end grain of the wood from splitting or brooming, particularly in severe climates or high head installations.

3.2 Steel Penstock

3.2.1 Shell

The steel penstock in the vicinity of the powerhouse at Pierre's Brook is of riveted steel construction. Welded steel construction became the norm for steel penstocks starting in the early 1940's, as welding technology improved. Therefore, as previously noted, it is believed the existing steel penstock at Pierre's Brook is the original penstock at this site. Typical sources of problems with riveted steel penstocks include corrosion of the plate steel and the rivet heads, leakage at the riveted joints, and leakage at expansion joints.

3.2.2 Expansion Joints

Unlike wood stave penstocks, steel penstocks require expansion joints to account for the rigidity of steel, and the high coefficient of thermal expansion. Expansion joints for steel penstocks typically consist of: a) mechanical expansion joint, or b) bolted sleeve type couplings (such as Dresser or Baker couplings). The penstock at Pierre's Brook contains a mechanical expansion joint, a short distance downstream of the concrete anchor block. The mechanical expansion joint is, essentially, a pipe within a pipe with a packing gland and packing to maintain the watertightness between the two telescoping pipes. Mechanical expansion joints allow more longitudinal movement that bolted sleeve type couplings, but they do not operate properly where shear or deflection conditions exist which can cause binding of the packing material. However, many older mechanical expansion joints have maintained their original integrity, and only need to be repacked to extend their service life. It should be noted there are certain requirements for selecting the type and size of packing, the number of layers of packing, and the jointing of the packing. If this is not done properly, the joint will fail prematurely.

3.2.3 Supports

Penstock supports typically consist of penstock ring girders supported on rockers (for supports spaced 20 to 40 ft apart), or cradles (either concrete or steel) for supports spaced closer together. The supports for the steel penstock at Pierre's Brook consist of concrete cradles cast to the underside of the penstock, with a low friction material between the penstock and the concrete to allow the penstock to expand and contract longitudinally.

4.0 SITE INSPECTION

The penstock at Pierre's Brook was inspected on February 18, 2014 by E. O'Neil of AMEC, and D. Ball of Newfoundland Power, with support provided by Robin Vivian of Newfoundland Power. The weather was sunny, windy and cold, with a temperature of -8 degrees Celsius. Approximately 2 inches of snow had fallen the night before the inspection. The penstock was inspected, starting from the downstream end and working upstream towards the dam. There was a significant amount of snow and ice on the ground which hampered the inspection. Mounds of ice had formed at locations of significant leakage in the penstock. Photos were taken to provide a summary of the conditions observed during the site inspection, and are presented in this report in Appendix C. To assist AMEC with the assessment of the penstock, Newfoundland Power provided AMEC with photos of the penstock taken in March 6, 2013. Some of those photos are also included in this report in Appendix C.

4.1 Steel Penstock Inspection

An overview of the steel penstock is shown in Photo C-1. The penstock shows no signs of settlement, sagging, wrinkling of the shell, or misalignment. The penstock shell is in good condition where it penetrates the upstream wall of the powerhouse, as seen in Photo C-2. The access hole just upstream of the powerhouse is in good condition, with no deterioration or leakage observed, as seen in Photo C-3. From its style, it appears this access hole is from the original construction. As seen in Photos C-4 and C-5, the exterior coating has failed over much of the penstock surface. The unprotected steel below is corroding. Although no significant loss of wall thickness or pitting was observed, the exposed steel will continue to corrode at an accelerated rate due to the proximity of the site to the Atlantic Ocean and exposure to the salt laden air. The riveted joints in the steel plate were in good condition, showing no signs of leakage. The rivet heads were in very good condition, with no loss of material noted. Photos C-6 and C-7 show the access hole just downstream of the anchor block. Its style, and the condition of the coating suggests it was installed in recent years. It is in good condition, with no leaks or signs of deterioration observed. The mechanical expansion joint, located a short distance downstream of the anchor block, is shown in Photo C-8 and C-9. As seen in those photos, there is some corrosion of the pipe and the gland. Some minor leakage was observed exiting the expansion joint at the underside of the pipe, as seen in Photo C-9. The volume of leakage indicates the joint is in good condition, and likely only requires the packing be replaced. A small bore tap was observed at the bottom of the pipe just downstream of the anchor block, as seen in Photo C-10. The purpose of this tap is unknown, and appears to have a plug installed in it.

Photos C-11 and C-12 show the typical concrete cradles / foundations supporting the steel penstock. The concrete is showing signs of deterioration, likely due to alkali-aggregate reactivity, exacerbated by freeze-thaw action. Similarly, the concrete in the anchor block, shown in Photos C-13 and C-14, is also showings signs of deterioration. The depth of deterioration should be determined to assess repair or replacement options.

4.1.1 Engineering Assessment

Overall, the steel penstock appears to be in generally good condition, but it requires refurbishment to maintain its reliability and long term performance. The concrete on the surface of the foundations and anchor block shows signs of deterioration. The depth of deterioration needs to be determined to assess refurbishment options.

4.1.2 Recommendations

1) The exterior coating on the penstock should be replaced
2) The tap on the bottom of the penstock near the anchor block should be removed and a patch installed in its place
3) The mechanical expansion joint should be disassembled, inspected, refurbished if required, and repacked
4) The interior of the penstock should be inspected to determine the condition of the coating and to check for areas of erosion and corrosion (particularly rivet heads and pin holes)
5) The thickness of the penstock shell should be checked (by ultrasonic means) to confirm the shell thickness meets design requirements
6) The depth of deterioration of the foundations anchor block should be determined to assess repair / replacement options. It is likely the foundations should be replaced, and the anchor block re-faced
7) Consider installing a penstock rupture protection system to mitigate damage caused by a penstock rupture

4.2 Wood Stave Penstock Inspection

The wood stave penstock extending from the concrete anchor block to the highway crossing is in markedly poorer condition than the length of penstock above the highway crossing. This length of penstock is characterized by areas of significant leakage, extensive patch repairs, particularly at the springline, poor drainage of the penstock bed, damaged stave ends, and deteriorated staves and cradles. However, for the entire length of the wood stave penstock, the bands and shoes are in good condition, with no significant deterioration observed on either the rolled threads or on the smooth part of the band. In the area under the highway crossing, the deteriorated bands have been augmented / replaced with additional bands that are in good condition.

4.2.1 Anchor Block to Surge Tank

Photo C-15 provides an overview of the wood stave penstock from the anchor block to the surge tank. Photo C-16 provides a close-up view of the bands and shoes this area, showing them to be in good condition. However, Photo C-17 illustrates the poor condition of the wood staves in this region, while the typical poor condition of the wood cradles in this area is shown in Photos C-18 and C-19. Photo C-20 shows the “broomed” ends of the wood staves despite the presence of the Kelsey Type Butt Joints, along with crushing of the staves by the bands. There are metal patches installed on the pipe to prevent leakage, as shown in Photo C-21 and especially along the springline as seen in Photo C-22. Crushed and delaminated staves are numerous in this area, as seen in Photos C-22 and C-23. A sag was observed in the profile of the penstock just downstream of the surge tank, as seen in Photo C-24. It is unlikely it would have been constructed in this manner, and is probably the result of either cradle(s) failure or settlement of a cradle(s) due to poor foundation conditions.

There is a small bore pipe approximately 6” to 8” diameter tapping into the penstock at the location of the utility pole seen in Photo C-24. This pipe is reportedly a water supply line to a local fish processing plant. A close-up view of the take-off, seen in Photos C-25 and C-26, show the electrical heat tracing that was used to protect the gate valve and exposed steel pipe from freezing has been vandalized and is not functioning. This should be re-instated as soon as possible to prevent damage to the exposed valve and pipe.

The connection between the wood stave penstock and the downstream and upstream ends of the surge tank tee are shown in Photos C-27 and C-28 respectively. There is some leakage at these connection points, but it is not significant. However, the exterior coating on the surge tank tee has completely failed, and the bare metal is corroding in the salt laden air.

4.2.2 Surge Tank to Highway Crossing

Photo C-29 shows the penstock immediately upstream of the surge tank. Minor seepage is present all along the springline in this location, due to poor cradle design resulting in ovalling of the penstock and crushing of the wood fibres at the springline. Photo C-30 shows the deteriorated cradle, which only provides 120 degrees of support to the penstock. As noted previously, penstocks of this size should have a minimum of 180 degrees of support. Photos C-30 to C-32 show the poor condition of the staves in this area. This is typical of the condition of the penstock from the surge tank to the highway crossing, and is likely due to the poor cradle design, and the large changes in internal pressure (waterhammer) every time the load changes on the plant, or the generating unit cycles on and off.

Photos C-33 to C-35 show the area where a blow-out occurred in the recent past, approximately 560 ft upstream of the surge tank. A review of the penstock profile shows this area to be within 100 ft of the location of the largest relative internal pressure swings in the penstock when the generating unit starts and stops. Of the entire length of penstock, the penstock at this location has the greatest tendency to ovalize. As shown in Photos C-33 to C-35, Newfoundland Power correctly assessed the likely cause as poor lateral support to the penstock shell by the cradles in this area, and installed timber uprights which provide lateral support at the springline of the penstock to prevent it from ovalling. Photos C-36 to C-41 show the typical leakage along the springline and, in some cases, the crown of the penstock from the surge tank to the highway crossing. Some of the larger leaks have created dramatic ice sculptures of significant size. While significant ice build-up itself is generally not detrimental to the shell of the penstock if the penstock is kept pressurized, it can overload the cradles and foundations in the spring when the ground thaws, or it can create significant lateral forces on the penstock if the leakage is predominantly on one side. In addition, heaving of the penstock due to ice build-up beneath may also be a problem due to the accumulation and freezing of the leakage water.

Photo C-42 shows the wood stave penstock at the highway crossing. As seen in Photo C-43, the cradles supporting the penstock from the surge tank to the highway crossing provide only 120 degrees of support. As seen in Photo C-44, some of the steel bands directly under the highway crossing are severely corroded, due to their exposure to roadway de-icing salts from above. According to the design drawings, the bands should have a spacing of 5¾" at this location. The bands appeared to be significantly closer than this in the field, meaning Newfoundland Power has likely installed replacement bands between the corroded bands, and left the corroded bands in position.

4.2.3 Highway Crossing to Dam

The cradle design upstream of the highway bridge is different than that used further downstream, and provides for a higher degree of support to the penstock. Photo C-45 shows the type of cradle installed between the highway crossing and the dam. Such cradles typically have inclined tension rods to prevent deformation of the cradle, which provides better lateral support to the penstock at the springline, but the cradles installed in the field do not have these tension rods. Consequently, as previously noted, the cradles in the upper half of the Pierre's Brook penstock likely do not provide a full 180 degrees of support, but they do provide significantly more support than the cradles on the penstock downstream of the highway crossing.

The length of penstock upstream of the highway bridge is characterized by the poor condition of the preservative treatment of the staves, a significant amount of damage (brooming) at the ends of the staves, delamination of the staves, widespread leakage along its length (springline and crown), and poor drainage of the penstock bed. However, similar to the penstock downstream of the highway bridge, the steel bands and shoes on the penstock upstream of the highway bridge are in good condition, with no missing or loose bands observed, and no significant corrosion of the rolled threads or the smooth part of the bands observed.

Photos C-47 and C-48 show the preservative treatment to be leached out of the wood. This is typical along this entire length of penstock. Photos C-49 to C-62 show typical examples of stave delamination, brooming, poor preservative treatment, and leakage along the length of the penstock. Photos C-57 and C-63 show examples of poor drainage of the penstock bed, which can lead to rotten staves and cradles, and settlement of the cradles. Photo C-64, which is the length of penstock immediately downstream of the dam, shows the poor condition of the preservative treatment. Photo C-65 shows the most upstream end of the penstock where it enters a corrugated metal pipe culvert on the downstream face of the dam. This culvert was reportedly installed around the wood stave penstock in this area when the downstream face of the dam was flattened. For access reasons, it was not possible to inspect the short length of penstock inside this culvert.

4.2.4 Engineering Assessment

1) The steel in the surge tank tee appears to be in generally good condition, but it requires refurbishment to maintain its reliability and long term performance
2) While the entire Pierre's Brook penstock is in poor condition, the portion located downstream of the highway crossing is more deteriorated than the portion upstream of the highway crossing. Contributing factors to the difference in the level of deterioration in the penstock upstream and downstream of the highway crossing include:
    a. Less support offer by the cradles downstream of the highway bridge
    b. Higher static internal water pressure on the downstream portion of the penstock, and more severe pressure fluctuations due to waterhammer when the load changes on the generating unit, or when the unit cycles on and off
    c. Differences in the level of maintenance. The cradles upstream of the highway crossing were replaced in 1965, but the cradles downstream of the highway crossing were salvaged from previous construction
3) The observed sag in the penstock immediately downstream of the surge tank is likely the result of foundation settlement, but appears to have stabilized.

4) Although the penstock shell and cradles downstream of the highway crossing are in poor condition, the steel bands and shoes along the entire length of penstock appear to be in good condition
5) With the exception of a foundation slope failure caused by leakage or a washout, the structural integrity of a wood penstock depends almost entirely on the strength and condition of the bands and shoes, which are in good condition in the Pierre's Brook penstock. It is likely for this reason there has been only one recorded blow-out in the Pierre's Brook penstock. This was probably a result of bands slipping off shoes due to the lateral deformation of the penstock shell or stretching of the bands under on / off cycling of the generating unit. Therefore, the penstock is not at high risk of a catastrophic failure, even in its deteriorated condition, provided the bands are maintained tight and in-position, and the cradles are replaced prior to falling apart.
6) The condition of the shell of a wood stave penstock, although seldom the initiating cause of catastrophic failure of a penstock, is the most important consideration in assessing its remaining service life. The staves in the Pierre's Brook penstock are typically in poor condition, suffering from a number of deficiencies throughout its length. The amount of leakage is significant, as observed by the ice accumulation along its length. Attempts have been made to reduce leakage by tightening the bands, which has led to crushing of the wood fibres of the staves in a number of locations. Metal patches have been applied on the crown of the penstock, and metal patches and wooden wedges installed along the springline to try to reduce leakage. Deterioration of the ends of staves is quite prevalent, and the preservative treatment on the wood staves has deteriorated along most of the penstock length upstream of the highway crossing. Given the number of attempts at reducing leakage, the amount of leakage still present and the number of broomed stave ends that will start to leak shortly, a significant number of staves need to be replaced. Based on this, the wood staves along the entire penstock length are approaching the end of their useful life, with the length of the penstock downstream of the highway crossing being in worse condition than the upstream section.

4.2.5 Recommendations

1) Reinstate the electrical heat tracing to the area where the water supply line to the fish plant taps into the side of the wooden penstock
2) The exterior coating on the surge tank tee should be replaced
3) The interior of the surge tank tee should be inspected to determine the condition of the coating and to check for areas of erosion and corrosion (particularly rivet heads and pin holes)
4) The thickness of the surge tank tee should be checked (by ultrasonic means) to confirm the shell thickness meets design requirements
5) The penstock should be replaced
6) Until the penstock is replaced, interim maintenance measures should continue and include the following:
    a. Continue routine repairs of leakage, where possible
    b. Ensure bands are maintained tight
    c. Ensure the bands are well positioned on the shoes, particularly along the downstream half of the penstock length downstream of the highway crossing
    d. Monitor cradles for signs of collapse and replace split struts as required
    e. If permitted, apply preservative treatment to the penstock
    f. Apply protective coating to the surge tank tee.

APPENDIX A

PIERRE'S BROOK OPERATING PROCEDURES

POG100.03.02

Pierre's Brook Operating Procedures

Created By: L. Thompson
Revised By: B. Hogan
Reviewed By: G. Humby / B. Ryan
Approved By: G. Humby

UNIT LOADING								
	Best Efficiency			Maximum Load			Rough Zone	
Unit	Load (kW)	Flow (m^3/s)	Eff. ($kW/m^3/s$)	Load (kW)	Flow (m^3/s)	Eff. ($kW/m^3/s$)	Minimum	Maximum
#1	3400	5.09	668	4300	6.54	657.5	1200	2500

FOREBAY OPERATING ELEVATIONS (Ft.)			
	Upper	Lower	Trip Level
Gull Pond (Forebay)	384.0	382.0	375.5

STORAGE ELEVATION LIMITS (Ft.)			
	Upper	Lower (normal)	Lower (summer)
Gull Pond (Forebay)	385.1	370.0	382.7
Big Country Pond	525.6	510.0	-
West Country Pond	474.6	457.0	-

- Lower summer elevation is a minimum that the reservoir will operate at between June 15 and September 15 under normal conditions.
- Gull Pond maximum storage elevation without stoplogs in place is 384.0 feet.

Flow Delay
- Big Country to Gull Pond: 4 hours
- West Country to Gull Pond: 2 hours

Pierre's Brook Operating Procedures

Created By: L. Thompson | Reviewed By: G. Humby / B. Ryan
Revised By: B. Hogan | Approved By: G. Humby

---

1. Inflows are such that this plant is in operation 75% to 80% of the time.

2. Operate unit at best efficiency unless heavy inflows are predicted or under extremely low inflow conditions.

3. Prior to spring runoff, Gull Pond elevation should be lowered to the minimum.

4. Big Country Pond gate usually kept at 3 to 5 inches in summer and West Country Pond gate kept at 3 inches in the summer.

5. Flow to be maintained to the tailrace and Lower Pond for at least two (2) hours per day for fisheries. If the plant has to be off for more than 24 hours, an alternate method of providing flow should be established.

6. West Country Pond spills out of the system.

7. Fish plant is fed from the penstock. The fish plant management will be notified, where possible, in advance of penstock dewatering such that they can procure alternate water sources or plan shut-down's at the fish plant (24 - 48 hour notice minimum).

8. All gates to be left open a minimum of 1 inch to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.

9. During cold weather, shut down the plant and let the forebay freeze over to prevent frazil ice formation on the trash racks.

10. Operate plant at full load when storage is above 68% full supply.

Pierre's Brook Operating Procedures

Created By: L. Thompson
Revised By: B. Hogan

Reviewed By: G. Humby / B. Ryan
Approved By: G. Humby

---

11. During cold weather conditions it may be necessary to reduce the load at Pierre's Brook to 1000 kW for 5 minutes to avoid surge tank freeze up. Guidelines for the frequency of variation are:

Temperature	**Frequency**
-10 C to –20 C	4 hours
Below –20 C	2 hours

12. Water level readings are observed by field operations staff using the following reference benchmarks:

Reservoir	Reference	Elevation
Gull Pond (Forebay)	Top of Stoplogs (height of logs = 1.0 feet)	385.1 feet
Big Country Pond	Spillway Sill	525.6 feet
West Country Pond	Top of Stoplogs (height of logs – 2.6 feet)	474.6 feet

APPENDIX B

LIST OF AVAILABLE DRAWINGS

Table B-1: List of Available Drawings

Drawing Number	Drawing Title	Date
1-607-22-5	Pierre's Brook Development – Pipeline Profile	1931/08/10
1-607-22-11	Pierre's Brook Pipeline Replacement-Steel Penstock	1959/11/01
1-607-22-12	Anchor Block at Sta. 78+71	1959/11/27
1-607-22-13	Piers for Penstock Saddles	1959/12/10
1-607-22-19	Details for 72" I.D.C.S Pipe	1959/12/17
1-607-22-24	Cradles for 72" I.D.C.S Pipe, Pierre's Brook Development	1959/12/17
1-607-23-18	Concrete repairs to Surge Tank Foundations	1981/04/10
1-607-23-19	Pierre's Brook Development, Surge Tank & Surge Tank Tee	1990/11/05
1-607-23-20	Existing Surge Tank Foundations	1990/11/09
1-607-23-21	Plan, Elevation Surge Tank Sections and Details	1991/02/02
1-607-23-22	Elevations, Sections and Details	1991/02/02
1-607-23-23	Surge Tank Replacement Ladder Details	1991/02/02
1-607-23-24	Sections and Details – Surge Tank	1991/02/02

APPENDIX C

SITE INSPECTION PHOTOS

Photo C-1: Overview of steel penstock, as seen from anchor block looking toward powerhouse

Photo C-2: Penetration at powerhouse wall

Photo C-3: Access hole near powerhouse

Photo C-4: General condition of steel penstock

Photo C-5: General condition of steel penstock shell

Photo C-6: General condition of steel penstock shell

Photo C-7: Access hole near anchor block

Photo C-8: Mechanical expansion joint

Photo C-9: Underside of penstock at mechanical expansion joint, showing minor leakage

Photo C-10: Tap at underside of penstock near anchor block

Photo C-11: Typical concrete cradle support

Photo C-12: Concrete cradle support showing signs of deterioration

Photo C-13: Anchor block at upstream end of steel penstock

Photo C-14: Anchor block at upstream end of steel penstock

Photo C-15: Looking upstream at wood stave penstock from anchor block to surge tank

Photo C-16: Bands near downstream end of wood stave penstock

Photo C-17: Deteriorated wood staves near downstream end of penstock

Photo C-18: Deteriorated cradle

Photo C-19: Deteriorated cradle

Photo C-20: Crushed staves, and broomed ends of staves

Photo C-21: Metal patch in top of penstock

Photo C-22: Example of delaminated stave, and repairs to reduce leakage along the springline

Photo C-23: Example of delaminated stave and crushing under the bands

Photo C-24: Penstock immediately downstream of surge tank, showing leakage and sagging

Photo C-25: Water supply line from side of penstock

Photo C-26: Water supply line from side of penstock

Photo C-27: Wood stave connection to downstream end of surge tank tee

Photo C-28: Wood stave connection to upstream end of surge tank tee

Photo C-29: Wood stave penstock immediately upstream of surge tank

Photo C-30: Deteriorated cradles, staves and patching upstream of surge tank (typical)

Photo C-31: Deteriorated staves upstream of surge tank (typical)

Photo C-32: Deteriorated staves and patching on springline upstream of surge tank (typical)

Photo C-33: Modifications at location of previous blow-out

Photo C-34: Modifications at location of previous blow-out

Photo C-35: Patching at springline at location of previous blow-out

Photo C-36: Leakage along springline upstream, of previous blow-out

Photo C-37: General view of penstock upstream of surge tank showing leakage

Photo C-38: General view of penstock showing leakage

Photo C-39: General view of penstock showing leakage

Photo C-40: General view of penstock showing leakage

Photo C-41: General view of penstock showing leakage

Photo C-42: Penstock at highway crossing

Photo C-43: Cradles at location of highway crossing

Photo C-44: Corroded bands under highway crossing

Photo C-45 Change in cradle design at location of highway crossing

Photo C-46: Typical damaged end of stave

Photo C-47: Typical condition of wood stave preservative treatment upstream of highway crossing

Photo C-48: Typical condition of wood stave preservative treatment upstream of highway crossing

Photo C-49: Damaged ends of wood staves

Photo C-50: Repairs and deteriorated staves

Photo C-51: Damaged ends of wood staves

Photo C-52: Widespread leakage at springline

Photo C-53: Delaminated wood stave with broomed end

Photo C-54: Delaminated wood stave with broomed end

Photo C-55: Typical condition of wood stave preservative treatment

Photo C-56: Widespread leakage along springline of pipe

Photo C-57: Poor drainage of penstock bed

Photo C-58: Areas of significant leakage

Photo C-59: Leakage along springline of penstock

Photo C-60: Leakage along springline of penstock

Photo C-61: Damaged ends of wood stave

Photo C-62: Typical damaged ends of wood stave and poor preservative treatment

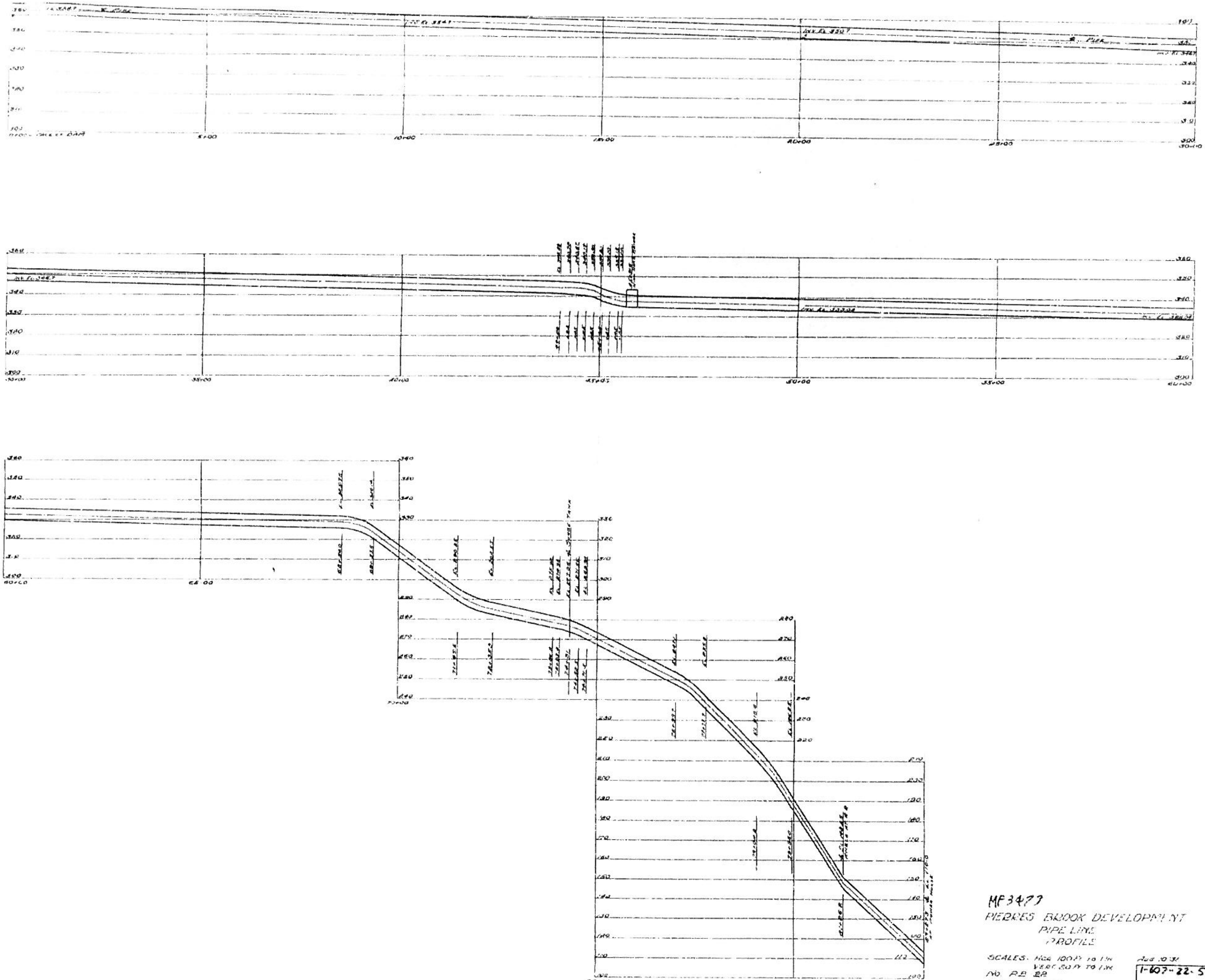
Photo C-63: Poor drainage of penstock bed

Photo C-64: Penstock immediately downstream of dam

Photo C-65: Penstock entering culvert at downstream toe of dam

APPENDIX D

PERTINENT DRAWINGS



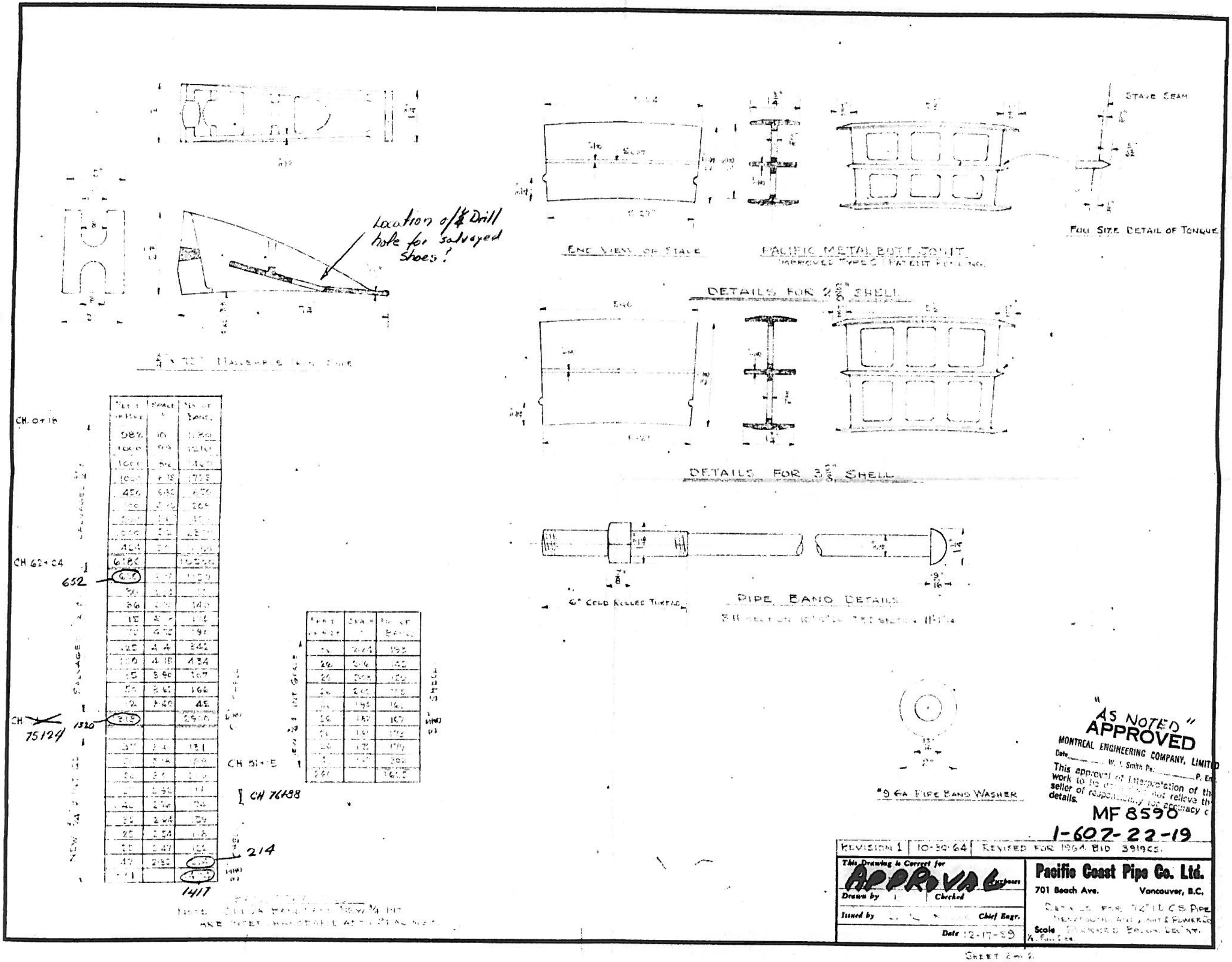
MF3477

PIERRES BROOK DEVELOPMENT
PIPE LINE
PROFILE

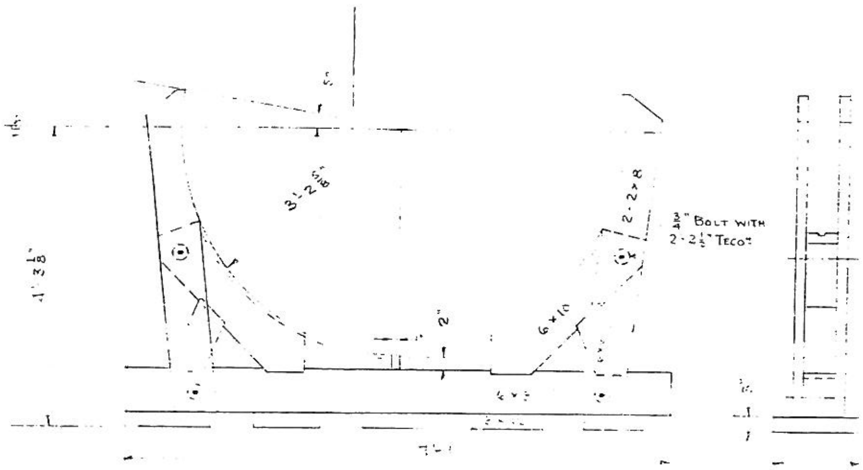
SCALES: HOR 100 FT TO 1 IN
VERT 50 FT TO 1 IN
NO. P.B. 22
DRAWN BY

AUG 10 '31

1-607-22-5



STAVE SEAM
FULL SIZE DETAIL OF TONGUE
END VIEW OF STAVE
PACIFIC METAL BUTT JOINT
DETAILS FOR 2 5/8" SHELL
DETAILS FOR 3 5/8" SHELL
PIPE BAND DETAILS
6" COLD ROLLED THREAD
#9 GA PIPE BAND WASHER
Location of 1/4 Drill hole for salvayed shoes?
CH 0+18
CH 62+04
652
CH 75124
1320
CH 51+E
CH 76+88
214
1417
"AS NOTED"
APPROVED
MONTREAL ENGINEERING COMPANY, LIMITED
This approval of interpretation of the work to be done does not relieve the seller of responsibility for accuracy of details.
MF 8590
1-607-22-19
REVISION 1
10-30-64
REVISED FOR 1964 BID 39195.
This Drawing is Correct for APPROVAL Purposes
Drawn by
Checked
Issued by
Chief Engr.
Date 12-17-59
Pacific Coast Pipe Co. Ltd.
701 Beach Ave.
Vancouver, B.C.
DETAILS FOR 72" I.D. C.S. PIPE
Scale
SHEET 2 of 2

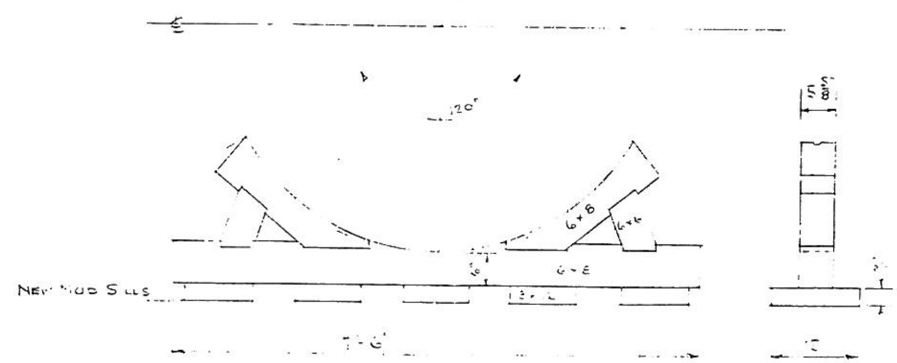


DRILL FOR NAILS AND
GROOVE FOR BANDS AS REQ'D

NEW 190° CRADLE

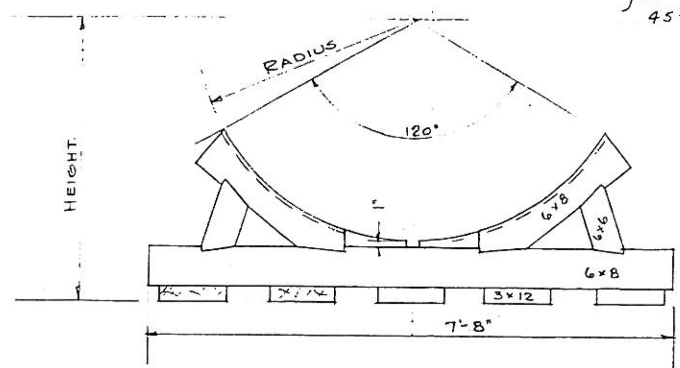
560 REQ'D FOR 2 5/8" SHELL
SPACED AT 8' CTS. FROM 0+18 TO 45+00

DRILL FOR NAILS AND
GROOVE FOR BANDS AS REQ'D



120° CRADLE
AS ORIGINALLY SUPPLIED

400 SALVAGED FOR
2 5/8" SHELL — SPACED
AT 8' CTS FROM
45+00 TO 77+05



NEW 120° CRADLE.

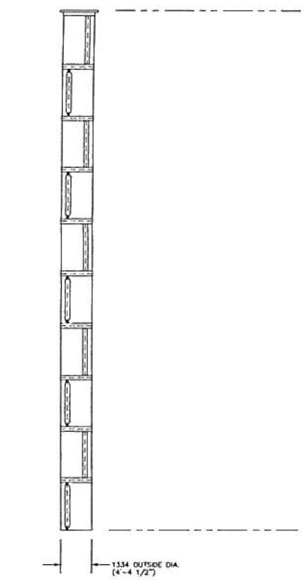
	RADIUS	HEIGHT	NO. REQ'D.	
FOR 2 5/8 SHELL	38 5/8	4'-2"	30 (EXTRA).	(FOR ABOVE)
FOR 3 3/8 SHELL	39 5/8	4'-3"	55	(77+05 TO 81+15)

SPACED AT 8' CENTERS.

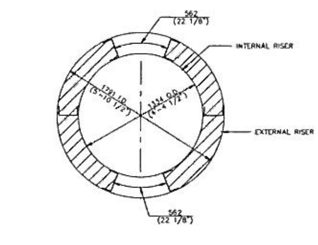
SEE P.C.P. DRAWING 9-16-30 FOR ORIGINAL CRADLES.

REVISION 1	10-30-64	REVISED FOR 1964 BID 3919CS.

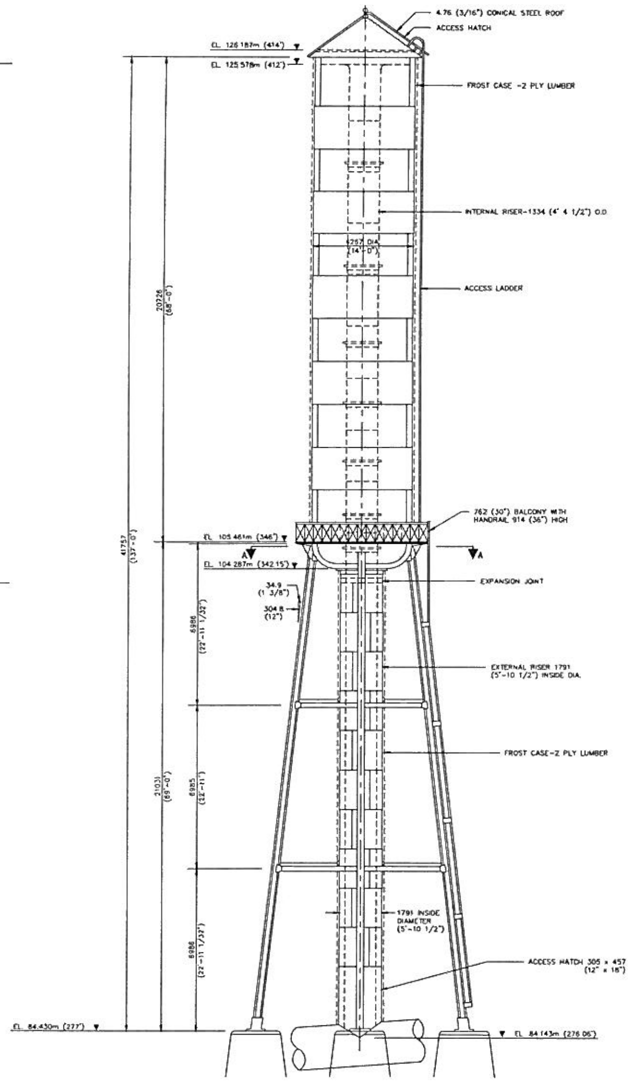
This Drawing is Correct for — Purposes		**Pacific Coast Pipe Co. Ltd.** 701 Beach Ave. Vancouver, B.C.
Drawn by K	Checked	CRADLES FOR 72" I.D. CS. PIPE NEWFOUNDLAND LIGHT & POWER Co. LTD. PIERRE'S BROOK DEV'NT.
Issued by D. D. Reeve. Chief Engr.	Date 12-17-59.	Scale 3/4"=1'-0"



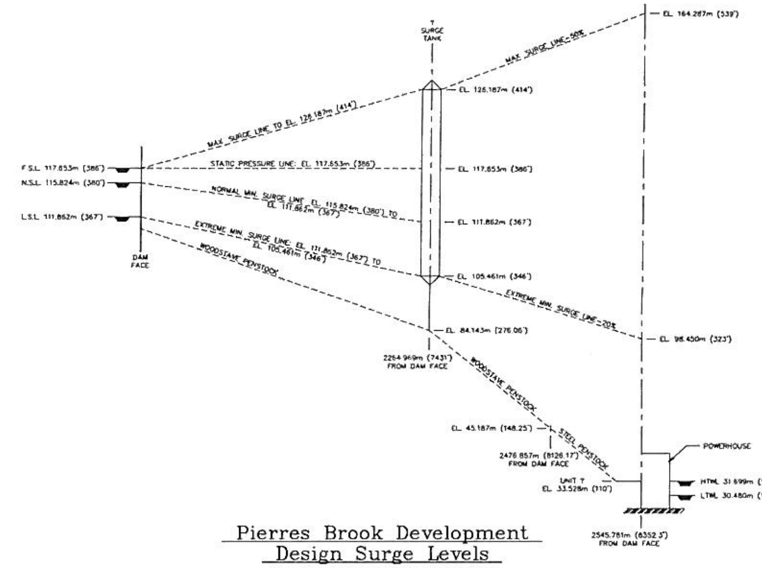
Internal Riser
Scale: 1:100



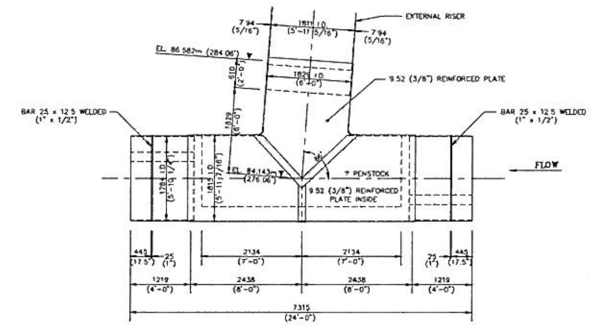
Enlarged Section 'A–A' Port Openings
Scale: 1:25



Elevation Existing Differential Surge Tank
Scale: 1:100



Pierres Brook Development Design Surge Levels
Taken From Montreal Engineering Drawing #14341
NTS



Existing Surge Tank Tee
Scale: 1:50

LEGEND

FSL	FULL SUPPLY LEVEL ELEVATION
NSL	NORMAL SUPPLY LEVEL ELEVATION
LSL	LOW SUPPLY LEVEL ELEVATION
HTWL	HIGH TAILWATER LEVEL ELEVATION
LTWL	LOW TAILWATER LEVEL ELEVATION

NOTES

1. SURGE TANK REFERENCE DRAWINGS: HORTON CONTRACT #2060; MONTREAL ENGINEERING DWG. #0-ML-22011
2. ALL ELEVATIONS IN METERS; ALL DIMENSIONS IN MILLIMETERS
3. STEEL USED IN MANUFACTURE OF ORIGINAL SURGE TANK AND TEE WAS BOILER FLANGE STEEL PLATE.

REV	DATE	DESCRIPTION	DRAWN BY	MADE BY	APP BY	MICROFILM NO.

REVISIONS

NEWFOUNDLAND LIGHT & POWER CO. LIMITED

DESIGNED:	Project: Pierres Brook Development
DRAWN: J.King	Title: Existing Differential Surge Tank & Surge Tank Tee
CHECKED:	
APPROVED:	Scale: As Shown
PASSED:	Date: 1990/11/05
DWG. NO.	1-607-23-19

AMEC Americas Limited
29-31 Pippy Place
Suite 2002
PO Box 9600
St. John's, NL A1A 3C1
Phone: (709) 724-1900 Fax: (709) 739-5458

amec.com

Appendix D
Pierre's Brook Surge Tank Inspection (AMEC)

Pierre's Brook
Surge Tank Inspection

Work Authorization Number: 09-058-WA-011

To Newfoundland Power
Date: March 11, 2014
From: Ellis O'Neil, P. Eng., Senior Project Manager
Project: 176007

PIERRE'S BROOK SURGE TANK INSPECTION

March 11, 2014

Submitted by:

AMEC Americas Limited

29-31 Pippy Place
Suite 2002
PO Box 9600
St. John's NL
Canada A1A 3C1

Tel: (709) 724-1900
Fax: (709) 739-5458

Contact Person:

Glen Forbes
Vice President – Atlantic Canada
Phone: (709) 724-1907
Fax: (709) 739-5458
Email: glen.forbes@amec.com

AMEC #176007

11 March 2014

#176007

Mr. David Ball, P.Eng.
Civil Engineer
Newfoundland Power
55 Kenmount Road
P.O. Box 8910
St. John's NL
A1B 3P6

Email : dball@newfoundlandpower.com

Dear Mr. Ball:

Re: Pierre's Brook Surge Tank Inspection – Final Report

Please find attached two (2) paper copies of the Final Report for the Pierre's Brook Surge Tank Inspection.

Thank you for the opportunity to work with you and your staff on this project, and please contact us if you require any explanation or further discussion.

Yours truly,

Ellis O'Neil

Ellis O'Neil, P.Eng.
Senior Project Manager
Atlantic Region
Power & Process Americas
Direct Tel.:(902) 420-8929
Direct Fax:(902) 420-8949
E-mail: ellis.oneil@amec.com

EO/cz

Attachments (2)

NEWFOUNDLAND POWER
PIERRE'S BROOK SURGE TANK INSPECTION
PROJECT 176007

Prepared by — Date: March 11/14

Checked by — Date: 11 March 14

Approved by Project Manager — Date: March 11/14

REGISTERED PROFESSIONAL ENGINEER
JAMES G. DUNCAN
SIGNATURE
11 Mar 14.
DATE
NEWFOUNDLAND & LABRADOR

REV.	Description	Prepared by	Checked	Approved	Date
1	Draft Report	E. O'Neil	J. Duncan	E. O'Neil	2014-02-28
2	Final Report	EO		EO	March 11/14

DISCLAIMER

This report is issued to Newfoundland Power for the sole purpose of evaluating the progress and future course of the project described in the report. AMEC disclaims all liability for damages arising from any use of this document by other persons or for other purposes. This disclaimer must appear on all complete or partial copies of this document.

AMEC Americas Limited
29-31 Pippy Place, Suite 2002
PO Box 9600
St. John's NL
Canada A1A 3C1

DISCLAIMER

This report is prepared for Newfoundland Power (the “Client”) by AMEC (the “CONSULTANT”) and is subject to the following limitations, qualifications and disclaimers:

1. The report is intended for the exclusive use of the Client and it may not be used or relied upon in any manner or for any purpose whatsoever by any other party.

2. The report is **Pierre’s Brook Surge Tank Inspection** (the “Project”). Data required to support detailed engineering assessments have not always been available and in such cases engineering judgements have been made which may subsequently turn out to be inaccurate. There are, therefore, risks inherent in the Project which are outlined in the report. The CONSULTANT accepts no liability beyond using reasonable diligence, professional skill and care in preparing the report in accordance with the standard of care, skill, and diligence expected of professional engineering firms performing substantially similar work at the time such work is performed, based on the circumstances the CONSULTANT knew or ought to have known based on the information it had at the date the report was written and after due inquiry based on that information.

3. The CONSULTANT shall not be responsible or liable for any interpretation or recommendation made by others including any determination in respect of any sale by the Client or any purchase by any third party or any valuation in respect of the Project based in whole or in part on the data, interpretations and/or recommendations generated by the CONSULTANT in the report.

4. The investigation described in the report is based solely upon site visit carried out on February 24, 2014 by the CONSULTANT, and the information received from the Client.

5. The report speaks only as of its date and to conditions observed at that time, which conditions may change (or may have changed) by virtue of the passage of time or due to direct or indirect human intervention causing any one or more changes in plans or procedures or due to other factors.

6. The report does not extend to any latent defect or other deficiency in the Project which could not have been reasonably discoverable or discovered by such observation, with the exception of any latent defect or other such deficiency of which the CONSULTANT had actual knowledge.

7. The report is to be read in conjunction with all other data and information received and referenced throughout the report, and all correspondence between the Client and the CONSULTANT. Except as stated in the report, the CONSULTANT has not made any independent verification of such data and information and does not have responsibility for the accuracy or completeness thereof.

TABLE OF CONTENTS

APPENDICES

Appendix A – Pierre's Brook Operating Procedures – Bulletin Number POG100.03.02

Appendix B – Pertinent Drawings

Appendix C – Surge Tank Inspection Report by Remote Access Technology

1.0 INTRODUCTION

In January, 2014, Newfoundland Power engaged AMEC to carry out a visual inspection and engineering assessment of the existing surge tank at the Pierre's Brook Hydroelectric Development near Witless Bay, Newfoundland. The condition assessment of the penstock and surge tank tee is presented in a separate report. The work was undertaken based on a proposal submitted by AMEC dated January 27, 2014.

1.1 Scope of Inspection and Report

The project scope consists of an external visual inspection of the 44 m high surge tank, including the external steel structure, cladding, anchor block, foundations, and fall protection system. The project scope also includes an engineering assessment of the surge tank based on the results of the visual inspection, and to provide recommendations for any observed deficiencies. There was no independent field verification of the information shown on the design drawings.

1.2 Background

The Pierre's Brook Hydroelectric Development is a single unit 4.3 MW plant commissioned in 1931, with an average annual generation of 24.4 GW hrs. The plant typically operates under a head of approximately 278 ft. (120 psi), and a maximum unit flow of 230 cfs. The normal supply level in the headpond is El. 380 ft, while the tailwater level varies between El. 100 ft and 104 ft. The most recent load rejection testing conducted on September 17, 2012 showed the upsurge creating a head of 323 ft (140 psi) on the unit.

According to the Operating Procedure for the Pierre's Brook development (Bulletin POG100.03.02 – see Appendix A), the plant is operated 75 to 80% of the time, typically at its best efficiency of 180 cfs, unless there is heavy inflow, or insufficient water to operate at this flow rate. Newfoundland Power noted it is not uncommon for the plant to start and stop once or twice a day in the summer months.

2.0 EXISTING CONDITIONS

The existing surge tank was installed in 1991, and consists of welded steel construction. It replaced an earlier surge tank at the same location. The surge tank is a differential type surge tank, with a 1334 mm I.D. internal riser, and an 1811 mm I.D. by 21.031 m high external riser leading up to the 4267 mm diameter by 20.726 m high elevated tank. The tank is supported on four inclined rolled steel columns, with rolled steel angle bracing. There is a balcony around the perimeter of the elevated tank at its base. The surge tank (external riser and elevated tank) is enclosed in cladding (frost casing) which is meant to mitigate the potential for water freezing inside the surge tank. There is an access ladder and associated cage extending from ground level to the balcony to the roof of the surge tank. The design drawings appear to indicate the previous foundations at the site were re-used when the surge tank was replaced in 1991, but a new anchor block and tee were installed at the base. The available design drawings for the surge tank are provided in Appendix B. As previously noted, no independent field verification of the information shown on the design drawings was carried out.

3.0 SITE INSPECTION

Due to the specialized training required to properly access the elevated portions of the surge tank to conduct a proper assessment, AMEC contracted the field inspection of the surge tank at Pierre's Brook to Remote Access Technology (RAT). RAT inspected the surge tank on AMEC's behalf on February 24, 2014. RAT's inspection report is presented here as Appendix C.

3.1 Results of Inspection

There is widespread failure of the coating system and minor corrosion on the ladder system. The ladder cage was deformed in most areas, but no structural failures were observed. The portion of the ladder attached to the tank (i.e. above the balcony) did not have the minimum required toe clearance from the cladding (i.e. 5 inches available versus 7 inches required). This is likely due to the ladder design not accounting for the thickness of the cladding. The handrail around the balcony has significant material loss due to corrosion, particularly where it abuts the ladder stringers.

The coating on the roof of the tank and the vent cap has failed, and corrosion is occurring. However, there does not appear to be significant material loss at this time.

Similar to the roof of the tank, the coating on the balcony has failed, and minor corrosion is occurring.

The legs, cross bracing and beams supporting the tank are in good condition, but the coating has failed on most of the area. There is scaling up to 6 mm thick in some places, with pitting up to 2.2 mm deep on some of the lower sections of the legs.

The tank cladding is generally in good condition, however, no rubber seals were found on the securing bolts, and two areas near the ladder were observed to have missing securing bolts. An area of punctured cladding was observed near the base of the riser, likely due to vandalism as graffiti was also observed in this area. A large piece of cladding on the riser reportedly became dislodged in the recent past, and was replaced. This extent of the replacement piece can be seen on the riser because of its slightly different colour.

While the anchor block at the base of the surge tank encapsulating the surge tank tee appeared to be in good physical condition, the visible parts of the foundations for the support legs for the tank showed signs of pattern cracking and deterioration. It appears the existing concrete may be an overlay / refurbishment of the previous foundations, because the concrete looks relatively new, but the observed level of cracking / deterioration is unusual for concrete that is only 23 years old. This is likely due to alkali-aggregate reactivity in the previous foundation reflecting through the newer concrete overlay, with the deterioration exacerbated by freeze-thaw action.

3.2 Engineering Assessment

The ladder above the balcony does not meet current design requirements, and needs to be refurbished. Overall, the coating system on the surge tank (roof, vent cap, balcony, legs, cross bracing and beams) has failed but, with the exception of a few areas, there has been no significant material loss due to corrosion to date. However, the exposed steel will continue to corrode at an accelerated rate due to the proximity of the site to the Atlantic Ocean and exposure to the salt laden air. If the coating is not replaced in the near future, significant material loss can be expected, resulting in more costly repairs and a reduced level of reliability.

The fasteners securing the cladding in position appear to be an issue, with missing fasteners and incomplete fasteners observed on site. This may be part of the reason a large piece of cladding became dislodged from the surge tank in the recent past.

No internal inspection of the surge tank was undertaken. An internal inspection should be carried out to determine the condition of the inside of the surge tank. That inspection should include thickness measurements of the tank and risers to ensure they meet design requirements.

Since the cladding completely covers the outside of the surge tank and external riser, the condition of the external faces of these elements was not assessed, nor was the expansion joint in the riser. As the cladding may trap moisture that can result in corrosion, the cladding should be removed from representative areas of these elements, and the condition of the surge tank and external riser assessed.

Overall, the surge tank appears to be in generally good condition, but it requires refurbishment to maintain its reliability and long term performance. The concrete on the surface of the foundations is showing signs of deterioration. The depth of deterioration needs to be determined to assess refurbishment options.

3.3 Recommendations

1) Replace / refurbish the ladder and ladder cage to meet current design requirements.
2) Repair / replace those exposed elements of the surge tank that have experienced significant material loss, particularly the handrail around the balcony where it abuts the ladder.
3) Replace the coating on all exposed steel portions of the surge tank.
4) Remove the cladding from representative areas of the surge tank and external riser, and assess the condition of the coating.
5) Remove the cladding from the area of the expansion joint in the riser, and inspect the expansion joint.
6) Replace missing, damaged, or incorrectly installed fasteners that secure the cladding in position
7) Undertake an internal inspection of the surge tank.
8) Undertake thickness testing of the tank and riser walls to confirm the wall thickness meets design requirements.
9) Determine the depth of deterioration of the foundations to assess repair / replacement options.

APPENDIX A

PIERRE'S BROOK OPERATING PROCEDURES

POG100.03.02

NEWFOUNDLAND POWER
A FORTIS COMPANY

Pierre's Brook Operating Procedures

Created By: L. Thompson
Revised By: B. Hogan
Reviewed By: G. Humby / B. Ryan
Approved By: G. Humby

UNIT LOADING								
	Best Efficiency			Maximum Load			Rough Zone	
Unit	Load (kW)	Flow (m^3/s)	Eff. ($kW/m^3/s$)	Load (kW)	Flow (m^3/s)	Eff. ($kW/m^3/s$)	Minimum	Maximum
#1	3400	5.09	668	4300	6.54	657.5	1200	2500

FOREBAY OPERATING ELEVATIONS (Ft.)			
	Upper	Lower	Trip Level
Gull Pond (Forebay)	384.0	382.0	375.5

STORAGE ELEVATION LIMITS (Ft.)			
	Upper	Lower (normal)	Lower (summer)
Gull Pond (Forebay)	385.1	370.0	382.7
Big Country Pond	525.6	510.0	-
West Country Pond	474.6	457.0	-

- Lower summer elevation is a minimum that the reservoir will operate at between June 15 and September 15 under normal conditions.
- Gull Pond maximum storage elevation without stoplogs in place is 384.0 feet.

Flow Delay

- Big Country to Gull Pond: 4 hours
- West Country to Gull Pond: 2 hours

Pierre's Brook Operating Procedures

Created By: L. Thompson
Revised By: B. Hogan

Reviewed By: G. Humby / B. Ryan
Approved By: G. Humby

---

1. Inflows are such that this plant is in operation 75% to 80% of the time.

2. Operate unit at best efficiency unless heavy inflows are predicted or under extremely low inflow conditions.

3. Prior to spring runoff, Gull Pond elevation should be lowered to the minimum.

4. Big Country Pond gate usually kept at 3 to 5 inches in summer and West Country Pond gate kept at 3 inches in the summer.

5. Flow to be maintained to the tailrace and Lower Pond for at least two (2) hours per day for fisheries. If the plant has to be off for more than 24 hours, an alternate method of providing flow should be established.

6. West Country Pond spills out of the system.

7. Fish plant is fed from the penstock. The fish plant management will be notified, where possible, in advance of penstock dewatering such that they can procure alternate water sources or plan shut-down's at the fish plant (24 - 48 hour notice minimum).

8. All gates to be left open a minimum of 1 inch to maintain flow for fisheries. If gate has to be closed, an alternate method of maintaining flow must be established.

9. During cold weather, shut down the plant and let the forebay freeze over to prevent frazil ice formation on the trash racks.

10. Operate plant at full load when storage is above 68% full supply.

Pierre's Brook Operating Procedures

Created By: L. Thompson — Reviewed By: G. Humby / B. Ryan
Revised By: B. Hogan — Approved By: G. Humby

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11. During cold weather conditions it may be necessary to reduce the load at Pierre's Brook to 1000 kW for 5 minutes to avoid surge tank freeze up. Guidelines for the frequency of variation are:

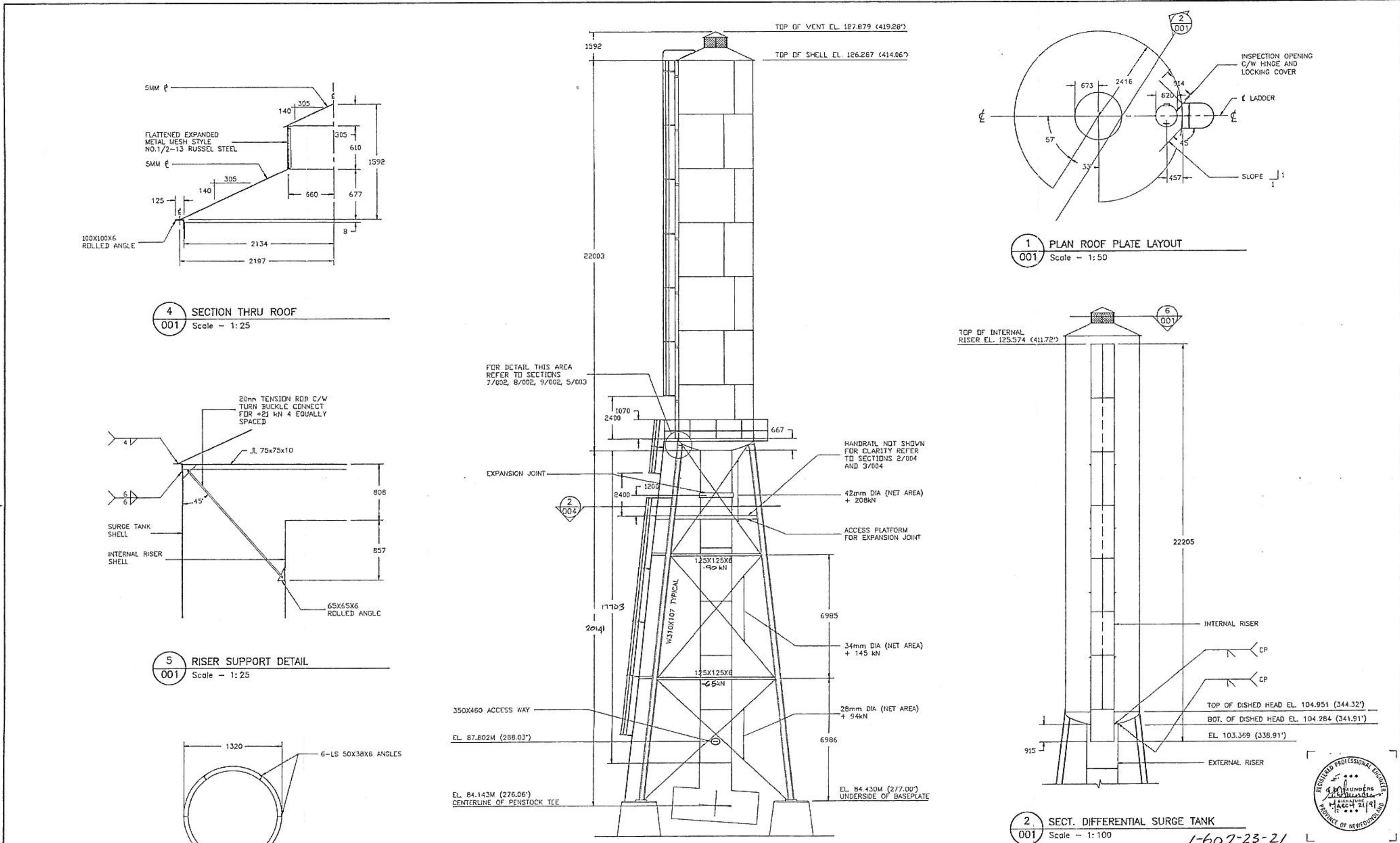
Temperature	**Frequency**
-10 C to –20 C	4 hours
Below –20 C	2 hours

12. Water level readings are observed by field operations staff using the following reference benchmarks:

Reservoir	Reference	Elevation
Gull Pond (Forebay)	Top of Stoplogs (height of logs = 1.0 feet)	385.1 feet
Big Country Pond	Spillway Sill	525.6 feet
West Country Pond	Top of Stoplogs (height of logs – 2.6 feet)	474.6 feet

APPENDIX B

PERTINENT DRAWINGS



NOT FOR CONSTRUCTION

DATE	NO.	REVISIONS	CH.	APP.	APP.
MAR 21 91	2	REISSUED FOR APPROVAL			
FEB 22 91	1	ISSUED FOR APPROVAL			
FEB 12 91	0	ISSUED FOR REVIEW			

ACRES

M & M ENGINEERING

PIERRES BROOK DEVELOPMENT

PLAN, ELEVATION SURGE TANK SECTIONS AND DETAILS

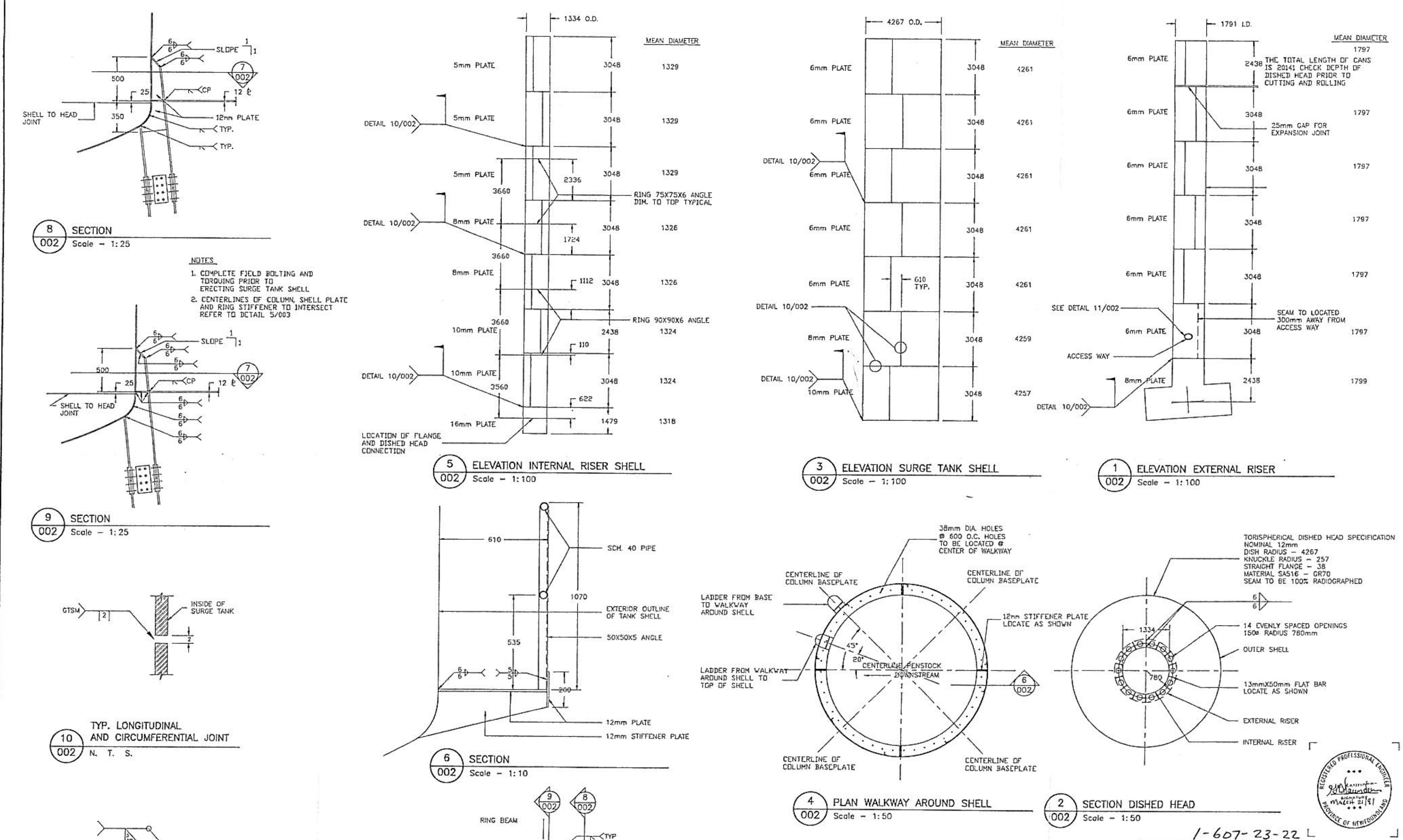
ACRES INTERNATIONAL LIMITED

DATE FEB 2 1991 — SCALE AS NOTED

DEPARTMENT — PROJECT

DRAWING NO. 9691-M-001 — SHEET 1 OF 4 — REV. 2

DRAWING No. 9691-M-001 SHEET 1 OF 4 REV. 2



NOT FOR CONSTRUCTION

DATE	NO.	REVISIONS	CH.	APP.	APP.
MAR 21 91	2	REISSUED FOR APPROVAL			
FEB 22 91	1	ISSUED FOR APPROVAL			
FEB 12 91	0	ISSUED FOR REVIEW			

ACRES — M & M ENGINEERING
PIERRES BROOK DEVELOPMENT

ELEVATIONS, SECTIONS & DETAILS

ACRES INTERNATIONAL LIMITED
DATE FEB 12 1991 — SCALE AS NOTED
DRAWING NO. 9691-M-002 — SHEET 2 OF 4 — REV. 2

DRAWING No. 9691-M-002 SHEET 2 OF 4 REV. 2

NOTES:

1. All welding of structural connections shall conform to the requirements of CSA W59.

   All bolted connections shall conform to the requirements of CSA-S16-76 Bolts shall be structural grade A325.

2. Welders shall be qualified in accordance with the requirements of CSA W47.1 or the ASME code where applicable.

3. Connections shall be designed to carry the design load where given or a minimum of 50% capacity of the member. All design load are unfactored in accordance with the working stress design standard AWWA D-100.

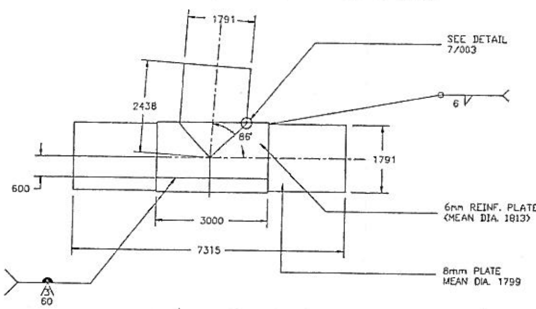
4. Groove welds shall be complete penetration unless specified otherwise. Fillet welds shall conform to the size given or where not indicated shall conform to the requirements of AWWA-D100.

5. Electrodes used for welding shall conform to E480XX electrode strength requirements. Structural support connection i.e. column to shell, shall use E48018 electrodes.

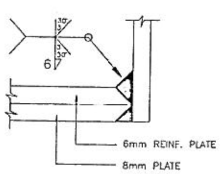
6. Column baseplate size subject to change based on concrete investigation of existing foundations.

7. Column splice shall be designed as a friction connection with bolts in double shear. Milled ends are not required.

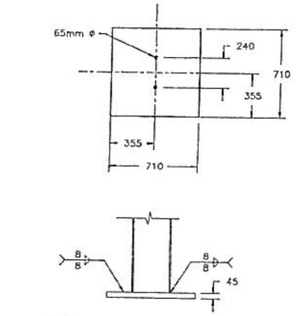
8. Structural bracing to incorporate method for pretensioning rods. ie. turnbuckle. Net area required excluding threads is given on drawings.



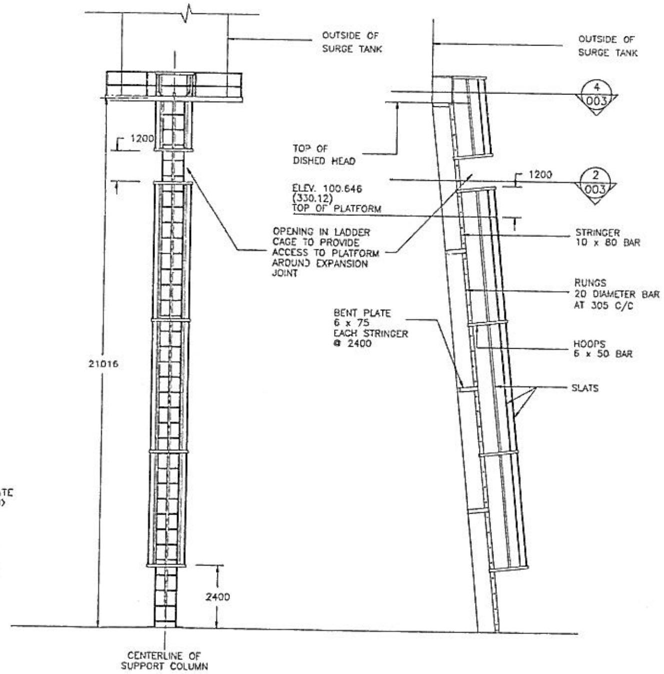
6/003 SURGE TANK TEE
N. T. S.



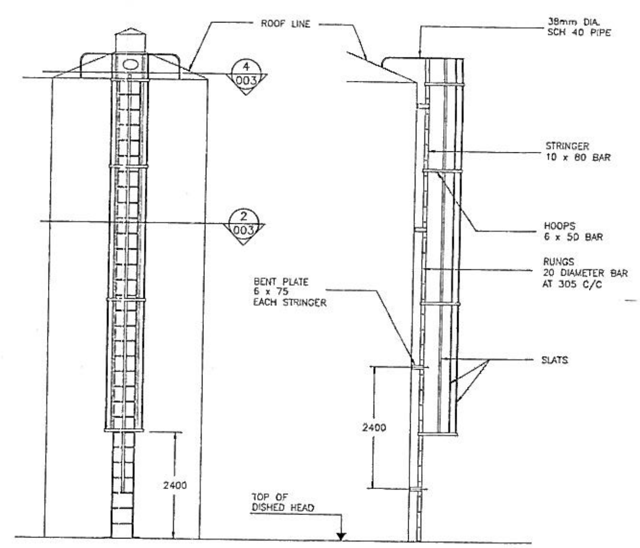
7/003 DETAIL
N. T. S.



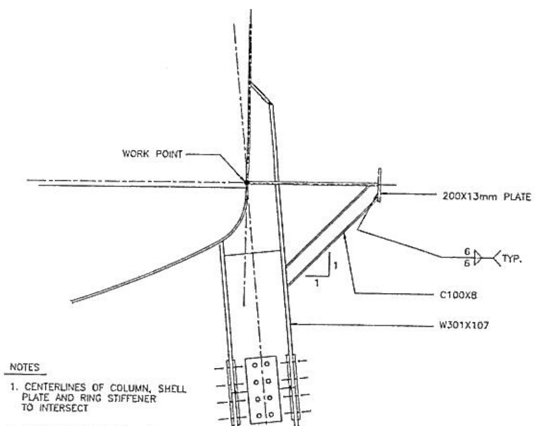
8/003 PLAN BASEPLATE
Scale – 1:20



3/003 ELEVATION LADDER
Scale – 1:100



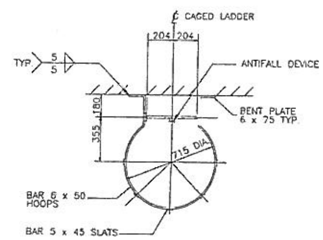
1/003 ELEVATION LADDER
Scale – 1:100



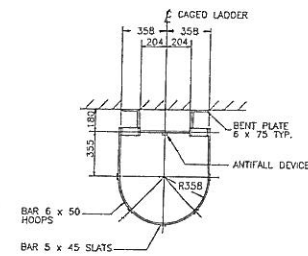
NOTES

1. CENTERLINES OF COLUMN, SHELL PLATE AND RING STIFFENER TO INTERSECT
2. CONNECT SPLICE FOR +430kN
3. BRACING NOT SHOWN FOR CLARITY (MINIMIZE BRACING ECCENTRICITY)

5/003 DETAIL RING STIFFENER
Scale – 1:15



4/003 SECTION
Scale – 1:20



2/003 SECTION
Scale – 1:20

REGISTERED PROFESSIONAL ENGINEER — SAUNDERS — SIGNATURE — MARCH 21/91 — PROVINCE OF NEWFOUNDLAND

1-607-23-23

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DATE	NO.	REVISIONS	CH.	APP.	APP.
MAR 21 91	2	REISSUED FOR APPROVAL			
FEB 22 91	1	ISSUED FOR APPROVAL			
FEB 12 91	0	ISSUED FOR REVIEW			

ACRES

M & M ENGINEERING

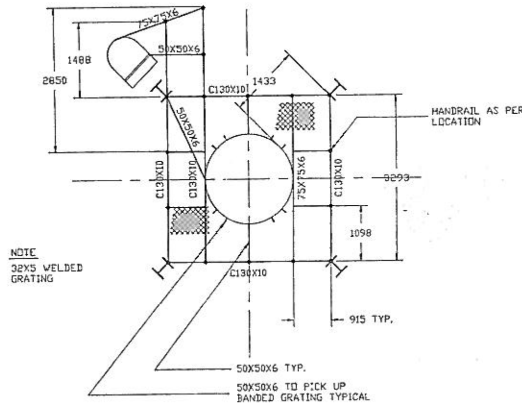
PIERRES BROOK DEVELOPMENT

SURGE TANK REPLACEMENT
LADDER DETAILS

ACRES INTERNATIONAL LIMITED

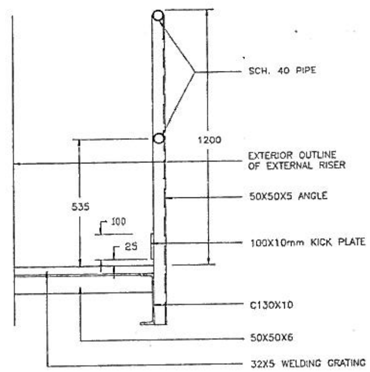
DATE FEB 12 1991 — SCALE AS NOTED
DEPARTMENT — DRAWING NO. 9691-M-003 — REV. 2
PROJECT — SHEET 3 OF 4

DRAWING No. 9691-M-003 SHEET 3 OF 4 REV. 2

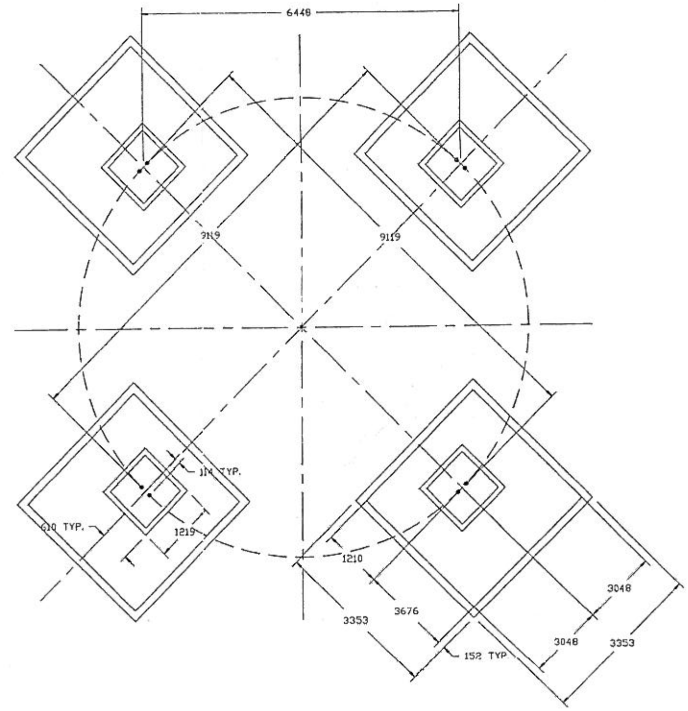


NOTE
32X5 WELDED GRATING

2/004 PLATFORM AROUND EXPANSION JOINT
Scale – 1:50



3/004 HANDRAIL DETAIL
Scale – 1:10



1/004 FOUNDATION PLAN
Scale – 1:50

1-607-23-24

REGISTERED PROFESSIONAL ENGINEER
G.M. SAUNDERS
SIGNATURE
March 21/91
PROVINCE OF NEWFOUNDLAND

NOT FOR CONSTRUCTION

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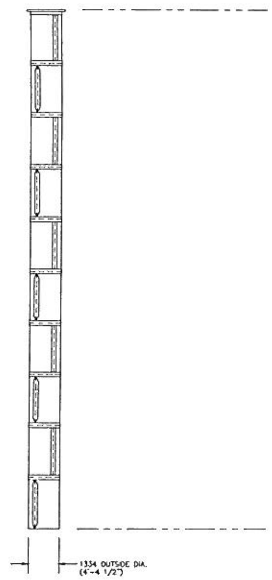
91/03/21	0	ISSUED FOR APPROVAL			

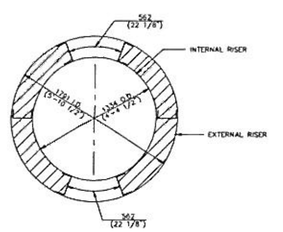
ACRES
M & M ENGINEERING
PIERRES BROOK DEVELOPMENT

SECTIONS & DETAILS

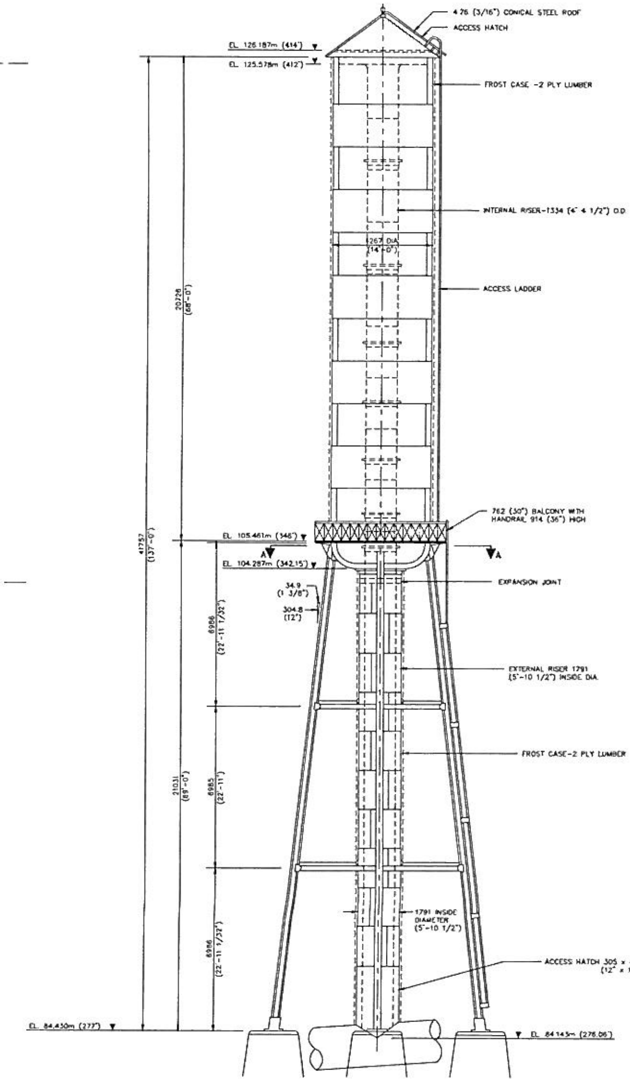
ACRES INTERNATIONAL LIMITED
DATE FEB 12 1991
DEPARTMENT
PROJECT
SCALE AS NOTED
DRAWING NO. 9691-M-004
SHEET 4 OF 4
REV. 0



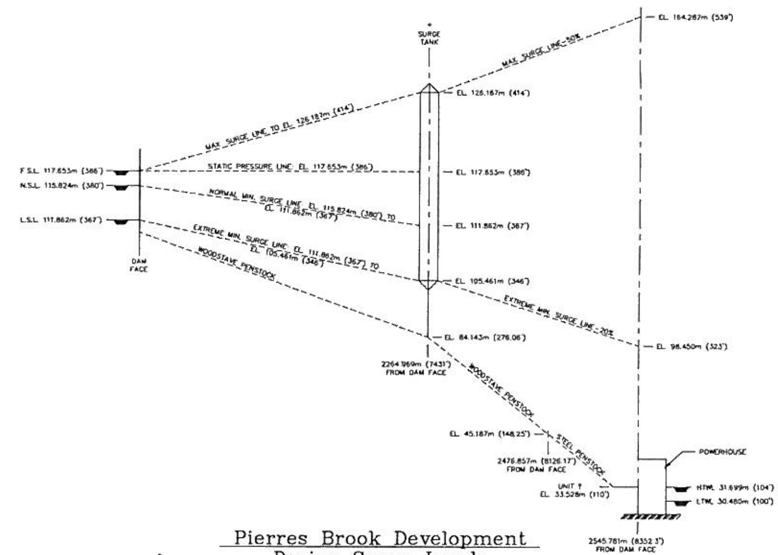
Internal Riser
Scale: 1:100



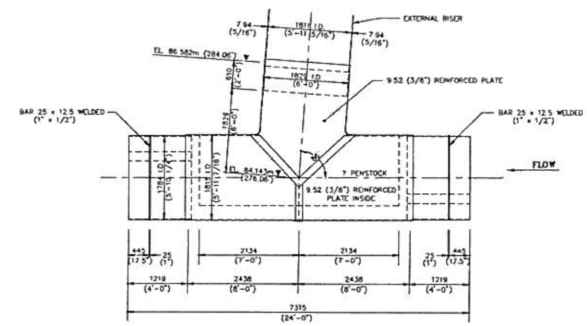
Enlarged Section 'A–A'
Port Openings
Scale: 1:25



Elevation
Existing Differential Surge Tank
Scale: 1:100



Pierres Brook Development
Design Surge Levels
Taken From Montreal Engineering Drawing #14341
NTS



Existing Surge Tank Tee
Scale: 1:50

LEGEND

FSL	FULL SUPPLY LEVEL ELEVATION
NSL	NORMAL SUPPLY LEVEL ELEVATION
LSL	LOW SUPPLY LEVEL ELEVATION
HTWL	HIGH TAILWATER LEVEL ELEVATION
LTWL	LOW TAILWATER LEVEL ELEVATION

NOTES

1. SURGE TANK REFERENCE DRAWINGS: HORTON CONTRACT #7060 MONTREAL ENGINEERING DWG. #0-NL-22011
2. ALL ELEVATIONS IN METERS; ALL DIMENSIONS IN MILLIMETERS
3. STEEL USED IN MANUFACTURE OF ORIGINAL SURGE TANK AND TEE WAS BOILER FLANGE STEEL PLATE.

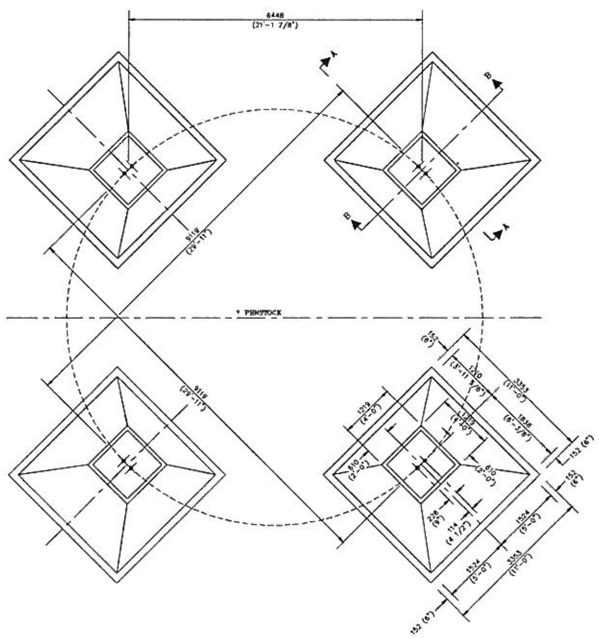
REV	DATE	DESCRIPTION	DRAWN BY	MADE BY	APP BY	MICROFILM NO.

REVISIONS

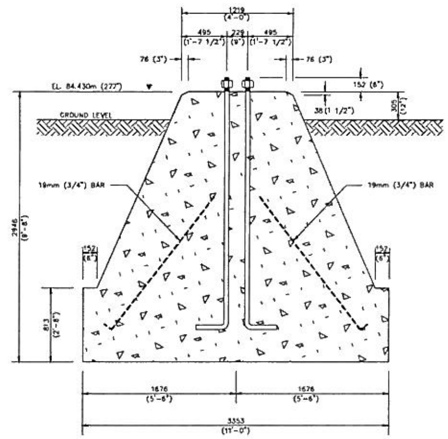
NEWFOUNDLAND LIGHT & POWER CO. LIMITED

DESIGNED:		Project:	Pierres Brook Development
DRAWN:	J.King	Title:	Existing Differential Surge Tank & Surge Tank Tee
CHECKED:			
APPROVED:		Scale:	As Shown
PASSED:		Date:	1990/11/05

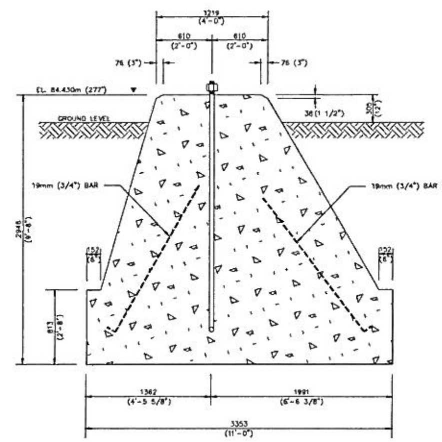
DWG. NO. 1-607-23-19



Plan
Scale: 1:50



Section 'A-A'
Scale: 1:25



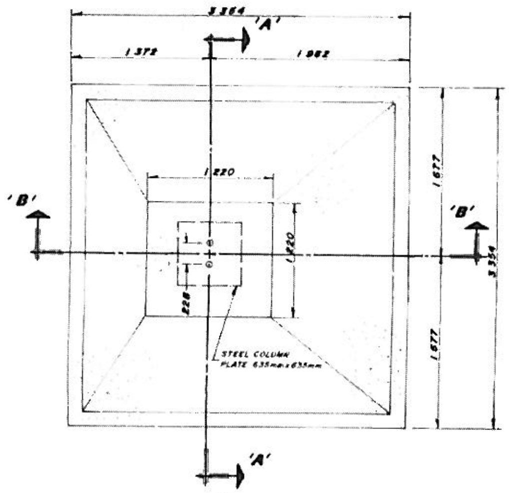
Section 'B-B'
Scale: 1:25

REV	DATE	DESCRIPTION	DRAWN BY	MADE BY	APP BY	MICROFILM NO.

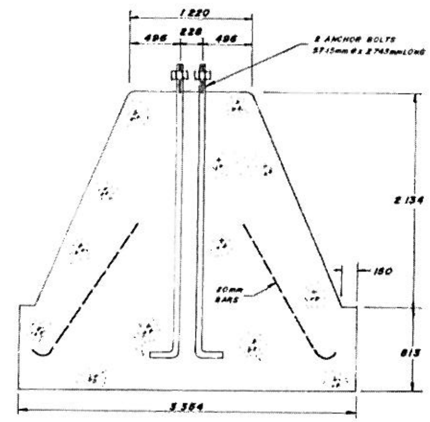
REVISIONS

NEWFOUNDLAND LIGHT & POWER CO. LIMITED

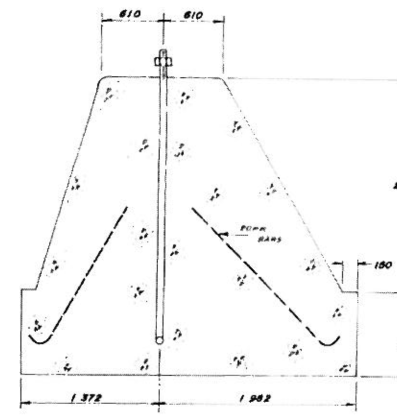
DESIGNED:	Project: Pierres Brook Development
DRAWN: J. King	Title: Existing Surge Tank Foundations
CHECKED:	
APPROVED:	Scale: As Shown
PASSED:	Date: 1990/11/09
	DWG. NO. 1-607-23-20



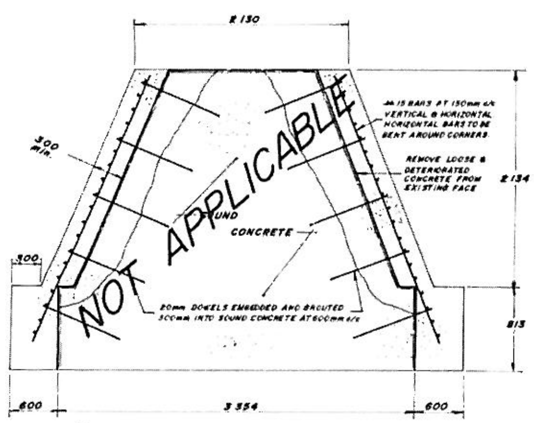
Plan
Existing Surge Tank Foundation



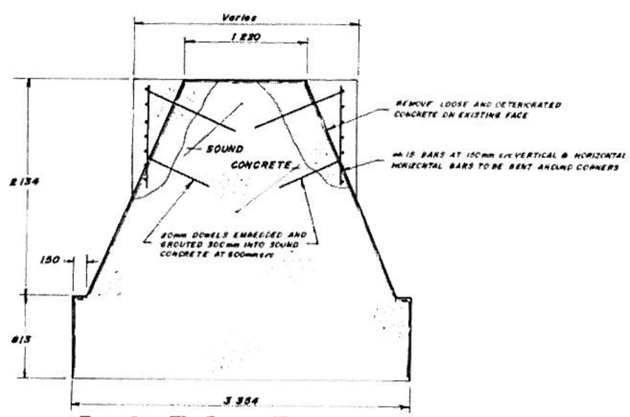
Section 'A-A'



Section 'B-B'



Repairs To Surge Tank Foundation
For Entire Block



Repairs To Surge Tank Foundation
For Top Section of Block

NOTES

1 CONCRETE USED FOR REBUILDING FOUNDATIONS SHALL HAVE A 28 DAY COMPRESSIVE STRENGTH OF 30MPa
2 REINFORCING STEEL TO BE INTERMEDIATE GRADE DEFORMED STEEL

REV.	DATE	DESCRIPTION	DRAWN BY	MADE BY	APP. BY	MICROFILM NO.

REVISIONS

NEWFOUNDLAND LIGHT & POWER CO. LIMITED

DESIGNED:
DRAWN: D Jackman
CHECKED:
APPROVED:
PASSED:

Project: Pierres Brook Surge Tank
Title: Concrete Repairs To Surge Tank Foundation
Scale: 1:25
Date: 1981 04 10
DWG. NO. 1-607-23-18

0 300 mm

20

APPENDIX C

SURGE TANK INSPECTION REPORT

BY REMOTE ACCESS TECHNOLOGY

www.RATintl.com

Remote Access Technology

Surge Tank Inspection

Pierre’s Brook Hydroelectric Power Station

1.0 Introduction

Remote Access Technology was mobilized to the Pierre's Brook hydroelectric power station, near Witless Bay, NL on 24 February 2014 to perform a visual inspection on the external condition of the Surge Tower. Internal access was not permitted thus preventing an inspection on the structural integrity of the Riser and Tank. For orientation purposes the west side of the tank faces the upper section of the penstock and east on the lower section of the penstock.

1.1 Inspection Summary

The external detailed visual inspection was performed concentrating on the ladder system, cladding, legs, and cross braces and roof. Rope access/work positioning was used to inspect the legs and cross braces. At the time of inspection access was prevented on the east side legs due to live wires, so a general inspection only was performed.

A detailed visual inspection was performed on the ladder system. Excessive coating breakdown and minor corrosion was present. The back scratchers were deformed in most areas but none were found to have failed. The upper ladder section attached to the Tank was found to fail ladder safety standards. 5 inches from the cladding to the rungs was found when 7 inches in the minimum. The hand rail system around the base of the tank (Balcony) at the ladder access was found to have excessive corrosion and metal loss.

The tank top had coating break down and corrosion. No defects were found. The hatch was not opened.

The cladding on the Surge Tank was found to be in good condition. No rubber seals were found on the securing bolts from the areas that were accessed. Two areas on the cladding near the ladder were missing securing bolts. An area of punctured cladding was found at the base of the riser on the south side.

The circular balcony at the base of the tank had coating breakdown and showed signs of minor corrosion.

The tank legs, horizontal steel beams and cross members were found to be in good general condition. All showed coating breakdown and scaling up to 6mm. Pitting was found on the outside North East Leg along the bottom 3 metres. The largest pits were found at 2.2mm.

2.0 External Inspection Results

2.1 Ladder System

Location: Ladder on the tank (Upper section of ladder)

Description: General photo. Coating breakdown and corrosion. Deformation on members of backscratchers are typical on both ladder systems.

Location: Ladder at the platform below the tank

Description: Deflection on the rung, approx. 15mm.

Location: Ladder on the tank

Description: Ladder rungs are 5 inches away from the cladding.

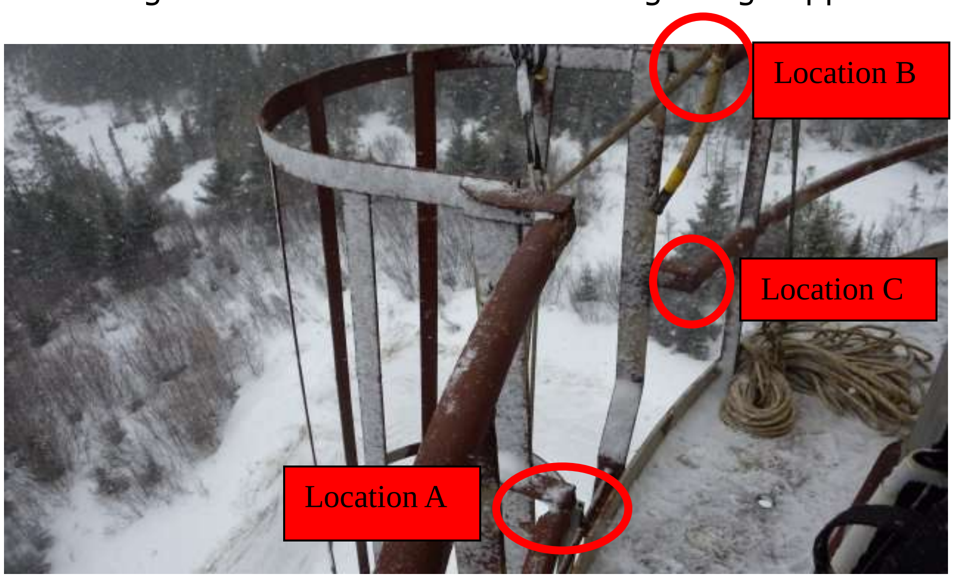
2.2 Balcony

Location: Circular landing on the north side

Description: General **c**oating breakdown and corrosion found throughout.

Location: Underside of the landing below the tank.

Description: Coating breakdown and corrosion on grating supports.



Location: Handrails at the top of the first ladder section.

Description: Excessive corrosion resulting in a loss of metal.

Location: Location A as seen in the previous photo.

Description: Excessive corrosion.

Location: Location B and C

Description: Major corrosion and scaling was found on the underside of the hand rails.

Location: Location C close up.

Description: Major corrosion and scaling found.

2.3 Tank Top

Location: Tank top rain cap

Description: Tank top rain cap, coating breakdown and minor corrosion found with a small tear in the mesh noted (circle above).

Location: Tank top inside the rain cap

Description: Coating breakdown and minor corrosion.

Location: Tank top west and north side

Description: Coating breakdown and minor corrosion.

Location: Tank top east and north side

Description: Coating breakdown and minor corrosion.

Location: Tank top south side and west side with hatch cover

Description: Coating breakdown and minor corrosion. Hatch was not opened.

Location: Tank top south and east side with hatch cover.

Description: Coating breakdown and minor corrosion.

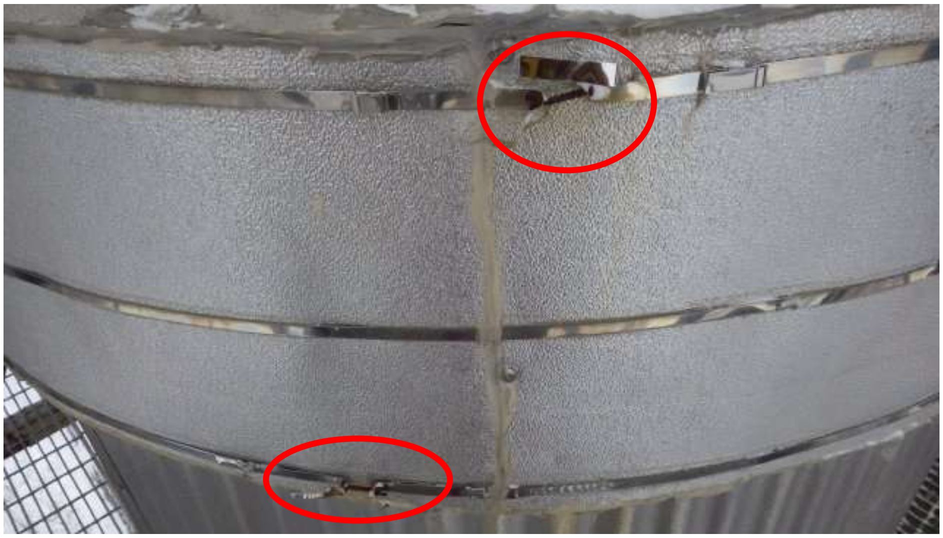
2.4 Surge Tank, Riser

Location: Surge tank, approx. 5 metres from the tank top, left of the ladder.

Description: Two securing bolts were missing, loose cladding.

Location: Riser

Description: General photo. Good condition some water staining present.



Location: Riser top south side

Description: Corrosion of the bolted connections.

Location: Riser Base South Side

Description: General Photo, puncture holes in the cladding.

Location: Riser base west side

Description: General Photo, Puncture holes in the cladding, coating breakdown and minor corrosion on the hatch. Hatch was not opened during the inspection.

2.5 Legs, Horizontal Beams, Cross Members

Location: Leg Connection, ladder leg

Description: Coating breakdown and moderate corrosion, scaling up to 6mm found throughout the leg connections.

Location: Upper cross member, south side

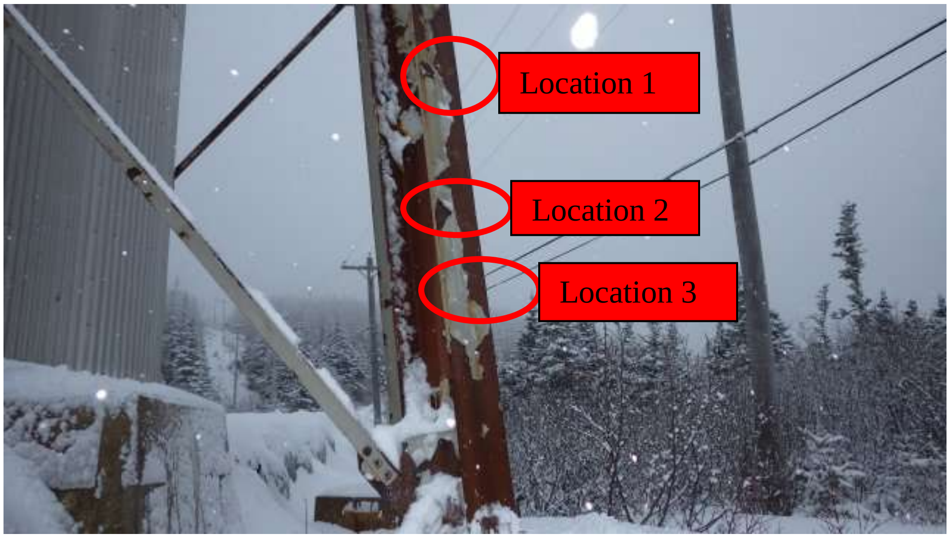
Description: General photo, coating breakdown and corrosion found on all cross members.

Location: Horizontal beams, south and west side, upper section.

Description: General photo, coating breakdown and corrosion found on all Beam members.

Location: Lower leg tie-in connection, south west leg.

Description: General photo, coating breakdown and corrosion found on all members.



Location: North east leg base

Description: General photo, coating breakdown and corrosion with pitting found. Circles indicate areas of largest pitting. Found only on the outboard side of the Flange.

Location: Location 1

Description: Deepest pit was 2.2mm, average was 1.8mm. Area was approx. 3cm by 2cm. Approx. 2.5 metres up from the base.

Location: Location 2

Description: Deepest pit was 1.6mm, average was 1.2mm. Area was approx. 3cm by 3cm. Approx. 2 metres up from the base.

Location: Location 3

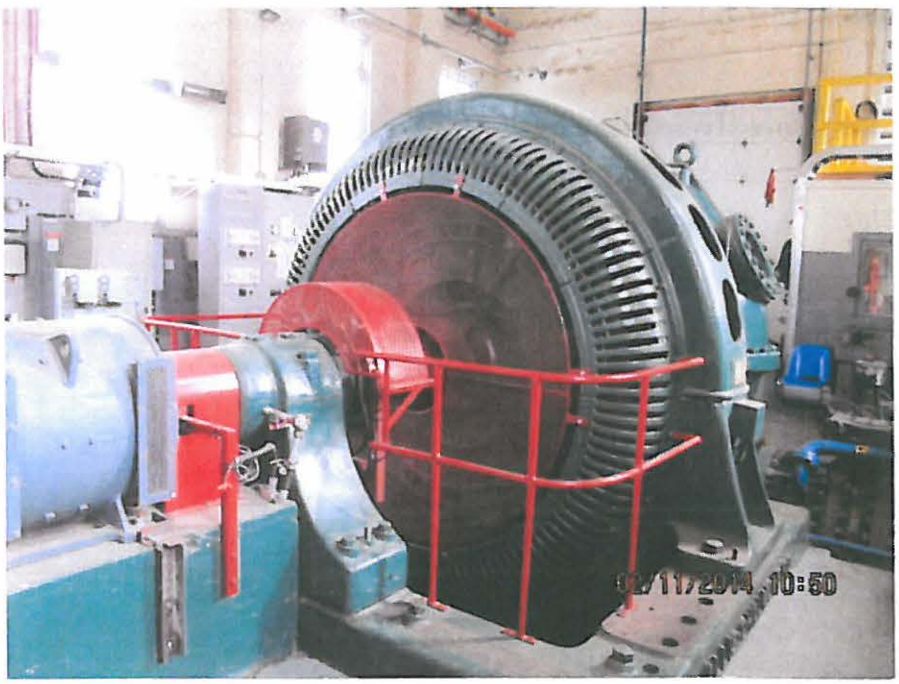
Description: Deepest pit was 1.2mm, average was 1.0mm. Area was typical for the base of the Leg. Approx. 1.5 metres up from the base.

AMEC Americas Limited
29-31 Pippy Place
Suite 2002
PO Box 9600
St. John's, NL A1A 3C1
Phone: (709) 724-1900 Fax: (709) 739-5458

amec.com

Seal Cove Hydro Plant Refurbishment
Generator No. 1 Rotor Rewind

June 2014



Prepared by:

Jeremy Decker, P.Eng.

Todd Hynes, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
TODD HYNES
SIGNATURE
06/25/2014
DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

Page

1.0 Background

1.1 General

Newfoundland Power's Seal Cove hydroelectric development (the "Plant") is located on the Avalon Peninsula, near the community of Seal Cove, approximately 20 km west of the City of St. John's.

The Plant was placed into service in 1924 and contains two generating units, a 1,000 kVA Allis Chalmers generating unit ("G1") and a 3,000 kVA Westinghouse generating unit ("G2") under a rated net head of 55.5 m. The two generating units have a nameplate capacity of 3.3 MW.[1] The Plant's normal annual production is approximately 9.4 GWh or 2.2 % of the total hydroelectric production of Newfoundland Power. The Plant has provided 90 years of reliable production.

The 2015 refurbishment and life extension of G1 at the Plant includes necessary work on the generator rotor at an estimated cost of $156,000. The estimated levelized cost of energy from the Plant over the next 50 years, including the estimated capital expenditure of $1.37 million over the next 25 years, is 1.93¢ per kWh.[2]

This report provides a summary of the engineering assessment of the Plant and the refurbishment proposed for 2015.

1.2 Previous Upgrades

There have been a number of upgrades to the original plant and equipment since commissioning in 1924.

The following is a list of the upgrades that have been completed in the past 25 years:

1988 – G1 stator rewind
2002 – New powerhouse crane
2002 – Steel penstock installed
2002 – Main valves, bypass valves and controls installed on G1 and G2
2003 – Fisheries compensation valve installed
2003 – Electric governors with digital controls installed on G1 and G2
2003 – G1 and G2 instrumentation and controls replaced
2003 – Switchgear replaced
2003 – G2 stator and rotor rewound
2009 – G2 turbine bearing, runner and shaft replaced
2009 – Powerhouse roof membrane installed
2009 – ION revenue meters installed
2010 – G1 governor controls upgraded
2010 – G1 runner, wicket gates and nose cone replaced and rotor shaft refurbished

1 Generator No. 1 is rated at 1,000 kVA at 85% power factor, which equates to a 850 kW load rating and Generator No. 2 is rated at 3,000 kVA at 80% power factor which equates to a 2,400 kW load rating.

2 Details of the feasibility analysis and the estimated capital expenditure of $1.37 million can be found in Appendix A.

2.0 Engineering Assessment

2.1 Generator ($156,000)

Figure 1 – SCV-G1 Rotor Pole

The G1 generator was manufactured in 1924 by Allis Chalmers. A typical alternating current ("AC") generator consists of a stationary stator winding and a rotor mounted within the stator. The stator was rewound in 1988 but the rotor windings are original to the 90 year old unit.

Electrical insulation of the rotor is subjected to thermal stresses due to the heat created by the 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. Thermal cycling causes expansion and contraction of the copper windings relative to the insulating material creating an abrasive effect on the insulation. Visual inspection has confirmed that thermal stress on the G1 rotor has resulted in degradation of the insulating material.

Mechanical stresses experienced by rotor poles are high due to centrifugal forces present during normal operation. During an emergency shutdown the speed of the rotor accelerates dramatically thereby increasing the magnitude of the centrifugal force exerted on the rotor poles. As the generator ages and is affected by thermal stresses, loss of insulating material causes movement when the rotor experiences centrifugal forces during operation. Over time thermal stresses will increase the negative impact of mechanical stresses on the rotor. Mechanical stress has resulted in some weakening of the G1 rotor poles.

The condition and age of the rotor insulation necessitates the rewinding of the 16 rotor poles in 2015.

The original G1 exciter was replaced with a unit manufactured by English Electric in 1963, which was overhauled by Siemens Canada Ltd. in 2002.[3] It will be inspected after disassembly to determine if any additional work is required at that time.

No spillage of water will occur as a result of the generator being out of service for this project since all available water can be used by G2.

[3] The exciter commutator was machined and undercut, the armature was balanced and the whole unit was cleaned and recoated.

3.0 Project Proposal

3.1 Cost Breakdown

The total project cost for the generator rotor refurbishment is estimated at $156,000. Table 1 summarizes the estimated cost breakdown.

Table 1
Project Cost
($000s)

Cost Category	**Cost**
Material	89
Labour - Internal	54
Labour - Contract	
Engineering	6
Other	7
Total	**$156**

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 9.4 GWh of energy to the Island Interconnected electrical system.

The estimated levelized cost of energy from the Plant over the next 50 years, including the capital expenditure of $1.37 million over the next 25 years, is 1.93¢ per kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation.[4]

4.0 Conclusion

An engineering assessment has been completed on the Seal Cove Hydro Plant Generator No. 1 and has determined that it is in generally good condition. The primary system requiring refurbishment at this time for the life extension of the Plant is the G1 rotor.

The feasibility analysis included in Appendix A verifies the financial viability of completing this project. The 9.4 GWh of energy that will be available from the Plant each year will provide

4 The avoided cost of fuel at the Holyrood Thermal Generating Station is estimated at 16.76¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.60 per barrel for 2014 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan - Fuel Price Projection dated April 30, 2014.

affordable energy to the customers of Newfoundland Power for the foreseeable future. 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 is recommended to proceed in 2015.

Appendix A
Seal Cove Hydro Plant
Feasibility Analysis

Table of Contents

1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Seal Cove hydroelectric plant (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2015.

With investment required in 2015 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 Plant are summarized in Table 1.

Table 1
Seal Cove Hydroelectric Plant
Capital Expenditures

Year	($000s)
2015	$156
2019	20
2021	725
2024	448
2034	20
Total	**$1,369**

The estimated capital expenditure for the Plant is $1.37 million. 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 $73,973 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.

The annual operating cost also includes a water power rental rate of $0.80 per MWh. This fee is paid annually to the Provincial Department of Environment and Conservation based on yearly

[1] 2014 dollars.

hydro plant generation/output. This charge is reflected in the historical annual operating costs for the Seal Cove plant.

4.0 Benefits

The maximum output from the Plant is 3,730 kW. The Plant normally operates at an efficient load of 3,180 kW to maximize the energy from the water.

The estimated long-term normal production of the Plant under present operating conditions is 9.4 GWh per year.

5.0 Financial Analysis

An overall financial analysis of combined costs and benefits has been completed 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 1.93¢ per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Seal Cove Plant 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.[2]

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 Seal Cove guarantees the availability of low cost energy to the Province. Otherwise, the projected annual production of 9.4 GWh would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood thermal generating station. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

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[2] The avoided cost of fuel at the Holyrood Thermal Generating Station is estimated at 16.76¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.60 per barrel for 2014 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan - Fuel Price Projection dated April 30, 2014.

Attachment A
Summary of Capital Costs

Seal Cove Feasibility Analysis Summary of Capital Costs ($000s)					
Description	**2015**	**2019**	**2021**	**2024**	**2034**
Civil					
Dam, Spillways and Gates					
Penstock & Intake			725		
Powerhouse					
Mechanical					
Turbine & Wicket Gates					
Main Inlet Valve					
Governor					
Cooling Water					
Heat and Ventilation					
Electrical					
Generator Rewind	156				
P&C and Gov. Controls				440	
Switchgear					
AC & DC Systems		20		8	20
Battery Bank/Charger					
Annual Totals ($2014)	**$156**	**$20**	**$725**	**$448**	**$20**

Attachment B
Summary of Operating Costs

Seal Cove Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs
($2014)

Year	Amount
2009	$ 75,130
2010	$ 63,234
2011	$ 62,227
2012	$ 68,212
2013	$100,163
Average	**$ 73,793**

5 -Year Average Operating Cost	$73,793[1]

[1] 2014 dollars.

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted Average Incremental Cost of Capital	**6.85%**	
Escalation Rate	**See following worksheet**	
PW Year	**2014**	

YEAR	---------- **Generation** Hydro 64.4yrs 8% CCA	---------- **Generation** Hydro 64.4yrs 50% CCA	**Capital Revenue Requirement**	**Operating Costs**	**Operating Benefits**	**Net benefit**	**Present Worth** Benefit +ve	**Cumulative Present Value** Benefit +ve	**Present Worth of Sunk Costs**	**Total Present Worth** Benefit +ve	**Rev Rqmt (¢/kWhr)**	**Levelized Rev Rqmt (¢/kWhr)** 50 years
2015	156,000	0	14,660	73,793	0	-88,453	-82,782	-82,782	-1,181,720	-1,264,503	0.941	1.9296
2016	0	0	15,867	75,269	0	-91,136	-79,825	-162,608	-1,167,823	-1,330,430	0.970	1.9296
2017	0	0	15,395	76,775	0	-92,170	-75,555	-238,163	-1,155,203	-1,393,366	0.981	1.9296
2018	0	0	14,946	78,310	0	-93,256	-71,545	-309,708	-1,143,737	-1,453,444	0.992	1.9296
2019	21,606	0	16,548	79,720	0	-96,268	-69,121	-378,829	-1,131,855	-1,510,684	1.024	1.9296
2020	0	0	16,306	81,216	0	-97,522	-65,533	-444,361	-1,120,898	-1,565,259	1.037	1.9296
2021	812,834	0	92,233	82,734	0	-174,966	-110,035	-554,396	-1,062,893	-1,617,289	1.861	1.9296
2022	0	0	98,084	84,249	0	-182,334	-107,317	-661,714	-1,005,163	-1,666,877	1.940	1.9296
2023	0	0	95,207	85,824	0	-181,032	-99,720	-761,434	-952,718	-1,714,153	1.926	1.9296
2024	530,885	0	142,353	87,446	0	-229,799	-118,468	-879,903	-879,331	-1,759,234	2.445	1.9296
2025	0	0	143,841	89,077	0	-232,918	-112,379	-992,281	-809,931	-1,802,212	2.478	1.9296
2026	0	0	139,730	90,744	0	-230,474	-104,071	-1,096,352	-746,835	-1,843,187	2.452	1.9296
2027	0	0	135,801	92,439	0	-228,240	-96,455	-1,192,807	-689,446	-1,882,252	2.428	1.9296
2028	0	0	132,038	94,169	0	-226,207	-89,467	-1,282,274	-637,223	-1,919,497	2.406	1.9296
2029	0	0	128,429	95,929	0	-224,358	-83,047	-1,365,321	-589,685	-1,955,005	2.387	1.9296
2030	0	0	124,962	97,740	0	-222,701	-77,149	-1,442,470	-546,395	-1,988,865	2.369	1.9296
2031	0	0	121,624	99,550	0	-221,174	-71,708	-1,514,177	-506,963	-2,021,140	2.353	1.9296
2032	0	0	118,405	101,425	0	-219,830	-66,703	-1,580,881	-471,035	-2,051,916	2.339	1.9296
2033	0	0	115,297	103,327	0	-218,624	-62,084	-1,642,965	-438,293	-2,081,258	2.326	1.9296
2034	28,532	0	114,970	105,273	0	-220,244	-58,535	-1,701,499	-407,738	-2,109,237	2.343	1.9296
2035	0	0	112,277	107,240	0	-219,517	-54,601	-1,756,101	-379,810	-2,135,911	2.335	1.9296
2036	0	0	109,362	109,248	0	-218,610	-50,890	-1,806,991	-354,352	-2,161,343	2.326	1.9296
2037	0	0	106,530	111,298	0	-217,828	-47,457	-1,854,448	-331,143	-2,185,591	2.317	1.9296
2038	0	0	103,774	113,387	0	-217,161	-44,279	-1,898,726	-309,984	-2,208,710	2.310	1.9296
2039	0	0	101,088	115,515	0	-216,603	-41,333	-1,940,060	-290,694	-2,230,753	2.304	1.9296
2040	0	0	98,467	117,683	0	-216,150	-38,603	-1,978,662	-273,108	-2,251,771	2.299	1.9296
2041	0	0	95,906	119,891	0	-215,797	-36,069	-2,014,731	-257,078	-2,271,809	2.296	1.9296
2042	0	0	93,399	122,141	0	-215,540	-33,716	-2,048,448	-242,468	-2,290,916	2.293	1.9296
2043	0	0	90,942	124,433	0	-215,375	-31,531	-2,079,978	-229,154	-2,309,133	2.291	1.9296
2044	13,743	0	89,823	126,768	0	-216,591	-29,676	-2,109,654	-216,847	-2,326,502	2.304	1.9296
2045	0	0	87,561	129,147	0	-216,708	-27,789	-2,137,443	-205,619	-2,343,062	2.305	1.9296
2046	0	0	85,191	131,571	0	-216,762	-26,013	-2,163,456	-195,396	-2,358,852	2.306	1.9296
2047	0	0	82,858	134,040	0	-216,898	-24,361	-2,187,817	-186,090	-2,373,907	2.307	1.9296
2048	771,663	0	153,075	136,555	0	-289,630	-30,445	-2,218,262	-169,999	-2,388,261	3.081	1.9296
2049	37,705	0	160,323	139,118	0	-299,441	-29,458	-2,247,720	-154,227	-2,401,947	3.186	1.9296
2050	0	0	156,047	141,729	0	-297,776	-27,416	-2,275,136	-139,860	-2,414,996	3.168	1.9296
2051	0	0	151,503	144,389	0	-295,892	-25,496	-2,300,632	-126,805	-2,427,437	3.148	1.9296
2052	0	0	147,093	147,098	0	-294,192	-23,725	-2,324,357	-114,943	-2,439,300	3.130	1.9296
2053	0	0	142,806	149,859	0	-292,665	-22,088	-2,346,445	-104,165	-2,450,610	3.113	1.9296
2054	0	0	138,632	152,671	0	-291,303	-20,576	-2,367,021	-94,373	-2,461,394	3.099	1.9296
2055	0	0	134,561	155,536	0	-290,097	-19,177	-2,386,199	-85,477	-2,471,676	3.086	1.9296
2056	0	0	130,586	158,455	0	-289,041	-17,883	-2,404,081	-77,398	-2,481,479	3.075	1.9296
2057	0	0	126,699	161,429	0	-288,127	-16,683	-2,420,764	-70,062	-2,490,826	3.065	1.9296
2058	0	0	122,892	164,458	0	-287,350	-15,572	-2,436,336	-63,403	-2,499,738	3.057	1.9296
2059	0	0	119,160	167,544	0	-286,705	-14,541	-2,450,876	-57,359	-2,508,236	3.050	1.9296
2060	0	0	115,497	170,688	0	-286,185	-13,584	-2,464,460	-51,877	-2,516,337	3.045	1.9296
2061	0	0	111,896	173,892	0	-285,788	-12,695	-2,477,155	-46,907	-2,524,062	3.040	1.9296
2062	0	0	108,353	177,155	0	-285,508	-11,870	-2,489,025	-42,402	-2,531,427	3.037	1.9296
2063	0	0	104,864	180,479	0	-285,344	-11,102	-2,500,128	-38,322	-2,538,449	3.036	1.9296
2064	69,766	0	107,980	183,866	0	-291,846	-10,627	-2,510,755	-34,390	-2,545,145	3.105	1.9296
2065	0	0	105,124	187,317	0	-292,441	-9,966	-2,520,721	-30,807	-2,551,528	3.111	1.9296

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects a statutory income tax rate of 29%.

Operating Costs: Operating costs were assumed to be in 2014 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55.00%	5.250%	2.89%
Common Equity	45.00%	8.800%	3.96%
Total	**100.00%**		**6.85%**

CCA Rates:

Class	Rate	Details
1	4.00%	All generating, transmission, substation and distribution equipment not otherwise noted.
17.1	8.00%	Expenditures related primarily to new generation or additions/alterations that increase the capacity of generating facilities.
43.2	50.00%	Expenditures related to the betterment of electrical generating facilities.

Escalation Factors: Conference Board of Canada GDP deflator, February 6, 2014.

Tors Cove Hydro Plant Refurbishment

June 2014

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NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Background

1.1 General

Newfoundland Power's (the "Company") Tors Cove hydroelectric generating plant (the "Plant") is located on the Avalon Peninsula, near the community of Tors Cove, approximately 40 km south of the City of St. John's. The development went into service in 1941 and has provided 73 years of reliable energy production. The normal annual plant production is approximately 25.4 GWh of energy, or about 5.9% of Newfoundland Power's total hydroelectric production.

The Plant was originally commissioned with two 2,350 kVA English Electric generators (G1 and G2) and 2,850 hp Francis turbines under a rated net head of 52.7 m. A third English Electric 2,780 kVA generator (G3) and 3,550 hp Francis turbine were installed in 1951. The 3 generating units combined have a nameplate capacity of 6.5 MW.[1]

The turbine runners for all 3 generators at Tors Cove, original to the Plant construction are deteriorated and in need of replacement. Likewise, all 3 generator rotors are original to the Plant construction and in need of rewinding. The replacement of the turbine runners and the refurbishment of the generator rotor windings will take place over the period from 2015 to 2018. The refurbishment of G2 will take place in 2015 and the Company plans to refurbish G3 and G1 in 2017 and 2018 respectively.[2]

The refurbishment and life extension of the Plant in 2015 involves the replacement of a trestle supporting a section of woodstave penstock and a mechanical refurbishment of Generator No. 2 ("G2") including necessary work on the turbine, main inlet valve and rotor. The estimated cost of this work in 2015 is $1.8 million. The estimated levelized cost of energy from the Plant over the next 50 years, including the capital expenditure of $10.8 million over the next 25 years, is 2.77¢ per kWh.[3]

This report provides a summary of the engineering assessment of the Plant and the refurbishment proposed for 2015.

1.2 Previous Upgrades

There have been a number of upgrades to the original plant and equipment since commissioning in 1941.

The following is a list of the upgrades that have been completed in the past 30 years:

1985 – G2 and G3 motorized butterfly valves and bypass valves installed

---

1 The 2 original generators are rated at 2,350 kVA at 85% power factor, which equates to a 2,000 kW load rating and the unit installed in 1951 is rated at 2,780 kVA at 90% power factor which equates to a 2,500 kW load rating.

2 The design of the penstock and main valves are such that undertaking the refurbishment of the 3 turbines over multiple years can occur without incurring additional lost production as each individual generator can be isolated from the others.

3 Details of the feasibility analysis can be found in Appendix B.

1988 – G2 and G3 governor modifications
1989 – Controls upgraded G2 and G3
1990 – G2 stator rewind
1999 – Cooling water system upgraded (coils, meters, etc.)
2000 – Surge tank and foundations replaced
2001 – Cooling water solenoid valves installed
2003 – Electric governors with digital controls installed on G2 and G3
2003 – Unit control and protection upgraded on G2 and G3 (PLC replaced)
2003 – Ventilation louvers replaced
2003 – Fiber optic forebay communications cable installed
2007 – Stainless steel heat exchanger installed on G2
2008 – Stainless steel heat exchanger installed on G3
2009 – ION 7550 revenue meter installed

2.0 Engineering Assessment

2.1 Penstock Trestle ($654,000)

The Tors Cove penstock trestle supports a 17 m section of 2,438 mm woodstave penstock as it crosses the spill channel which conveys spill from Tors Cove Pond to the ocean.[4] The trestle was constructed as part of the original 1941 construction of the development. When the penstock was rebuilt in 1985, the trestle was reused with only minor repairs and painting being completed.

Figure 1 - Tors Cove Penstock Trestle

In 2012, due to severe corrosion present on the structure, the Company retained Bridger Design Associates Limited ("BDAL") to conduct an assessment of the structure.[5] BDAL assessed the structure and provided recommendations on required upgrading to regain the structural integrity of the truss system. Overall the structure was assessed to be in fair to poor condition with rust and paint scaling throughout. The bottom horizontal truss, penstock support bands and the concrete abutments were assessed to be poor to very poor condition.[6]

Newfoundland Power has considered 3 potential alternatives, (i) refurbishment of the trestle, (ii) replacement of the trestle only and (iii) replacement of the trestle with a section of reinforced steel penstock.[7]

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4 The trestle is a rigid frame used as a support for the woodstave penstock.

5 The BDAL report is included as Appendix A. The report covers 2 bridges on the Tors Cove site along with the assessment of the penstock trestle. With respect to the bridges, the Company has implemented load restrictions and undertaken safety improvements to the railing, as recommended by BDAL.

6 In 2012 the Company completed high priority repairs to stabilize the structure and extend the life until refurbishment or replacement alternatives could be implemented.

7 All 3 alternatives will require refurbishment of the concrete retaining walls on either side of the spill channel.

Alternative 1 - Refurbishment of the Trestle
Under this alternative the existing woodstave penstock would remain in place. The trestle would be sandblasted then inspection and testing of all members would take place. Where deficiencies were observed, members would be repaired or replaced. The majority of this work would take place from elevated work platforms.

The extent of the repairs required for this alternative has been estimated based on visual observations. The exact repairs required will not be known until significant expenditures are incurred to access, clean, test and analyze all of the approximately 130 steel components of the existing structure. This presents a significant risk to project cost and schedule.

At present, it is estimated that the existing 30 year old woodstave penstock has a remaining life of 15 to 20 years. At that time, the woodstave penstock would be replaced, likely with steel or fibre reinforced plastic (‘FRP”) penstock. It is expected that the trestle would require additional refurbishment or replacement at 15 to 20 years in the future following the refurbishment in 2015.

The cost of refurbishment of the trestle, including sand blasting, testing and upgrading of deteriorated members along with replacement of the retaining wall is estimated to be $511,000.

Alternative 2 - Replacement of the Trestle Only
Under this alternative a steel structure would be constructed outside of the existing trestle, and the loads gradually transferred to the new structure such that the old structure could be cut away.

Similar to the previous alternative, the penstock will be replaced in 15 to 20 years. If the trestle were replaced in 2015, it is likely that some refurbishment and modification would be required to accept a new penstock in 15 to 20 years.

The cost of a complete replacement of the trestle structure, leaving the existing woodstave penstock in place, is estimated to be $582,000.

Alternative 3 - Replacement of the Trestle with a Section of Steel Penstock
Engineering reviews have determined that a reinforced steel penstock section independently spanning the channel, without the additional support afforded by a trestle, would be the most effective replacement solution. This option would require a robust section of penstock and significant anchorage that would not be required if the penstock were to be supported by a trestle.

This option has the added advantage that minimal changes will be required in the future when the remaining sections of woodstave penstock are replaced. When the remainder of the penstock is replaced, it will be joined to this section. It is expected that some minor refurbishment would be required at the time of the remaining woodstave penstock replacement to restore it to its original condition, taking advantage of resource that would already be onsite for the future penstock replacement.

The cost of a complete replacement of both the penstock and trestle structure with a reinforced section of steel penstock is estimated to be $654,000.

NPV Analysis
To determine the least cost alternative, a net present value ("NPV") analysis was completed for the above 3 alternatives. Included in the analysis are planned capital expenditures for 2015 and any capital expenditure required in the future. Based on a comparison of the NPV for the 3 alternatives, Alternative 3, *Replacement of the Trestle with a Section of Steel Penstock* is the least cost alternative. Alternative 3 also carries greater certainty and the lowest risk to project cost and schedule.

Table 1 presents a summary of the NPV analysis.

Table 1
NPV Results

Alternative	NPV
Alternative 1 Refurbishment of the Trestle	$815,548
Alternate 2 Replacement of the Trestle Only	$867,575
Alternate 3 Replacement of the Trestle with a Section of Steel Penstock	$760,185

To ensure the continued safe and reliable operation of the Tors Cove hydroelectric facility, it is recommended that the Tors Cove penstock trestle be replaced. Alternate 3, the replacement of the trestle with a section of steel penstock is the least cost alternative to regain the structural integrity of the truss system.

2.2 Turbine ($630,000)

The G2 turbine runner is the original unit installed by English Electric is 1941. The turbine unit was overhauled in 1985. During the overhaul the unit was realigned and runner clearances recorded. There was no excessive wear or damage of the turbine runner recorded at that time.

A recent inspection of the turbine runner showed some erosion on the low and high pressure side of the turbine blades.[8] The heaviest erosion is on the high pressure side where the blade is welded to the runner band. There were also isolated areas of heavier erosion on the inside of the runner band.

[8] The Company has completed inspections of all 3 generator turbines at Tors Cove plant and has included refurbishment for G1 and G3 in subsequent years of the 5-year capital plan.

Figure 2 – 2014 Photos of the G2 Turbine Runner
Showing High Pressure and Low Pressure Erosion Respectively

Index testing, performed by ACRES in 2001, determined the peak efficiency of G2 was 83%. This is considered low compared to that expected of a modern turbine runner design. To improve efficiency and minimize the operating cost associated with maintaining the existing runner, it will be replaced with a higher efficiency stainless steel unit. A replacement runner is expected to result in a peak efficiency of 90% with a resulting increase in energy of 0.5 GWh annually.[9]

The turbine stay vanes in the scroll case were found to be in good condition. The original 1941 wicket gates were found to have considerable erosion on the toe of the gates (see Figure 3). Considerable leakage was also observed between all gate stems and the gland followers. Stainless steel wicket gates and links will be installed to minimize erosion and ensure continued reliability. Self-lubricating bushings, which require no maintenance and have less environmental risk, will be installed with the new wicket gates.

[9] The turbine runner installed in Tors Cove G3 is physically the same size as the runner in G2. Index testing completed on G3 by ACRES in 2001 yielded a unit efficiency of 90% which will be used as the benchmark for the G2 runner replacement. The avoided cost of fuel at the Holyrood thermal generating station associated with the 0.5 GWh annual increase in energy is approximately $84,000. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.60 per barrel for 2014 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan - Fuel Price Projection dated April 30, 2014.

Figure 3 - 2014 Inspection of the G2 Wicket Gates and Scroll Case

2.3 Main Inlet Valve ($186,900)

The G2 main inlet valve is a 42-inch electrically actuated butterfly valve which replaced the original manual operated butterfly valve in 1985. It is evident from the constant flow of water when the valve is in the closed position that it is not sealing properly. Furthermore there are recorded instances where the rubber seal has separated from the disc allowing a large quantity of water to flow through. (See Figure 4) Replacing the rubber seal following one of these incidents requires that the valve be removed from the pipe requiring a plant outage.

The valve cannot be used safely as a point of isolation to allow for turbine inspections due to the excessive amount of leakage. After 30 years of service the valve will be replaced in 2015 with a modern butterfly valve. In addition, a dismantling joint and rearrangement of the bypass valve will be incorporated into the new design to increase maintainability of the new main inlet valve. The scroll case drain valve is also in poor condition and currently not operational. The drain valve and piping will also be replaced at the same time.

Figure 4 - Main Valve Rubber Seal Separation (Photo Taken in 1991)

2.4 Overhead Crane ($149,100)

The overhead crane is the original 73 year old 15-ton Vaughan Crane Company double girder unit. Two horizontal travel chains and 2 vertical lifting chains are operated manually and in unison to lift and move heavy pieces of equipment through 3 dimensions. The mechanical gearing of the chain mechanism requires continuous operation for long periods of time to effectively lift and move heavy equipment. As a result the operation of the crane is labour intensive and requires 2 or 3 operators to lift and maneuver equipment in the powerhouse.

During normal plant operations the crane is used infrequently. However during the planned hydro plant refurbishment the crane will be used continuously and the labour intensive operation will result in inefficient execution of work. The crane will be refurbished with an electrically operated trolley/hoist unit and motorization of the bridge with pendant control. This will ensure work is completed in a safe and efficient manner.

2.5 Generator ($156,900)

G2 was manufactured in 1941 by English Electric Co. Ltd. The stator was rewound in 1964 by Canadian Westinghouse Co. Ltd and again in 1990 by Ozark Electric. However, the rotor windings are original to the 73 year old generator.

Electrical insulation of the rotor is subjected to similar thermal stresses as the stator 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. Thermal cycling causes expansion and contraction of the copper windings relative to the insulating material creating an abrasive effect on the insulation. Visual inspection has confirmed that thermal stress on the G2 rotor has resulted in degradation of the insulating material.

Mechanical stresses experienced by rotor poles are high due to centrifugal forces present during normal operation. During an emergency shutdown the speed of the rotor accelerates dramatically thereby increasing the magnitude of the centrifugal force exerted on the rotor poles. As the generator ages and is affected by thermal stresses, loss of insulating material causes movement when the rotor experiences centrifugal forces during operation. Over time thermal stresses will increase the negative impact of mechanical stresses on the rotor. Mechanical stress has resulted in some weakening of the G2 rotor poles.

The condition and age of the rotor insulation necessitates the rewinding in 2015.

The power cables between the exciter and the rotor are original to the 1941 installation. Visual inspection has identified degradation due to thermal stresses and cycling. The condition and age of the cables require that they be replaced.

3.0 Project Proposal

3.1 Cost Breakdown

The total project cost for the refurbishment of the Plant is estimated at $1,777,000. Table 2 below provides the cost breakdown.

Table 2
Project Cost
($000s)

Cost Category	**Cost**
Material	1,420
Labour - Internal	173
Labour - Contract	-
Engineering	85
Other	99
Total	**$1,777**

3.2 Feasibility Analysis

Appendix B 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 25.9 GWh of energy to the Island Interconnected system.

The feasibility analysis includes estimates for work to be completed within the next 25 years including expenditures in 2017 and 2018. The major items included in the 2017 and 2018 estimate include a turbine and generator overhaul on G1 and G3, switchgear replacement and automation of G1.

The estimated levelized cost of energy from the Plant over the next 50 years, including the capital expenditure of $10.8 million over the next 25 years, is 2.77¢ per kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation.[10]

4.0 Conclusion

An engineering assessment has been completed on the Tors Cove Hydro Plant and 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 penstock trestle, generator including the rotor and power cables, the main inlet valve and turbine. Completing all of the Plant refurbishment work during the same outage will minimize the cost of disassembly and reassembly and reduce Plant downtime reducing potential spill.

The feasibility analysis included in Appendix B verifies the financial viability of completing this project. The 25.9 GWh of energy that will be available from Tors Cove 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 is recommended to proceed in 2015.

[10] The avoided cost of fuel at the Holyrood Thermal Generating Station is estimated at 16.76¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.60 per barrel for 2014 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan - Fuel Price Projection dated April 30, 2014.

Appendix A
Bridger Design Associates Report

STRUCTURAL ASSESSMENT REPORT
BRIDGES AND PENSTOCK TRUSS, TORS COVE HYDRO PLANT
TORS COVE, NL

NOVEMBER 2012

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
STEPHEN PEARCE
SIGNATURE
11/21/12
DATE
NEWFOUNDLAND & LABRADOR

PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
CLASS "A"
This Permit Allows
BRIDGER DESIGN ASSOCIATES LTD.
To practice Professional Engineering in this Province
D0156 Permit No.
2012 Year

BRIDGER DESIGN ASSOCIATES LIMITED
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0	11/21/12	Issued for Final	SP	BB
Rev	**Date**	**Reason**	**Prepared**	**Checked**

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INTRODUCTION

SECTION 1.0

1.0 INTRODUCTION

Newfoundland Power engaged **Bridger Design Associates Limited** in September 2012 to carry out a structural review and condition assessment of two (2) bridges along the access road to the Tors Cove Hydro Plant and a steel truss supporting the timber penstock at a river crossing. Personnel from **Bridger Design Associates Limited** visited the site on September 24, 2012 and September 27, 2012 to perform the required investigation. The balance of this report discusses the existing condition of each structure, structural analysis, upgrading options, associated costs as well as conclusions and recommendations.

Photo No. 1.1 – Site Plan, Tors Cove Hydro Plant Access Road

INDIVIDUAL CONDITION ASSESSMENT

SECTION 2.0

2.0 INDIVIDUAL CONDITION ASSESSMENT

2.1 General

Bridger Design Associates Limited performed a visual condition assessment of each bridge structure and the penstock truss. For the purpose of this report Bridge No. 1 refers to the bridge spanning over the wooden penstock and Bridge No. 2 is located just beyond spanning over the river. The penstock truss is located just upstream from the bridge locations and also spans across the same river.

2.2 Bridge No. 1

2.2.1 Existing Conditions

Bridge No. 1 is a steel girder bridge structure with transverse timber decking, a timber deck raceway, concrete abutments, and steel pipe handrail.

The following is a list of existing conditions that were recorded at Bridge No. 1:

- The overall bridge structure is shown in Photo No. 2.2.1.1. The bridge superstructure consists of two (2) larger beams and three (3) smaller beams. Each beam has significant rusting and scaling (Photo No. 2.2.1.2 and No. 2.2.1.3).
- Steel channels providing lateral support for steel beams have severe rust and scaling (Photo No. 2.2.1.4).
- Remnants of steel angle cross-bracing and welded wide flange sections are visible on bottom flange of two (2) larger steel beams (Photo No. 2.2.1.5 and No. 2.2.1.6).
- Abutments appear to be unreinforced and in very poor condition. Each abutment has significant cracking; efflorescence is evident indicating possible Alkali-Aggregate Reactivity (AAR) and the beam seats are deteriorated under several beams (Photo No. 2.2.1.7, No. 2.2.1.8, and No. 2.2.1.9).
- Timber decking appears to be in good condition while raceway members have some rot and are broken in a few locations (Photo No. 2.2.1.10).
- Bridge handrail has surface rust and is in fair condition. Handrail has wide openings that pose safety hazards for pedestrians using this structure. This type of handrail is not a suitable guardrail for this bridge and there is no wheelguard present (Photo No. 2.2.1.11).

Photo No. 2.2.1.1 – Overall Bridge Structure

Photo No. 2.2.1.2 - Severe Scaling on Beams, Typical

Photo No. 2.2.1.3 – Severe Rust on Beams, Typical

Photo No. 2.2.1.4 – Severe Rust and Scaling on Channels, Typical

Photo No. 2.2.1.5 – Remaining Section of Steel Angle Cross-bracing, Typical

Photo No. 2.2.1.6 – Remaining Section of Steel Column, Typical

Photo No. 2.2.1.7 – Significant Cracks in Concrete Abutment

Photo No. 2.2.1.8 – Significant Cracks and Efflorescence, Concrete Abutment

Photo No. 2.2.1.9 – Concrete Severely Deteriorated Under Beam

Photo No. 2.2.1.10 – Broken Timber Raceway Members

Photo No. 2.2.1.11 – Rust on Handrail

2.2.2 Structural Analysis

Bridger Design Associates Limited performed a structural analysis on the bridge main girders for gravity loads only. The structure was analyzed based on the following assumptions:

- Main girders have a maximum yield strength, Fy = 230 MPa (33ksi),
- Bridge sub-structure has significant capacity to carry required loads.

Given the current rusted condition of the girders, we carried out the analysis based on an assumed steel loss of 1mm and repeated that analysis for assumed steel loss of 2mm. The analysis indicates that the safe maximum axle loads for this bridge is:

- For 1mm steel loss – 9 tons.
- For 2mm steel loss – 7 tons.

This can be compared to an axel load of 20 tons as required by the current bridge code.

2.2.3 Upgrading Options

Given the current condition of this bridge structure, we have considered two (2) upgrading options as follows:

- **Option 1 –** Update the existing structure in place.
- **Option 2 –** Replace the existing structure with a new bridge.

Option 1 would include the following items to be performed as part of the upgrade:

- Install new reinforced concrete abutments - both abutments on this bridge are severely cracked and deteriorated. The presence of Alkali-Aggregate Reactivity (AAR) indicates they will only continue to deteriorate.
- Further investigation should be carried out on the structural steel as this was mainly a visual inspection on the members. Moving forward with this option would require the steel members be cleaned and ultrasonic thickness measurements obtained to ensure members do not have excessive loss of section properties.
- Upgrade existing steel members - existing members would require upgrading to increase the load capacity of the existing bridge to meet the current design requirements.
- Install new guiderail/wheelguard system in accordance with the bridge code.

Table 2.2.4.1 is the estimated cost to perform the upgrading work under Option 1. Table 2.2.4.2 is the estimated cost to replace the existing structure in Option 2.

2.2.4 Cost Estimates

Table 2.2.4.1 – Bridge No. 1, Option 1 Estimated Cost – Upgrade Existing Structure

ITEM	UNIT	QUANTITY	UNIT PRICE	COST
1. Demolition and Removal	L.S.	L.S.	$5,000.00	$5,000.00
2. Abutment Wall Repairs	L.S.	L.S.	$20,000.00	$20,000.00
3. Sandblasting, Ultrasonic Thickness Testing and Painting	L.S.	L.S.	$50,000.00	$50,000.00
4. New Guiderail/Handrail	L.S.	L.S.	$40,000.00	$40,000.00
5. Beam Upgrades *	L.S.	L.S.	$40,000.00	$40,000.00
			CONTINGENCY	$30,000.00
			ENGINEERING	$25,000.00
			TOTAL	***$210,000.00***

*Note: This price is estimated only and may vary based on the level of steel upgrading required.

Table 2.2.4.2 – Bridge No. 1, Option 2 Estimated Cost – Replace Existing Structure

ITEM	UNIT	QUANTITY	UNIT PRICE	COST
1. Demolition and Removal	L.S.	L.S.	$25,000.00	$25,000.00
2. Supply and Install New Bailey Bridge	L.S.	L.S.	$50,000.00	$50,000.00
3. Excavation and Backfilling	L.S.	L.S.	$15,000.00	$15,000.00
4. New Treated Timber Crib Abutments	m^3	25	$400.00	$10,000.00
5. Timber Decking	L.S.	L.S.	$6,000.00	$6,000.00
6. Replace Guiderail	L.S.	L.S.	$10,000.00	$10,000.00
			CONTINGENCY	$22,000.00
			ENGINEERING	$20,000.00
			TOTAL	***$158,000.00***

2.3 Bridge No. 2

2.3.1 Existing Conditions

Bridge No. 2 is a steel girder bridge structure with transverse timber decking, a timber deck raceway, concrete abutments, and steel pipe handrail.

The following is a list of existing conditions that were recorded at Bridge No. 2:

- The overall bridge structure is shown in Photo No. 2.3.1.1. The bridge superstructure consists of two (2) larger beams and three (3) smaller beams. Each beam has significant rusting and scaling (Photo No. 2.3.1.2 and No. 2.3.1.3).
- Steel channels and steel angle cross-bracing providing lateral support for steel beams have significant rust and scaling (Photo No. 2.3.1.4 and No. 2.3.1.5).
- Remnants of welded wide flange sections are visible on bottom flange of two (2) larger steel beams (Photo No. 2.3.1.6).
- Abutments appear to be unreinforced and in poor condition. Each abutment has significant cracking; efflorescence is evident indicating possible Alkali-Aggregate Reactivity (AAR) and one beam seat has significant deterioration under the beam (Photo No. 2.3.1.7, No. 2.3.1.8, and No. 2.3.1.9).
- Timber decking appears to be in good condition while raceway members have some rot and are broken in a few locations (Photo No. 2.3.1.10 and No. 2.3.1.11).
- Bridge handrail has surface rust and is in fair condition. Handrail has wide openings that pose safety hazards for pedestrians using this structure. This type of handrail is not a suitable guardrail for this bridge and there is no wheelguard present (Photo No. 2.3.1.12).
- Retaining wall on south side of bridge is in very poor condition, severely cracked and deteriorated (Photo No. 2.3.1.13).

Photo No. 2.3.1.1 – Overall Bridge Structure

Photo No. 2.3.1.2 - Severe Scaling on Beams, Typical

Photo No. 2.3.1.3 – Severe Rust and Scaling on Beams, Typical

Photo No. 2.3.1.4 – Severe Rust and Scaling on Channels, Typical

Photo No. 2.3.1.5 – Sever Rust on Angle Cross-bracing, Typical

Photo No. 2.3.1.6 – Remaining Section of Steel Column, Typical

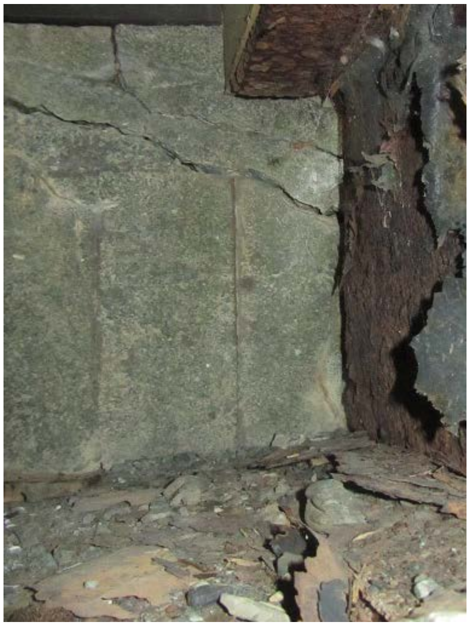

Photo No. 2.3.1.7 – Significant Cracks in Concrete Abutment

Photo No. 2.3.1.8 – Significant Cracks and Efflorescence, Concrete Abutment

Photo No. 2.3.1.9 – Concrete Severely Deteriorated Under Beam

Photo No. 2.3.1.10 – Slight Rotting on Timber Raceway

Photo No. 2.3.1.11 – Broken Timber Raceway Members

Photo No. 2.3.1.12 – Rust on Handrail

Photo No. 2.3.1.13 – Retaining Wall Severely Deteriorated

2.3.2 Structural Analysis

Bridger Design Associates Limited performed a structural analysis on the bridge main steel girders for gravity loads only. The structure was analyzed based on the following assumptions:

- Main girders have a maximum yield strength, Fy = 230 MPa (33ksi),
- Bridge sub-structure has significant capacity to carry required loads.

Given the current rusted condition of the girders, we carried out the analysis based on an assumed steel loss of 1mm and repeated that analysis for assumed steel loss of 2mm. The analysis indicates that the safe maximum axle loads for this bridge is:

- For 1mm steel loss – 12 tons.
- For 2mm steel loss – 9 tons.

This can be compared to an axel load of 20 tons as required by the current bridge code.

2.3.3 Upgrading Options

Given the current condition of this bridge structure, we have considered two (2) upgrading options as follows:

Option 1 – Upgrade the existing structure in place.
Option 2 – Replace the existing structure.

Option 1 would include the following items to be performed as part of the upgrade:

- Install new reinforced concrete abutments - both abutments on this bridge are severely cracked and deteriorated. The presence of Alkali-Aggregate Reactivity (AAR) indicates they will only continue to deteriorate.
- Further investigation should be carried out on the structural steel as this was mainly a visual inspection on the members. Moving forward with this option would require the steel members be cleaned and ultrasonic thickness measurements obtained to ensure members do not have excessive loss of section properties.
- Upgrade existing steel members - existing members would require upgrading to increase the load capacity of the existing bridge to meet the current design requirements.
- Install new guiderail/wheelguard system in accordance with the bridge code.

Table 2.3.4.1 is the estimated cost to perform the upgrading work under Option 1. Table 2.3.4.2 is the estimated cost to replace the existing structure in Option 2.

2.3.4 Cost Estimates

Table 2.3.4.1 – Bridge No. 2, Option 1 Estimated Cost – Upgrade Existing Structure

ITEM	UNIT	QUANTITY	UNIT PRICE	COST
1. Demolition and Removal	L.S.	L.S.	$5,000.00	$5,000.00
2. Abutment Wall Repairs	L.S.	L.S.	$20,000.00	$20,000.00
3. Sandblasting, Ultrasonic Thickness Testing and Painting	L.S.	L.S.	$60,000.00	$60,000.00
4. New Guiderail/Handrail	L.S.	L.S.	$50,000.00	$50,000.00
5. Beam Upgrades *	L.S.	L.S.	$50,000.00	$50,000.00
			CONTINGENCY	$35,000.00
			ENGINEERING	$30,000.00
			TOTAL	***$250,000.00***

*Note: This price is estimated only and may vary based on the level of steel upgrading required.

Table 2.3.4.2 – Bridge No. 2, Option 2 Estimated Cost – Replace Existing Structure

ITEM	UNIT	QUANTITY	UNIT PRICE	COST
1. Demolition and Removal	L.S.	L.S.	$25,000.00	$25,000.00
2. Supply and Install New Bailey Bridge	L.S.	L.S.	$60,000.00	$60,000.00
3. Excavation and Backfilling	L.S.	L.S.	$15,000.00	$15,000.00
4. New Treated Timber Crib Abutments	m^3	25	$400.00	$10,000.00
5. Timber Decking	L.S.	L.S.	$7,000.00	$7,000.00
6. Replace Guiderail	L.S.	L.S.	$10,000.00	$10,000.00
			CONTINGENCY	$25,000.00
			ENGINEERING	$20,000.00
			TOTAL	***$172,000.00***

2.4 Penstock Truss

2.4.1 Existing Conditions

The penstock truss is constructed from steel I beams, channels, angles, gusset plates, and rests on concrete abutments.

The following is a list of existing conditions that were recorded at the penstock truss:

- Overall the truss is in fair to poor condition with rust and paint scaling throughout (Photo No. 2.4.1.1).
- The members and connections at the top horizontal truss have significant surface rusting with paint scaling (Photo No. 2.4.1.2 and No. 2.4.1.3).
- The members along the south truss are in fair condition. Truss members and connections have surface rusting and paint scaling (Photo No. 2.4.1.4, No. 2.4.1.5, and No. 2.4.1.6).
- The members along the north truss are in similar condition to the members along the south truss (Photo No. 2.4.1.7 and No. 2.4.1.8).
- The members in the bottom horizontal truss have severe rust, paint scaling and are in very poor condition. Heavy corrosion has left many of the members with a significant loss in cross-section and holes have formed in some members. The joints connecting the bottom truss to both side trusses have severe rusting and scaling (Photo 2.4.1.9, No. 2.4.1.10, No. 2.4.1.11, and 2.4.1.12).
- There is a band, consisting of a bent channel, wrapping around and supporting the weight of the penstock. The channel and the members connecting this band to the truss, located at the joint between the bottom and side truss, are in poor condition with severe rust and scaling (Photo 2.4.1.13 and No. 2.4.1.14).
- Abutments are in poor condition with significant cracks. Efflorescence is present indicating possible Alkali-Aggregate Reactivity (AAR). The baseplates supporting trusses at the abutments have significant rust and scaling (Photo No. 2.4.1.15, No. 2.4.1.16 and No. 2.4.1.17).

Photo No. 2.4.1.1 – Overall Penstock Truss Structure

Photo No. 2.4.1.2 – Rust on Top Chord Members, Typical

Photo No. 2.4.1.3 – Rust on Top Chord Connection, Typical

Photo No. 2.4.1.4 – Rust on South Chord Member, Typical

Photo No. 2.4.1.5 – Rust and Scaling on South-Top Chord Connection, Typical

Photo No. 2.4.1.6 – Rust on South-Bottom Chord Connection, Typical

Photo No. 2.4.1.7 – Rust on North Chord Member, Typical

Photo No. 2.4.1.8 – Rust on North-Bottom Chord Connection, Typical

Photo No. 2.4.1.9 – Heavy Corrosion Forming Holes in Bottom Chord Member, Typical

Photo No. 2.4.1.10 – Rust and Scaling on Bottom Chord Cross-bracing Member, Typical

Photo No. 2.4.1.11 – Rust and Scaling on Bottom Chord Connection, Typical

Photo No. 2.4.1.12 – Rust and Scaling on Bottom Chord Cross-bracing Connection, Typical

Photo No. 2.4.1.13 – Rust and Scaling on Penstock Support Band, Typical

Photo No. 2.4.1.14 – Rust and Scaling on Support Band-Bottom Chord Connection Member, Typical

Photo No. 2.4.1.15 – Severe Deterioration Below Baseplate on East Abutment

Photo No. 2.4.1.16 – Significant Cracks and Efflorescence, Concrete Abutment, Typical

Photo No. 2.4.1.17 – Significant Cracks, Concrete Abutment, Typical

Photo No. 2.4.1.18 – Rust and Scaling on Abutment Baseplate, Typical

2.4.2 Penstock Truss Upgrading

The penstock truss in its current condition requires several upgrades. The following items are recommended as part of the upgrading:

- Install new reinforced concrete abutments - both abutments on this structure are severely cracked and deteriorated. The presence of Alkali-Aggregate Reactivity (AAR) indicates they will only continue to deteriorate.
- Further investigation should be carried out on all structural members and connections of this truss as this was mainly a visual inspection on the members. Moving forward with this option would require all steel members/connections be cleaned and ultrasonic thickness measurements obtained to ensure other members do not have excessive loss of section properties.
- Remove and replace all bottom horizontal truss members - several members along the bottom horizontal truss have experienced heavy corrosion and have significant loss of section properties. Remaining members are in poor condition. In its current condition, the capacity of this horizontal truss is greatly reduced.
- After completion of cleaning and ultrasonic survey of all structural members, upgrade existing steel members/connections as required.

Table 2.4.3.1 is the estimated cost to perform upgrading work under.

2.4.3 Cost Estimates

Table 2.4.3.1 – Penstock Truss Estimated Cost – Upgrade Existing Structure

ITEM	UNIT	QUANTITY	UNIT PRICE	COST
1. Demolition and Removal	L.S.	L.S.	$15,000.00	$15,000.00
2. Abutment Repairs	L.S.	L.S.	$50,000.00	$50,000.00
3. Sandblasting, Ultrasonic Thickness Testing and Painting	L.S.	L.S.	$100,000.00	$100,000.00
4. Replace Bottom Horizontal Truss	L.S.	L.S.	$25,000.00	$25,000.00
5. Member Upgrades *	L.S.	L.S.	$50,000.00	$50,000.00
			CONTINGENCY	$50,000.00
			ENGINEERING	$30,000.00
			TOTAL	***$320,000.00***

* Note: This price is estimated only and may vary based on the level of steel upgrading required.

CONCLUSIONS AND RECOMMENDATIONS

SECTION 3.0

3.0 CONCLUSIONS AND RECOMMENDATIONS

3.1 General

The system used to rank the priority of recommended repairs is as follows:

- Priority 1 – Work which needs to be undertaken within one (1) year.
- Priority 2 – Work which needs to be undertaken within two (2) to three (3) years.
- Priority 3 – Work which needs to be undertaken within three (3) to five (5) years.

3.2 Bridges

- It is recommended that a safe maximum axle load be placed on these bridges once the recommended investigation of the truss members is complete. This load limit shall remain in place until all recommended upgrades are complete. In the short term, limit all heavy loads travelling across these bridges.
- It is recommended that both bridge structures be upgraded/replaced to bring the traffic loading for the access road up to the current bride design code. If upgrading is the selected method, the following is a list of recommended action in order of priority:

TASK	COMMENT	PRIORITY
1. Carry out further investigation on existing steel.	• To determine the severity of corrosion and whether upgrading or replacement is required.	1

2. Install new guiderail/wheelguard.	• This is a life safety issue.
	• The existing handrail/guard has the following deficiencies:
	  • Wide vertical spacing of horizontal members facilitates climbing, refer to NBCC-2010, Clause 3.4.6.6.7. Due to their location, pedestrians use these bridges on a regular basis.
	  • Pedestrian guards are typically designed for a horizontal load of 0.75 kN/m or concentrated load of 1.0 kN applied at any point on a guard and a 1.5 kN/m vertical load along the top of the guard, refer to NBCC-2012, Clause 9.8.8.2.1. This design load is significantly less than that required for barriers of vehicular traffic identified in the bridge code. The minimum design loads identified in CAN/CSA-S6-06, Clause 3.8.8.1, Table 3.6 for barrier type PL-1 are:
	    o Transverse = 50kN;
	    o Longitudinal = 20 kN;
		1

TASK	COMMENT	PRIORITY
2. Install new guiderail/wheelguard. (cont'd)	o Vertical = 10 kN. These loads are to be applied simultaneously. • As a minimum, in the short term, a safety mesh shall be installed along the inside of the rail system on both sides.	1
3. Upgrade the existing members (if possible).	• This is dependant on findings of the recommended investigation in Item 1.	2
4. Install new reinforced concrete abutments.	• Due to the poor quality of concrete and apparent presence of AAR, it is difficult to repair these abutments.	3

3.3 Penstock Truss

- It is recommended that the penstock truss be upgraded to regain the structural integrity of the existing truss system. The following is a list of recommended actions in order of priority:

TASK	COMMENT	PRIORITY
1. Carry out further investigation on existing truss members and connections.	• To determine severity of corrosion and the amount of upgrading required to bring the structure back the design capacity.	1
2. Remove and replace all members in the bottom horizontal truss with new members.	• Due to severe deterioration, all members require replacement.	1
3. Upgrade the existing members.	• This is dependant on findings of the recommended investigation in Item 1.	2
4. Install new reinforced concrete abutments.	• Due to the poor quality of concrete and apparent presence of AAR, it is difficult to repair these abutments.	3

BRIDGER
DESIGN ASSOCIATES LIMITED
ENGINEERING CONSULTANTS

18 MOUNTBATTEN DRIVE
ST. JOHN'S, NL
CANADA A1A 3X7

BUS: (709) 739-7890
FAX: (709) 739-7601

December 14, 2012

Newfoundland Power Inc.
55 Kenmount Road
St. John's, NL A1B 3P6

Attention: Mr. David Ball

Dear Mr. Ball:

Re: Penstock Truss Repairs
Tors Cove Hydro Plant
Tors Cove, NL
Project No. 12161

Personnel from **Bridger Design Associates Limited** visited the above-noted site on December 7, 2012 to perform a follow-up visual inspection of the Penstock Truss at the Tors Cove Hydro Plant.

As part of our previous report submitted to Newfoundland Power in November, it was recommended that:

- A further investigation be performed on the existing truss members and connections.
- All members in the bottom horizontal truss be removed and replaced with new members.

These items were assigned as Priority 1; this is work which needs to be undertaken within one (1) year.

Newfoundland Power engaged Vytrell Engineering Limited to set up a working platform to assist in performing a closer inspection of the truss members and to perform all required repairs. Inspection of the truss resulted in the following deficiencies that required immediate attention:

- three (3) transverse angle members, in the bottom horizontal truss,
- three (3) angle cross braces in the bottom horizontal truss, and
- one (1) penstock truss hanging support.

It was decided to upgrade the severely deteriorated members only. The deterioration was generally localized to these members and not as severe on remaining members as previously reported.

The following photographs indicate the different types of deficiencies reported as well as the various methods of repair:

- Photo No. 1 – Severely deteriorated bottom truss transverse member.
- Photo No. 2 – Typical bottom truss transverse member repair.
- Photo No. 3 – Deteriorated bottom truss horizontal cross brace.
- Photo No. 4 – Typical bottom truss horizontal cross brace repair.
- Photo No. 5 – Deteriorated hanging support.
- Photo No. 6 – Hanging support repair detail.

Completion of these recommended repairs addresses tasks 1, 2, and 3 of the previous report. Newfoundland Power are aiming to extend the life of the structure for an additional three (3) to five (5) years prior to complete replacement of the structure. We feel that with these repairs, the life of the existing structure can be extended to meet the three (3) to five (5) year window. However, it is recommended that the existing structure have yearly visual inspections to ensure other members do not experience similar significant deterioration.

We trust the foregoing meets your current needs. However, if you have any questions, please feel free to contact us at (709) 739-7890 at your convenience.

Yours very truly,

BRIDGER DESIGN ASSOCIATES LIMITED

Stephen Pearce, P. Eng.

jb

Enclosures

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
STEPHEN PEARCE
SIGNATURE
12-14-12
DATE
NEWFOUNDLAND & LABRADOR

PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
CLASS "A"
This Permit Allows
BRIDGER DESIGN ASSOCIATES LTD.
To practice Professional Engineering in this Province
D0156 Permit No.
2012 Year

Photo No. 1 – Severely Deteriorated Bottom Truss Transverse Member

Photo No. 2 – Typical Bottom Truss Transverse Member Repair

Photo No. 3 – Deteriorated Bottom Truss Horizontal Cross Brace

Photo No. 4 – Typical Bottom Truss Horizontal Cross Brace Repair

Photo No. 5 – Deteriorated Hanging Support

Photo No. 6 – Hanging Support Repair Detail

Appendix B
Tors Cove Hydro Plant
Feasibility Analysis

Table of Contents

1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Tors Cove hydroelectric plant (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2015.

With investment required in 2015 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
Tors Cove Hydroelectric Plant
Capital Expenditures

Year	($000s)
2015	$1,777
2016	10
2017	800
2018	2,615
2024	20
2029	8
2033	5,275
2039	20
2040	275
Total	**$10,800**

The estimated capital expenditure for the Plant listed above is $10.8 million. 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 $121,000 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

[1] 2014 dollars.

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.
The annual operating cost also includes a water power rental rate of 0.80¢ per MWh. This fee is paid annually to the Provincial Department of Environment and Conservation 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 7,340 kW. The Plant normally operates at an efficient load of 6,360 kW to maximize the energy from the water.

The estimated long-term normal production of the Plant under present operating conditions is 25.9 GWh per year.

5.0 Financial Analysis

An overall financial analysis of combined costs and benefits has been completed 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 2.77¢ per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Tors Cove 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.[2]

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 25.9 GWh would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood thermal generating station. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

[2] The avoided cost of fuel at the Holyrood Thermal Generating Station is estimated at 16.76¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.60 per barrel for 2014 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan - Fuel Price Projection dated April 30, 2014.

Attachment A
Summary of Capital Costs

Tors Cove Feasibility Analysis Summary of Capital Costs ($000s)									
Description	**2015**	**2016**	**2017**	**2018**	**2024**	**2029**	**2033**	**2039**	**2040**
Civil									
Dam, Spillways and Gates									
Penstock & Intake	654						5,000		
Powerhouse									
Crain	149								
Mechanical									
Turbine & Wicket Gates	630	10	640	630					
Main Inlet Valve	187								
Governor				15					
Cooling Water									
Heat and Ventilation				20					
Electrical									
Generator Rewind	157		160	475			275		275
P&C and Gov. Controls				935					
Switchgear				475					
AC & DC Systems				65					
Battery Bank/Charger					20	8		20	
Annual Totals ($2014)	**$1,777**	**$10**	**$800**	**$2,615**	**$20**	**$8**	**$5,275**	**$20**	**$275**

Attachment B
Summary of Operating Costs

Tors Cove Feasibility Analysis
Summary of Operating Costs

<u>Actual Annual Operating Costs</u>
<u>($2014)</u>

Year	Amount
2009	$113,940
2010	$128,821
2011	$125,135
2012	$ 89,943
2013	$145,485
Average	**$120,665**

5 -Year Average Operating Cost	$120,665[1]

[1] 2014 dollars.

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted Average Incremental Cost of Capital	**6.85%**
Escalation Rate	**See following worksheet**
PW Year	**2014**

YEAR	Generation Hydro 64.4yrs 8% CCA	Generation Hydro 64.4yrs 50% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net benefit	Present Worth Benefit +ve	Cumulative Present Value Benefit +ve	Present Worth of Sunk Costs	Total Present Worth Benefit +ve	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2015	1,777,000	0	166,987	120,665	0	-287,652	-269,211	-269,211	-7,547,829	-7,817,039	1.132	2.7678
2016	10,200	0	181,695	123,078	0	-304,773	-266,948	-536,159	-7,388,684	-7,924,843	1.200	2.7678
2017	832,320	0	254,616	125,540	0	-380,156	-311,629	-847,788	-7,179,965	-8,027,752	1.497	2.7678
2018	2,775,059	0	516,687	128,050	0	-644,737	-494,635	-1,342,422	-6,783,569	-8,125,991	2.538	2.7678
2019	0	0	530,735	130,355	0	-661,090	-474,666	-1,817,089	-6,402,498	-8,219,587	2.603	2.7678
2020	0	0	515,263	132,802	0	-648,065	-435,483	-2,252,572	-6,056,254	-8,308,826	2.551	2.7678
2021	0	0	500,506	135,283	0	-635,790	-399,845	-2,652,417	-5,741,488	-8,393,905	2.503	2.7678
2022	0	0	486,407	137,762	0	-624,169	-367,372	-3,019,789	-5,455,200	-8,474,989	2.457	2.7678
2023	0	0	472,912	140,338	0	-613,249	-337,805	-3,357,594	-5,194,699	-8,552,293	2.414	2.7678
2024	23,700	0	462,201	142,989	0	-605,189	-311,994	-3,669,588	-4,956,421	-8,626,009	2.383	2.7678
2025	0	0	449,957	145,656	0	-595,614	-287,372	-3,956,960	-4,739,325	-8,696,285	2.345	2.7678
2026	0	0	437,930	148,382	0	-586,312	-264,749	-4,221,709	-4,541,577	-8,763,287	2.308	2.7678
2027	0	0	426,340	151,154	0	-577,494	-244,050	-4,465,759	-4,361,406	-8,827,165	2.274	2.7678
2028	0	0	415,151	153,982	0	-569,133	-225,097	-4,690,856	-4,197,209	-8,888,066	2.241	2.7678
2029	10,400	0	405,309	156,860	0	-562,169	-208,089	-4,898,945	-4,047,183	-8,946,128	2.213	2.7678
2030	0	0	394,911	159,821	0	-554,732	-192,172	-5,091,118	-3,910,376	-9,001,494	2.184	2.7678
2031	0	0	384,713	162,781	0	-547,494	-177,506	-5,268,624	-3,785,647	-9,054,270	2.155	2.7678
2032	0	0	374,805	165,847	0	-540,652	-164,050	-5,432,674	-3,671,919	-9,104,593	2.129	2.7678
2033	7,386,158	0	1,059,250	168,957	0	-1,228,207	-348,783	-5,781,457	-3,371,116	-9,152,573	4.835	2.7678
2034	0	0	1,107,001	172,140	0	-1,279,141	-339,960	-6,121,417	-3,076,906	-9,198,323	5.036	2.7678
2035	0	0	1,075,502	175,356	0	-1,250,858	-311,131	-6,432,548	-2,809,392	-9,241,940	4.925	2.7678
2036	0	0	1,045,280	178,639	0	-1,223,919	-284,914	-6,717,461	-2,566,064	-9,283,525	4.819	2.7678
2037	0	0	1,016,233	181,992	0	-1,198,224	-261,050	-6,978,511	-2,344,663	-9,323,175	4.717	2.7678
2038	0	0	988,267	185,407	0	-1,173,674	-239,309	-7,217,820	-2,143,158	-9,360,979	4.621	2.7678
2039	31,308	0	964,237	188,886	0	-1,153,124	-220,046	-7,437,866	-1,959,157	-9,397,023	4.540	2.7678
2040	438,559	0	979,635	192,431	0	-1,172,066	-209,322	-7,647,188	-1,784,202	-9,431,390	4.614	2.7678
2041	0	0	957,719	196,042	0	-1,153,761	-192,843	-7,840,030	-1,624,126	-9,464,157	4.542	2.7678
2042	0	0	931,862	199,721	0	-1,131,584	-177,011	-8,017,041	-1,478,357	-9,495,399	4.455	2.7678
2043	0	0	906,786	203,469	0	-1,110,256	-162,541	-8,179,582	-1,345,605	-9,525,186	4.371	2.7678
2044	0	0	882,428	207,288	0	-1,089,716	-149,306	-8,328,888	-1,224,700	-9,553,588	4.290	2.7678
2045	262,518	0	883,399	211,178	0	-1,094,577	-140,358	-8,469,246	-1,111,421	-9,580,667	4.309	2.7678
2046	0	0	862,340	215,141	0	-1,077,481	-129,308	-8,598,553	-1,007,933	-9,606,486	4.242	2.7678
2047	0	0	839,015	219,178	0	-1,058,193	-118,852	-8,717,405	-913,698	-9,631,103	4.166	2.7678
2048	0	0	816,242	223,291	0	-1,039,534	-109,271	-8,826,676	-827,898	-9,654,574	4.093	2.7678
2049	15,082	0	795,395	227,482	0	-1,022,876	-100,627	-8,927,303	-749,650	-9,676,953	4.027	2.7678
2050	0	0	773,714	231,751	0	-1,005,465	-92,573	-9,019,876	-678,414	-9,698,291	3.959	2.7678
2051	0	0	752,301	236,100	0	-988,401	-85,168	-9,105,044	-613,591	-9,718,635	3.891	2.7678
2052	0	0	731,286	240,531	0	-971,817	-78,370	-9,183,414	-554,617	-9,738,032	3.826	2.7678
2053	0	0	710,637	245,044	0	-955,681	-72,128	-9,255,543	-500,983	-9,756,526	3.763	2.7678
2054	41,378	0	694,213	249,643	0	-943,856	-66,669	-9,322,212	-451,948	-9,774,160	3.716	2.7678
2055	0	0	674,530	254,328	0	-928,858	-61,404	-9,383,615	-407,357	-9,790,972	3.657	2.7678
2056	0	0	654,687	259,101	0	-913,788	-56,535	-9,440,150	-366,852	-9,807,003	3.598	2.7678
2057	0	0	635,112	263,963	0	-899,076	-52,058	-9,492,209	-330,078	-9,822,287	3.540	2.7678
2058	0	0	615,785	268,917	0	-884,701	-47,942	-9,540,151	-296,708	-9,836,859	3.483	2.7678
2059	0	0	596,684	273,963	0	-870,647	-44,156	-9,584,307	-266,447	-9,850,754	3.428	2.7678
2060	0	0	577,791	279,105	0	-856,896	-40,672	-9,624,979	-239,022	-9,864,001	3.374	2.7678
2061	0	0	559,091	284,342	0	-843,434	-37,467	-9,662,446	-214,186	-9,876,632	3.321	2.7678
2062	0	0	540,568	289,678	0	-830,246	-34,517	-9,696,963	-191,713	-9,888,675	3.269	2.7678
2063	0	0	522,207	295,115	0	-817,322	-31,801	-9,728,764	-171,394	-9,900,158	3.218	2.7678
2064	0	0	503,996	300,653	0	-804,649	-29,301	-9,758,065	-153,041	-9,911,106	3.168	2.7678

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects a statutory income tax rate of 29%.

Operating Costs: Operating costs were assumed to be in 2014 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55.00%	5.250%	2.89%
Common Equity	45.00%	8.800%	3.96%
Total	**100.00%**		**6.85%**

CCA Rates:

Class	Rate	Details
1	4.00%	All generating, transmission, substation and distribution equipment not otherwise noted.
17.1	8.00%	Expenditures related primarily to new generation or additions/alterations that increase the capacity of generating facilities.
43.2	50.00%	Expenditures related to the betterment of electrical generating facilities.

Escalation Factors: Conference Board of Canada GDP deflator, February 6, 2014.

Public Safety Around Dams

June 2014

Prepared by:

David Ball, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
DAVID S. BALL
SIGNATURE
12 Jun 14
DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

Newfoundland Power (the "Company") has over 150 dam structures throughout its 23 hydroelectric facilities. The Company through its dam safety inspection and review processes identifies public safety deficiencies at any of its structures.[1] In recent years public safety measures have been handled by having high risk items being addressed and improvements made where possible during routine rehabilitations.[2]

In 2011, the Canadian Dam Association ("CDA") published their *Guidelines for Public Safety Around Dams* (the "Guidelines").[3] These Guidelines were published to address the risk of accidents or incidents in which a member of the public is exposed to a hazard created by a hydroelectric development. In the absence of provincial legislation, the CDA Guidelines provide utilities with a standard which is broadly accepted across the industry.

The Company over a 3-year period plans to address public safety throughout its various hydroelectric developments. It is estimated that expenditures of approximately $2.0 million will be necessary to implement public safety improvements at the Company's hydroelectric developments over this period. The Company has completed detailed public safety assessments of 4 of its 23 hydroelectric developments to be included in the 2015 Capital Budget. The 2015 expenditures associated with the public safety improvements identified through the assessments total $429,000. Expenditures in future years will be based upon detailed public safety assessments and presented in the capital budget application for that year.

2.0 Guidelines for Public Safety Around Dams

Although the Company's dam portfolio consists of small dams, the Guidelines recognize that all dams pose a risk to public safety, regardless of size or impoundment. The Guidelines also state that low head and small dams may be equally or more hazardous than high dams as the hazards may not be as apparent and they may not command the same respect as high dams from the general public.

Risk assessments are a key step and are used to review existing infrastructure to identify risks and evaluate if risk treatments are required.[4] After all activities and hazards at a particular site have been identified, risk ratings for each are determined by multiplying the *incident likelihood*

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1 Internal engineering inspections are typically completed on a 2 year cycle with inspections conducted by an external consultant typically on an 8 year cycle.

2 In recent years public safety improvements have been completed as part of the capital expenditures associated with the annual Facility Rehabilitation capital project. In 2012 public safety improvements were completed at the Tors Cove Forebay Spillway approved in Order No. P.U. 26 (2011). In 2013 public safety improvements were completed at the Soldiers Pond Outlet as approved in Order No. P.U. 31 (2012). In 2014 public safety improvements will be completed at the Cape Broyle Spillway approved in Order No. P.U. 27 (2013).

3 These guidelines are in addition to the *CDA Dam Safety Guidelines 2007*. Copies of these guidelines can be ordered online from www.cda.ca.

4 A risk treatment is any process intended to modify risk.

rating by the *incident consequence rating*.[5] As outlined in the Guidelines, the purpose of the risk assessment methodology is to enable the dam owner to make risk-informed decisions regarding public safety and provide a framework to demonstrate how the dam owner has exercised due diligence in managing public safety at a dam.

In addition to outlining the program, the Guidelines also provide 3 technical bulletins relating to (i) signage, (ii) booms and buoys, and (iii) audible and visual signals. The Guidelines do not prescribe when risk treatments are to be implemented however the bulletins assist dam owners with correctly implementing risk treatment work as well as promote a consistent approach among dam owners.

3.0 Work Completed to Date

Newfoundland Power's existing dam safety program focuses on reducing risk of dam failure.[6] Through the Company's existing inspection framework, public safety deficiencies were detected and addressed. In recent years, many facilities rehabilitation projects have had significant public safety components as a result of these inspections.[7]

Beginning in 2012 through early 2014, public safety assessments were completed for 4 of the Company's 23 hydroelectric developments using the 2011 Guidelines. Over 80 treatments, totalling $429,000 have been planned for 2015. Details of the proposed 2015 project and associated costs can be found in Section 5.

4.0 3-Year Capital Plan

The Company plans to develop a public safety plan for each of its 23 hydroelectric developments. This will involve (i) integrating monitoring and evaluation into the existing dam safety process, (ii) implementing periodic audits and reviews with the purpose of determining if treatments are effective and (iii) to ensure on an ongoing basis that all dams are meeting applicable Guidelines.

The Company will address the various safety improvement projects on a per-development basis. Due to the size and geographic separation of the Company's hydroelectric developments, it is least cost to complete *all* work within a single development in the same year.[8]

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5 The Incident Likelihood Rating is used to rate the frequency with which the public is exposed to a hazard. The rating is directly tied to the number of times the public were within a hazardous area, and not impacted by occurrence of public safety incidents. Incident Consequence Rating is assigned on a scale that is tied to the most likely outcome of direct exposure to the hazard (i.e. should an incident occur, the most likely consequence).

6 The Company's existing dam safety program is based on the 2007 revision of the Canadian Dam Association's Dam Safety Guidelines.

7 Three examples of Facility Rehabilitation projects with significant public safety projects can be found in footnote 2.

8 Each hydro development varies in size, complexity and condition. As a result the developments will be grouped such that cost and workload are normalized as much as possible while attempting to address developments with higher levels of public interaction first.

Based on the results of the first 4 public safety assessments, implementation of the public safety strategy across Newfoundland Power's 23 hydro developments is estimated to cost approximately $2.0 Million over 3 years. Newfoundland Power will complete approximately 10 assessments annually. The expenditures resulting from each assessment will be included in the Company's annual capital budget submission.

Table 1 outlines the forecast expenditures over the 3-year capital plan.[9]

Table 1
3-Year Capital Plan
($000s)

Description	2015	2016	2017
Petty Harbour, Topsail, Seal Cove, Pierre's Brook Hydro	429		
Remaining Hydro Developments on the Avalon Peninsula[10]		880	
Remaining Hydro Developments off the Avalon Peninsula[11]			662

5.0 2015 Project Description

Assessments have been completed for Petty Harbour, Topsail, Seal Cove and Pierre's Brook hydroelectric developments.[12] These developments were selected to be completed first as they generally see the highest levels of recreational use by the general public. A number of hazardous intakes are located within the developments reviewed. Based on the level of activity and site particulars, varying levels of treatment have been recommended. Minimum treatment to be implemented involves signage with text viewable from outside of the hazardous area.[13] Additional treatments such as warning buoys are required at intakes and other hazardous areas. These will be placed outside of the hazardous area for swimmers, boaters or snowmobilers. In hazardous areas where signage or buoys would not provide adequate deterrence, safety booms may also be required.[14]

Deficiencies relating to railing and fencing were also identified. Like signage, as a result of the detailed risk assessment, fencing and railing has been recommended in places where none currently exists. In addition, a number of extensions or improvements have been planned where

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9 The forecast expenditures for 2016 and 2017 are estimated based upon the amount of work identified in the initial 4 assessments completed for the 2015 project. The forecast expenditures for 2016 and 2017 are subject to change when the actual assessments are completed for the respective hydro developments.

10 These hydro developments are associated with plants at Tors Cove, Rocky Pond, Cape Broyle, Horse Chops, Mobile, Morris, New Chelsea, Pitman's Pond, Victoria and Hearts Content.

11 These hydro developments are associated with plants at West Brook, Fall Pond, Lawn, Sandy Brook, Rattling Brook, Lookout Brook, Rose Blanche, Port Union and Lockston.

12 Appendix A provides a description of the projects to be completed in 2015.

13 Some of the existing signage is too small allowing the public to approach too close to the hazardous area. Larger signage is required to keep the public away from the hazardous area.

14 For example, the intake and spillway at Pierre's Brook hydro plant are located near a frequently used swimming and boating area. Signage, booms and buoys will be implemented as per the technical bulletins to ensure they are adequately visible, promote self-rescue and do not create additional hazards to the public.

the existing railing and fencing do not provide adequate protection. In some locations railing and fencing must be extended to limit the public access to the hazardous area. The height of some railings and fences do not meet the minimum standard establish by regulations, and adjustment is required. In many locations the railing has top and mid rails but no toe boards. These improvements are required to improve public safety.[15]

Some significant projects to be completed in 2015 include:

(i) A safety boom at Pierre's Brook Forebay
(ii) A safety boom at Three Arm Pond, within the Topsail development
(iii) Fencing at the Seal Cove Forebay

Details of proposed treatments for each of the 4 developments can be found in Appendix A.

The assessments also identified approximately 80 smaller items requiring attention. Many of these items are related to deficiencies in signage. The Company currently has many different signs in service without any consistency in message, size and material. New signage is required at locations where signs are required but no signage currently exists or where existing signage does not meet the Guidelines for text size, condition and/or messaging. Development of new signage, along with guidelines on placement and use in accordance with the relevant technical bulletin is ongoing. Where possible, existing signage will be reused and once it has deteriorated, replaced with the new standard signage.

6.0 2015 Project Cost

Table 2 provides a breakdown of the proposed expenditures for 2015.

Table 2
2015 Projected Expenditures
($000s)

Cost Category	**Cost**
Material	$300
Labour – Internal	39
Labour – Contract	
Engineering	77
Other	13
Total	**$429**

15 For example, existing fencing installed on a hydro plant parking lot provides a barrier to pedestrians and a warning of danger to vehicles from the hazardous flows associated with the adjacent tailrace. The existing fencing does not extend enough to prevent fishers from walking behind the fence and into the hazardous zone.

Appendix A
2015 Public Safety Around Dams Project

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2015 Projects

In 2015 the Company has identified 4 hydroelectric developments where public safety projects will take place. Assessments have been completed for Petty Harbour, Topsail, Seal Cove and Pierre's Brook hydroelectric developments. These developments were selected to be completed first as they generally see the highest levels of recreational use by the general public. A number of hazardous intakes are located within the developments reviewed. Based on the level of activity and site particulars, varying levels of treatment have been recommended.

1.0 Petty Harbour Development

Petty Harbour Development is located on the east coast of the Avalon Peninsula. The powerhouse is situated in the community of Petty Harbour. Storage is provided by structures located at First Pond (Forebay), Bay Bulls Big Pond and Cochrane Pond.

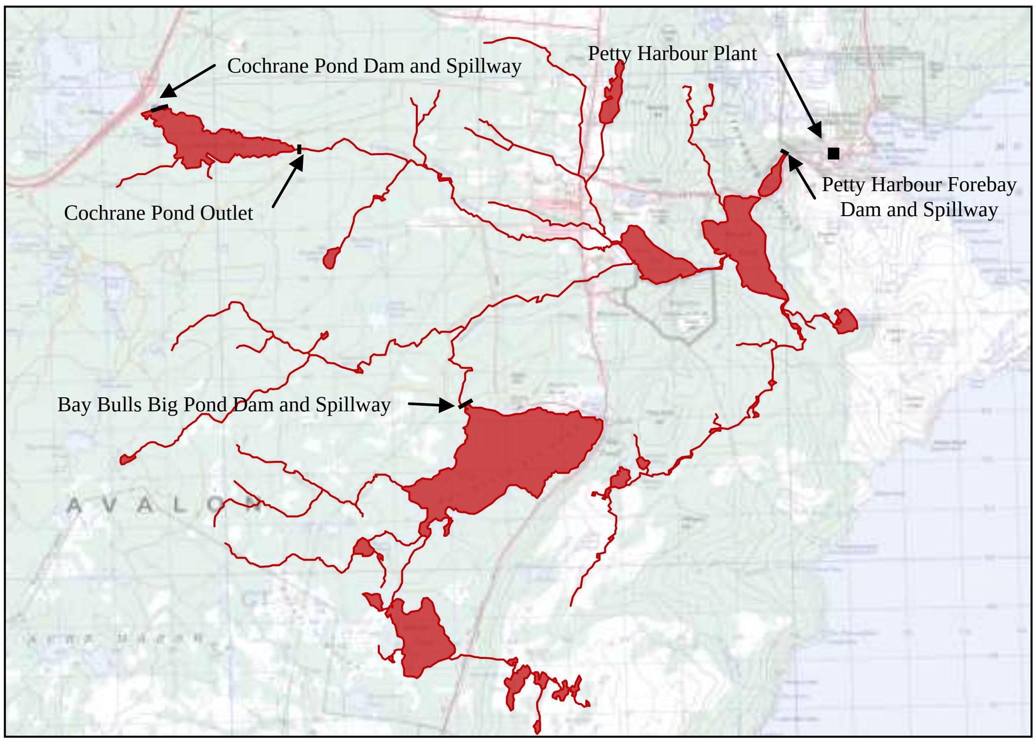

Figure 1 - Petty Harbour Hydroelectric Development

Petty Harbour Plant and Associated Infrastructure
The concrete powerhouse is supplied from the intake by a 975 m long, 2.3 m diameter penstock. A steel surge tank approximately 5.0 m in diameter and 15 m high is located on the hillside behind the plant. The tank is joined to the penstock by a 2.0 m diameter steel riser pipe approximately 95 m long. The plant has a tailrace channel which is excavated through bedrock for a distance of about 140 m from the powerhouse to a natural river channel.

First Pond Forebay Dam
The forebay dam is a concrete gravity structure approximately 75 m long with a maximum height of 9 m. The overflow spillway section is approximately 40 m long and is incorporated into the dam. The Petty Harbour penstock intake is also built into the dam and includes steel trash-racks, access platform and a wooden gatehouse.

Bay Bulls Big Pond
Bay Bulls Big Pond dam is an earth fill dam approximately 120 m long and 9 m high with a concrete outlet structure incorporated into the main dam. Adjacent to the dam is a 40 m long rock-fill overflow spillway with a galvanized steel core. Bay Bulls Big Pond is a major water supply for the City of Mount Pearl, the western section of the City of St. John's, and several other communities in the Northeast Avalon Peninsula.

Cochrane Pond Outlet
The Cochrane Pond outlet is approximately 10 m long and 1.5 m high. This rock-fill overflow spillway with a galvanized steel core was reconstructed in 2013, eliminating a number of public safety deficiencies.

Cochrane Pond Dam and Spillway
Cochrane Pond dam is approximately 340 m long and 3 m high. The dam is of earth fill construction with an upstream riprap layer except for a section of the structure which has an upstream layer of sand which is used as a public beach. A 20 m long reinforced concrete overflow spillway with walkway is incorporated into the dam. The structure is located in Cochrane Pond Park, a private campground.

Public safety treatments identified for the Petty Harbour Development are listed in Table 1 below:

Table 1
Public Safety Treatments
Petty Harbour Development

Site	Signage	Reflectors	Buoys[1]	Fencing[2]
Petty Harbour Plant	×			×
First Pond Forebay Dam	×		×	×
Bay Bulls Big Pond	×			×
Cochrane Pond Outlet	×			
Cochrane Pond Dam and Spillway	×	×		×

[1] Buoys include treatments involving marker buoys and larger booms to restrict access by recreational boaters and swimmers to hazardous areas.
[2] Fencing includes treatments involving new and refurbishment of existing fences, gates and other barriers to restrict access by pedestrians to hazardous areas.

2.0 Topsail Development

Topsail Development is located on the southern part of Conception Bay near the community of Topsail. Storage is provided at Topsail Pond (Forebay), Three Island Pond, Three Arm Pond, Paddy's Pond and Thomas Pond.

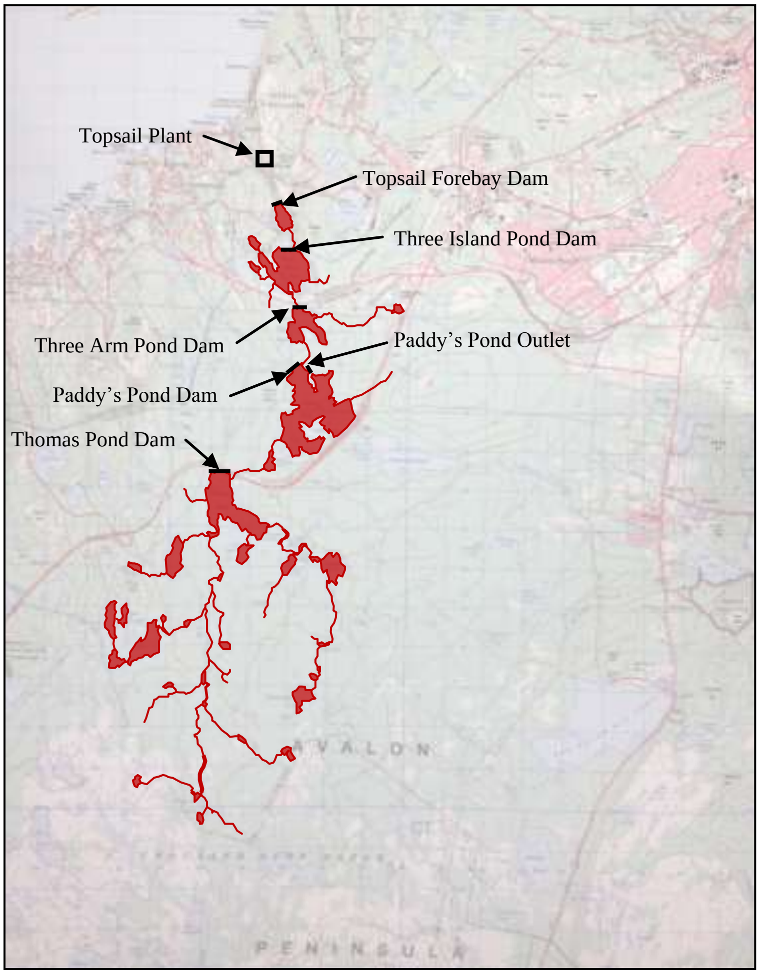

Figure 2 - Topsail Hydroelectric Development

Topsail Plant and Associated Infrastructure
The powerhouse is supplied from the intake by a 1,915 m long, 1,067 mm diameter penstock. The first 300 m downstream from the intake is buried, while the remainder is constructed above ground on timber cradles. The penstock travels through a residential neighborhood.

The plant has a tailrace channel which is excavated earth about 45 m in length and 3 m wide.

Topsail Forebay
The forebay dam is a low concrete gravity structure approximately 18 m long and 0.9 m high located at the end of the canal exiting Topsail Pond. It abuts the intake and incorporates a 7.6 m long overflow and gated spillway consisting of concrete piers and steel gates. It is adjacent to

the concrete intake which is topped with a wooden gatehouse. It includes steel trash racks, steel gate and control equipment.

Three Island Pond Dam
The Three Island Pond dam is 31 m long with a maximum height of 1.8 m and consists of an overflow spillway and concrete outlet. The structure was rebuilt in 2013.

Three Arm Pond Dam
The Three Arm Pond is a 46 m long timber structure with a maximum height of about 1.9 m. The structure has a 12 m spillway and timber outlet with control gate.

Paddy's Pond Outlet
Paddy' Pond outlet structure is an 85 m long embankment dam with a 9 m long rock fill treated timber crib outlet. The structure reaches a maximum height of 3 m.

Paddy's Pond Dam
The Paddy's Pond dam is 145 m long with a maximum height of 3 m. A 60 m steel core, rock overflow spillway is incorporated in the central section of the dam.

Thomas Pond Dam
Thomas Pond dam is approximately 520 m long with a maximum height of 10.7 m. The structure is primarily of earth fill construction, incorporating a reinforced concrete spillway at the left abutment and a reinforced concrete outlet at the right abutment.

The concrete overflow spillway is approximately 50 m long with a maximum height of 2 m. The outlet structure is approximately 20 m long with a maximum height of 5 m.

Public safety treatments identified for the Topsail Development are listed in Table 2 below:

Table 2
Public Safety Treatments
Topsail Development

Site	Signage	Reflectors	Buoys[3]	Fencing[4]
Topsail Plant	×			×
Topsail Forebay	×		×	×
Three Island Pond Dam	×			
Three Arm Pond Dam	×		×	×
Paddy's Pond Outlet	×			×
Paddy's Pond Dam	×			×
Thomas Pond Dam	×			×

3 Buoys include treatments involving marker buoys and larger booms to restrict access by recreational boaters and swimmers to hazardous areas.
4 Fencing includes treatments involving new and refurbishment of existing fences, gates and other barriers to restrict access by pedestrians to hazardous areas.

3.0 Seal Cove Development

Seal Cove Development is located on the southern part of Conception Bay near the Community of Seal Cove. Storage is provided by structures located at White Hill Pond (Forebay), Fenolon's Pond, and Soldier's Pond.

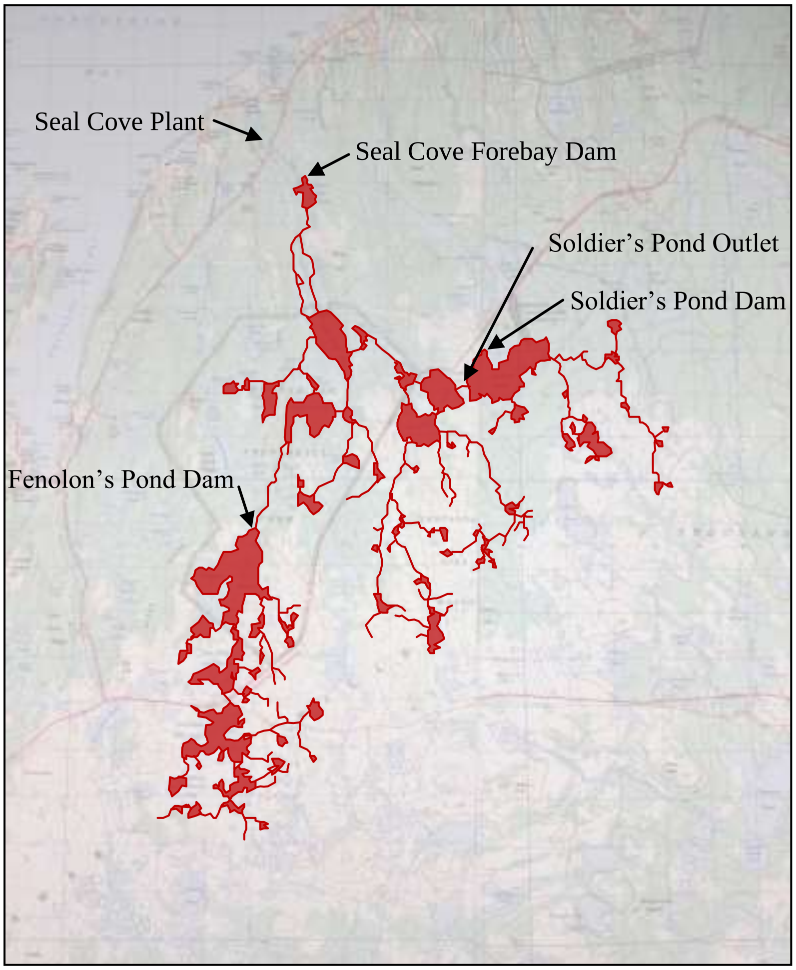

Figure 3 - Seal Cove Hydroelectric Development

Seal Cove Plant and Associated Infrastructure

The Seal Cove Plant is fed by a 1,200 m long steel penstock. The plant has a tailrace channel which is excavated for a distance of about 30 m from the powerhouse to the Seal Cove River.

Seal Cove Forebay

The Seal Cove forebay dam is 240 m long 4 m high concrete slab and buttress dam with downstream rock fill. A spillway consisting of an 87 m concrete weir and downstream rock fill is present on the right abutment.

The intake is of reinforced concrete construction with concrete wing walls on both sides. It includes a steel sluice gate, gate lift, wooden trash racks, control equipment, and a wooden gatehouse.

Fenolon's Pond Dam
Fenolon's Pond dam is 250 m long 5 m high earth fill dam. The spillway structure is a 45 m long rock-fill overflow spillway with a galvanized steel core with walkway. The dam also has an outlet with control gate.

Soldier's Pond Outlet
The Soldier's Pond outlet structure consists of a 100 m section of homogeneous earth fill dam with a concrete outlet structure. The maximum height of the structure is 4 m. The outlet structure was rebuilt in 2013 to replace the aging timber and gabion structure. A number of public safety issues were addressed during that rebuild.

Soldier's Pond Dam
The Soldier's Pond dam structure is 245 m long and approximately 3 m high. The dam is of earth fill construction. A 50 m long rock-fill overflow spillway with a galvanized steel core is incorporated into the dam.

Public safety treatments identified for the Seal Cove Development are listed in Table 3 below:

Table 3
Public Safety Treatments
Seal Cove Development

Site	Signage	Reflectors	Buoys[5]	Fencing[6]
Seal Cove Plant	×			
Seal Cove Forebay	×	×	×	×
Fenolon's Pond Dam	×	×		×
Soldier's Pond Outlet	×			
Soldier's Pond Dam	×	×		

5 Buoys include treatments involving marker buoys and larger booms to restrict access by recreational boaters and swimmers to hazardous areas.
6 Fencing includes treatments involving new and refurbishment of existing fences, gates and other barriers to restrict access by pedestrians to hazardous areas.

4.0 Pierre's Brook

Pierre's Brook Development is located on the east coast of the Avalon Peninsula, northwest of the community of Witless Bay. Storage reservoirs for the generating station are provided by structures located at Gull Pond (Forebay), West Country Pond, and Big Country Pond.

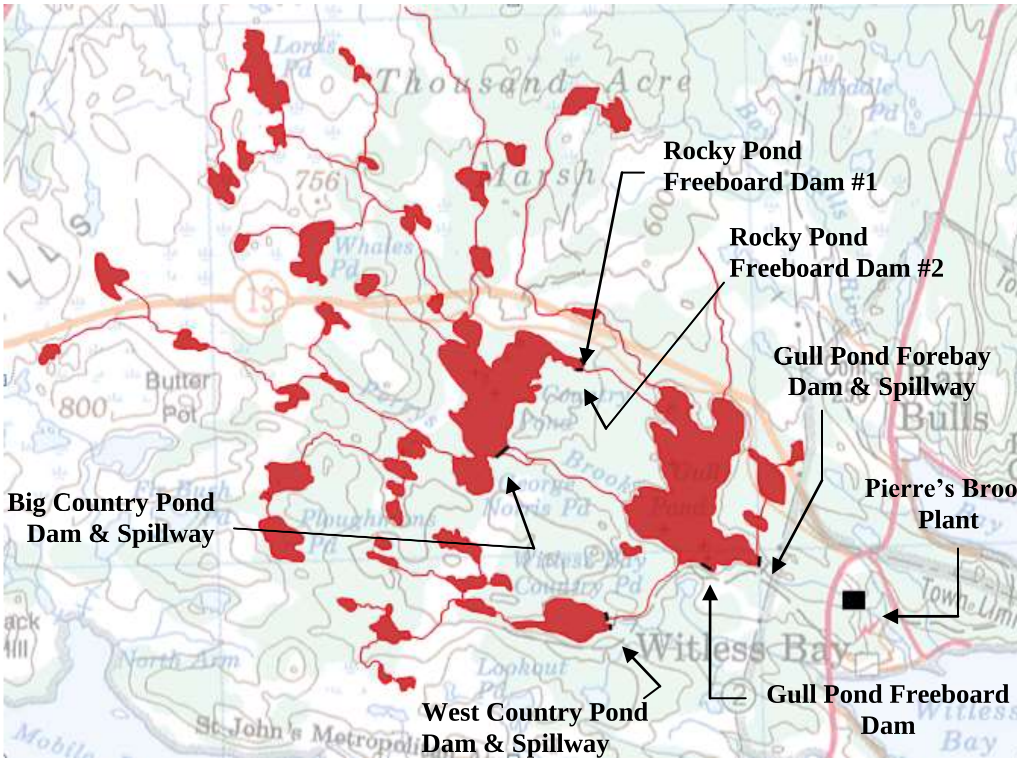

Figure 4 – Pierre's Brook Hydroelectric Development

Pierre's Brook Plant and Associated Infrastructure
Pierre's Brook Plant is supplied from the intake by a 2,533 m long 1.8 m diameter steel and woodstave penstock. A surge tank, located upstream of the plant is 43 m high. A 300 m tailrace returns the water to Pierre's Brook.

Pierre's Brook Forebay
The forebay dam is a 120 m long earth-fill and rock-fill dam and is approximately 7.6 m high. The core of the dam is made of an impervious concrete structure. A concrete intake passes through the dam and is equipped with a gate hoist, steel trash racks, control equipment, and a wooden gatehouse.

The forebay spillway is a 30 m long 2 m high concrete overflow structure. The spillway is topped by a walkway.

Gull Pond Freeboard Dam
Gull Pond freeboard dam is a 380 m long 6 m high earth fill dam with no outlet or spillway present.

West Country Pond Dam
West Country Pond dam is located on the east end of West Country Pond, and is approximately 60 m long and 7.6 m high. It is an earth-fill dam with an outlet and control gate covered by a wooden gatehouse. A 1,370 m long canal extends from this structure to Gull Pond to convey the flow. The spillway structure is located just to the south of the dam, and consists of a concrete gravity overflow structure that has concrete wing walls and earth-fill abutments. The total length of the spillway, including earth-fill, is 120 m with the overflow section being 40 m.

Big Country Pond Dam & Spillway
The Big Country Pond dam is a 90 m long 6 m high zoned earth-fill structure. A concrete outlet and control gate are located in the dam. The spillway is located just south of the dam, and consists of a rock-fill overflow spillway with a galvanized steel core. Public safety treatments identified for the Pierre's Brook Development are listed in Table 4.

Table 4
Public Safety Treatments
Pierre's Brook Development

Site	Signage	Reflectors	Buoys[7]	Fencing[8]
Pierre's Brook Plant	×			×
Pierre's Brook Forebay	×		×	×
Gull Pond Freeboard Dam	×			×
West Country Pond Dam	×			×
Big Country Pond Dam & Spillway	×			×

7 Buoys include treatments involving marker buoys and larger booms to restrict access by recreational boaters and swimmers to hazardous areas.
8 Fencing includes treatments involving new and refurbishment of existing fences, gates and other barriers to restrict access by pedestrians to hazardous areas.

2015 Substation Refurbishment and Modernization

June 2014

Prepared by:

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J. W. Pardy, P. Eng.

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Substation Refurbishment and Modernization Strategy

Newfoundland Power (the "Company") has 130 substations located throughout its operating territory. Distribution substations connect the low voltage distribution system to the high voltage transmission system. Transmission substations connect transmission lines of different voltages. Generation substations connect generating plants to the electrical system. Substations are critical to reliability; an unplanned substation outage can affect thousands of customers. The Company's substation maintenance program and the Substation Refurbishment and Modernization project ensure the delivery of reliable least cost electricity to customers in a safe and environmentally responsible manner.

The Substation Refurbishment and Modernization project provides a structured approach for the overall refurbishment and modernization of substations and coordinates major equipment maintenance and replacement activities.[1] Where practical the substation plan is coordinated with the maintenance cycle for major substation equipment. Such coordination minimizes customer service interruptions and ensures optimum use of resources. This approach is consistent with the least cost delivery of reliable service.

Substation refurbishment and modernization is reviewed annually. When updating the substation refurbishment and modernization plan, assessments are made based upon (i) the condition of the infrastructure and equipment, (ii) the need to upgrade and modernize protection and control systems, and (iii) other relevant work. Starting in 2015, an initiative to accelerate substation feeder automation has been incorporated into the Substation Refurbishment and Modernization Project. This initiative has been identified to accelerate the automation of 49 distribution feeders that are not part of any other project identified over the next 5 years. This in conjunction with previously identified projects will result in the automation of all Company distribution feeders within 5 years.[2] This will enhance the Company's ability to ensure system reliability.

Substation refurbishment and modernization typically requires power transformers to be removed from service. Therefore, the timing of the work is restricted to the availability of a portable substation if customer outages are to be avoided. Due to capacity limitations of portable substations, this often requires the work to be completed in the late spring and summer when substation load is reduced.

The current 5-year forecast for the Substation Refurbishment and Modernization Plan is shown in Appendix A.

2.0 Substation Refurbishment and Modernization 2015 Projects

The 2015 Substation Refurbishment and Modernization project includes planned refurbishment and modernization of 5 substations and 1 portable substation. This substation work is estimated to cost a total of $9,153,000 which comprises approximately 92% of the total 2015 project cost. The remaining project cost includes $648,000 for Substation Feeder Automation to automate 10

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1 The Company's Substation Refurbishment and Modernization Project is the result of the Substation Strategic Plan filed with the 2007 Capital Budget Application.

2 By the end of 2014 there will be 206 distribution feeders automated representing approximately 67% of all distribution feeders.

distribution feeders and $160,000 associated with Substation Monitoring and Operations upgrades to automate substation communication systems to accommodate increased data requirements.

Table 1 identifies the 2015 Substation Refurbishment and Modernization Project expenditures.

Table 1
2015 Substation Refurbishment and Modernization Projects
(000s)

Project	**Budget**
Ridge Road (RRD)	$1,035
Gander (GAN)	$2,930
Clarenville (CLV)	$1,402
Colliers (COL)	$1,452
Springfield (SPF)	$1,462
Portable Substation P4 (P435)	$872
Substation Feeder Automation	$648
Substation Monitoring and Operations	$160
Total	**$9,961**

The location of the 5 substations undergoing refurbishment and modernization projects in 2015 is shown on the map below.

2015 Substation Refurbishment and Modernization Projects

The following pages outline the capital work required for each substation.

2.1 2015 Substation Projects ($9,961,000)

Ridge Road Substation ($1,035,000)

Ridge Road Substation (RRD) was built in 1960 as both a transmission and distribution substation. The transmission portion of the substation contains three 66 kV transmission lines.[3] Two 66 kV to 12.5 kV, 20 MVA power transformers (RRD-T2 and RRD-T3) provide distribution voltage to the 12.5 kV bus structure. There are eight 12.5 kV distribution feeders directly serving approximately 4,740 customers in the Ridge Road and Airport Heights area of St. John's.

Engineering assessments determine that the 66 kV steel structure, bus work, insulators, switches and concrete foundations are all in good condition. Transformers T2 and T3 are in good condition. Also, the 12.5 kV metal clad switchgear is in good condition.

There are a total of 8 distribution feeders with 4 supplied from RRD-T2 and 4 supplied from RRD-T3 through 2 separate low voltage buses. To increase operation flexibility a new 12.5 kV bus tie breaker will be installed to permit paralleling of the separate low voltage buses.[4]

The 8 feeder breakers are not equipped with protection and control capabilities that would facilitate automation, enhanced fault isolation, and remote settings changes to minimize unnecessary trips in the event of cold load pickup.[5] Protection for the 8 feeder breakers will be upgraded to modern digital relays that will be automated for monitoring and control from the System Control Center ("SCC"). With feeder automation, the Ridge Road feeders will be added to the provincial under-frequency load shedding scheme.[6]

The existing relays for transmission lines, transformer and bus protection are vintage electromechanical types that are original to the 1960 substation construction. Electromechanical relays work by using torque-producing coils, energized by current and voltage inputs, which open or close contacts based upon mechanically calibrated thresholds. The mechanical parts contained within electromechanical relays can fail as they age, wear, and accumulate dirt and dust. The age of these relays dictate they are to be replaced with new microprocessor based digital relays. The new microprocessor based digital relays supply more reliable protection to the equipment and support automated monitoring and control from the SCC.

At present, there are 71 electromechanical relays installed in 15 individual protection panels inside the substation control building. Replacing the electromechanical relays with digital relays reduces the total protection relay device count from 71 to 16.

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[3] The three 66 kV transmission lines are 32L and 67L both to Oxen Pond Substation and 30L to King's Bridge Substation.

[4] The improved operational flexibility will result from being able to supply all 8 distribution feeders from either transformer through the operation of the new bus tie breaker.

[5] The feeder breakers are protected using vintage electromechanical relays original to the substation's 1960 construction.

[6] The automation of distribution feeders through digital relays or intelligent reclosers allows for remote monitoring and control through SCADA. In addition these feeders can be remotely tagged for employee safety, included in under-frequency load shedding and have their protection setting adjusted remotely to allow for cold load pickup after extended outages.

66kV Bus Protection Panel (Electromechanical Relays)

The protection upgrade will also involve replacing 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. In addition, the communications package will be upgraded to enhance SCADA system remote-control and monitoring of the power system from the newly installed protection equipment.[7] The gateway will integrate the digital protection relays for the transmission lines, distribution feeders, power transformers and the 66 kV bus into the SCADA system.

Three potential transformers are required to be installed on the 66 kV bus to provide voltage signals for microprocessor based transformer and bus protection relays.

A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation.[8]

Gander Substation ($2,930,000)

Gander Substation (GAN) was built in 1959 as both a transmission and distribution substation. The transmission portion of the substation contains two 138 kV transmission lines and two 66 kV transmission lines.[9] A 138 kV to 66 kV, 26.7 MVA power transformer (GAN-T2) connects

[7] Remote monitoring and control of protection equipment provides efficiency improvements by remote tagging and setting changes on distribution feeders and transmission lines without personnel needing to actually visit the substation.

[8] Newfoundland Power designs substation ground grids using the *ANSI/IEEE Standard 80-2000 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practice for designing substation ground grids.

[9] The two 138kV transmission lines are 144L to Cobb's Pond Substation and 146L to Gambo Substation. The two 66kV transmission lines are 102L to Rattling Brook Substation and 108L to Gander Bay Substation.

the 138 kV and 66 kV buses. There is a single 138 kV to 12.5 kV, 20 MVA power transformer (GAN-T1) which provides distribution voltage to the 12.5 kV bus structure. In addition, there are 3 single-phase 69 kV to 6.9 kV, 1.667 MVA transformers (GAN-T3) acting as a ground source connected to the 66 kV bus. There are four 12.5 kV distribution feeders (GAN-01, GAN-02, GAN-03 and GAN-04), serving approximately 1,683 customers in the Gander area.

Engineering assessments determine that 138 kV and 12.5 kV steel structures, buses, and insulators are all in good condition. The 66 kV wood pole structure is in a deteriorated condition. Twisting and movement of the wood poles has resulted in misalignment of the 66 kV switches on the structure. The wood pole structure will be replaced by steel structures. The concrete foundations generally are in good condition with the exception of four 138 kV pier foundations and breaker foundations that need to be refurbished.

A 138 kV Pier Foundation that Requires Refurbishment

66 kV Wood Pole Structures that Requires Replacement

A spill containment foundation will be constructed for grounding transformers T3 to protect against environmental damage in the event of an oil spill from the units. To provide improved monitoring and protection for the grounding transformers, 3 current transformers will be installed.

Existing Grounding Transformers T3

The 66kV bus structure will be reconstructed. All of the switches on the 138kV and 66kV bus structures are in excess of 35 years in service and will be replaced due to their mechanical condition and age.[10] This includes 6 side break switches, the existing T1 air break switch (GAN-T1-A), T2 air break switches (GAN-T2-A1 and GAN-T2-A2) and the existing T3 air break switch (GAN-T3-A). The air break switches will be replaced with motorized air break switches complete with ground switches.[11]

The power transformers GAN-T1 and GAN-T2, both installed in 1974, will be refurbished and upgrades made to the transformers' auxiliary protection. The existing auxiliary protection devices, including temperature gauges and gas detection relays will be replaced. Having been in service for 35 years or more, these devices are showing signs of deterioration. This has led to false trips, and as such, these devices no longer operate reliably. These auxiliary devices are used to monitor and protect the power transformers, and due to their exposure to the elements, require replacement to ensure continued protection and safe operation of the 2 power transformers.[12]

At present, there are 62 electromechanical relays installed in 12 individual protection panels inside the substation control building. These relays, used for the protection of 3 transmission lines, 4 distribution feeders, 2 transformers and 2 bus structures are vintage electromechanical type, ranging in age from 23 to 48 years old.[13] Electromechanical relays contain moving parts that can fail as they age, wear, and accumulate dirt and dust. The age of these relays dictate they are to be replaced.

The protection and control of the substation will be modernized by replacing these obsolete devices with microprocessor based digital relays, reducing the total protection relay device count from 62 to 15.[14] 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 4 feeder breakers are not equipped with protection and control capabilities that would facilitate automation, enhanced fault isolation, and remote settings changes to minimize

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10 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.

11 The motorized air break switches in conjunction with the upgraded protection relays will improve equipment protection.

12 The Company's strategy for these protection devices is to replace them once they approach 25 to 30 years of service life.

13 Transmission lines 108L, 102L and 146L use electromechanical protection relays original to the substation's 1959 construction. The electromechanical relays used on transmission line 144L failed in service and were replaced by a microprocessor based digital relay. The installation of the relay was completed in the existing control panel using the existing 55 year old wiring. This relay will be returned to inventory when the new protection panels are installed.

14 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.

unnecessary trips in the event of cold load pickup.[15] Protection for the 4 feeder breakers will be upgraded to modern digital relays that will be automated for monitoring and control from the SCC. With feeder automation, the Gander feeders will be added to the provincial under-frequency load shedding scheme.[16]

A complete communications package including a gateway will be installed to facilitate SCADA system remote control and monitoring of the power system protection equipment. The gateway will integrate the digital devices providing monitoring and control of the transmission lines, distribution feeders and substation transformers into the SCADA system.

Existing Control Building with Electromechanical Relays

The existing 55 year old control building at Gander Substation cannot accommodate the new relay and communication panels required to complete the protection upgrades. The building is deteriorated and does not meet current standards.[17] A new control building will be constructed adjacent to the existing building. The new building will permit installation of the protection and communications panels with minimum disruption to the existing protection scheme and impact to the integrity of the electrical system during construction.

[15] The feeder breakers are protected using vintage electromechanical relays original to the substation's 1959 construction.

[16] The automation of distribution feeders through digital relays or intelligent reclosers allows for remote monitoring and control through SCADA. In addition these feeders can be remotely tagged for employee safety, included in under-frequency load shedding and have their protection setting adjusted remotely to allow for cold load pickup after extended outages.

[17] There is corrosion present on both the metal roof panels and siding, the exterior walls are not insulated, and there is no cable trench extending inside the building. Overcrowding of the panels inside the building limits access to the rear of the panels where the wiring is terminated. The battery room does not meet current electrical and building codes.

All low voltage equipment will have standard varmint protection installed.[18]

A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation.[19]

Clarenville Substation ($1,402,000)

The refurbishment and modernization of Clarenville Substation (CLV) will be undertaken in 2015 in concert with the installation of an additional power transformer.[20]

Clarenville substation was built in 1967 as both a transmission and distribution substation. The transmission portion of the substation contains four 138 kV transmission lines and one 66 kV transmission line.[21] A 138 kV to 66 kV, 25 MVA power transformer (CLV-T1) connects the 138 kV and 66 kV buses. There is a single 138 kV to 12.5 kV, 20 MVA power transformer (CLV-T2) which provides distribution voltage to the 12.5 kV bus structure. There are three 12.5 kV distribution feeders (CLV-01, CLV-02 and CLV-03), serving approximately 2,465 customers in the Clarenville area.

Engineering assessments determine that the 138 kV, 66 kV and 12.5 kV steel structures, foundations, buses, and insulators are all in good condition. A large section of cable trench and 91 trench covers will be replaced with rust-resistant trench covers.[22]

The CLV-T1 transformer 138 kV air break switch (CLV-T1-A), three 138kV bus tie air break switches (CLV-BTS-1, CLV-BTS-2, CLV-BTS-3) and transmission line 123L bypass air break switch (CLV-123L-BP) are all more than 35 years old and will be replaced due to their mechanical condition and in-service age.[23] In addition, all transmission line side break switches and ground switches will be replaced due to their mechanical condition and in-service age.

At present, there are 65 electromechanical relays installed in 14 individual protection panels inside the substation control building. These relays, used for the protection of 5 transmission lines, 2 transformers and 2 buses are vintage electromechanical type, ranging in age from 18 to

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18 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.

19 Newfoundland Power designs substation ground grids using the *ANSI/IEEE Standard 80-2000 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practise for designing substation ground grids.

20 The Substations project *2015 Additions Due to Load Growth* includes a new 25 MVA substation transformer required for Clarenville Substation.

21 The four 138kV transmission lines are 100L and 109L to Sunnyside Substation, 123L to Catalina Substation and 124L to Port Blanford Substation. The 66kV transmission line is 110L to Milton Substation.

22 In addition to being corroded the cable tray covers are bent as they were not designed for heavy vehicle traffic. As a result the existing cable trench presents a tripping hazard for employees working in the substation.

23 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.

43 years old.[24] Electromechanical relays contain moving parts and can fail as they age, wear, and accumulate dirt and dust. The age of these relays dictate they are to be replaced.

Electromechanical Relay Panels of Transformer, Buses and 110L Protection

The protection and control of the substation will be modernized by replacing these obsolete devices with microprocessor based digital relays, reducing the total protection relay device count from 65 to 14. 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 3 feeder breakers are not equipped with protection and control capabilities that would facilitate automation, enhanced fault isolation, and remote settings changes to minimize unnecessary trips in the event of cold load pickup.[25] Protection for the 3 feeder breakers will be upgraded to modern digital relays that will be automated for monitoring and control from the SCC. With feeder automation, the Clarenville feeders will be added to the provincial under-frequency load shedding scheme.[26]

[24] Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electromechanical relays contain moving parts and can fail as they age, wear and accumulate dirt and dust.

[25] The feeder breakers are protected using vintage electromechanical relays original to the substation's 1960 construction.

[26] The automation of distribution feeders through digital relays or intelligent reclosers allows for remote monitoring and control through SCADA. In addition these feeders can be remotely tagged for employee safety, included in under-frequency load shedding and have their protection setting adjusted remotely to allow for cold load pickup after extended outages.

A complete communications package including a gateway will be installed to facilitate SCADA system remote control and monitoring of the power system protection equipment. The gateway will integrate the digital devices providing monitoring and control of the transmission lines, distribution feeders and substation transformers into the SCADA system.

The existing 47 year old control building at Clarenville substation cannot accommodate the new relay and communication panels required to complete the protection upgrades. The building is deteriorated and does not meet current standards.[27] A new control building will be constructed. The construction of the building will permit installation of the protection and communications panels with minimum disruption to the existing protections scheme and impact to the integrity of the electrical system during construction. The protection upgrade will also include replacement of all existing protection panels and control cables.

All low voltage switches and breaker bushings will have standard varmint protection installed.[28]

A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation.[29]

Colliers Substation ($1,452,000)

Colliers Substation (COL) was built in 1992 as both a transmission and distribution substation. The transmission portion of the substation contains two 138 kV transmission lines.[30] A 138 kV to 12.5 kV, 16.7 MVA power transformer (COL-T1) supplies the 12.5 kV bus. There are two 12.5 kV distribution feeders (COL-01 and COL-02) serving approximately 1,377 customers in the community of Colliers and surrounding area.[31]

The transmission lines terminated at Colliers Substation are part of a critical 138 kV transmission system from Newfoundland & Labrador Hydro's Western Avalon Terminal Station to the Holyrood Thermal Generating Station, passing through Newfoundland Power substations at Blaketown, Bay Roberts, Springfield, Colliers and Holyrood.[32] The 138 kV transmission system operates in parallel with Hydro's 230 kV transmission system and has a rated capacity of 170

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[27] There is corrosion present on both the metal roof panels and siding. Overcrowding of the panels inside the building limits access to the rear of the panels where the wiring is terminated. The battery room does not meet current electrical and building codes.

[28] 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.

[29] Newfoundland Power designs substation ground grids using the *ANSI/IEEE Standard 80-2000 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practise for designing substation ground grids.

[30] The two 138kV transmission lines are 42L to Holyrood Substation and 46L to Springfield Substation. Originally these transmission lines were all referred to as 39L, but with the installation of transmission line breakers in 2014 and 2015 the nomenclature will be changed to 42L and 46L.

[31] The automation of the 2 distribution feeders will be completed as part of the 2014 Capital Budget Supplemental Application approved by the Board in Order No. P.U. 14 (2014).

[32] The criticality of the 138 kV transmission system from Western Avalon Terminal Station to the Holyrood Thermal Generating Station was discussed in the 2014 Capital Budget Supplemental Application, Schedule A report titled *Electrical System Improvements*. In Order No. P.U. 14 (2014) the Board approved the installation of two 138 kV breakers at Holyrood Substation to decrease the impact of outages to customers supplied from these substations.

MVA. This Substation Refurbishment and Modernization project includes the installation of two 138 kV breakers and associated protective relaying to achieve the operational flexibility required for this 138 kV transmission system.

Colliers Substation High Voltage Structure

Maintenance records and on-site engineering assessments determine that the 138kV steel structures and 12.5 kV wood poles, foundations, buses, and insulators are all in good condition.

The tap changer controller on power transformer COL-T1 has been in service since 1992 and is at the end of its service life. Typically tap changer controllers operate between 5,000 and 10,000 time per year. This high number of operations cause wear on the moving parts over the life of the equipment. A new transformer tap changer controller will be installed to provide the ability to adjust the transformer's output voltage. This upgrade will enhance operational versatility and account for seasonal variations in transformer loading. The new tap changer controller will be integrated with the SCADA system, enabling remote control from the SCC.

Bus protection, transmission line protection and transformer differential protection will be provided by installing microprocessor based digital relays to support remote monitoring and control by the SCC. A complete communications package including a gateway will be installed to facilitate SCADA system remote control and monitoring of the power system protection equipment. The gateway will integrate the digital devices that monitor and control the transmission lines, distribution feeders and substation transformers into the SCADA system.

An incoming circuit breaker will be installed between transformer COL-T1 and the 12.5 kV bus as part of the improved protection scheme. This will minimize the potential for disturbances on the distribution system and power transformer from disrupting the 138 kV transmission system supplying customers in the adjacent substations of Springfield and Holyrood.[33]

[33] The protection system currently at Colliers Substation uses a high speed ground switch to place a line to ground fault on the 138 kV transmission line when a transformer or bus fault is detected. This fault is quickly detected by the transmission line protection at both Bay Roberts Substation and Hydro's terminal station at the Holyrood Thermal Generating Station. These protection devices will de-energize the entire 138 kV transmission system from Bay Roberts to the Holyrood Thermal Generating Station affecting approximately 7,200 customers.

A small 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. All low voltage switches and recloser bushings will be installed with standard varmint protection.[34]

A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation.[35]

Springfield Substation ($1,462,000)

Springfield substation (SPF) was built in 1976 as both a transmission and distribution substation. The transmission portion of the substation contains two 138 kV transmission lines.[36] A 138 kV to 12.5 kV, 20 MVA power transformer (SPF-T1) supplies the 12.5 kV bus. There are three 12.5 kV distribution feeders (SPF-01, SPF-02 and SPF-03) serving approximately 3,141 customers in the Springfield and surrounding area from Brigus to North River.[37]

The transmission lines terminated at Springfield Substation are part of a critical 138 kV transmission system from Newfoundland & Labrador Hydro's Western Avalon Terminal Station to the Holyrood Thermal Generating Station, passing through Newfoundland Power substations at Blaketown, Bay Roberts, Springfield, Colliers and Holyrood.[38] The 138 kV transmission system operates in parallel with Hydro's 230 kV transmission system and has a rated capacity of 170 MVA. This Substation Refurbishment and Modernization project includes the installation of two 138 kV breakers and associated protective relaying to achieve the operational flexibility required for this 138 kV transmission system.

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[34] 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.

[35] Newfoundland Power designs substation ground grids using the *ANSI/IEEE Standard 80-2000 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practise for designing substation ground grids.

[36] The two 138kV transmission lines are 47L to Bay Roberts Substation and 46L to Colliers Substation. Originally these transmission lines were all referred to as 39L, but with the installation of transmission line breakers in 2014 and 2015 the nomenclature will be changed to 46L and 47L.

[37] The automation of the 3 distribution feeders will be completed as part of the 2014 Capital Budget Supplemental Application approved by the Board in Order No. P.U. 14 (2014).

[38] See footnote 31.

Springfield Substation High Voltage Structure

Maintenance records and on-site engineering assessments determined that the 138kV and 12.5 kV steel structures, foundations, buses, and insulators are all in good condition.

The power transformer SPF-T1 installed in 1976 will be refurbished and upgrades made to the transformer's auxiliary protection. The existing auxiliary protection devices, including a temperature gauge and gas detection relay will be replaced. Having been in service for more than 35 years, these devices are showing signs of deterioration. This has led to false trips, and as such, these devices no longer operate reliably. These auxiliary devices are used to monitor and protect the power transformer, and due to their exposure to the elements, require replacement to ensure continued protection and safe operation of the power transformer.[39]

Bus protection, transmission line protection and transformer differential protection will be provided by installing microprocessor based digital relays to support remote monitoring and control by the SCC. A complete communications package including a gateway will be installed to facilitate SCADA system remote control and monitoring of the power system protection equipment. The gateway will integrate the digital devices monitoring and control of the transmission lines, distribution feeders and substation transformers into the SCADA system.

An incoming circuit breaker will be installed between transformer SPF-T1 and the 12.5 kV bus as part of the improved protection scheme. The improved protection scheme will minimize the potential for disturbances on the distribution system and power transformer from disrupting the 138 kV transmission system supplying customers in the adjacent substations of Colliers and Holyrood.[40]

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39 The Company's strategy for these protection devices is to replace them once they approach 25 to 30 years of service life.

40 The protection system currently at Springfield Substation uses a high speed ground switch to place a line to ground fault on the 138 kV transmission line when a transformer or bus fault is detected. This fault is quickly detected by the transmission line protection at both Bay Roberts Substation and Hydro's terminal station at the Holyrood Thermal Generating Station. These protection devices will de-energize the entire 138 kV transmission system from Bay Roberts to the Holyrood Thermal Generating Station affecting approximately 7,200 customers.

A small 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. All low voltage switches and recloser bushings will be installed with standard varmint protection.[41]

A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation.[42]

Portable Substation P4 ($872,000)

Portable substation P4 was purchased in 1993. It is used to respond to power transformer failures and for planned transformer maintenance and substation refurbishment and modernization work. P4 can provide backup for 70% of the 192 power transformers in service on Newfoundland Power's system.

The refurbishment was scheduled to be completed in 2013. However, due to the increased use of the portable substations associated with completion of the PCB Bushing Phase-out project, the unit was unavailable for refurbishment in 2013 and 2014. The refurbishment of portable substation P4 will take place in 2015. This will be the first comprehensive refurbishment of this portable substation since its purchase in 1992 ensuring its availability into the future.

Portable Substation P4

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[41] 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.

[42] Newfoundland Power designs substation ground grids using the *ANSI/IEEE Standard 80-2000 Guide for Safety in AC Substation Grounding*. This standard is considered industry best practise for designing substation ground grids.

An inspection of the portable substation trailer has identified areas of excessive corrosion, deteriorated welding and stress cracks in the trailer chassis. These issues will be corrected and a rust inhibiting coating applied to the chassis and axles to inhibit further deterioration.

Corrosion on 7" C-Channel

A fall arrest system and work platform will be installed in areas where employees have to work aloft. External lighting will be provided at locations around the trailer to improve visibility for employees during setup and operation of the unit.

The alarm annunciation panel has had several failures and will be replaced. The original protection relays will be replaced with microprocessor based protection relays.[43] A digital metering system for measuring power, voltage and current will be provided.

The wiring associated with the protection and control of the portable substation is original wiring showing signs of deterioration. Deteriorated wiring, termination and junction boxes will be replaced.

Online monitoring of transformer gas and oil analysis will be provided to protect the transformer. High voltage linkages connecting the power transformer to the switches are deteriorated and will be replaced. The batteries and charging system are at the end of life and will be replaced.

Automated transformer tap changer controls will be installed on P4 to improve the voltage regulation capabilities to maintain voltage levels supplied to the customers. This automated tap changer controller will be integrated with the SCADA system, enabling remote monitoring and control from the SCC.

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[43] Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electromechanical relays contain moving parts and can fail as they age, wear and accumulate dirt and dust.

A communication package will be installed on the portable substation to provide remote monitoring and control capability of the unit from the SCC.

2.2 Substation Feeder Automation ($648,000)

Approximately 60% of Newfoundland Power's distribution feeders are currently automated at the substation breaker or recloser. On the Avalon Peninsula the penetration of automated distribution feeder breakers and reclosers is 72%. Automation of distribution feeders at the substation breaker or recloser improves restoration from 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.

In the approved 2014 Capital Budget Application 12 distribution feeders will be automated.[44] The Company filed a 2014 Supplementary Capital Budget Application to improve the electricity system, including the automation of an additional 7 distribution feeders.[45]

In 2015 the Company plans to automate an additional 25 distribution feeders. The refurbishment and modernization of Ridge Road (8), Gander (4) and Clarenville (3) substations will automate an additional 15 distribution feeders. An additional 10 distribution feeders not associated with any of the substations undergoing refurbishment and modernization will be automated in 2015.[46]

2.3 Substation Monitoring and Operations ($160,000)

Over the past decade, there has been a substantial increase of computer-based equipment in electrical system control and operations. Periodic upgrades of this equipment are necessary to ensure continued effective electrical system control and operations.

In 2015, upgrades to the communications hubs that connect multiple devices in substations to the SCADA system are planned. Effective management of increased volumes of electrical system data requires the upgrading of the hubs. This requires both hardware and software upgrades.

In 2015, the required work will incorporate manufacturers' upgrades to communications and other computer-based equipment located in Company substations. These upgrades typically increase functionality of the equipment and software and remedy known deficiencies.

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[44] 2014 Capital Budget Application was approved by the Board in Order No. P.U. 27 (2013).

[45] The 2014 Capital Budget Supplemental Application was approved by the Board in Order No. P.U. 14 (2014).

[46] The Company plans to automate *all* distribution feeders over the next five years. The plan will be executed through the refurbishment and modernization of 17 substations with the remaining 49 distribution feeders being automated through this Substation Feeder Automation item. The cost to automate these remaining 49 distribution feeders is estimated at approximately $3.5 million.

Appendix A
Substation Refurbishment and Modernization Plan
Five-Year Forecast 2015 to 2019

Substation Refurbishment and Modernization Plan
Five-Year Forecast
2015 to 2019
($000s)

2015		2016		2017		2018		2019	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
RRD	$1,035	VIC	$1,825	BVA	$1,228	HCP	$ 546	WAL	$ 402
GAN	$2,930	P135	$ 763	CAT	$2,553	HUM	$1,959	SUN	$ 991
CLV	$1,402	BVS	$1,519	SPO	$1,707	TCV	$ 575	HGR	$3,064
COL	$1,452	SFA	$ 655	SFA	$ 681	BLA	$ 799	MOL	$2,000
SPF	$1,462	SMU	$ 165	SMU	$ 170	SLA	$ 951	BCV	$ 768
P435	$ 872					GBS	$1,533	HWD	$ 507
SFA	$ 648					SFA	$ 718	VIR	$ 507
SMU	$ 160					SMU	$ 175	NCH	$1,617
								PUL	$ 507
								SFA	$ 753
								SMU	$ 180
	$9,961		**$4,927**		**$6,339**		**$7,256**		**$11,296**

Note: SUB: Substation - Refer to the Electrical System handbook included with the 2006 Capital Budget Application for three letter substation designations. P1, P3 and P4 are the designations for the portable substations.

2015 Additions Due to Load Growth

June 2014

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NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

As load increases on an electrical system, individual components can become overloaded. The focus of Newfoundland Power's system planning is to avoid or minimize component overloading through cost effective upgrades to the system. In the case of substation transformers, an engineering study is completed to identify and evaluate technical alternatives in advance of the overloads.[1] These technical alternatives are fully examined, cost estimates are prepared, and an economic analysis is performed to identify the least cost alternative.

Peak load forecasts completed for the 2015 Capital Budget planning cycle have identified systems where 5 substation transformers will be overloaded in 2015 if no capital improvements are undertaken. To address these overloads, the addition of transformer capacity at Lethbridge, Clarenville, St. John's Main, and Kenmount substations is required. The decision to add transformer capacity to these substations was based on the results of studies conducted for each substation. These studies are discussed in Sections 2, 3, 4, and 5 of this report and the study results are attached.

This report provides the justifications for the 4 items to be included in the 2015 Capital Budget Application *2015 Additions Due to Load Growth* project.

2.0 Lethbridge Substation ($3,029,000)

An engineering study has been completed on the distribution system upgrades to meet the electrical demands in the Lethbridge area. This 25 kV distribution system includes customers served from Lethbridge ("LET") and Milton ("MIL") substations. This study is presented in Attachment A to this report.

The study examined 3 alternatives to determine the least cost alternative for dealing with the forecasted overload conditions of the LET 25 kV system over a 20 year load forecast period. Both economic and sensitivity analyses were performed on the 3 alternatives to determine the least cost alternative.

The least cost alternative involves installing a new 16.7 MVA substation transformer to replace an existing 6.7 MVA substation transformer at LET substation.

3.0 Clarenville Substation ($2,727,000)

An engineering study has been completed on the distribution system upgrades to meet the electrical demands in the Clarenville area. This distribution system includes customers served from Clarenville ("CLV") and Milton ("MIL") substations. This study is presented in Attachment B to this report.

[1] A substation transformer converts electricity from transmission level voltages (typically between 66 kV and 138 kV) to distribution level voltages (typically between 4 kV and 25 kV).

The study examined 3 alternatives to determine the least cost alternative for dealing with the forecasted overload conditions of the CLV 12.5 kV system over a 20 year load forecast period. Both economic and sensitivity analyses were performed on the 3 alternatives to determine the least cost alternative.

The least cost alternative involves installing a new 25 MVA substation transformer at CLV substation.[2]

4.0 St. John's Main Substation ($1,479,000)

An engineering study has been completed on the distribution system upgrades to meet the electrical demands in the downtown St. John's area and St. John's west end area. This 12.5 kV distribution system includes customers served from St. John's Main ("SJM") and Molloy's Lane ("MOL") substations. This study is presented in Attachment C to this report.

The study examined 2 alternatives to determine the least cost alternative for dealing with the forecasted transformer overload conditions at both SJM and MOL substations over a 20 year load forecast period. Both economic and sensitivity analyses were performed on the 2 alternatives to determine the least cost alternative.

The least cost alternative involves installing a spare 25 MVA substation transformer at SJM substation.[3]

5.0 Kenmount Substation ($2,190,000)

An engineering study has been completed on the distribution system upgrades to meet the electrical demands in the Kenmount Road area. This 25 kV system includes customers served from Kenmount ("KEN") and Hardwoods ("HWD") substations. This study is presented in Attachment D to this report.

The study examined 3 alternatives to determine the least cost alternative for dealing with the forecasted overload conditions of the KEN 25 kV system over a 20 year load forecast period. Both economic and sensitivity analyses were performed on the 3 alternatives to determine the least cost alternative.

The least cost alternative involves installing a new 50 MVA substation transformer to replace an existing 25 MVA substation transformer and constructing a new 25 kV distribution feeder at KEN.[4]

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[2] This project is clustered with the Clarenville item in the Substations Refurbishment and Modernization project.

[3] The spare 25 MVA substation transformer to be installed at SJM will come from HWD after the 50 MVA substation transformer is installed in 2014, as approved in Order No. P.U. 27 (2013).

[4] This project is clustered with the KEN-05 item in the Substation Feeder Termination project and the Distribution project Feeder Additions for Growth.

6.0 Project Cost

Table 1 shows the total 2015 project capital costs for the least cost alternatives.

Table 1
2015 Project Costs
($000's)

Cost Category	Lethbridge Substation Transformer Replacement	Clarenville Substation Transformer Addition	St. John's Main Substation Transformer Addition	Kenmount Substation Transformer Replacement
Material	2,752	2,439	1,239	1,565
Labour – Internal	24	22	22	23
Engineering	160	195	191	81
Other	93	71	27	31
Total	**3,029**	**2,727**	**1,479**	**1,700**[5]

7.0 Conclusion

The Company continues to experience load growth in the Lethbridge, Clarenville, downtown St. John's and Kenmount Road areas. As a result, the available transformer capacity has diminished and equipment overloads are forecast to occur.

It is recommended that the projects identified as being a part of the least cost alternatives in the attached studies be undertaken in 2015 to address the capacity issues in the Lethbridge, Clarenville, downtown St. John's and Kenmount Road areas. The recommended projects include:

- The replacement of the existing 6.7 MVA LET-T1 transformer with a new 16.7 MVA transformer,
- The addition of a new 25 MVA transformer in CLV,
- The installation of a spare 25 MVA transformer in SJM, and
- The replacement of the existing 25 MVA KEN-T2 transformer with a new 50 MVA transformer.

This project is estimated to cost $8,935,000 in 2015.

[5] The cost of $1,700,000 is for the replacement of KEN-T2 transformer only. The total cost of this project is $2,190,000 which includes costs for constructing a new feeder (KEN-05). The costs to construct the new feeder are included in 2 other 2015 Capital Budget Application projects, *Substation Feeder Termination* and *Feeder Additions for Growth*.

Attachment A
Lethbridge Substation Study

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1.0 Introduction

The purpose of this study is to determine the distribution system alternative that best meets the electrical demands of Lethbridge Substation ("LET").

In the winter of 2015, the substation transformer at LET is expected to experience a total peak load of 7.8 MVA. The current capacity of LET-T1 is 6.7 MVA. As a result, the load forecast indicates that LET-T1 will be overloaded in 2015. Load growth on this transformer is primarily the result of additional load being added at the Sexton and Jamestown saw mills in the town of Lethbridge.

This report identifies the capital project(s) required to avoid the 2015 forecasted overload by determining the least cost expansion plan required to meet a 20 year load forecast.

2.0 Description of Existing Systems

2.1 Lethbridge Substation

LET is located in the community of Lethbridge on the Bonavista Peninsula. There is 1 transformer located in the substation, LET-T1. LET-T1 is a 6.7 MVA, 66/25 kV transformer that serves customers through a single distribution feeder, LET-01.

LET-01 feeder serves approximately 1,744 customers. The main trunk portion of this feeder consists of approximately 2.2 km of 4/0 AASC primary conductor heading along Route 233, 7.7 km of 4/0 AASC primary conductor that runs along Route 233 and the Main Road in Musgravetown, 4.0 km of #4 ACSR primary conductor through the community of Lethbridge and approximately 16.0 km of a combination of 1/0 AASC primary conductor and #2 ACSR primary conductor along Route 234 through the communities of Portland and Jamestown.

There are currently no other feeders that LET-01 can be paralleled with.[1]

2.2 Milton Substation

Milton Substation ("MIL") is located in the community of Milton on the Bonavista Peninsula near the causeway at the beginning of Route 231 to Random Island. There is 1 transformer located in the substation, MIL-T1. MIL-T1 is a 16.7 MVA, 66/25 kV transformer that serves customers through 2 MIL distribution feeders.

There are two 25 kV feeders originating from MIL:

1) MIL-01 feeder serves approximately 1,104 customers in the community of Shoal Harbour. The main trunk portion of this feeder consists of approximately 4.0 km of 4/0 AASC conductor that heads south along Balbo Drive and Harbour Drive.

[1] There are no distribution feeders supplied from adjacent substations that can currently be connected to LET-01 feeder. The only option for offloading the LET-T1 transformer is to construct approximately 16.5 KM of new line to tie to distribution feeder MIL-02. This option is included in this study as Alternative 3.

2) MIL-02 feeder serves approximately 1,438 customers. The main trunk portion of this feeder consists of approximately 27.0 km of 4/0 AASC conductor that heads east along Route 231 serving the communities on Random Island. It also heads north through the community of Milton and then along Route 232 to the community of Burgoyne's Cove.

A map of the LET and MIL service area is shown in Appendix A.

3.0 Load Forecast

The following is the forecasted peak substation load that is expected for LET-T1 in the winter of 2015.

- LET-T1 is rated for 6.7 MVA. The peak load on LET-T1 is forecasted to be 7.8 MVA.

This study uses a 20 year load forecast for this substation transformer. The base case 20 year substation forecast for both LET-T1 and MIL-T1 is located in Appendix B. High and low load growth forecasts have also been created for each alternative for use in a sensitivity analysis. With the exception of the first year forecast, the sensitivities are based on increasing the load growth by a factor of 50% for the high forecast and decreasing by a factor of 50% for the low forecast.

4.0 Development of Alternatives

Three alternatives have been developed to eliminate the forecasted overload conditions using a set of defined technical criteria.[2] These alternatives will provide sufficient capacity to meet forecasted loads over the next 20 years.

Each alternative contains estimates for all of the costs involved, including new transformers and feeders. The results of a net present value ("NPV") calculation are provided for each alternative.

4.1 Alternative 1

- In 2015, replace the existing LET-T1 with a new 16.7 MVA, 66/25 kV transformer. This would increase the total substation capacity from 6.7 MVA to 16.7 MVA.[3]

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[2] The following technical criteria were applied:
- The steady state substation transformer loading should not exceed the nameplate rating.
- The minimum steady state feeder voltage should not fall below 116 Volts (on a 120 Volt base).
- The feeder normal peak loading should be sufficient to permit cold load pickup.

[3] The existing 6.7 MVA 66/25 kV transformer is currently scheduled to be moved to Doyle's substation to replace a 4 MVA unit in 2016.

Table 1 shows the capital costs estimated for Alternative 1.

Table 1
Alternative 1 Capital Costs

Year	Item	Cost
2015	Purchase and install a new 16.67 MVA transformer to replace the existing LET-T1.	$3,029,000
	Total	**$3,029,000**

The resultant peak load forecasts for LET-T1 and MIL-T1 under Alternative 1 are shown in Appendix C.

4.2 Alternative 2

- In 2015, add a new 8.3 MVA, 66/25 kV transformer to LET. The additional transformer would be configured to operate in parallel with the existing 6.7 MVA, 66/25 kV LET-T1 transformer. This would increase the total substation capacity from 6.7 MVA to 13.4 MVA.

Table 2 shows the capital costs estimated for Alternative 2.

Table 2
Alternative 2 Capital Costs

Year	Item	Cost
2015	Purchase and install a new 8.3 MVA transformer to LET and parallel it with the existing LET-T1.	$3,177,000
	Total	**$3,177,000**

The resultant peak load forecasts for LET-T1, LET-T2, and MIL-T1 under Alternative 2 are shown in Appendix D.

4.3 Alternative 3

- In 2015, extend MIL-02 feeder's main trunk 5.9 km, upgrade a total of 10.8 km of MIL-02 and LET-01 from single-phase to 3-phase, and re-conductor 2.9 km of MIL-02 with 4/0 AASC conductor to enable a 2.0 MVA load transfer from LET-01 to MIL-02.

Table 3 shows the capital costs estimated for Alternative 3.

Table 3
Alternative 3 Capital Costs

Year	Item	Cost
2015	Extend MIL-02 feeder's main trunk 5.9 km, upgrade 10.5 km of MIL-02 from single-phase to 3- phase, and re-conductor 2.9 km of MIL-02 with 4/0 AASC conductor.	$2,263,000
2034	Purchase and install a new 16.67 MVA transformer to replace the existing LET-T1.	$3,029,000
	Total	**$5,292,000**

The resultant peak load forecasts for LET-T1 and MIL-T1 under Alternative 3 are shown in Appendix E.

5.0 Evaluation of Alternatives

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 2015 to 2034 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.[4] Capital costs required beyond the 20 year forecast period that are required to balance the installed transformer capacity across all 3 alternatives are also included in the NPV calculation and are known simply as end effect capital costs.

[4] This analysis captures the customer revenue requirement for the life of a new transformer asset.

Table 4 shows the NPV of customer revenue requirement for each alternative under the base case load forecast.

Table 4
Net Present Value Analysis
($000)

Alternative	NPV
1	3,114
2	3,424
3	3,675

Alternative 1 has the lowest NPV of customer revenue requirement. As a result, Alternative 1 is recommended as the most appropriate expansion plan.

5.2 Sensitivity Analysis

To assess the sensitivity to load forecast variability of each alternative, high and low load growth forecasts were developed. The peak load forecasts for the sensitivity analysis are shown in Appendix C, D, and E for Alternatives 1, 2, and 3 respectively.

In general, the low load growth forecast results in delaying the required construction projects. Similarly, with a higher load growth forecast the timing of the required construction projects is advanced. Using these revised dates, the NPV of the customer revenue requirement was recalculated.

Table 5 shows the NPV of customer revenue requirement for each alternative under the high and low load forecasts.

Table 5
Sensitivity Analysis
($000)

Alternative	High Load Forecast NPV	Low Load Forecast NPV
1	3,114	3,114
2	3,424	3,424
3	4,174	2,708

Under the high load forecast scenario, Alternative 1 is the least cost alternative.

Under the low load forecast scenario, Alterative 3 is the least cost alternative at approximately 13% less than Alternative 1. However, it should be noted that under the high load forecast scenario Alternative 1 is the least cost alternative at approximately 34% less than Alternative 3.

The cost difference between Alternative 1 and the least cost alternative for both of the sensitivity forecasts indicates that Alternative 1 is still a suitable alternative under varying load growth scenarios. As a result, the recommendation to implement Alternative 1 is still appropriate given the results of the sensitivity analysis.

6.0 Project Cost

Table 6 shows the estimated project costs for the chosen alternative.

Table 6
Project Capital Costs

Year	Item	Cost
2015	Purchase and install a new 16.67 MVA transformer to replace the existing LET-T1.	$3,029,000
	Total	**$3,029,000**

7.0 Conclusion and Recommendation

A 20 year load forecast has projected the electrical demands for LET. The development and analysis of distribution system alternatives has established a preferred expansion plan to meet the forecasted needs of the area.

The economic analysis performed in section 5.1 of this study indicates that Alternative 1 is the least cost alternative that meets all of the required technical criteria. The sensitivity analyses indicates that Alternative 1 is the least cost alternative under the high load growth forecast and that Alternative 3 is the least cost alternative under the low load growth forecast. The sensitivity analysis is performed to ensure that the least cost alternative indicated by the economic analysis is a suitable alternative for varying levels of load growth. As a result, the Alternative 1 expansion plan has been selected as the most appropriate project.

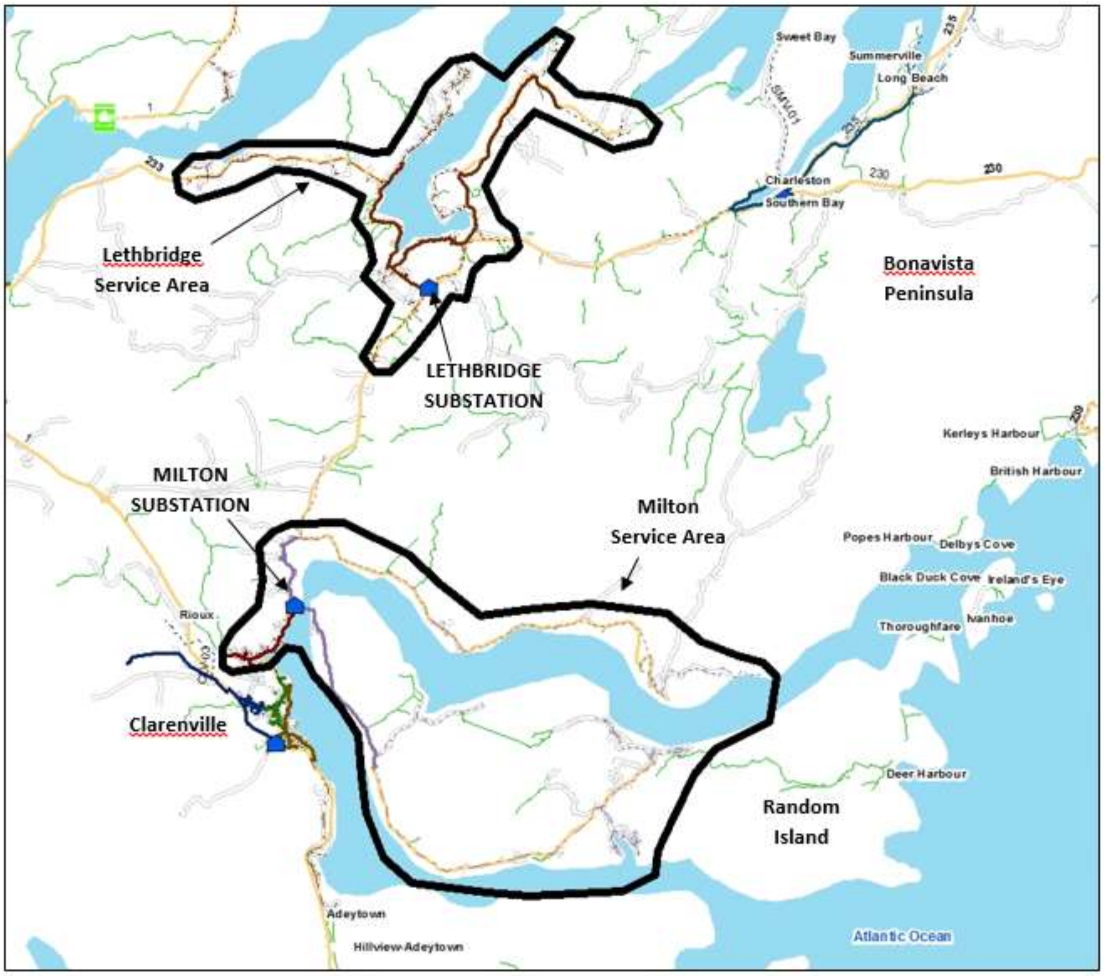
The least cost expansion plan includes the following item in the 2015 Capital Budget:

1) The purchase and installation of a new 16.7 MVA transformer (LET-T1) at LET.

The 2015 project is estimated to cost $3,029,000.

Appendix A
LET and MIL Service Area Map

Lethbridge Substation and Milton Substation Service Area



Appendix B
2013 Substation Load Forecast – Base Case

20 Year Substation Load Forecast – Base Case

Device	LET-T1	MIL-T1
Sec. Voltage (kV)	25.0	25.0
Rating (MVA)	6.7	16.7
2012 Peak (MVA)	7.4	8.9
Year	**Forecasted Undiversified Peak (MVA)**	
2013	7.7	9.5
2014	7.7	9.6
2015	7.8	9.7
2016	7.8	9.8
2017	7.9	9.9
2018	7.9	10.0
2019	8.0	10.1
2020	8.0	10.2
2021	8.1	10.3
2022	8.1	10.4
2023	8.2	10.5
2024	8.2	10.6
2025	8.3	10.7
2026	8.3	10.8
2027	8.4	10.9
2028	8.4	11.0
2029	8.5	11.2
2030	8.6	11.3
2031	8.6	11.4
2032	8.7	11.5

Appendix C
Alternative 1
20 Year Substation Load Forecasts

Alternative 1
20 Year Substation Load Forecast – Base Case

Device	LET-T1	LET-T1 (New)	MIL-T1
Sec. Voltage (kV)	25.0	25.0	25.0
Rating (MVA)	6.7	16.7	16.7
2012 Peak (MVA)	7.4	N/A	8.9
Year	**Forecasted Undiversified Peak (MVA)**		
2013	7.7	0.0	9.5
2014	7.7	0.0	9.6
2015	0.0	7.8	9.7
2016	0.0	7.8	9.8
2017	0.0	7.9	9.9
2018	0.0	7.9	10.0
2019	0.0	8.0	10.1
2020	0.0	8.0	10.2
2021	0.0	8.1	10.3
2022	0.0	8.1	10.4
2023	0.0	8.2	10.5
2024	0.0	8.2	10.6
2025	0.0	8.3	10.7
2026	0.0	8.3	10.8
2027	0.0	8.4	10.9
2028	0.0	8.4	11.0
2029	0.0	8.5	11.2
2030	0.0	8.6	11.3
2031	0.0	8.6	11.4
2032	0.0	8.7	11.5

Alternative 1
20 Year Substation Load Forecast – High Growth

Device	LET-T1	LET-T1 (New)	MIL-T1
Sec. Voltage (kV)	25.0	25.0	25.0
Rating (MVA)	6.7	16.7	16.7
2012 Peak (MVA)	7.4	N/A	8.9
Year	**Forecasted Undiversified Peak (MVA)**		
2013	7.7	0.0	9.5
2014	7.8	0.0	9.7
2015	0.0	7.8	9.8
2016	0.0	7.9	10.0
2017	0.0	8.0	10.1
2018	0.0	8.1	10.3
2019	0.0	8.1	10.4
2020	0.0	8.2	10.6
2021	0.0	8.3	10.7
2022	0.0	8.4	10.9
2023	0.0	8.4	11.1
2024	0.0	8.5	11.2
2025	0.0	8.6	11.4
2026	0.0	8.7	11.6
2027	0.0	8.8	11.7
2028	0.0	8.9	11.9
2029	0.0	8.9	12.1
2030	0.0	9.0	12.3
2031	0.0	9.1	12.4
2032	0.0	9.2	12.6

Alternative 1
20 Year Substation Load Forecast – Low Growth

Device	LET-T1	LET-T1 (New)	MIL-T1
Sec. Voltage (kV)	25.0	25.0	25.0
Rating (MVA)	6.7	16.7	16.7
2012 Peak (MVA)	7.4	N/A	8.9
Year	**Forecasted Undiversified Peak (MVA)**		
2013	7.7	0.0	9.5
2014	7.7	0.0	9.6
2015	0.0	7.7	9.6
2016	0.0	7.8	9.6
2017	0.0	7.8	9.7
2018	0.0	7.8	9.7
2019	0.0	7.8	9.8
2020	0.0	7.9	9.8
2021	0.0	7.9	9.9
2022	0.0	7.9	9.9
2023	0.0	7.9	10.0
2024	0.0	8.0	10.0
2025	0.0	8.0	10.1
2026	0.0	8.0	10.1
2027	0.0	8.0	10.2
2028	0.0	8.1	10.2
2029	0.0	8.1	10.3
2030	0.0	8.1	10.3
2031	0.0	8.1	10.4
2032	0.0	8.2	10.5

Appendix D
Alternative 2
20 Year Substation Load Forecasts

Alternative 2
20 Year Substation Load Forecast – Base Case

Device	**LET-T1**	**LET-T2 (New)**	**MIL-T1**
Sec. Voltage (kV)	25.0	25.0	25.0
Rating (MVA)	6.7	8.3	16.7
2012 Peak (MVA)	7.4	N/A	8.9
Year	**Forecasted Undiversified Peak (MVA)**		
2013	7.7	0.0	9.5
2014	7.7	0.0	9.6
2015	3.9	3.9	9.7
2016	3.9	3.9	9.8
2017	4.0	3.9	9.9
2018	4.0	3.9	10.0
2019	4.0	4.0	10.1
2020	4.0	4.0	10.2
2021	4.1	4.0	10.3
2022	4.1	4.0	10.4
2023	4.1	4.1	10.5
2024	4.1	4.1	10.6
2025	4.2	4.1	10.7
2026	4.2	4.1	10.8
2027	4.2	4.2	10.9
2028	4.2	4.2	11.0
2029	4.3	4.2	11.2
2030	4.3	4.3	11.3
2031	4.3	4.3	11.4
2032	4.4	4.3	11.5

Alternative 2
20 Year Substation Load Forecast – High Growth

Device	**LET-T1**	**LET-T2 (New)**	**MIL-T1**
Sec. Voltage (kV)	25.0	25.0	25.0
Rating (MVA)	6.7	8.3	16.7
2012 Peak (MVA)	7.4	N/A	8.9
Year	**Forecasted Undiversified Peak (MVA)**		
2013	7.7	0.0	9.5
2014	7.8	0.0	9.7
2015	3.9	3.9	9.8
2016	4.0	3.9	10.0
2017	4.0	4.0	10.1
2018	4.0	4.0	10.3
2019	4.1	4.0	10.4
2020	4.1	4.1	10.6
2021	4.2	4.1	10.7
2022	4.2	4.2	10.9
2023	4.2	4.2	11.1
2024	4.3	4.2	11.2
2025	4.3	4.3	11.4
2026	4.4	4.3	11.6
2027	4.4	4.4	11.7
2028	4.4	4.4	11.9
2029	4.5	4.4	12.1
2030	4.5	4.5	12.3
2031	4.6	4.5	12.4
2032	4.6	4.6	12.6

Alternative 2
20 Year Substation Load Forecast – Low Growth

Device	LET-T1	LET-T2 (New)	MIL-T1
Sec. Voltage (kV)	25.0	25.0	25.0
Rating (MVA)	6.7	8.3	16.7
2012 Peak (MVA)	7.4	N/A	8.9
Year	**Forecasted Undiversified Peak (MVA)**		
2013	7.7	0.0	9.5
2014	7.7	0.0	9.6
2015	3.9	3.8	9.6
2016	3.9	3.8	9.6
2017	3.9	3.9	9.7
2018	3.9	3.9	9.7
2019	3.9	3.9	9.8
2020	3.9	3.9	9.8
2021	3.9	3.9	9.9
2022	4.0	3.9	9.9
2023	4.0	3.9	10.0
2024	4.0	3.9	10.0
2025	4.0	4.0	10.1
2026	4.0	4.0	10.1
2027	4.0	4.0	10.2
2028	4.0	4.0	10.2
2029	4.0	4.0	10.3
2030	4.1	4.0	10.3
2031	4.1	4.0	10.4
2032	4.1	4.0	10.5

Appendix E
Alternative 3
20 Year Substation Load Forecasts

Alternative 3
20 Year Substation Load Forecast – Base Case

Device	LET-T1	MIL-T1
Sec. Voltage (kV)	25.0	25.0
Rating (MVA)	6.7	16.7
2012 Peak (MVA)	7.4	8.9
Year	**Forecasted Undiversified Peak (MVA)**	
2013	7.7	9.5
2014	7.7	9.6
2015	5.8	11.7
2016	5.8	11.8
2017	5.9	11.9
2018	5.9	12.0
2019	6.0	12.1
2020	6.0	12.2
2021	6.1	12.3
2022	6.1	12.4
2023	6.2	12.5
2024	6.2	12.6
2025	6.3	12.7
2026	6.3	12.8
2027	6.4	12.9
2028	6.4	13.0
2029	6.5	13.2
2030	6.6	13.3
2031	6.6	13.4
2032	6.7	13.5

Alternative 3
20 Year Substation Load Forecast – High Growth

Device	LET-T1	LET-T1 (New)	MIL-T1
Sec. Voltage (kV)	25.0	25.0	25.0
Rating (MVA)	6.7	16.7	16.7
2012 Peak (MVA)	7.4	N/A	8.9
Year	**Forecasted Undiversified Peak (MVA)**		
2013	7.7	0.0	9.5
2014	7.8	0.0	9.7
2015	5.8	0.0	11.8
2016	5.9	0.0	12.0
2017	6.0	0.0	12.1
2018	6.1	0.0	12.3
2019	6.1	0.0	12.4
2020	6.2	0.0	12.6
2021	6.3	0.0	12.7
2022	6.4	0.0	12.9
2023	6.4	0.0	13.1
2024	6.5	0.0	13.2
2025	6.6	0.0	13.4
2026	6.7	0.0	13.6
2027	0.0	6.8	13.7
2028	0.0	6.9	13.9
2029	0.0	6.9	14.1
2030	0.0	7.0	14.3
2031	0.0	7.1	14.4
2032	0.0	7.2	14.6

Alternative 3
20 Year Substation Load Forecast – Low Growth

Device	LET-T1	MIL-T1
Sec. Voltage (kV)	25.0	25.0
Rating (MVA)	6.7	16.7
2012 Peak (MVA)	7.4	8.9
Year	**Forecasted Undiversified Peak (MVA)**	
2013	7.7	9.5
2014	7.7	9.6
2015	5.7	11.6
2016	5.8	11.6
2017	5.8	11.7
2018	5.8	11.7
2019	5.8	11.8
2020	5.9	11.8
2021	5.9	11.9
2022	5.9	11.9
2023	5.9	12.0
2024	6.0	12.0
2025	6.0	12.1
2026	6.0	12.1
2027	6.0	12.2
2028	6.1	12.2
2029	6.1	12.3
2030	6.1	12.3
2031	6.1	12.4
2032	6.2	12.5

Attachment B
Clarenville Substation Study

Table of Contents

1.0 Introduction

The purpose of this study is to determine the distribution system alternative that best meets the electrical demands of the Clarenville substation ("CLV").

In the winter of 2015, the substation transformer at CLV is expected to experience a total peak load of 21.8 MVA.[1] The current capacity of CLV-T2 is 20.0 MVA. As a result, the load forecast indicates that CLV-T2 will be overloaded in 2015. Load growth on this transformer is primarily the result of an increase in commercial development along Shoal Harbour Drive in the town of Clarenville and residential subdivision developments including Clearview Terrace, Bare Mountain Road, Riverview Subdivision and Hibernia Drive.

This report identifies the capital project(s) required to avoid the 2015 forecasted overload by determining the least cost expansion plan required to meet a 20 year load forecast.

2.0 Description of Existing System

2.1 Clarenville Substation

CLV is located along the TCH, just south of the St. Jude Hotel. There are 2 transformers located in the substation: CLV-T1 and CLV-T2. CLV-T1 is a 25 MVA, 138/66 kV system transformer that supplies the 66 kV transmission lines to Lethbridge and Milton ("MIL") substations.[2] CLV-T2 is a 20 MVA, 138/12.5 kV substation transformer that is used to convert 138 kV to a distribution level voltage of 12.5 kV to serve customers through 3 CLV distribution feeders.

There are three 12.5 kV feeders originating from CLV:

1) CLV-01 feeder serves approximately 1,050 customers. The main trunk portion of this feeder consists of approximately 1.0 km of 4/0 AASC conductor heading northeast along Tilleys Road and 2.5 km of #4 copper primary conductor that runs north along Marine Drive. It can be paralleled with CLV-02 at the intersection of Marine Drive and Memorial Drive.

2) CLV-02 feeder serves approximately 916 customers. The main trunk portion of this feeder consists of 4/0 AASC primary conductor heading northeast along Tilley's Road and north along Memorial Drive. It can be paralleled with CLV-01 at the intersection of Marine Drive and Memorial Drive or CLV-03 near the intersection of Manitoba Drive and Memorial Drive. This feeder is also used as a backup for the Clarenville Hospital which has a 1.2 MVA demand requirement.

3) CLV-03 feeder serves approximately 497 customers. The main trunk portion of this feeder consists of approximately 5.0 km of 4/0 AASC primary conductor that runs northwest along the TCH and east along Manitoba Drive. It also continues northwest along the TCH providing electricity to White Hills Ski Resort. It can be paralleled with CLV-02 near the

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[1] A substation transformer typically converts electricity from transmission level voltages (typically between 66 kV and 138 kV) to distribution level voltages (typically between 4 kV and 25 kV).

[2] A system transformer converts electricity from one transmission level voltage (typically between 230 kV and 66 kV) to another transmission level voltage.

intersection of Manitoba Drive and Memorial Drive. This feeder has seen significant growth in recent years with new commercial and residential development along Shoal Harbour Drive.

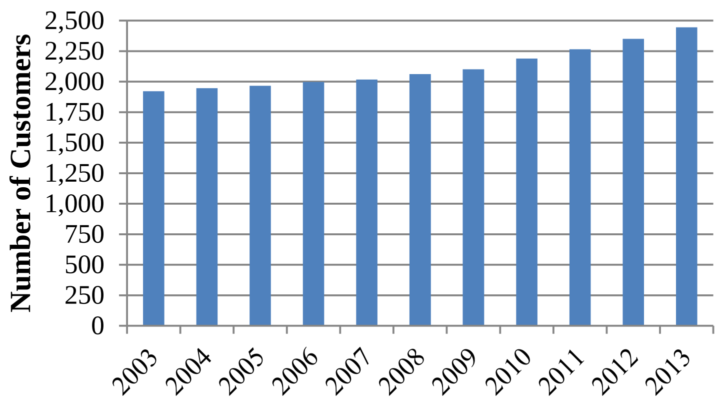
The 12.5 kV distribution feeders supplied from CLV cannot be connected to any other 12.5 kV distribution feeders from adjacent substations to permit offloading CLV-T2 onto other substation transformers. However, Milton substations ("MIL") supplies a 25kV distribution system which is adjacent to CLV-02. The conversion of a section of CLV-02 to 25kV and transferring a portion of its load onto MIL is included as Alternative 3.

A map of the CLV service area is shown in Appendix A.

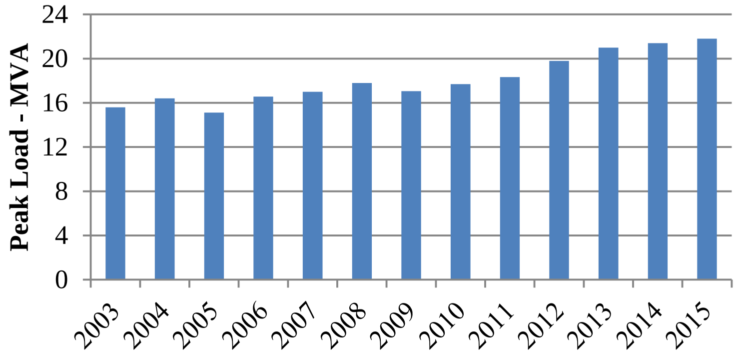
3.0 Load Forecast

From 2003 to 2013, the number of customers served from CLV has increased by 27% from 1,922 to 2,445 customers. In addition, the load on CLV-T2 has increased 35% from 15.6 MVA to 21.0 MVA. These increases are due to the expansion of residential and commercial developments in the town of Clarenville. In recent years, this expansion has primarily occurred in the form of commercial development along Shoal Harbour Drive and new residential subdivisions. Graph 1 shows the customer growth on CLV between 2003 and 2013. Graph 2 shows the load growth on CLV between 2003 and 2013 along with the forecasted load growth for 2014 and 2015.

Graph 1
CLV Customer Growth



Graph 2
CLV-T2 Load Growth



The following is the forecasted peak substation load that is expected for CLV-T2 in the winter of 2015.

- CLV-T2 is rated for 20 MVA. The peak load on CLV-T2 is forecasted to be 21.8 MVA.

This study uses a 20 year load forecast for this substation transformer. The base case 20 year substation forecast for CLV-T2 and MIL-T1 is located in Appendix A. High and low load growth forecasts have also been created for each alternative for use in a sensitivity analysis. With the exception of the first year forecast, the sensitivities are based on increasing the load growth by a factor of 50% for the high forecast and decreasing by a factor of 50% for the low forecast.

4.0 Development of Alternatives

Three alternatives have been developed to eliminate the forecasted overload conditions using a set of defined technical criteria.[3] These alternatives will provide sufficient capacity to meet forecasted loads over the next 20 years.

Each alternative contains estimates for all of the costs involved, including new transformers and feeders. The results of a net present value ("NPV") calculation are provided for each alternative.

4.1 Alternative 1

- In 2015, add a new 25 MVA, 138/12.5 kV transformer to CLV. The additional transformer would be configured to operate in parallel with the existing 20 MVA, 138/12.5 kV CLV-T2 transformer. This would increase the total substation capacity from 20 MVA to 41.5 MVA.[4]

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3 The following technical criteria were applied:
- The steady state substation transformer loading should not exceed the nameplate rating.
- The minimum steady state feeder voltage should not fall below 116 Volts (on a 120 Volt base).
- The feeder normal peak loading should be sufficient to permit cold load pickup.

4 The total substation capacity is not necessarily equal to the sum of the individual transformer nameplate capacities. The electrical characteristics of each transformer, more specifically the transformer's per unit impedance, determines how load is split between new and existing transformers that operate in parallel.

Table 1 shows the capital costs estimated for Alternative 1.

Table 1
Alternative 1 Capital Costs

Year	Item	Cost
2015	Purchase and install a new 25 MVA transformer (CLV-T3) at CLV and parallel it with the existing CLV-T2.	$2,727,000
	Total	**$2,727,000**

The resultant peak load forecasts for CLV-T2, CLV-T3, and MIL-T1 under Alternative 1 are shown in Appendix C.

4.2 Alternative 2

- In 2015, replace the existing 20 MVA, 138/12.5 kV CLV-T2 transformer with a new 25 MVA, 138/12.5 kV transformer. This would increase the total substation capacity from 20 MVA to 25 MVA and the existing 20 MVA, 138/12.5 kV CLV-T2 transformer would become a system spare.
- In 2023, add a new 25 MVA, 138/12.5 kV transformer at CLV. The additional transformer would be configured to operate in parallel with the existing 25 MVA, 138/12.5 kV CLV-T2 transformer. This would increase the total substation capacity from 25 MVA to 50 MVA.

Table 2 shows the capital costs estimated for Alternative 2.

Table 2
Alternative 2 Capital Costs

Year	Item	Cost
2015	Purchase and install a new 25 MVA transformer to replace the existing CLV-T2.	$2,293,000
2023	Purchase and install a new 25 MVA transformer (CLV-T3) to CLV and parallel it with the existing CLV-T2.	$2,727,000
	Total	**$5,020,000**

The resultant peak load forecasts for CLV-T2, CLV-T3, and MIL-T1 under Alternative 2 are shown in Appendix D.

4.3 Alternative 3

- In 2015, upgrade approximately 0.6 km of the single-phase portion of CLV-03 feeder to 3-phase and extend the feeder another 1.0 km upgraded with 25 kV infrastructure to permit a load transfer of 2.0 MVA from CLV-03 feeder (12.5 kV) to MIL-01 feeder (25 kV).[5]
- In 2016, add a new 25 MVA, 138/12.5 kV transformer to CLV. The additional transformer would be configured to operate in parallel with the existing 20 MVA, 138/12.5 kV CLV-T2 transformer. This would increase the total substation capacity from 20.0 MVA to 41.5 MVA.

Table 3 shows the capital costs estimated for Alternative 3.

Table 3
Alternative 3 Capital Costs

Year	Item	Cost
2015	Upgrade approximately 0.6 km of the single-phase portion of CLV-03 feeder to 3-phase and extend the feeder another 1.0 km as well as install appropriate 25 kV infrastructure to permit a load transfer of 2.0 MVA from CLV-03 feeder to MIL-01 feeder.	$434,000
2016	Purchase and install a new 25 MVA transformer (CLV-T3) at CLV and parallel it with the existing CLV-T2.	$2,727,000
	Total	**$3,161,000**

The resultant peak load forecasts for CLV-T2, CLV-T3, and MIL-T1 under Alternative 3 are shown in Appendix E.

5.0 Evaluation of Alternatives

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 2015 to 2034 were converted to the customer revenue requirement and the resulting customer revenue requirement was reduced to a NPV using the Company's weighted average

[5] The transfer of load from CLV-03 to MIL-01 is practically limited to 2.0 MVA. Further conversion and transfer of load will require the voltage conversion of a significant portion of the commercial load on Manitoba Drive and will reduce the level of reliability currently provided through existing ties between CLV-02 and other CLV distribution feeders.

incremental cost of capital.[6] Capital costs required beyond the 20 year forecast period that are required to balance the installed transformer capacity across all 3 alternatives are also included in the NPV calculation and are known simply as end effect capital costs.

Table 5 shows the NPV of customer revenue requirement for each alternative under the base case load forecast.

Table 4
Net Present Value Analysis
($000)

Alternative	NPV
1	3,217[7]
2	4,228
3	3,491[8]

Alternative 1 has the lowest NPV of customer revenue requirement. As a result, Alternative 1 is recommended as the most appropriate expansion plan.

5.2 Sensitivity Analysis

To assess the sensitivity to load forecast error of each alternative, high and low load growth forecasts were developed. The peak load forecasts for the sensitivity analysis are shown in Appendix B, C, and D for Alternatives 1, 2, and 3 respectively.

In general, the low load forecast results in delaying the required construction projects. Similarly, with a higher load growth forecast the timing of the required construction projects is advanced. Using these revised dates, the NPV of the customer revenue requirement was recalculated.

6 This analysis captures the customer revenue requirement for the life of a new transformer asset.

7 The NPV of Alternative 1 is higher than the capital cost of Alternative 1 listed in Table 1 above because additional capacity is required for this alternative at the end of the 20 year forecast period.

8 The NPV of Alternative 3 is higher than the capital cost of Alternative 3 listed in Table 3 above because additional capacity is required for this alternative at the end of the 20 year forecast period.

Table 5 shows the NPV of customer revenue requirement for each alternative under the high and low load forecasts.

Table 5
Sensitivity Analysis
($000)

Alternative	High Load Forecast NPV	Low Load Forecast NPV
1	3,584	2,939
2	4,228	3,465
3	3,963	2,892

Under the high load forecast scenario, Alternative 1 is the least cost alternative.

Under the low load forecast scenario, Alterative 3 is the least cost alternative. However, it should be noted that the cost for Alternative 1 is only 1.6% higher than Alternative 3.

The cost difference between Alternative 1 and the least cost alternative for both of the sensitivity forecasts indicates that Alternative 1 is still a suitable alternative under varying load growth scenarios. As a result, the recommendation to implement Alternative 1 is still appropriate given the results of the sensitivity analysis.

6.0 Project Cost

Table 6 shows the estimated project costs for the chosen alternative.

Table 6
Project Capital Costs

Year	Item	Cost
2015	Purchase and install a new 25 MVA transformer (CLV-T3) at CLV and parallel it with the existing CLV-T2.	$2,727,000
	Total	**$2,727,000**

7.0 Conclusion and Recommendation

A 20 year load forecast has projected the electrical demands for the Clarenville 12.5 kV system. The development and analysis of distribution system alternatives has established a preferred expansion plan to meet the forecasted needs of the area.

The economic analysis performed in section 5.1 of this study indicates that Alternative 1 is the least cost alternative that meets all of the required technical criteria. The sensitivity analyses indicates that Alternative 1 is the least cost alternative under the high load growth forecast and that Alternative 3 is the least cost alternative under the low load growth forecast. The sensitivity analysis is performed to ensure that the least cost alternative indicated by the economic analysis is a suitable alternative for varying levels of load growth. As a result, the Alternative 1 expansion plan has been selected as the most appropriate project.

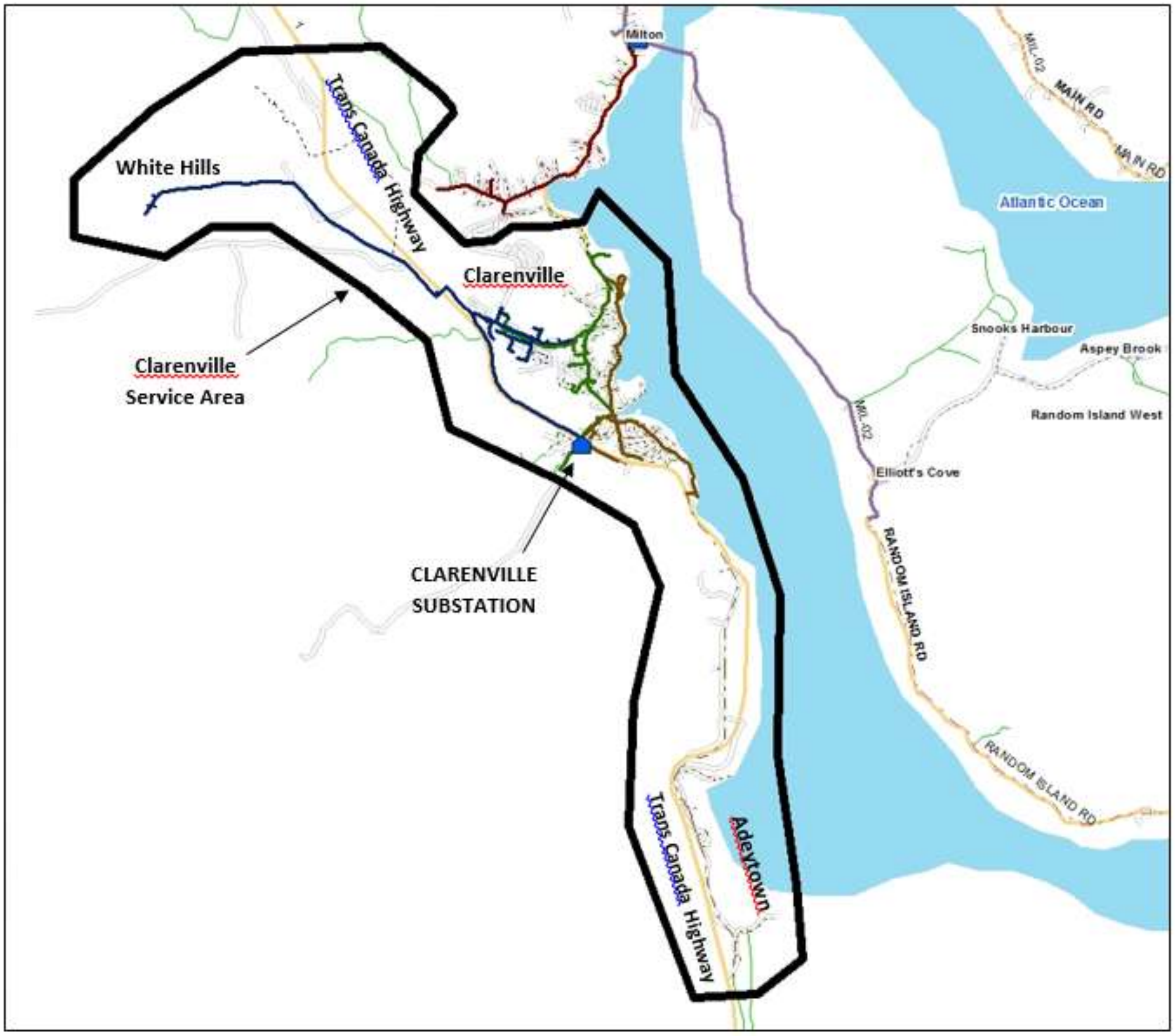
The least cost expansion plan includes the following item in the 2015 Capital Budget:

1) The purchase and installation of a new 25 MVA transformer (CLV-T3) at CLV and parallel it with the existing CLV-T2.

The 2015 project is estimated to cost $2,727,000.

Appendix A
CLV Service Area Map

Clarenville Substation Service Area



Appendix B
2013 Substation Load Forecast – Base Case

20 Year Substation Load Forecast – Base Case

Device	**CLV-T2**	**MIL-T1**
Sec. Voltage (kV)	12.5	25.0
Rating (MVA)	20.0	16.7
2012 Peak (MVA)	19.8	8.9
Year	**Forecasted Undiversified Peak (MVA)**	
2013	21.0	9.5
2014	21.4	9.6
2015	21.8	9.7
2016	22.2	9.8
2017	22.6	9.9
2018	23.0	10.0
2019	23.4	10.1
2020	23.8	10.2
2021	24.3	10.3
2022	24.7	10.4
2023	25.1	10.5
2024	25.5	10.6
2025	26.0	10.7
2026	26.4	10.8
2027	26.9	10.9
2028	27.4	11.0
2029	27.8	11.2
2030	28.3	11.3
2031	28.8	11.4
2032	29.3	11.5

Appendix C
Alternative 1
20 Year Substation Load Forecasts

Alternative 1
20 Year Substation Load Forecast – Base Case

Device	**CLV-T2**	**CLV-T3 (New)**	**MIL-T1**
Sec. Voltage (kV)	12.5	25.0	25.0
Rating (MVA)	20.0	25.0	16.7
2012 Peak (MVA)	19.8	N/A	8.9
Year	**Forecasted Undiversified Peak (MVA)**		
2013	21.0	0.0	9.5
2014	21.4	0.0	9.6
2015	10.5	11.3	9.7
2016	10.7	11.5	9.8
2017	10.9	11.7	9.9
2018	11.1	11.9	10.0
2019	11.3	12.2	10.1
2020	11.5	12.4	10.2
2021	11.7	12.6	10.3
2022	11.9	12.8	10.4
2023	12.1	13.0	10.5
2024	12.3	13.2	10.6
2025	12.5	13.5	10.7
2026	12.7	13.7	10.8
2027	13.0	13.9	10.9
2028	13.2	14.2	11.0
2029	13.4	14.4	11.2
2030	13.6	14.7	11.3
2031	13.9	14.9	11.4
2032	14.1	15.2	11.5

Alternative 1
20 Year Substation Load Forecast – High Growth

Device	CLV-T2	CLV-T3 (New)	MIL-T1
Sec. Voltage (kV)	12.5	12.5	25.0
Rating (MVA)	20.0	25.0	16.7
2012 Peak (MVA)	19.8	N/A	8.9
Year	**Undiversified Forecasted Peak (MVA)**		
2013	21.0	0.0	9.5
2014	21.6	0.0	9.7
2015	10.7	11.5	9.8
2016	11.0	11.9	10.0
2017	11.3	12.2	10.1
2018	11.6	12.5	10.3
2019	11.9	12.8	10.4
2020	12.2	13.2	10.6
2021	12.5	13.5	10.7
2022	12.9	13.8	10.9
2023	13.2	14.2	11.1
2024	13.5	14.6	11.2
2025	13.9	15.0	11.4
2026	14.3	15.3	11.6
2027	14.6	15.7	11.7
2028	15.0	16.2	11.9
2029	15.4	16.6	12.1
2030	15.8	17.0	12.3
2031	16.2	17.5	12.4
2032	16.6	17.9	12.6

Alternative 1
20 Year Substation Load Forecast – Low Growth

Device	**CLV-T2**	**CLV-T3**	**MIL-T1**
Sec. Voltage (kV)	12.5	12.5	25.0
Rating (MVA)	20.0	25.0	16.7
2012 Peak (MVA)	19.8	N/A	8.9
Year	**Forecasted Undiversified Peak (MVA)**		
2013	21.0	0.0	9.5
2014	21.2	0.0	9.6
2015	10.3	11.1	9.6
2016	10.4	11.2	9.6
2017	10.5	11.3	9.7
2018	10.6	11.4	9.7
2019	10.7	11.5	9.8
2020	10.8	11.6	9.8
2021	10.9	11.7	9.9
2022	11.0	11.8	9.9
2023	11.1	11.9	10.0
2024	11.2	12.0	10.0
2025	11.3	12.1	10.1
2026	11.4	12.2	10.1
2027	11.5	12.3	10.2
2028	11.6	12.4	10.2
2029	11.7	12.6	10.3
2030	11.8	12.7	10.3
2031	11.9	12.8	10.4
2032	12.0	12.9	10.5

Appendix D
Alternative 2
20 Year Substation Load Forecasts

Alternative 2
20 Year Substation Load Forecast – Base Case

Device	**CLV-T2**	**CLV-T2 (New)**	**CLV-T3 (New)**	**MIL-T1**
Sec. Voltage (kV)	12.5	12.5	12.5	25.0
Rating (MVA)	20.0	25.0	25.0	16.7
2012 Peak (MVA)	19.8	N/A	N/A	8.9
Year		**Forecasted Undiversified Peak (MVA)**		
2013	21.0	0.0	0.0	9.5
2014	21.4	0.0	0.0	9.6
2015	0.0	21.8	0.0	9.7
2016	0.0	22.2	0.0	9.8
2017	0.0	22.6	0.0	9.9
2018	0.0	23.0	0.0	10.0
2019	0.0	23.4	0.0	10.1
2020	0.0	23.8	0.0	10.2
2021	0.0	24.3	0.0	10.3
2022	0.0	24.7	0.0	10.4
2023	0.0	12.6	12.6	10.5
2024	0.0	12.8	12.8	10.6
2025	0.0	13.0	13.0	10.7
2026	0.0	13.2	13.2	10.8
2027	0.0	13.5	13.5	10.9
2028	0.0	13.7	13.7	11.0
2029	0.0	13.9	13.9	11.2
2030	0.0	14.2	14.2	11.3
2031	0.0	14.4	14.4	11.4
2032	0.0	14.7	14.7	11.5

Alternative 2
20 Year Substation Load Forecast – High Growth

Device	CLV-T2	CLV-T2 (New)	CLV-T3 (New)	MIL-T1
Sec. Voltage (kV)	12.5	12.5	12.5	25.0
Rating (MVA)	20.0	25.0	25.0	16.7
2011 Peak (MVA)	19.8	N/A	N/A	8.9
Year	**Forecasted Undiversified Peak (MVA)**			
2013	21.0	0.0	0.0	9.5
2014	21.6	0.0	0.0	9.7
2015	0.0	22.2	0.0	9.8
2016	0.0	22.9	0.0	10.0
2017	0.0	23.5	0.0	10.1
2018	0.0	24.1	0.0	10.3
2019	0.0	24.7	0.0	10.4
2020	0.0	12.7	12.7	10.6
2021	0.0	13.0	13.0	10.7
2022	0.0	13.4	13.4	10.9
2023	0.0	13.7	13.7	11.1
2024	0.0	14.1	14.1	11.2
2025	0.0	14.4	14.4	11.4
2026	0.0	14.8	14.8	11.6
2027	0.0	15.2	15.2	11.7
2028	0.0	15.6	15.6	11.9
2029	0.0	16.0	16.0	12.1
2030	0.0	16.4	16.4	12.3
2031	0.0	16.8	16.8	12.4
2032	0.0	17.3	17.3	12.6

Alternative 2
20 Year Substation Load Forecast – Low Growth

Device	**CLV-T2**	**CLV-T2 (New)**	**CLV-T3 (New)**	**MIL-T1**
Sec. Voltage (kV)	12.5	12.5	12.5	25.0
Rating (MVA)	20.0	25.0	25.0	16.7
2012 Peak (MVA)	19.8	N/A	N/A	8.9
Year		**Forecasted Undiversified Peak (MVA)**		
2013	21.0	0.0	0.0	9.5
2014	21.2	0.0	0.0	9.6
2015	0.0	21.4	0.0	9.6
2016	0.0	21.6	0.0	9.6
2017	0.0	21.8	0.0	9.7
2018	0.0	22.0	0.0	9.7
2019	0.0	22.2	0.0	9.8
2020	0.0	22.4	0.0	9.8
2021	0.0	22.6	0.0	9.9
2022	0.0	22.8	0.0	9.9
2023	0.0	23.0	0.0	10.0
2024	0.0	23.2	0.0	10.0
2025	0.0	23.4	0.0	10.1
2026	0.0	23.6	0.0	10.1
2027	0.0	23.8	0.0	10.2
2028	0.0	24.0	0.0	10.2
2029	0.0	24.2	0.0	10.3
2030	0.0	24.4	0.0	10.3
2031	0.0	24.6	0.0	10.4
2032	0.0	24.9	0.0	10.5

Appendix E
Alternative 3
20 Year Substation Load Forecasts

Alternative 3
20 Year Substation Load Forecast – Base Case

Device	CLV-T2	CLV-T3 (New)	MIL-T1
Sec. Voltage (kV)	12.5	12.5	25.0
Rating (MVA)	20.0	25.0	16.7
2012 Peak (MVA)	19.8	N/A	8.9
Year	**Forecasted Undiversified Peak (MVA)**		
2013	21.0	0.0	9.5
2014	21.4	0.0	9.6
2015	19.8	0.0	11.7
2016	9.7	10.5	11.8
2017	9.9	10.7	11.9
2018	10.1	10.9	12.0
2019	10.3	11.1	12.1
2020	10.5	11.3	12.2
2021	10.7	11.5	12.3
2022	10.9	11.8	12.4
2023	11.1	12.0	12.5
2024	11.3	12.2	12.6
2025	11.6	12.4	12.7
2026	11.8	12.7	12.8
2027	12.0	12.9	12.9
2028	12.2	13.2	13.0
2029	12.4	13.4	13.2
2030	12.7	13.6	13.3
2031	12.9	13.9	13.4
2032	13.2	14.2	13.5

Alternative 3
20 Year Substation Load Forecast – High Growth

Device	**CLV-T2**	**CLV-T3 (New)**	**MIL-T1**
Sec. Voltage (kV)	12.5	12.5	25.0
Rating (MVA)	20.0	25.0	16.7
2012 Peak (MVA)	19.8	N/A	8.9
Year	**Forecasted Undiversified Peak (MVA)**		
2013	21.0	0.0	9.5
2014	21.6	0.0	9.7
2015	9.7	10.5	11.8
2016	10.0	10.8	12.0
2017	10.3	11.1	12.1
2018	10.6	11.5	12.3
2019	10.9	11.8	12.4
2020	11.3	12.1	12.6
2021	11.6	12.5	12.7
2022	11.9	12.8	12.9
2023	12.2	13.2	13.1
2024	12.6	13.5	13.2
2025	12.9	13.9	13.4
2026	13.3	14.3	13.6
2027	13.7	14.7	13.7
2028	14.0	15.1	13.9
2029	14.4	15.5	14.1
2030	14.8	16.0	14.3
2031	15.2	16.4	14.4
2032	15.7	16.9	14.6

Alternative 3
20 Year Substation Load Forecast – Low Growth

Device	CLV-T2	CLV-T3 (New)	MIL-T1
Sec. Voltage (kV)	12.5	12.5	25.0
Rating (MVA)	20.0	25.0	16.7
2012 Peak (MVA)	19.8	N/A	8.9
Year	**Forecasted Undiversified Peak (MVA)**		
2013	21.0	0.0	9.5
2014	21.2	0.0	9.6
2015	19.4	0.0	11.6
2016	19.6	0.0	11.6
2017	19.8	0.0	11.7
2018	20.0	0.0	11.7
2019	9.7	10.5	11.8
2020	9.8	10.6	11.8
2021	9.9	10.7	11.9
2022	10.0	10.8	11.9
2023	10.1	10.9	12.0
2024	10.2	11.0	12.0
2025	10.3	11.1	12.1
2026	10.4	11.2	12.1
2027	10.5	11.3	12.2
2028	10.6	11.4	12.2
2029	10.7	11.5	12.3
2030	10.8	11.6	12.3
2031	10.9	11.7	12.4
2032	11.0	11.9	12.5

Attachment C
St. John's Main / Molloy's Lane Substation Study

Table of Contents

1.0 Introduction

The purpose of this study is to determine the distribution system alternative that best meets the electrical demands of the St. John's Main substation ("SJM").

In the winter of 2015, the substation transformers that supply electricity to the SJM 12.5 kV bus are expected to experience a total peak load of 51.7 MVA.[1] The current parallel capacity of the SJM 12.5 kV transformers is 47.7 MVA.[2] As a result, the load forecast indicates that SJM will be overloaded in 2015. Load growth on these transformers is primarily the result of increased commercial development in the downtown St. John's area. This includes the replacement of the Woolworth's building at 351 Water Street, the new Fortis building, Pier 7 restaurants and condominium buildings such as the Meridor and Marconi developments.

This report identifies the capital project(s) required to avoid the 2015 forecasted overload by determining the least cost expansion plan required to meet a 20 year load forecast.

2.0 Description of Existing System

2.1 SJM-MOL 12.5 kV System

The SJM-MOL 12.5 kV System serves approximately 14,000 customers throughout the downtown and center city areas of St. John's. SJM serves 5,100 customers in the downtown area of St. John's including the majority of customers along Duckworth Street, Water Street and Harbour Drive. Molloy's Lane Substation ("MOL") serves 8,900 customers in the center city area of St. John's including the majority of customers in the Waterford Valley, Village Shopping Center and Cornwall Avenue areas. A map showing the SJM and MOL service areas can be found in Appendix A.

From 2010 to 2013, the combined peak electrical load on these 2 substations has increased at a rate of approximately 4.3% per year. This is due to the steady increases in commercial, hotel, condominium and other residential development that is occurring throughout the combined service areas. The forecast indicates that the load on this 12.5 kV system will reach 104 MVA in 2015.[3] Graph 1 shows the historical load growth for the SJM-MOL 12.5 kV System between 2003 and 2013, along with the 2014 and 2015 forecast loads.[4]

The potential to transfer load from the SJM-MOL 12.5 kV System to adjacent substations is limited. The adjacent substation transformers are approaching capacity limits and forecast to have a peak load are approaching 95% of the transformers' capacity rating.

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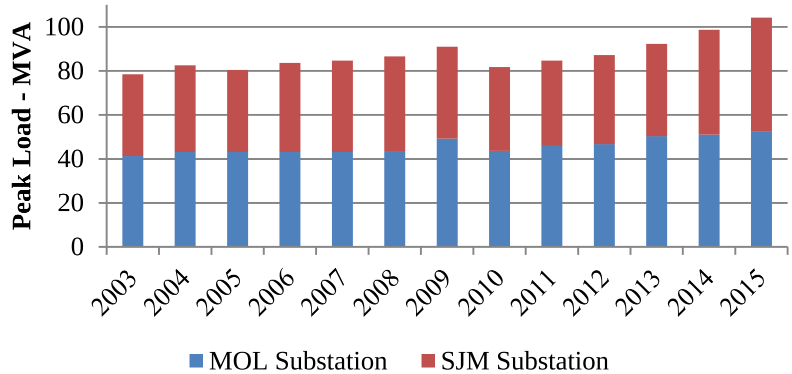
1 A substation transformer converts electricity from transmission level voltages (typically between 66 kV and 138 kV) to distribution level voltages (typically between 4 kV and 25 kV).

2 SJM serves an additional 60 customers at a distribution voltage of 4.16 kV.

3 The substation transformer capacity of this system at the end of 2014 will be 96.3 MVA.

4 The decrease in load from 2009 to 2010 in Graph 1 is the result of distribution load transfers from Molloy's Lane substation to Stamp's Lane and Goulds substations. Such transfers of customer load between substations and/or distribution feeders to utilize available spare capacity are least cost alternatives for dealing with substation transformer overloads.

Graph 1
SJM-MOL 12.5 kV System Load Growth



2.2 St. John's Main Substation

SJM is located along Southside Road near the St. John's harbour. There are 3 transformers located in the substation: SJM-T1, SJM-T2, and SJM-T4. SJM-T1 and SJM-T2 are both 25 MVA, 66/12.5 kV transformers that are used to convert 66 kV to a distribution level voltage of 12.5 kV to supply customers through 12 SJM distribution feeders. SJM-T4 is a 7.5 MVA, 66/4.16 kV transformer that is used to convert 66 kV to a distribution voltage of 4.16 kV to serve customers through a single SJM distribution feeder.

There are 12 feeders originating from SJM. Four of these feeders run underground through a series of duct banks and manholes serving large commercial customers in downtown St. John's along Water Street, Harbour Drive, and parts of Duckworth Street and New Gower Street. The Company has completed projects in recent years to replace aging civil infrastructure and increase the capacity of the distribution system in downtown St. John's as a result of load growth. This has included installation of new duct banks and manholes along Water Street and Harbour Drive, and replacing underground cables used to supply electricity to the downtown core.[5]

The remaining 8 feeders originating from SJM are overhead construction and supply residential and commercial customers in the areas of Shea Heights, Southside Road, Hamilton Avenue, Shaw Street, Springdale Street, Livingstone Street, Gower Street, as well as Blackhead and Cape Spear.

[5] The installation of underground civil infrastructure was approved under Order No. P. U. 19 (2008). Distribution system upgrades have been ongoing following a planning study of the St. John's Main underground system submitted as part of the Company's 2011 Capital Budget Application.

3.0 Load Forecast

Both SJM-T1 and SJM-T2 transformers are rated for 25 MVA, with a combined capacity of 47.7 MVA. The following is the forecasted peak substation load that is expected for SJM-T1 and SJM-T2 in the winter of 2015.

- SJM-T1 is rated for 25 MVA. The peak load on SJM-T1 is forecasted to be 24.6 MVA.
- SJM-T2 is rated for 25 MVA. The peak load on SJM-T2 is forecasted to be 27.1 MVA.

This study uses a 20 year load forecast for these substation transformers. The base case 20 year substation forecast for SJM-T1, SJM-T2, MOL-T1, and MOL-T2 is located in Appendix B. High and low load growth forecasts have also been created for each alternative for use in a sensitivity analysis. With the exception of the first year forecast, the sensitivities are based on increasing the load growth by a factor of 50% for the high forecast and decreasing by a factor of 50% for the low forecast.

4.0 Development of Alternatives

Two alternatives have been developed to eliminate the forecasted overload conditions using a set of defined technical criteria.[6] These 2 alternatives will provide sufficient capacity to meet forecasted loads over the next 20 years.[7]

Each alternative contains estimates for all of the costs involved, including new transformers and feeders. The results of a net present value ("NPV") calculation are provided for each alternative.

4.1 Alternative 1

- In 2015, add a spare 25 MVA, 66/12.5 kV transformer at SJM. The additional transformer would be configured to operate in parallel with the existing 25 MVA, 66/12.5 kV SJM-T1 and SJM-T2 transformers. This would increase the total substation 12.5 kV transformer capacity from 47.7 MVA to 70.8 MVA.[8]
- In 2017, perform a 1.0 MVA load transfer from MOL-09 to SJM-13.
- In 2019, add a spare 25 MVA, 66/12.5 kV transformer at MOL. The additional transformer would be configured to operate in parallel with the existing 25 MVA, 66/12.5 kV MOL-T1 and MOL-T2 transformers. This would increase the total substation transformer capacity from 48.7 MVA to 73.0 MVA.

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[6] The following technical criteria were applied:
- The steady state substation transformer loading should not exceed the nameplate rating.
- The minimum steady state feeder voltage should not fall below 116 Volts (on a 120 Volt base).
- The feeder normal peak loading should be sufficient to permit cold load pickup.

[7] The 2 alternatives considered in this report are the only reasonable alternatives. Other alternatives that included new 25MVA transformer purchases were eliminated due to the additional cost when compared to the alternatives that use an available spare transformer.

[8] The total substation capacity is not necessarily equal to the sum of the individual transformer nameplate capacities. The electrical characteristics of each transformer, more specifically the transformer's per unit impedance, determines how load is split between new and existing transformers that operate in parallel.

Table 1 shows the capital costs estimated for Alternative 1.

Table 1
Alternative 1 Capital Costs

Year	Item	Cost
2015	Install a spare 25 MVA transformer to SJM and parallel it with the existing SJM-T1 and SJM-T2.	$1,479,000
2019	Install a spare 25 MVA transformer to MOL and parallel it with the existing MOL-T1 and MOL-T2.	$1,809,000
	Total	**$3,288,000**

The resultant peak load forecast for SJM-T1, SJM-T2, SJM-T3, MOL-T1, MOL-T2, and MOL-T3 under Alternative 1 are shown in Appendix C.

4.2 Alternative 2

- In 2015, add a spare 25 MVA, 66/12.5 kV transformer at MOL. The additional transformer would be configured to operate in parallel with the existing 25 MVA, 66/12.5 kV MOL-T1 and MOL-T2 transformers. This would increase the total substation 12.5 kV transformer capacity from 48.7 MVA to 73.0 MVA.
- In 2015, perform a 2.5 MVA load transfer from SJM-11 to MOL-09, a 3.0 MVA load transfer from SJM-13 to MOL-09, and a 2.5 MVA load transfer from SJM-09 to SLA-10.
- In 2016, add a spare 25 MVA, 66/12.5 kV transformer at SJM. The additional transformer would be configured to operate in parallel with the existing 25 MVA, 66/12.5 kV SJM-T1 and SJM-T2 transformers. This would increase the total substation 12.5 kV transformer capacity from 47.7 MVA to 70.8 MVA.

Table 2 shows the capital costs estimated for Alternative 2.

Table 2
Alternative 2 Capital Costs

Year	Item	Cost
2015	Install a spare 25 MVA transformer at MOL and parallel it with the existing MOL-T1 and MOL-T2.	$1,809,000
2016	Install a spare 25 MVA transformer at SJM and parallel it with the existing SJM-T1 and SJM-T2.	$1,479,000
	Total	**$3,288,000**

The resultant peak load forecast for SJM-T1, SJM-T2, SJM-T3, MOL-T1, MOL-T2, and MOL-T3 under Alternative 3 are shown in Appendix D.

5.0 Evaluation of Alternatives

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 2015 to 2034 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.[9] Capital costs required beyond the 20 year forecast period that are required to balance the installed transformer capacity across both alternatives are also included in the NPV calculation and are known simply as end effect capital costs.

Table 3 shows the NPV of customer revenue requirement for each alternative under the base case load forecast.

Table 3
Net Present Value Analysis
($000)

Alternative	NPV
1	3,209
2	3,471

Alternative 1 has the lowest NPV of customer revenue requirement. As a result, Alternative 1 is recommended as the most appropriate project expansion plan.

5.2 Sensitivity Analysis

To assess the sensitivity to load forecast error of each alternative, high and low load growth forecasts were developed. The peak load forecasts for the sensitivity analysis are shown in Appendix C and D for Alternatives 1 and 2, respectively.

In general, the low load forecast results in delaying the required construction projects. Similarly, with a higher load growth forecast the timing of the required construction projects is advanced. Using these revised dates, the NPV of the customer revenue requirement was recalculated.

[9] This analysis captures the customer revenue requirement for the life of a new transformer asset.

Table 4 shows the NPV of customer revenue requirement for each alternative under the high and low load forecasts.

Table 4
Sensitivity Analysis
($000)

Alternative	High Load Forecast NPV	Low Load Forecast NPV
1	3,455	2,550
2	3,543	2,520

Under the high load forecast scenario, Alternative 1 is the least cost alternative by 2.5%. Under the low load forecast scenario, Alterative 2 is the least cost alternative by 1.2%.

The cost difference between Alternative 1 and the least cost alternative for both of the sensitivity forecasts indicates that Alternative 1 is still a suitable alternative under varying load growth scenarios. As a result, the recommendation to implement Alternative 1 is still appropriate given the results of the sensitivity analysis.

6.0 Project Cost

Table 5 shows the estimated project costs for the chosen alternative.

Table 5
Project Capital Costs

Year	Item	Cost
2015	Install a spare 25 MVA transformer (SJM-T3) at SJM and parallel it with the existing SJM-T1 and SJM-T2.	$1,479,000
2019	Install a spare 25 MVA transformer (MOL-T3) at MOL and parallel it with the existing MOL-T1 and MOL-T2.	$1,809,000
	Total	**$3,288,000**

7.0 Conclusion and Recommendation

A 20 year load forecast has projected the electrical demands for the St. John's Main substation. The development and analysis of distribution system alternatives has established a preferred expansion plan to meet the forecasted needs.

The economic analysis performed in section 5.1 of this study indicates that Alternative 1 is the least cost alternative that meets all of the required technical criteria. The sensitivity analyses indicates that Alternative 1 is the least cost alternative under the high load growth forecast and that Alternative 2 is the least cost alternative under the low load growth forecast. The sensitivity analysis is performed to ensure that the least cost alternative indicated by the economic analysis is a suitable alternative for varying levels of load growth. As a result, the Alternative 1 expansion plan has been selected as the most appropriate project.

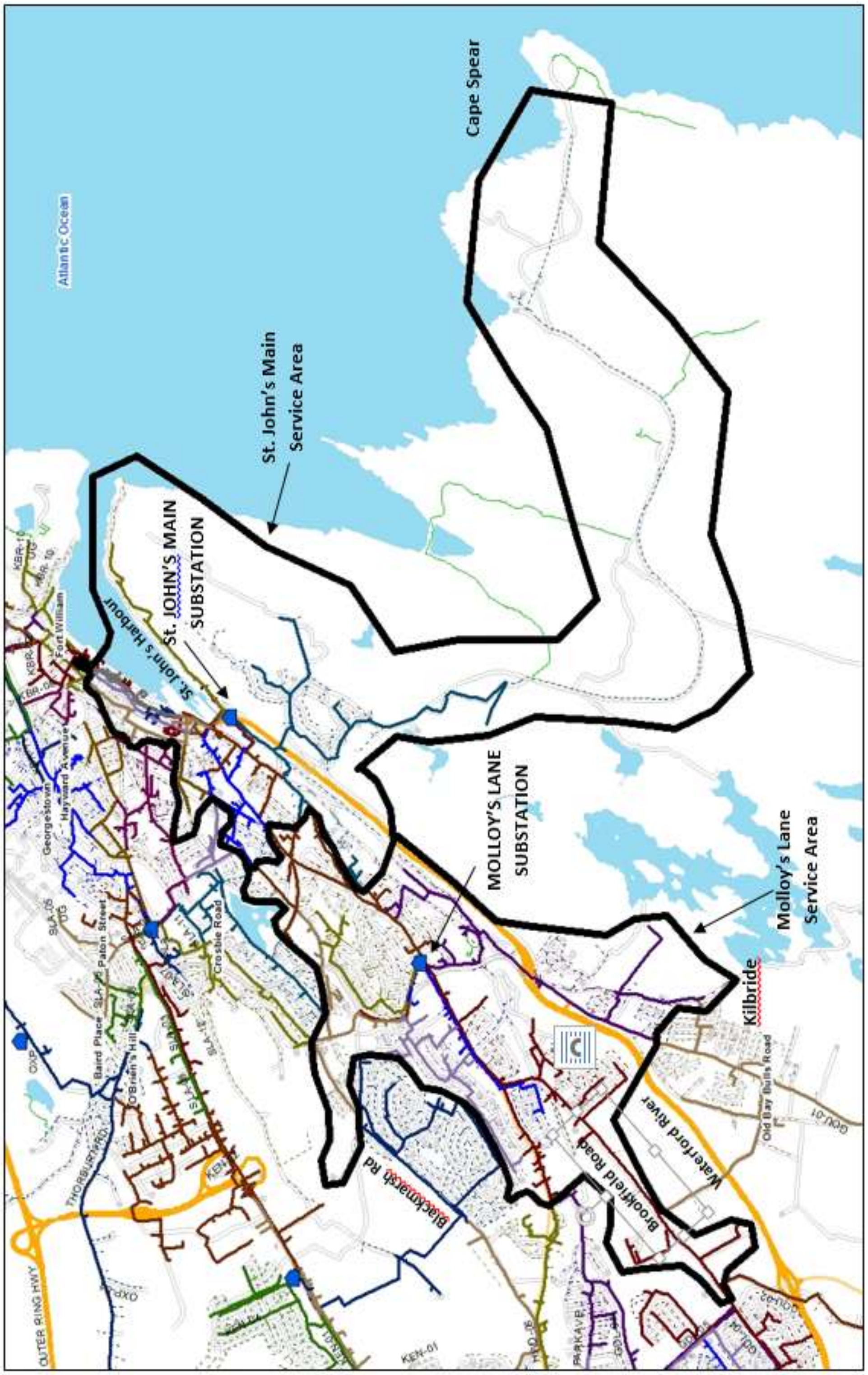
The least cost expansion plan includes the following item in the 2015 Capital Budget:

1) The installation of a spare 25 MVA transformer at SJM and parallel it with the existing SJM-T1 and SJM-T2 transformers.

The 2015 project is estimated to cost $1,479,000.

Appendix A
SJM and MOL Service Area Map

St. John's Main Substation and Molloy's Lane Substation Service Areas



Appendix B
2012 Substation Load Forecast – Base Case

20 Year Substation Load Forecast – Base Case

Device	**SJM-T1**	**SJM-T2**	**MOL-T1**	**MOL-T2**
Sec. Voltage (kV)	12.5	12.5	12.5	12.5
Rating (MVA)	25.0	25.0	25.0	25.0
2012 Peak (MVA)	19.3	21.3	23.9	22.6
Year	**Forecasted Undiversified Peak (MVA)**			
2013	20.5	22.6	25.8	24.4
2014	22.7	25.0	26.2	24.8
2015	24.6	27.1	27.0	25.5
2016	26.6	29.3	27.5	25.9
2017	26.9	29.6	27.7	26.2
2018	27.0	29.8	27.9	26.4
2019	27.2	30.0	28.1	26.6
2020	27.4	30.2	28.3	26.7
2021	27.6	30.4	28.5	26.9
2022	27.8	30.6	28.7	27.1
2023	28.0	30.9	28.9	27.3
2024	28.2	31.1	29.1	27.5
2025	28.4	31.3	29.3	27.7
2026	28.6	31.6	29.5	27.9
2027	28.8	31.8	29.8	28.1
2028	29.0	32.0	30.0	28.3
2029	29.2	32.3	30.2	28.5
2030	29.4	32.5	30.4	28.7
2031	29.6	32.7	30.6	28.9
2032	29.8	33.0	30.8	29.1

Appendix C
Alternative 1
20 Year Substation Load Forecasts

Alternative 1
20 Year Substation Load Forecast – Base Case

Device	**SJM-T1**	**SJM-T2**	**SJM-T3 (New)**	**MOL-T1**	**MOL-T2**	**MOL-T3 (New)**
Sec. Voltage (kV)	12.5	12.5	12.5	12.5	12.5	12.5
Rating (MVA)	25.0	25.0	25.0	25.0	25.0	25.0
2012 Peak (MVA)	19.3	21.3	N/A	23.9	22.6	N/A
Year	**Forecasted Undiversified Peak (MVA)**					
2013	20.5	22.6	0.0	25.8	24.4	0.0
2014	22.5	24.7	0.0	23.7	22.4	0.0
2015	17.1	18.8	17.4	24.5	23.2	0.0
2016	18.4	20.2	18.7	25.0	23.6	0.0
2017	18.9	20.8	19.2	24.8	23.4	0.0
2018	19.0	20.9	19.4	24.9	23.5	0.0
2019	19.1	21.1	19.5	16.8	15.8	16.3
2020	19.3	21.2	19.6	16.9	16.0	16.4
2021	19.4	21.4	19.8	17.0	16.1	16.5
2022	19.5	21.5	19.9	17.2	16.2	16.7
2023	19.7	21.7	20.0	17.3	16.4	16.8
2024	19.8	21.8	20.2	17.4	16.5	16.9
2025	19.9	22.0	20.3	17.6	16.6	17.1
2026	20.1	22.1	20.5	17.7	16.7	17.2
2027	20.2	22.3	20.6	17.9	16.9	17.3
2028	20.4	22.4	20.7	18.0	17.0	17.5
2029	20.5	22.6	20.9	18.1	17.2	17.6
2030	20.6	22.7	21.0	18.3	17.3	17.7
2031	20.8	22.9	21.2	18.4	17.4	17.9
2032	20.9	23.0	21.3	18.6	17.6	18.0

Alternative 1
20 Year Substation Load Forecast – High Growth

Device	SJM-T1	SJM-T2	SJM-T3 (New)	MOL-T1	MOL-T2	MOL-T3 (New)
Sec. Voltage (kV)	12.5	12.5	12.5	12.5	12.5	12.5
Rating (MVA)	25.0	25.0	25.0	25.0	25.0	25.0
2012 Peak (MVA)	19.3	21.3	N/A	23.9	22.6	N/A
Year	**Forecasted Undiversified Peak (MVA)**					
2013	20.5	22.6	0.0	25.8	24.4	0.0
2014	23.6	25.9	0.0	23.9	22.6	0.0
2015	18.9	20.8	19.2	24.6	23.3	0.0
2016	21.0	23.1	21.4	16.9	15.9	16.4
2017	21.3	23.5	21.7	17.2	16.2	16.7
2018	21.5	23.7	21.9	17.3	16.4	16.8
2019	21.7	23.9	22.1	17.5	16.6	17.0
2020	22.0	24.2	22.4	17.8	16.8	17.2
2021	22.2	24.4	22.6	18.0	17.0	17.4
2022	22.4	24.7	22.8	18.2	17.2	17.6
2023	22.7	24.9	23.1	18.4	17.4	17.9
2024	20.3	22.4	20.7	20.5	19.4	19.9
2025	20.6	22.6	20.9	20.7	19.6	20.1
2026	20.8	22.9	21.2	21.0	19.8	20.3
2027	21.1	23.2	21.4	21.2	20.0	20.6
2028	21.3	23.4	21.7	21.4	20.2	20.8
2029	21.6	23.7	21.9	21.6	20.5	21.0
2030	21.8	24.0	22.2	21.9	20.7	21.2
2031	22.1	24.3	22.5	22.1	20.9	21.5
2032	22.3	24.6	22.7	22.4	21.1	21.7

Alternative 1
20 Year Substation Load Forecast – Low Growth

Device	SJM-T1	SJM-T2	SJM-T3 (New)	MOL-T1	MOL-T2	MOL-T3 (New)
Sec. Voltage (kV)	12.5	12.5	12.5	12.5	12.5	12.5
Rating (MVA)	25.0	25.0	25.0	25.0	25.0	25.0
2012 Peak (MVA)	19.3	21.3	N/A	23.9	22.6	N/A
Year	**Forecasted Undiversified Peak (MVA)**					
2013	20.5	22.6	0.0	25.8	24.4	0.0
2014	21.4	23.5	0.0	23.5	22.3	0.0
2015	15.7	17.2	16.0	24.0	22.6	0.0
2016	16.3	17.9	16.6	24.2	22.8	0.0
2017	16.3	18.0	16.6	24.3	23.0	0.0
2018	16.4	18.0	16.7	24.4	23.0	0.0
2019	16.5	18.1	16.8	24.5	23.1	0.0
2020	16.5	18.2	16.8	24.6	23.2	0.0
2021	16.6	18.2	16.9	24.7	23.3	0.0
2022	16.6	18.3	16.9	24.8	23.4	0.0
2023	16.7	18.4	17.0	24.9	23.5	0.0
2024	16.7	18.4	17.0	25.0	23.6	0.0
2025	17.1	18.8	17.4	24.6	23.2	0.0
2026	17.2	18.9	17.5	24.7	23.3	0.0
2027	17.2	19.0	17.6	24.8	23.4	0.0
2028	17.3	19.0	17.6	24.9	23.5	0.0
2029	17.4	19.1	17.7	25.0	23.6	0.0
2030	17.4	19.2	17.7	16.7	15.8	16.2
2031	17.5	19.2	17.8	16.8	15.9	16.3
2032	17.5	19.3	17.9	16.9	15.9	16.3

Appendix D
Alternative 2
20 Year Substation Load Forecasts

Alternative 2
20 Year Substation Load Forecast – Base Case

Device	SJM-T1	SJM-T2	SJM-T3 (New)	MOL-T1	MOL-T2	MOL-T3 (New)
Sec. Voltage (kV)	12.5	12.5	12.5	12.5	12.5	12.5
Rating (MVA)	25.0	25.0	25.0	25.0	25.0	25.0
2012 Peak (MVA)	19.3	21.3	N/A	23.9	22.6	N/A
Year	**Forecasted Undiversified Peak (MVA)**					
2013	20.5	22.6	0.0	25.8	24.4	0.0
2014	22.5	24.7	0.0	23.7	22.4	0.0
2015	21.5	23.7	0.0	18.3	17.3	17.7
2016	15.8	17.4	16.1	18.5	17.5	18.0
2017	16.0	17.6	16.3	18.7	17.7	18.2
2018	16.1	17.7	16.4	18.9	17.8	18.3
2019	16.2	17.9	16.5	19.0	17.9	18.4
2020	16.4	18.0	16.7	19.1	18.1	18.6
2021	16.5	18.2	16.8	19.3	18.2	18.7
2022	16.6	18.3	17.0	19.4	18.3	18.8
2023	16.8	18.5	17.1	19.5	18.5	18.9
2024	16.9	18.6	17.2	19.7	18.6	19.1
2025	17.1	18.8	17.4	19.8	18.7	19.2
2026	17.2	18.9	17.5	19.9	18.9	19.4
2027	17.3	19.1	17.7	20.1	19.0	19.5
2028	17.5	19.2	17.8	20.2	19.1	19.6
2029	17.6	19.4	17.9	20.4	19.3	19.8
2030	17.8	19.5	18.1	20.5	19.4	19.9
2031	17.9	19.7	18.2	20.7	19.5	20.1
2032	18.0	19.9	18.4	20.8	19.7	20.2

Alternative 2
20 Year Substation Load Forecast – High Growth

Device	SJM-T1	SJM-T2	SJM-T3 (New)	MOL-T1	MOL-T2	MOL-T3 (New)
Sec. Voltage (kV)	12.5	12.5	12.5	12.5	12.5	12.5
Rating (MVA)	25.0	25.0	25.0	25.0	25.0	25.0
2012 Peak (MVA)	19.3	21.3	N/A	23.9	22.6	N/A
Year	**Forecasted Undiversified Peak (MVA)**					
2013	20.5	22.6	0.0	25.8	24.4	0.0
2014	23.6	25.9	0.0	23.9	22.6	0.0
2015	16.0	17.6	16.3	18.7	17.6	18.1
2016	18.1	20.0	18.5	19.1	18.1	18.5
2017	18.4	20.3	18.8	19.4	18.3	18.8
2018	18.6	20.5	19.0	19.6	18.5	19.0
2019	18.8	20.7	19.2	19.8	18.7	19.2
2020	19.1	21.0	19.4	20.0	18.9	19.4
2021	19.3	21.3	19.7	20.2	19.1	19.6
2022	19.5	21.5	19.9	20.4	19.3	19.8
2023	19.8	21.8	20.1	20.6	19.5	20.0
2024	20.0	22.0	20.4	20.8	19.7	20.2
2025	20.2	22.3	20.6	21.1	19.9	20.4
2026	20.5	22.6	20.9	21.3	20.1	20.7
2027	20.7	22.8	21.1	21.5	20.3	20.9
2028	21.0	23.1	21.4	21.8	20.6	21.1
2029	21.2	23.4	21.6	22.0	20.8	21.3
2030	21.5	23.6	21.9	22.2	21.0	21.6
2031	21.7	23.9	22.1	22.5	21.2	21.8
2032	22.0	24.2	22.4	22.7	21.5	22.0

Alternative 2
20 Year Substation Load Forecast – Low Growth

Device	SJM-T1	SJM-T2	MOL-T1	MOL-T2	MOL-T3 (New)
Sec. Voltage (kV)	12.5	12.5	12.5	12.5	12.5
Rating (MVA)	25.0	25.0	25.0	25.0	25.0
2012 Peak (MVA)	19.3	21.3	23.9	22.6	N/A
Year	**Forecasted Undiversified Peak (MVA)**				
2013	20.5	22.6	25.8	24.4	0.0
2014	21.4	23.5	23.5	22.3	0.0
2015	19.4	21.4	17.9	16.9	17.3
2016	20.3	22.4	18.0	17.0	17.5
2017	20.5	22.5	18.1	17.1	17.6
2018	20.5	22.6	18.2	17.2	17.6
2019	20.6	22.7	18.2	17.2	17.7
2020	20.7	22.8	18.3	17.3	17.7
2021	20.8	22.9	18.4	17.3	17.8
2022	20.9	23.0	18.4	17.4	17.9
2023	21.0	23.1	18.5	17.5	17.9
2024	21.0	23.2	18.5	17.5	18.0
2025	21.1	23.3	18.6	17.6	18.1
2026	21.2	23.4	18.7	17.7	18.1
2027	21.3	23.5	18.7	17.7	18.2
2028	21.4	23.6	18.8	17.8	18.3
2029	21.5	23.7	18.9	17.8	18.3
2030	21.6	23.8	18.9	17.9	18.4
2031	21.7	23.8	19.0	18.0	18.4
2032	21.8	23.9	19.1	18.0	18.5

Attachment D
Kenmount Substation Study

Table of Contents

1.0 Introduction

The purpose of this study is to determine the distribution system alternative that best meets the electrical demands of the Kenmount Substation ("KEN"), which is part of the Chamberlains ("CHA") – Hardwoods ("HWD") – Kenmount 25 kV system.

In the winter of 2015, the substation transformers that supply electricity to KEN are expected to experience a total peak load of 55.1 MVA.[1] The current total capacity of KEN is 49.8 MVA. As a result, the load forecast indicates that KEN will be overloaded in 2015. Load growth on these transformers is primarily the result of commercial and residential development in Paradise and along Kenmount Road in St. John's, including subdivisions such as Kenmount Terrace, Mount Carson Terrace and Elizabeth Park.

This report identifies the capital project(s) required to avoid the 2015 forecasted overload by determining the least cost expansion plan required to meet a 20 year load forecast.

2.0 Description of Existing System

2.1 CHA-HWD-KEN 25 kV System

The CHA-HWD-KEN 25 kV System serves approximately 20,100 customers, including customers in Conception Bay South, Paradise and the Kenmount Road and Cowan Heights areas of St. John's. The distribution feeders in this system operate at a voltage of 25 kV. All other distribution feeders in the St. John's Region operate at 12.5 kV or 4.16 kV. As a result, for the purposes of this study, the CHA-HWD-KEN 25 kV system is considered to be independent from these adjacent 12.5 kV or 4.16 kV systems.[2]

CHA serves 7,500 customers in Conception Bay South east of Greeleytown Road and in Paradise along St. Thomas Line. The HWD 25 kV feeders supply 5,200 customers in the town of Paradise.[3] KEN serves 7,400 customers in Paradise, Kenmount Road and Cowan Heights areas of St. John's. A map of the areas supplied by CHA, HWD, and KEN is shown in Appendix A.

From 2003 to 2013, the combined peak electrical load on this system has nearly doubled from 76 MVA to 139 MVA. This is due to the high rate of commercial and industrial growth along Kenmount Road in St. John's and McNamara Drive in Paradise, as well as residential subdivision growth in Conception Bay South, Paradise and St. John's. The forecast indicates that the load on this system will reach 153 MVA in 2015.[4] Graph 1 shows the historical load

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1 A typical substation transformer converts electricity from transmission level voltages (typically between 66 kV and 138 kV) to distribution level voltages (typically between 4 kV and 25 kV).

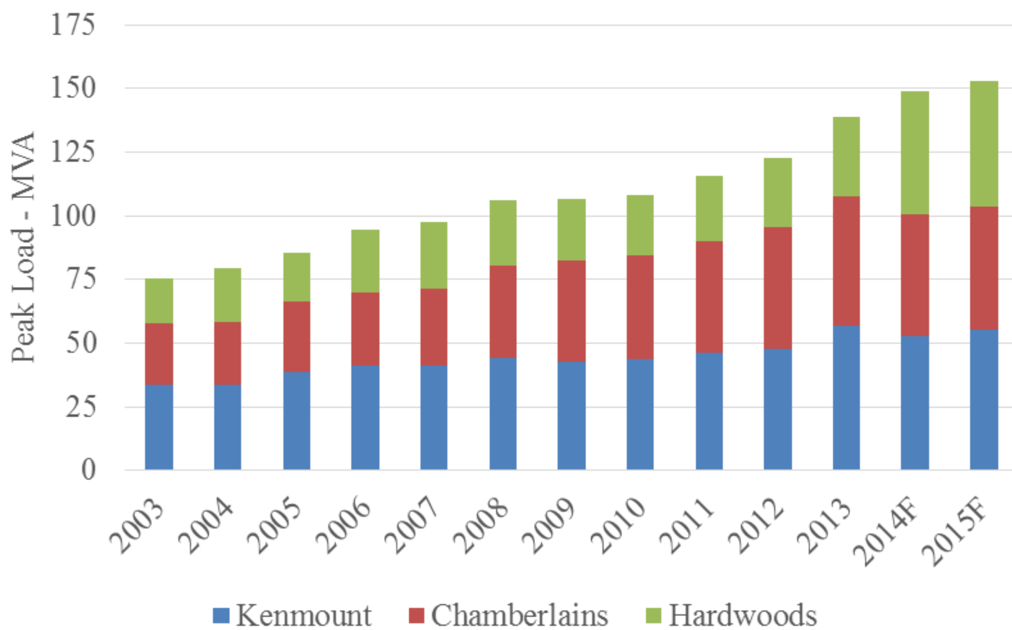
2 Load transfers between feeders that operate at different voltage levels typically require that all pole-mounted and padmount distribution transformers on the section of feeder being transferred must be replaced. Also, when transferring load to a feeder with a higher operating voltage, all of the insulators on the section being transferred must be replaced if they are not rated for the higher voltage level. As a result, these transfers are more costly and time consuming than transfers between feeders with the same operating voltage.

3 HWD serves an additional 4,200 customers at a distribution voltage of 12.5 kV.

4 The substation transformer capacity of this system at the end of 2014 will be 149.1 MVA.

growth for the CHA-HWD-KEN 25 kV System between 2003 and 2013, as well as the forecast 2014 and 2015 loads.

Graph 1
CHA-HWD-KEN 25kV System Load Growth



2.2 Kenmount Substation

KEN is located along Kenmount Road in the City of St. John's. There are 2 transformers located in the substation: KEN-T1 and KEN-T2. Both transformers are used to convert a transmission level voltage of 66 kV to a distribution level voltage of 25 kV to supply electricity to approximately 7,400 customers through 4 KEN distribution feeders:

There are four 25 kV feeders originating from KEN:

1) KEN-01 feeder serves approximately 1,828 customers. The main trunk portion of this feeder consists of approximately 3.0 km of 477 ASC conductor that runs southwest along Kenmount Road, 3.0 km of 477 ASC conductor that runs south along Mount Carson Avenue, and 4.0 km of 477 ASC conductor that runs south parallel to Wyatt Boulevard, Holden Street and Farrell Drive.

2) KEN-02 feeder serves approximately 684 customers. The main trunk portion of this feeder consists of approximately 2.5 km of 477 ASC conductor that runs northeast along Kenmount Road. This feeder also serves the Pippy Place and O'Leary Avenue commercial area.

3) KEN-03 feeder serves approximately 2,391 customers in the Cowan Heights area. The main trunk portion of this feeder consists of approximately 3.0 km of 477 ASC conductor that runs

southeast over Kenmount Hill and 2.0 km of 477 ASC conductor that runs northeast along Blackmarsh Road.

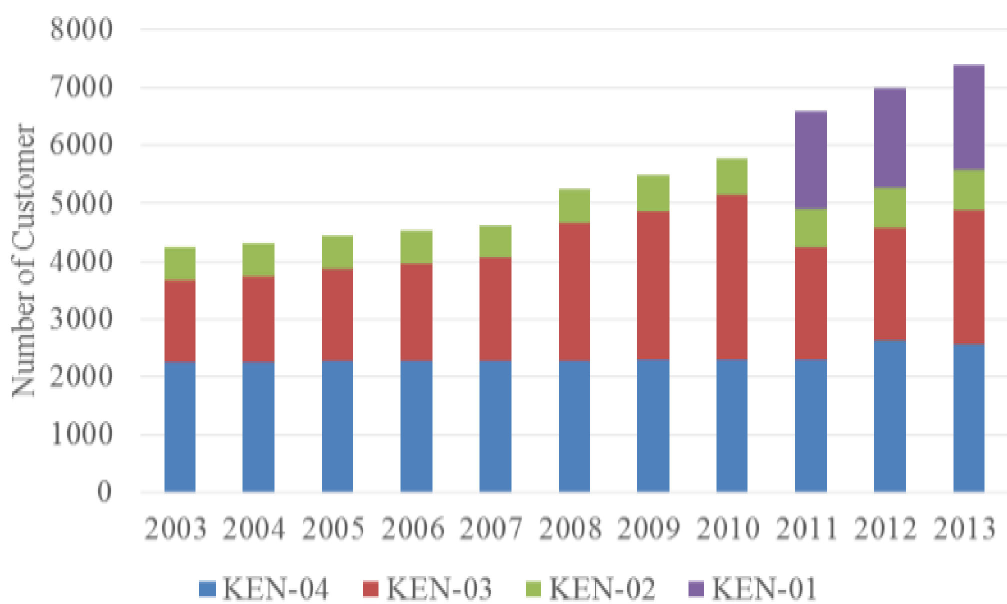
4) KEN-04 feeder serves approximately 2,527 customers. The main trunk portion of this feeder consists of approximately 5.0 km of 477 ASC conductor that runs northwest from the substation to supply the Kenmount Terrace residential development and approximately 2.0 km of 477 ASC conductor that runs southwest along Kenmount Road to supply a portion of the Elizabeth Park residential development.

A map of the KEN service area is shown in Appendix B.

3.0 Load Forecast

KEN has experienced a high level of commercial and residential customer growth in recent years. This is due to commercial development growth on Kelsey Drive, Kenmount Road and Kenmount Business Park and residential subdivision growth in Kenmount Terrace, Elizabeth Park, and Mount Carson Terrace. From 2003 to 2013, the number of customers served by KEN has increased from 4,200 to 7,400. Graph 2 shows the number of customers, by feeder, served from KEN each year between 2003 and 2013.

Graph 2
KEN Customer Growth



Both KEN-T1 and KEN-T2 transformers are rated for 25 MVA, with a combined capacity of 49.8 MVA. The following is the forecasted peak substation load that is expected for KEN-T1 and KEN-T2 in the winter of 2015.

- KEN-T1 is rated for 25 MVA. The peak load on KEN-T1 is forecasted to be 27.4 MVA.
- KEN-T2 is rated for 25 MVA. The peak load on KEN-T2 is forecasted to be 27.6 MVA.

This study uses a 20 year load forecast for this substation transformer. The base case 20 year substation forecast for KEN-T1, KEN-T2, and HWD-T3 is located in Appendix C.[5] High and low load growth forecasts have also been created for each alternative for use in a sensitivity analysis. With the exception of the first year forecast, the sensitivities are based on increasing the load growth by a factor of 50% for the high forecast and decreasing by a factor of 50% for the low forecast.

4.0 Development of Alternatives

Three alternatives have been developed to eliminate the forecasted overload conditions using a set of defined technical criteria.[6] These alternatives will provide sufficient capacity to meet forecasted loads over the next 20 years.

Each alternative contains estimates for all of the costs involved, including new transformers and feeders. The results of a net present value ("NPV") calculation are provided for each alternative.

4.1 Alternative 1

- In 2015, replace the existing KEN 25 MVA, 66/25 or12.5 kV transformer (KEN-T2) with a new 50 MVA, 66/25 kV transformer. The new transformer would be configured to operate in parallel with the existing 25 MVA, 66/25 kV KEN-T1 transformer. This would increase the total substation capacity from 49.8 MVA to 74.5 MVA.[7]
- In 2015, construct a new 25 kV distribution feeder (KEN-05). This involves installing a new feeder termination at KEN, including a breaker and associated switches, as well as constructing approximately 0.5 km of new 477 AASC trunk feeder and reconductoring approximately 2.0 km of 1/0 AASC to 477 AASC conductor. This new feeder will supply commercial customers in the Kelsey Drive area as well as a section of residential customers in Kenmount Terrace subdivision, providing sufficient feeder capacity for future load growth in the area.
- In 2027, purchase and install a new 25 MVA, 66/25 kV transformer at HWD (HWD-T4). The transformer would be configured to operate in parallel with the existing 50 MVA, 66/25 kV HWD-T3 transformer. This would increase the total substation capacity to 75 MVA.

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5 HWD is adjacent to KEN and, as part of the 25 kV system, distribution load transfer from KEN feeders to HWD feeders were considered in the development of alternatives. These load transfers affect the forecast peak load on the 25 kV transformer HWD-T3 located at HWD.

6 The following technical criteria were applied:
- The steady state substation transformer loading should not exceed the nameplate rating.
- The minimum steady state feeder voltage should not fall below 116 Volts (on a 120 Volt base).
- The feeder normal peak loading should be sufficient to permit cold load pickup.

7 The total substation capacity is not necessarily equal to the sum of the individual transformer nameplate capacities. The electrical characteristics of each transformer, more specifically the transformer's per unit impedance, determines how load is split between new and existing transformers that operate in parallel.

Table 1 shows the capital costs estimated for Alternative 1.

Table 1
Alternative 1 Capital Costs

Year	Item	Cost
2015	Purchase and install a new 50 MVA transformer at KEN to replace the existing KEN-T2 and parallel it with the existing KEN-T1.	$1,700,000
2015	Distribution portion of the construction of a new 25 kV distribution feeder (KEN-05).	$254,000
2015	Substation termination of the new 25 kV distribution feeder (KEN-05).	$236,000
2027	Purchase and install a new 25 MVA transformer at HWD and parallel it with the existing HWD-T3.	$1,591,000
	Total	**$3,781,000**

The resultant peak load forecasts for KEN-T1, KEN-T2, and HWD-T3 under Alternative 1 are shown in Appendix D.

4.2 Alternative 2

- In 2015, add a new 25 MVA, 66/25 kV transformer (KEN-T3) at KEN. The additional transformer would be configured to operate in parallel with the existing 25 MVA, 66/25 kV KEN-T1 and KEN-T2 transformers. This would increase the total substation capacity from 49.8 MVA to 74.1 MVA.
- In 2015, construct a new 25 kV distribution feeder (KEN-05). This involves installing a new feeder termination at KEN, including a breaker and associated switches, as well as constructing approximately 0.5 kms of new 477 AASC trunk feeder and re-conductor approximately 2.0 kms of 1/0 AASC to 477 AASC conductor. This new feeder will supply commercial customers in the Kelsey Drive area as well as a section of residential customers in Kenmount Terrace subdivision, providing sufficient feeder capacity for future load growth in the area.
- In 2027, purchase and install a new 25 MVA, 66/25 kV transformer at HWD (HWD-T4). The transformer would be configured to operate in parallel with the existing 50 MVA, 66/25 kV HWD-T3 transformer. This would increase the total substation capacity to 75 MVA.

Table 2 shows the capital costs estimated for Alternative 2.

Table 2
Alternative 2 Capital Costs

Year	Item	Cost
2015	Purchase and install a new 25 MVA transformer (KEN-T3) at KEN and parallel it with the existing KEN-T1 and KEN-T2.	$2,633,000
2015	Distribution portion of the construction of a new 25 kV distribution feeder (KEN-05).	$254,000
2015	Substation termination of the new 25 kV distribution feeder (KEN-05).	$236,000
2027	Purchase and install a new 25 MVA transformer at HWD and parallel it with the existing HWD-T3.	$1,591,000
	Total	**$4,714,000**

The resultant peak load forecasts for KEN-T1, KEN-T2, and HWD-T3 under Alternative 2 are shown in Appendix E.

4.3 Alternative 3

- In 2015, add a new 25 MVA, 66/25 kV transformer (HWD-T4) at HWD. The additional transformer would be configured to operate in parallel with the new 50 MVA, 66/25 kV HWD-T3 transformer. This would increase the total substation capacity from 50.0 MVA to 75.0 MVA.
- In 2015, construct a new distribution feeder (HWD-10) between HWD and KEN to permit a load transfer of 6.0 MVA from KEN-04 feeder to HWD-10 feeder. This involves installing a new feeder termination at HWD, including a breaker and associated switches. Approximately 2.5 km of new 477 AASC trunk feeder will also be installed to create the necessary distribution connection to complete the load transfer.
- In 2016, construct a new distribution feeder (HWD-11) between HWD and KEN to permit a load transfer of 10.5 MVA from KEN-01 feeder to HWD-11 feeder. This involves installing a new feeder termination at HWD, including a breaker and associated switches. Approximately 3.8 km of new 477 AASC trunk feeder will also be installed to create the necessary distribution connection to complete the load transfer.
- In 2027, replace the existing KEN 25 MVA, 66/25 or12.5 kV transformer (KEN-T2) with a new 50 MVA, 66/25 kV transformer. The new transformer would be configured to

operate in parallel with the existing 25 MVA, 66/25 kV KEN-T1 transformer. This would increase the total substation capacity from 49.8 MVA to 74.5 MVA. [8]

- In 2027, construct a new 25 kV distribution feeder (KEN-05). This involves installing a new feeder termination at KEN, including a breaker and associated switches, as well as constructing approximately 0.5 km of new 477 AASC trunk feeder and reconductoring approximately 2.0 km of 1/0 AASC to 477 AASC conductor. This new feeder will supply commercial customers in the Kelsey Drive area as well as a section of residential customers in Kenmount Terrace subdivision, providing sufficient feeder capacity for future load growth in the area.

Table 3 shows the capital costs estimated for Alternative 3.

Table 3
Alternative 3 Capital Costs

Year	Item	Cost
2015	Purchase and install a new 25 MVA transformer at HWD and parallel it with the existing HWD-T3.	$1,591,000
2015	Distribution portion of the construction of a new 25 kV distribution feeder (HWD-10).	$413,000
2015	Substation termination of the new 25 kV distribution feeder (HWD-10).	$236,000
2016	Distribution portion of the construction of a new 25 kV distribution feeder (HWD-11).	$639,000
2016	Substation termination of the new 25 kV distribution feeder (HWD-11).	$236,000
2027	Purchase and install a new 50 MVA transformer at KEN to replace the existing KEN-T2 and parallel it with the existing KEN-T1.	$1,700,000
	Total	**$4,815,000**

The resultant peak load forecasts for KEN-T1, KEN-T2, and HWD-T3 under Alternative 3 are shown in Appendix F.

[8] The total substation capacity is not necessarily equal to the sum of the individual transformer nameplate capacities. The electrical characteristics of each transformer, more specifically the transformer's per unit impedance, determines how load is split between new and existing transformers that operate in parallel.

5.0 Evaluation of Alternatives

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 2015 to 2034 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.[9] Capital costs required beyond the 20 year forecast period that are required to balance the installed transformer capacity across all 3 alternatives are also included in the NPV calculation and are known simply as end effect capital costs.

Table 4 shows the NPV of customer revenue requirement for each alternative under the base case load forecast.

Table 4
Net Present Value Analysis
($000)

Alternative	NPV
1	2,850
2	4,329
3	4,120

Alternative 1 has the lowest NPV of customer revenue requirement. As a result, Alternative 1 is recommended as the most appropriate expansion plan.

5.2 Sensitivity Analysis

To assess the sensitivity to load forecast error of each alternative, high and low load growth forecasts were developed. The peak load forecasts for the sensitivity analysis are shown in Appendix D, E, and F for Alternatives 1, 2, and 3 respectively.

In general, the low load forecast results in delaying the required construction projects. Similarly, with a higher load growth forecast the timing of the required construction projects is advanced. Using these revised dates, the NPV of the customer revenue requirement was recalculated.

[9] This analysis captures the customer revenue requirement for the life of a new transformer asset.

Table 5 shows the NPV of customer revenue requirement for each alternative under the high and low load forecasts.

Table 5
Sensitivity Analysis
($000)

Alternative	High Load Forecast NPV	Low Load Forecast NPV
1	3,581	1,881
2	5,080	3,359
3	4,795	3,136

Under all 3 scenarios, the base case, high and low growth forecasts, Alternative 1 is the least cost. This indicates that Alternative 1 is a suitable alternative under varying load growth scenarios. As a result, the recommendation to implement Alternative 1 is still appropriate given the results of the sensitivity analysis.

6.0 Project Cost

Table 6 shows the estimated project costs for the chosen alternative.

Table 6
Project Capital Costs

Year	Item	Cost
2015	Purchase and install a new 50 MVA transformer at KEN to replace the existing KEN-T2 and parallel it with the existing KEN-T1.	$1,700,000
2015	Distribution portion of the construction of a new 25 kV distribution feeder (KEN-05).	$254,000
2015	Substation termination of the new 25 kV distribution feeder (KEN-05).	$236,000
	Total	**$2,190,000**

7.0 Conclusion and Recommendation

A 20 year load forecast has projected the electrical demands for KEN. The development and analysis of distribution system alternatives has established a preferred expansion plan to meet the forecasted needs of the area.

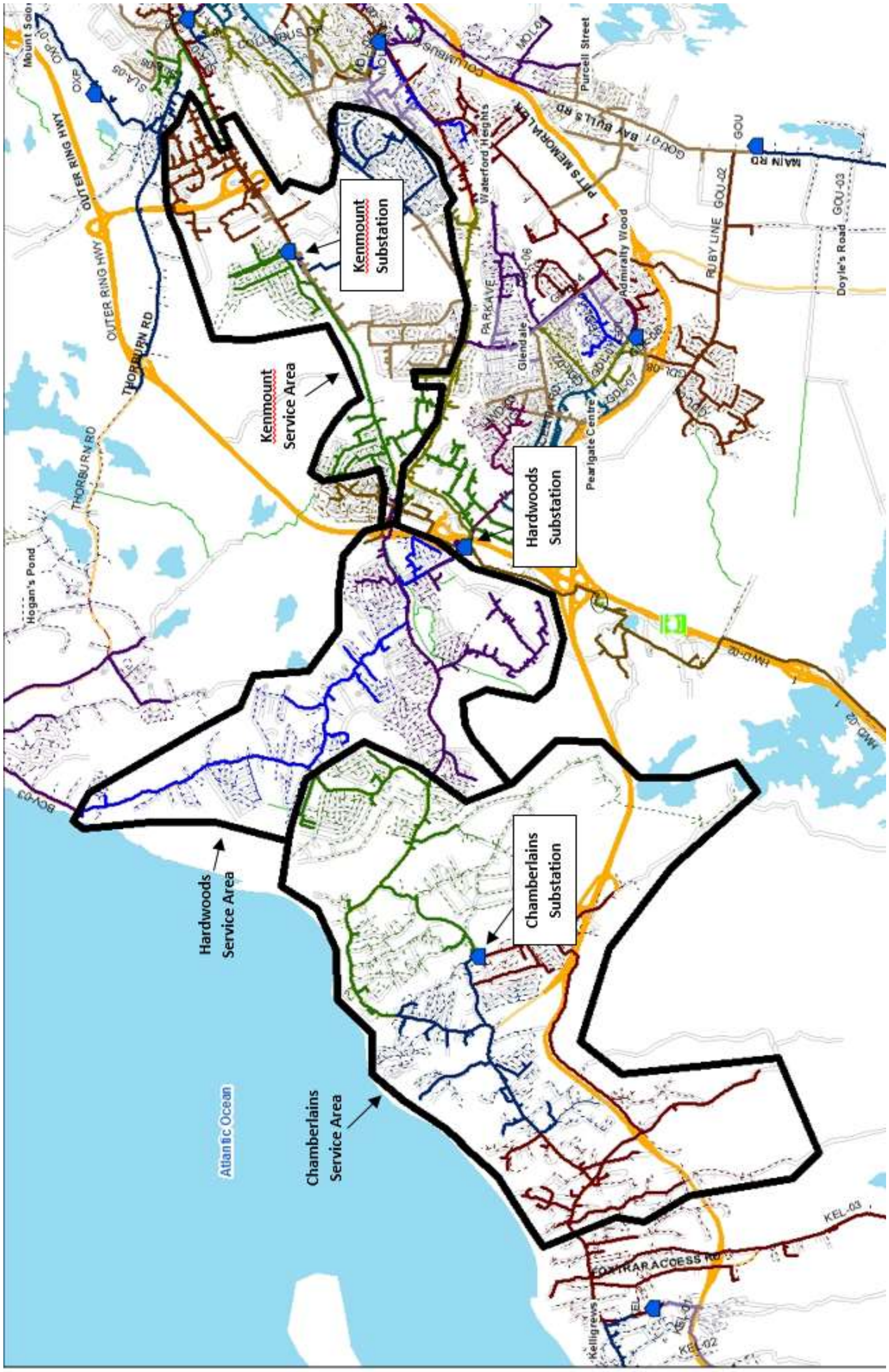
The economic analysis performed in section 5.1 of this study indicates that Alternative 1 is the least cost alternative that meets all of the required technical criteria. The sensitivity analysis indicates that Alternative 1 is the least cost alternative under both the high load growth forecast and the low load growth forecast. The sensitivity analysis is performed to ensure that the least cost alternative indicated by the economic analysis is a suitable alternative for varying levels of load growth. As a result, the Alternative 1 expansion plan has been selected as the most appropriate project.

The least cost expansion plan includes the following items in the 2015 Capital Budget:

- The purchase and installation of a new 50 MVA transformer at KEN to replace the existing KEN-T2 and parallel it with the existing KEN-T1.
- The construction of a new 25 kV distribution feeder for KEN (KEN-05).

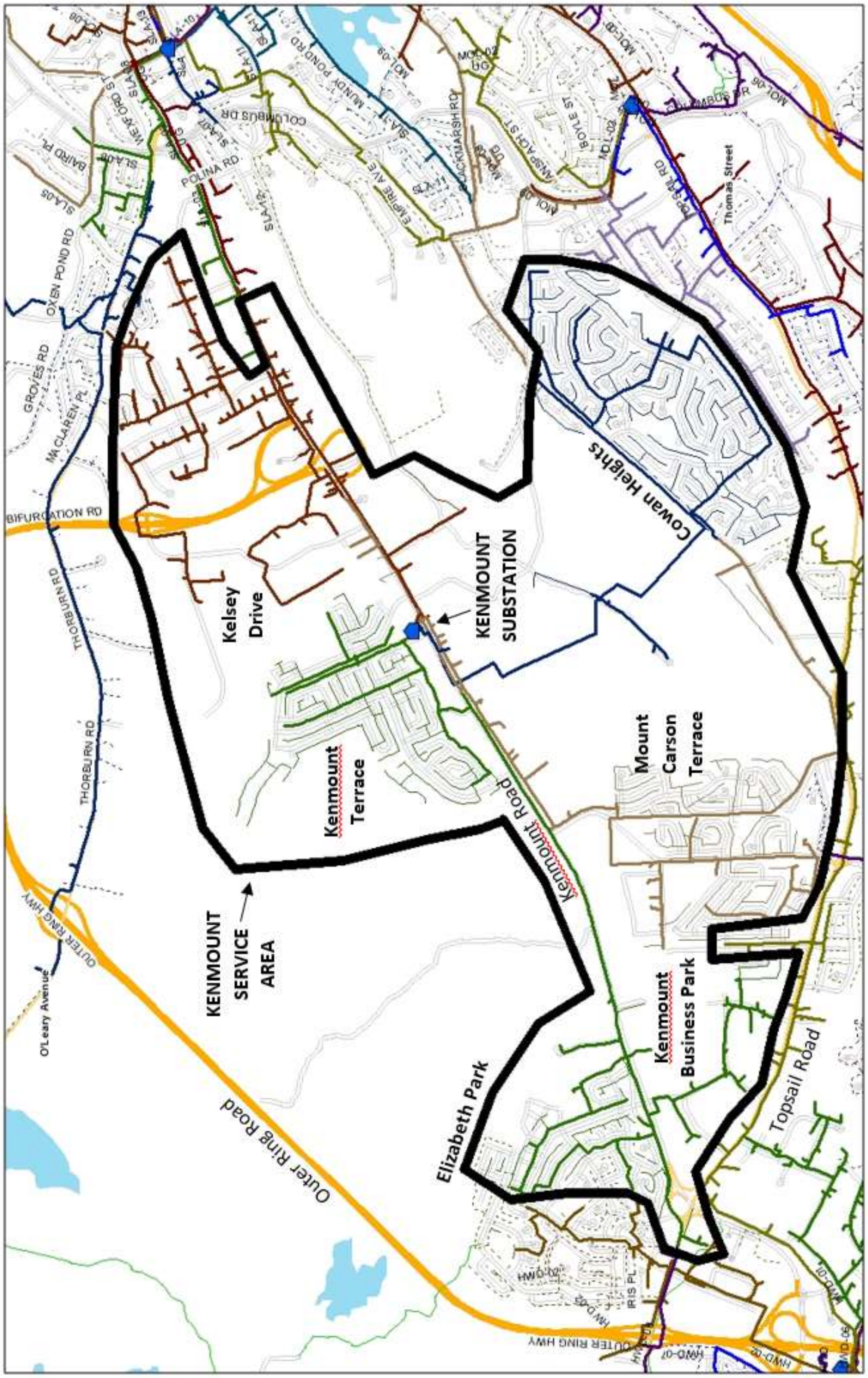
The total project cost for this 2015 project is estimated to cost $2,190,000, which includes $1,936,000 in Substations and $254,000 in Distribution.

Appendix A
Map of Chamberlains-Hardwoods-Kenmount 25 kV System


Kenmount Substation
Kenmount Service Area
Hardwoods Substation
Hardwoods Service Area
Chamberlains Substation
Chamberlains Service Area
Atlantic Ocean
OUTER RING HWY
THORBURN RD
PARKAVE
Glendale
Pearlgate Centre
Waterford Heights
Admiralty Wood
RUBY LINE
Doyle's Road
Purcell Street
MAIN RD
Hogan's Pond
FOXTRAP ACCESS RD
Kelligrews
KEL-03
KEL-02

Appendix B
Map of Kenmount Substation Service Area

Kenmount Substation Service Area



Appendix C
2013 Substation Load Forecast – Base Case

20 Year Substation Load Forecast – Base Case

Device	**KEN-T1**	**KEN-T2**	**HWD-T3**	**HWD-T3 (New)**
Sec. Voltage (kV)	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	25.0	50.0
2012 Peak (MVA)	23.9	24.1	27.4	N/A
Year	**Forecasted Undiversified Peak (MVA)**			
2013[1]	28.4	28.6	31.1	0.0
2014[2]	26.3	26.6	0.0	48.5
2015	27.4	27.6	0.0	49.7
2016	28.7	28.9	0.0	50.3
2017	29.0	29.2	0.0	50.7
2018	29.4	29.7	0.0	51.4
2019	29.9	30.1	0.0	52.2
2020	30.3	30.5	0.0	52.9
2021	30.7	31.0	0.0	53.7
2022	31.2	31.4	0.0	54.4
2023	31.6	31.9	0.0	55.2
2024	32.0	32.3	0.0	56.0
2025	32.5	32.7	0.0	56.7
2026	32.9	33.2	0.0	57.5
2027	33.4	33.6	0.0	58.2
2028	33.8	34.0	0.0	59.0
2029	34.2	34.5	0.0	59.8
2030	34.7	34.9	0.0	60.5
2031	35.1	35.4	0.0	61.3
2032	35.5	35.8	0.0	62.0

1 Substation peaks for 2013 includes peak load information available up to the middle of February 2014.
2 Includes load transfers planned for 2014 to address potential transformer overloads during the 2014/2015 winter season.

Appendix D
Alternative 1
20 Year Substation Load Forecasts

Alternative 1
20 Year Substation Load Forecast – Base Case

Device	KEN-T1	KEN-T2	KEN-T2 (New)	HWD-T3	HWD-T3 (New)	HWD-T4 (New)
Sec. Voltage (kV)	25.0	25.0	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	50.0	25.0	50.0	25.0
2012 Peak (MVA)	23.9	24.1	N/A	27.4	N/A	N/A
Year	**Forecasted Undiversified Peak (MVA)**					
2013	28.4	28.6	0.0	31.1	0.0	0.0
2014	26.4	26.6	0.0	0.0	48.5	0.0
2015	20.4	0.0	41.7	0.0	42.7	0.0
2016	21.2	0.0	43.3	0.0	43.3	0.0
2017	21.5	0.0	43.8	0.0	43.7	0.0
2018	21.8	0.0	44.4	0.0	44.2	0.0
2019	22.1	0.0	45.1	0.0	44.8	0.0
2020	22.4	0.0	45.7	0.0	45.3	0.0
2021	22.7	0.0	46.3	0.0	45.9	0.0
2022	23.0	0.0	47.0	0.0	46.4	0.0
2023	23.3	0.0	47.6	0.0	47.0	0.0
2024	23.7	0.0	48.3	0.0	47.6	0.0
2025	24.0	0.0	48.9	0.0	48.1	0.0
2026	24.3	0.0	49.5	0.0	48.7	0.0
2027	23.0	0.0	46.8	0.0	36.2	18.1
2028	23.3	0.0	47.5	0.0	36.5	18.3
2029	23.6	0.0	48.1	0.0	36.9	18.4
2030	23.9	0.0	48.8	0.0	37.3	18.6
2031	24.2	0.0	49.4	0.0	37.6	18.8
2032	24.5	0.0	49.9	0.0	38.1	19.1

Alternative 1
20 Year Substation Load Forecast – High Growth

Device	KEN-T1	KEN-T2	KEN-T2 (New)	HWD-T3	HWD-T3 (New)	HWD-T4 (New)
Sec. Voltage (kV)	25.0	25.0	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	50.0	25.0	50.0	25.0
2012 Peak (MVA)	23.9	24.1	N/A	27.4	N/A	N/A
Year	**Forecasted Undiversified Peak (MVA)**					
2013	28.4	28.6	0.0	31.1	0.0	0.0
2014	26.7	26.9	0.0	0.0	50.5	0.0
2015	21.0	0.0	42.9	0.0	45.3	0.0
2016	22.3	0.0	45.5	0.0	46.3	0.0
2017	22.6	0.0	46.2	0.0	46.9	0.0
2018	23.1	0.0	47.2	0.0	47.8	0.0
2019	23.6	0.0	48.2	0.0	48.7	0.0
2020	24.1	0.0	49.3	0.0	49.6	0.0
2021	23.0	0.0	46.9	0.0	37.0	18.5
2022	23.5	0.0	48.0	0.0	37.7	18.8
2023	24.0	0.0	49.0	0.0	38.3	19.1
2024	24.6	0.0	50.1	0.0	38.9	19.5
2025	25.1	0.0	51.2	0.0	39.6	19.8
2026	23.3	0.0	47.6	0.0	44.9	22.4
2027	23.8	0.0	48.6	0.0	45.5	22.8
2028	24.4	0.0	49.7	0.0	46.2	23.1
2029	22.6	0.0	46.1	0.0	48.1	24.1
2030	23.1	0.0	47.2	0.0	48.8	24.4
2031	23.7	0.0	48.3	0.0	49.5	24.7
2032	24.2	0.0	49.5	0.0	50.1	25.1

Alternative 1
20 Year Substation Load Forecast – Low Growth

Device	KEN-T1	KEN-T2	KEN-T2 (New)	HWD-T3	HWD-T3 (New)
Sec. Voltage (kV)	25.0	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	50.0	25.0	50.0
2012 Peak (MVA)	23.9	24.1	N/A	27.4	N/A
Year	**Forecasted Undiversified Peak (MVA)**				
2013	28.4	28.6	0.0	31.1	0.0
2014	26.0	26.2	0.0	0.0	46.6
2015	19.8	0.0	40.4	0.0	40.1
2016	20.2	0.0	41.2	0.0	40.4
2017	20.3	0.0	41.5	0.0	40.6
2018	20.5	0.0	41.8	0.0	40.8
2019	20.6	0.0	42.1	0.0	41.1
2020	20.8	0.0	42.4	0.0	41.3
2021	20.9	0.0	42.7	0.0	41.6
2022	21.0	0.0	43.0	0.0	41.8
2023	21.2	0.0	43.2	0.0	42.1
2024	21.3	0.0	43.5	0.0	42.3
2025	21.5	0.0	43.8	0.0	42.6
2026	21.6	0.0	44.1	0.0	42.8
2027	21.8	0.0	44.4	0.0	43.0
2028	21.9	0.0	44.7	0.0	43.3
2029	22.0	0.0	45.0	0.0	43.5
2030	22.2	0.0	45.2	0.0	43.7
2031	22.3	0.0	45.5	0.0	44.0
2032	22.4	0.0	45.8	0.0	44.2

Appendix E
Alternative 2
20 Year Substation Load Forecasts

Alternative 2
20 Year Substation Load Forecast – Base Case

Device	**KEN-T1**	**KEN-T2**	**KEN-T3 (New)**	**HWD-T3**	**HWD-T3 (New)**	**HWD-T4 (New)**
Sec. Voltage (kV)	25.0	25.0	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	25.0	25.0	50.0	25.0
2012 Peak (MVA)	23.9	24.1	N/A	27.4	N/A	N/A
Year	**Forecasted Undiversified Peak (MVA)**					
2013	28.4	28.6	0.0	31.1	0.0	0.0
2014	26.4	26.6	0.0	0.0	48.5	0.0
2015	20.5	20.7	20.9	0.0	42.7	0.0
2016	21.3	21.5	21.8	0.0	43.3	0.0
2017	21.5	21.7	22.0	0.0	43.7	0.0
2018	21.9	22.0	22.3	0.0	44.2	0.0
2019	22.2	22.3	22.6	0.0	44.8	0.0
2020	22.5	22.7	22.9	0.0	45.3	0.0
2021	22.8	23.0	23.3	0.0	45.9	0.0
2022	23.1	23.3	23.6	0.0	46.4	0.0
2023	23.4	23.6	23.9	0.0	47.0	0.0
2024	23.8	23.9	24.2	0.0	47.6	0.0
2025	24.1	24.2	24.6	0.0	48.1	0.0
2026	24.4	24.6	24.9	0.0	48.7	0.0
2027	23.1	23.2	23.5	0.0	36.2	18.1
2028	23.4	23.5	23.8	0.0	36.5	18.3
2029	23.7	23.9	24.2	0.0	36.9	18.4
2030	24.0	24.2	24.5	0.0	37.3	18.6
2031	24.3	24.5	24.8	0.0	37.6	18.8
2032	24.4	24.6	24.9	0.0	38.5	19.2

Alternative 2
20 Year Substation Load Forecast – High Growth

Device	**KEN-T1**	**KEN-T2**	**KEN-T3 (New)**	**HWD-T3**	**HWD-T3 (New)**	**HWD-T4 (New)**
Sec. Voltage (kV)	25.0	25.0	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	25.0	25.0	50.0	25.0
2012 Peak (MVA)	23.9	24.1	N/A	27.4	N/A	N/A
Year	**Forecasted Undiversified Peak (MVA)**					
2013	28.4	28.6	0.0	31.1	0.0	0.0
2014	26.7	26.9	0.0	0.0	50.5	0.0
2015	21.1	21.3	21.6	0.0	45.3	0.0
2016	22.4	22.6	22.8	0.0	46.3	0.0
2017	22.7	22.9	23.2	0.0	46.9	0.0
2018	23.2	23.4	23.7	0.0	47.8	0.0
2019	23.7	23.9	24.2	0.0	48.7	0.0
2020	24.2	24.4	24.7	0.0	49.6	0.0
2021	23.1	23.3	23.6	0.0	37.0	18.5
2022	23.6	23.8	24.1	0.0	37.7	18.8
2023	24.1	24.3	24.6	0.0	38.3	19.1
2024	24.7	24.8	25.2	0.0	38.9	19.5
2025	22.9	23.0	23.3	0.0	44.2	22.1
2026	23.4	23.6	23.9	0.0	44.9	22.4
2027	23.9	24.1	24.4	0.0	45.5	22.8
2028	22.2	22.3	22.6	0.0	47.5	23.7
2029	22.7	22.9	23.2	0.0	48.1	24.1
2030	23.2	23.4	23.7	0.0	48.8	24.4
2031	23.8	24.0	24.3	0.0	49.5	24.7
2032	24.3	24.5	24.8	0.0	50.1	25.1

Alternative 2
20 Year Substation Load Forecast – Low Growth

Device	**KEN-T1**	**KEN-T2**	**KEN-T3 (New)**	**HWD-T3**	**HWD-T3 (New)**
Sec. Voltage (kV)	25.0	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	25.0	25.0	50.0
2012 Peak (MVA)	23.9	24.1	N/A	27.4	N/A
Year	**Forecasted Undiversified Peak (MVA)**				
2013	28.4	28.6	0.0	31.1	0.0
2014	26.0	26.2	0.0	0.0	46.6
2015	19.9	20.0	20.3	0.0	40.1
2016	20.3	20.4	20.7	0.0	40.4
2017	20.4	20.6	20.8	0.0	40.6
2018	20.6	20.7	21.0	0.0	40.8
2019	20.7	20.9	21.1	0.0	41.1
2020	20.9	21.0	21.3	0.0	41.3
2021	21.0	21.1	21.4	0.0	41.6
2022	21.2	21.3	21.6	0.0	41.8
2023	21.3	21.4	21.7	0.0	42.1
2024	21.5	21.6	21.9	0.0	42.3
2025	21.6	21.7	22.0	0.0	42.6
2026	21.7	21.9	22.1	0.0	42.8
2027	21.9	22.0	22.3	0.0	43.0
2028	22.0	22.1	22.4	0.0	43.3
2029	22.2	22.3	22.6	0.0	43.5
2030	22.3	22.4	22.7	0.0	43.7
2031	22.4	22.6	22.9	0.0	44.0
2032	22.6	22.7	23.0	0.0	44.2

Appendix F
Alternative 3
20 Year Substation Load Forecasts

Alternative 3
20 Year Substation Load Forecast – Base Case

Device	KEN-T1	KEN-T2	KEN-T2 (New)	HWD-T3	HWD-T3 (New)	HWD-T4 (New)
Sec. Voltage (kV)	25.0	25.0	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	25.0	25.0	50.0	25.0
2012 Peak (MVA)	23.9	24.1	N/A	27.4	N/A	N/A
Year			**Forecasted Undiversified Peak (MVA)**			
2013	28.4	28.6	0.0	31.1	0.0	0.0
2014	26.3	26.6	0.0	0.0	48.5	0.0
2015	24.5	24.6	0.0	0.0	37.1	18.6
2016	20.5	20.6	0.0	0.0	44.5	22.3
2017	20.8	20.9	0.0	0.0	44.8	22.4
2018	21.3	21.4	0.0	0.0	45.1	22.6
2019	21.7	21.9	0.0	0.0	45.5	22.8
2020	22.2	22.4	0.0	0.0	45.9	22.9
2021	22.7	22.9	0.0	0.0	46.3	23.1
2022	23.2	23.3	0.0	0.0	46.6	23.3
2023	23.6	23.8	0.0	0.0	47.0	23.5
2024	24.1	24.3	0.0	0.0	47.4	23.7
2025	24.6	24.8	0.0	0.0	47.7	23.9
2026	25.1	25.3	0.0	0.0	48.1	24.1
2027	16.9	0.0	40.9	0.0	48.5	24.2
2028	17.2	0.0	42.0	0.0	48.9	24.4
2029	17.5	0.0	43.1	0.0	49.2	24.6
2030	17.8	0.0	44.2	0.0	49.6	24.8
2031	18.3	0.0	45.7	0.0	49.6	24.8
2032	18.6	0.0	46.8	0.0	49.9	25.0

Alternative 3
20 Year Substation Load Forecast – High Growth

Device	KEN-T1	KEN-T2	KEN-T2 (New)	HWD-T3	HWD-T3 (New)	HWD-T4 (New)
Sec. Voltage (kV)	25.0	25.0	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	50.0	25.0	50.0	25.0
2012 Peak (MVA)	23.9	24.1	N/A	27.4	N/A	N/A
Year	**Forecasted Undiversified Peak (MVA)**					
2013	28.4	28.6	0.0	31.1	0.0	0.0
2014	26.7	26.9	0.0	0.0	50.5	0.0
2015	20.1	20.3	0.0	0.0	45.9	22.9
2016	22.1	22.2	0.0	0.0	46.5	23.3
2017	22.6	22.7	0.0	0.0	46.9	23.5
2018	23.3	23.5	0.0	0.0	47.5	23.8
2019	24.1	24.3	0.0	0.0	48.1	24.1
2020	24.9	25.0	0.0	0.0	48.8	24.4
2021	16.9	0.0	34.5	0.0	49.4	24.7
2022	17.4	0.0	35.6	0.0	50.0	25.0
2023	20.3	0.0	41.3	0.0	46.0	23.0
2024	20.8	0.0	42.4	0.0	46.6	23.3
2025	21.3	0.0	43.5	0.0	47.2	23.6
2026	21.8	0.0	44.5	0.0	47.9	23.9
2027	22.4	0.0	45.6	0.0	48.5	24.3
2028	22.9	0.0	46.7	0.0	49.2	24.6
2029	23.4	0.0	47.8	0.0	49.8	24.9
2030	24.0	0.0	48.9	0.0	48.5	24.2
2031	23.9	0.0	48.7	0.0	49.1	24.6
2032	24.4	0.0	49.8	0.0	49.8	24.9

Alternative 3
20 Year Substation Load Forecast – Low Growth

Device	**KEN-T1**	**KEN-T2**	**HWD-T3**	**HWD-T3 (New)**	**HWD-T4 (New)**
Sec. Voltage (kV)	25.0	25.0	25.0	25.0	25.0
Rating (MVA)	25.0	25.0	25.0	50.0	25.0
2012 Peak (MVA)	23.9	24.1	27.4	N/A	N/A
Year	**Forecasted Undiversified Peak (MVA)**				
2013	28.4	28.6	31.1	0.0	0.0
2014	26.0	26.2	0.0	46.6	0.0
2015	23.5	23.7	0.0	35.4	17.7
2016	24.1	24.3	0.0	35.6	17.8
2017	24.3	24.5	0.0	35.7	17.9
2018	24.5	24.7	0.0	35.9	17.9
2019	24.7	24.9	0.0	36.0	18.0
2020	19.7	19.9	0.0	43.2	21.6
2021	20.0	20.1	0.0	43.4	21.7
2022	20.2	20.3	0.0	43.5	21.8
2023	20.4	20.5	0.0	43.7	21.9
2024	20.6	20.8	0.0	43.9	21.9
2025	20.8	21.0	0.0	44.0	22.0
2026	21.0	21.2	0.0	44.2	22.1
2027	21.2	21.4	0.0	44.4	22.2
2028	21.5	21.6	0.0	44.5	22.3
2029	21.7	21.8	0.0	44.7	22.3
2030	21.9	22.0	0.0	44.8	22.4
2031	22.1	22.2	0.0	45.0	22.5
2032	22.3	22.5	0.0	45.1	22.6

2015 Transmission Line Rebuild

June 2014

Prepared by:

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A FORTIS COMPANY

Table of Contents

1.0 Transmission Line Rebuild Strategy

Newfoundland Power's transmission lines are the bulk transmitter of electricity providing service to customers. Transmission lines operate at higher voltages, either 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 lays 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 2015 Transmission Line Rebuild Projects

In 2015, the Company proposes to rebuild sections of 5 transmission lines totalling 17.9 km with an average age of 58 years.[1] Appendix B contains maps of each of the lines to be rebuilt. Appendix C contains photographs of the existing lines. The transmission lines sections to be rebuilt in 2015 are included in Table 1.

Table 1
2015 Transmission Line Rebuilds

Transmission Line	Distance to be Rebuilt	Year Constructed
14L	0.68 km	1950
15L	0.80 km	1958
30L	1.50 km	1959
69L	2.74 km	1951
400L	12.2 km	1967

All of these sections of transmission line 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 of these sections of line will improve the overall reliability of the transmission system that services customers in these areas.

[1] This 17.9 km represents approximately 1% of the total 2,000 km of transmission lines owned and maintained by Newfoundland Power.

2.1 Transmission Line 14L ($243,000)

Transmission line 14L is a 66 kV line running between Memorial University Substation ("MUN") and Stamp's Lane Substation ("SLA") in St. John's. The line consists of a 1.13 km aerial section and a 1.13 km underground cable section located through the university campus area. 14L, in conjunction with 12L, are the transmission lines that provide service to Memorial University, the Health Sciences Centre and the Janeway Children's Health and Rehabilitation Centre.

The aerial section of transmission line was originally constructed in 1950; however a 0.45 km section along Stamp's Lane was rebuilt in 1993. The remaining 22 single pole structures along University Avenue all have under built distribution circuitry. The route taken by the transmission line, as shown by Figure 1 of Appendix B, is through a residential area of the City of St. John's.

With the infrastructure additions in this area, load growth at MUN substation will continue to increase.[2] With this increase in load, the existing 477 ASC conductor on 14L will not be able to carry peak load if 12L experiences an outage. To address these loading concerns the 477 ASC conductor on 14L will be replaced with 715.5 ASC.

Inspections have identified deterioration due to decay, splits and checks in the poles and crossarms.[3] Some components, such as crossarms and guys, do not meet today's material and construction standards. Many of the wooden components are in advanced stages of deterioration and require replacement. The majority of the wooden poles are original vintage and have surpassed their normal life expectancy.

Due to the age and condition of the line it is susceptible to damage should it become exposed to severe wind, ice or snow loading. This section of line was built to weather loading criteria that are less than the standards currently used to construct new lines in this area. In January 2014, one structure failed during a wind event and had to be replaced.

The transmission line has reached a point where continued maintenance is no longer feasible and it has to be rebuilt to continue its safe, reliable operation.

Based on the overall deteriorated condition of the line, it is recommended the line be rebuilt in 2015 at an estimated cost of $243,000.

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[2] Recent infrastructure additions have taken place at the Health Science Centre and Janeway Children's Health and Rehabilitation Centre and with 2 new residence buildings at Memorial University.

[3] Most of the poles are located adjacent to city streets and are prone to damage by passing snowploughs and other vehicles. Where practical, new poles will be located behind the curb and sidewalk to mitigate future damage. Relocating these poles will add to the complexity of the rebuild project.

2.2 Transmission Line 15L ($350,000)

Transmission line 15L is a 66 kV single pole line running between Molloy's Lane Substation ("MOL") and Stamp's Lane Substation ("SLA") in St. John's. The entire line is 4.22 km in length and is comprised of 73 mostly single pole structures.

The transmission line was originally constructed in 1958, with most of the line having under built distribution circuitry. Over the years a number of sections have been replaced and relocated for road widening and other third party development, leaving a total of 0.8 km or 27 structures of original construction to be rebuilt in 2015. The transmission line route as shown in Figure 2 of Appendix B is through residential and high traffic areas of the City of St. John's.[4]

Inspections have identified deterioration due to decay, splits and checks in the poles and crossarms, as well as deficiencies with guys and anchors, hardware, and insulators. Many of these components are in advanced stages of deterioration and require replacement.

Due to the age and condition of the line, it is susceptible to damage should it become exposed to severe wind, ice or snow loading. This section of line was built to weather loading criteria that are less than the standards currently used to construct new lines in this area. Additionally, a section of this line was built with 266.8 ACSR conductor. This conductor has had corrosion issues causing failures on other lines and as a result has been discontinued from use in new construction.

Relocating the poles away from high traffic areas will serve to minimize future maintenance costs and extend structure life.

The transmission line has reached a point where continued maintenance is no longer feasible and it has to be rebuilt to the current wind and ice loading criteria, to continue its safe, reliable operation.

Based on the overall deteriorated condition of the line, it is recommended the line be rebuilt in 2015 using 477 ASC conductor at an estimated cost of $350,000.

2.3 Transmission Line 30L ($590,000 in 2015 and $511,000 in 2016)

Transmission line 30L is a 66 kV single pole line running between Ridge Road Substation ("RRD") and King's Bridge Road Substation ("KBR") in St. John's.

The 2.9 km transmission line was originally constructed in 1959 and consists of 87 single pole structures, all of which have under built distribution circuitry. The route taken by the transmission line, as shown by Figure 3 of Appendix B, is through heavy residential areas of the

---

[4] Most of the poles are located adjacent to city streets and are prone to damage by passing snowploughs and other vehicles. Where practical, new poles will be located behind the curb and sidewalk to mitigate future damage. Relocating these poles will add to the complexity of the rebuild project.

City of St. John's.[5] Recognizing the added complexity associated with access to private property, obtaining permits from municipal authorities and construction in heavy traffic areas, the Company has chosen to complete the rebuild of transmission line 30L over 2 years. Inspections have identified deterioration due to decay, splits and checks in the poles and crossarms. Many of these wooden components are in advanced stages of deterioration and require replacement. The majority of the wooden poles are original vintage and have surpassed their normal life expectancy.

Transmission line 30L also contains insulators manufactured by Canadian Ohio Brass.[6] These insulators are identified as deficiencies due to a history of premature failure caused by cement growth. As the cement in these insulators expands, cracks in the porcelain insulator discs occur making the insulators more susceptible to flashovers.

Due to the age and condition of the line it is susceptible to damage should it become exposed to severe wind, ice or snow loading. This line was built to weather loading criteria that are less than the standards currently used to construct new lines in this area.

The transmission line has reached a point where continued maintenance is no longer feasible and it has to be rebuilt to continue its safe, reliable operation.

Based on the overall deteriorated condition of the line, it is recommended that 1.5 km of the line be rebuilt in 2015 at an estimated cost of $590,000 and the remaining 1.4 km be rebuilt in 2016 at an estimated cost of $511,000.

2.4 Transmission Line 69L ($727,000)

Transmission line 69L is a 66 kV line running between Kenmount Substation ("KEN") and Stamp's Lane Substation ("SLA") in St. John's. The line was originally constructed in 1959, and while some sections were rebuilt during subsequent system reconfigurations, approximately 2.74 km of original vintage line remains in service. Of the 48 single-pole wood structures to be replaced, approximately one-third have under built distribution circuitry.

Much of the route taken by the transmission line, as shown by Figure 4 of Appendix B, is through residential areas of the City of St. John's.

Due to age and condition of the remaining original structures, the line remains susceptible to damage should it become exposed to ice, wind or snow loading. This section of line is built with 266.8 ACSR conductor. This conductor has had corrosion issues with the steel core causing failures on other lines and as a result has been discontinued from use in new construction.[7] The conductor size on the section being rebuilt will be upgraded to match the conductor size on the remainder of the line. This will increase the overall transfer capacity of the line.

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[5] Similar to 14L and 15L, most of the poles are located adjacent to city streets and are prone to damage by passing snowploughs and other vehicles. Where practical, new poles will be located behind the curb and sidewalk to mitigate future damage.

[6] See Figure 10 of Appendix C for a photograph of these insulators.

[7] See Figures 33 and 34 of Appendix C for photographs of corrosion of 266.8 ACSR.

Recent inspections have identified substantial deterioration of the poles, crossarms and insulators. These components are in advanced stages of deterioration and require replacement. Many of the wooden components show decay, splits and checks. The majority of the poles are original vintage and have surpassed their normal life expectancy.

Transmission line 69L also contains insulators manufactured by Canadian Ohio Brass.[8] These insulators are identified as deficiencies due to a history of premature failure caused by cement growth. As the cement in these insulators expands, cracks in the porcelain insulator discs occur making the insulators more susceptible to flashovers.

The transmission line has reached a point where continued maintenance is no longer feasible and it has to be rebuilt to continue its safe, reliable operation.

Based on the age, deteriorated condition and weather loadings on this section of line it is recommended that the section be rebuilt in 2015 using 715.5 ASC conductor at an estimated cost of $727,000.

2.5 Transmission Line 400L/404L ($1,920,000 in 2015 and $1,807,000 in 2016)

General

Transmission line 400L is a 66 kV line running between Newfoundland & Labrador Hydro's ("Hydro") Bottom Brook Substation ("BBK") and the Company's Wheeler's Substation ("WHE"), located on the Hansen Highway near Stephenville. Transmission line 400L was constructed in 1967. It is 21.9 km in length and comprised of 90 H-Frame structures. Transmission line 404L, also constructed in 1967, extends from WHE to the tap with transmission line 401L. It is 1.2 km in length and is comprised of 14 single pole structures. For the purposes of this report we will refer to the combination of transmission lines 400L and 404L as simply 400L.

Transmission line 400L is 1 of only 2 transmission lines connecting Stephenville and the Port au Port Peninsula to the Island Interconnected System. The Company has approximately 10,000 customers in Stephenville and on the Port au Port Peninsula, including Stephenville International Airport, Sir Thomas Roddick Hospital, and Lower Cove Mine.

The other transmission line connecting the Stephenville and the Port au Port Peninsula to the Island Interconnected System is Hydro's transmission line TL209. Transmission line 400L along with Hydro's Stephenville Gas Turbine are used to supply customer load for unscheduled outages and scheduled maintenance on transmission line TL209.[9] Figure 1 provides a simplified single-line diagram for the transmission system connecting substations in the Stephenville and the Port au Port Peninsula area to the Island Interconnected System.

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8 See Figure 15 of Appendix C for a photograph of these insulators.

9 Transmission line 400L is currently able to supply all Newfoundland Power's customers in the Stephenville and the Port au Port Peninsula for the months of June, July, August and September without support from transmission line TL209 or the Stephenville Gas Turbine.

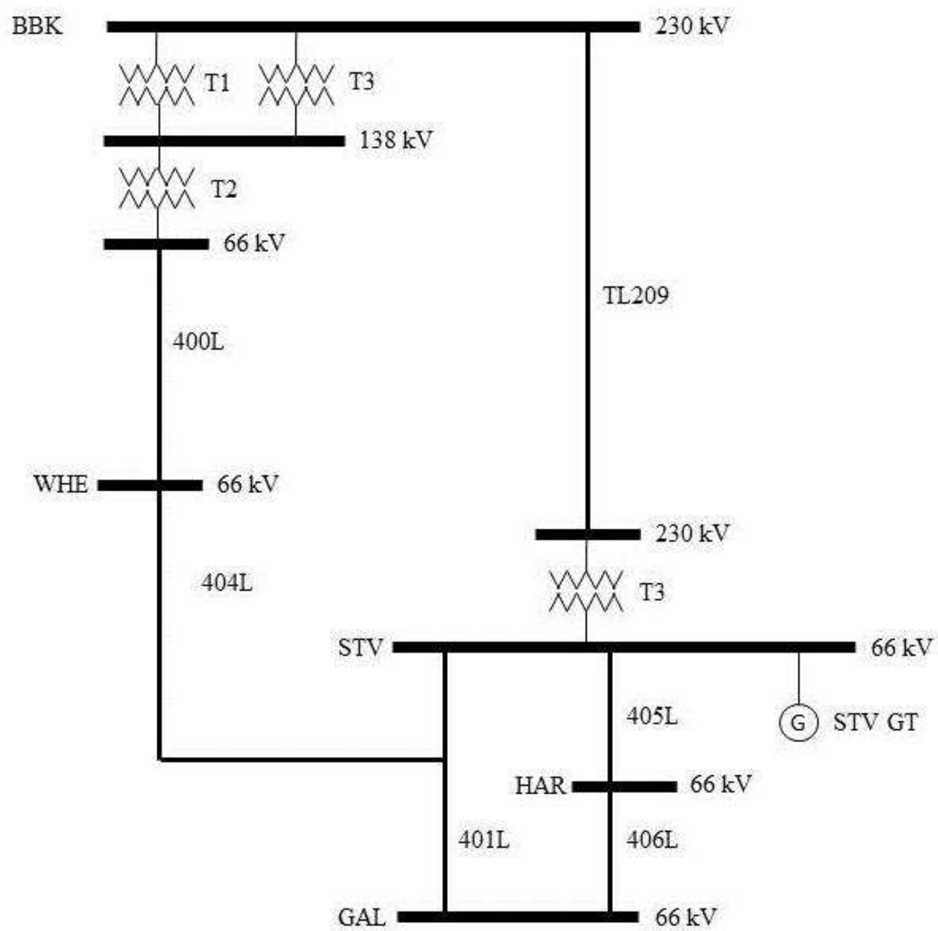

Figure 1 – Simplified Single Line Diagram

Transmission line 400L is limited in its ability to supply the peak load of the Stephenville and the Port au Port Peninsula area as a back-up to TL209 by (i) the capacity of transformer BBK-T2 and (ii) the capacity of the existing conductor.[10] Rebuilding 400L and replacing the conductor will address the load carrying capacity of the transmission line conductor.[11]

Inspections have identified significant deterioration of the transmission line due to decay, splits and checks in the poles, cross braces and crossarms, loss of rock ballast in pole cribs, cracks in insulators and other hardware deficiencies. Many of these components are in advanced stages of deterioration and require replacement.

[10] Transmission line 400L is rated at 50 MVA. The current condition of the conductor, and the presence of splices in the conductor, makes the actual line rating less than 50 MVA.

[11] Discussions have taken place with Hydro on the long term benefits of 400L and the Company's plan to rebuild the transmission line in 2015 and 2016. Hydro acknowledges the requirement for 400L as a backup to TL209 especially following the decommissioning of the Stephenville Gas Turbine at some future date.

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.[12] 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 premature deterioration of the poles.

The outer shell separation on the 400L poles 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.

Over the past number of years, some structures have been replaced or temporarily repaired due to significant deterioration and damage. Sounding tests and core sampling of the poles have been performed as part of recent inspections, and indicate that approximately one third of the structures on the line are in advanced stages of deterioration. More than half of the remaining structures are also significantly deteriorated and will require replacement in the near future.

Hardware

Sections of this transmission line traverse open and exposed terrain over which very high winds are frequent. The resulting wind-induced vibration of the conductor has caused loose and worn hardware on many structures. Many of the clamps that secure guys to the poles are twisted and pulled out from the poles due to the forces exerted on the transmission line by high winds and ice loading. Examples of damaged hardware can be seen in Figures 21, 25 and 43 of Appendix C.

Insulators

The 1960 vintage porcelain insulators on 400L were manufactured by Canadian Ohio Brass ("COB"), Ohio Brass ("OB") and Canadian Porcelain ("CP"). Premature failure of porcelain insulators due to cement growth and radial cracking is a known problem through the utility industry. Newfoundland Power began to experience abnormal failures of porcelain insulation in the early 1980s. The COB insulators experience cement growth and eventually the discs will separate causing failure of the insulator string. Suspension insulators also fail by radial cracks, which are sometimes contained inside the metal cap and are not visible. The crack causes a current path between the metal cap and pin thereby shorting out the insulator causing an energy

[12] Pictures of this phenomenon and the resulting condition of the poles can be found in Appendix C.

release that causes the conductor to float clear of the structure. Since the 1990s, the Company has replaced a significant number of defective COB, OB and CP suspension insulators.[13]

Transmission line 400L has a variety of insulator types and manufacturers. Figure 2 shows a single structure with 3 different types of insulator.

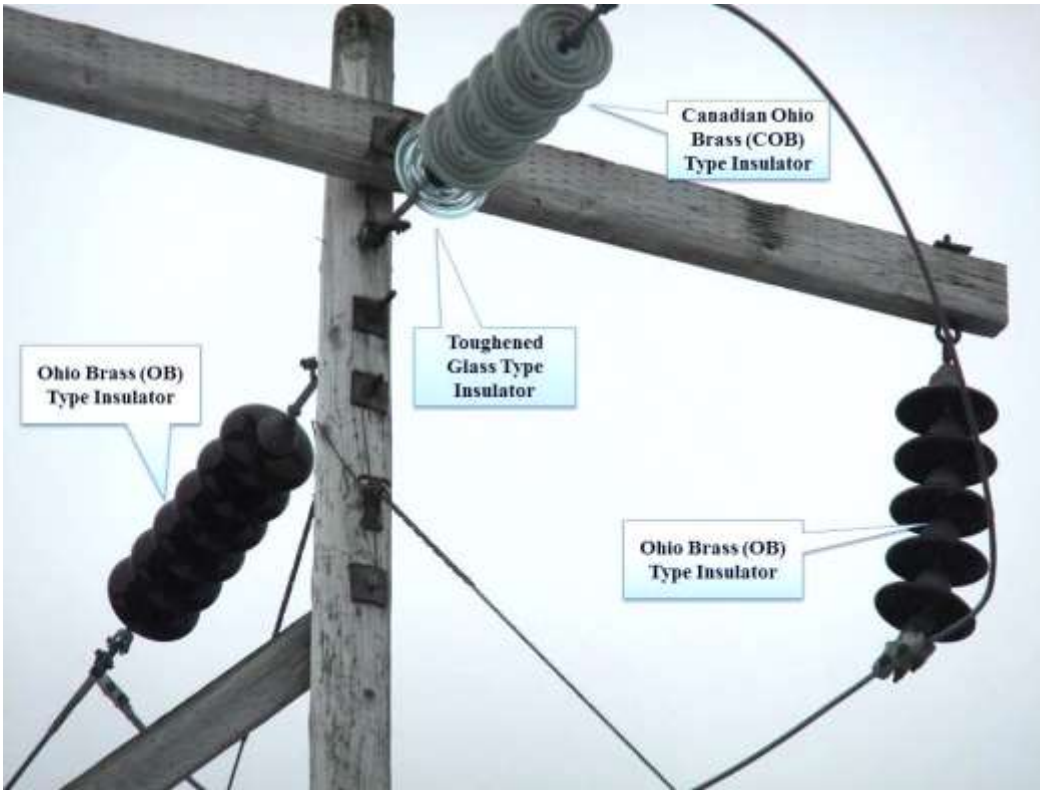

Figure 2 – Insulators

The dark colored Ohio Brass ("OB") type insulator is original to the 1967 construction. The grey colored COB type insulators were used to replace some of the OB insulators on 400L in the 1980s. There is one toughened glass disc on the COB string of insulators. This type of replacement was typically undertaken in the 1990s.

Many of the insulators on 400L have hairline cracks in them. These cracks will eventually fail causing the conductor to separate from the structure. Examples of insulators with hairline cracks present can be seen in Figures 47 and 48 of Appendix C.

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13 COB suspension insulators fail by radial cracks, which are sometimes contained inside the metal cap and are not visible. The crack causes a current path between the metal cap and pin thereby shorting out the insulator causing an energy release that causes the conductor to float clear of the structure.

Conductor

Conductor on transmission line 400L is heavily corroded due to its close proximity to the ocean. The Port au Port Peninsula experiences strong winds that carry salt spray on shore causing corrosion of distribution and transmission line conductors.[14] The 266.8 ACSR conductor used in the original construction of 400L is particularly susceptible to salt contamination and no longer used for new construction due to the corrosion problems experienced with the steel core.

In some places the conductor has failed as 2 phases of the conductor came into contact with each other causing flashover damage. Repairs have been made by placing sleeves on the conductor. Without replacement and proper sagging of the conductor there is danger of the phases coming into contact again. The condition of the conductor combined with the poor general condition of the poles places this transmission line at risk of a costly, extended repair should failure occur. Also, the conductor damage and small size means that 400L is a reliable backup for TL209 for only 4 months of the year.

Pole Cribs

Inspections have also identified pole cribs that have rotted and no longer contain a suitable quantity of rock, which compromises the overall strength of the cribbed structures. There are 36 pole cribs on transmission line 400L used to support the structures in terrain unable to directly support the poles. The wooden pole cribs are deteriorated and no longer contain the rock ballast necessary to support the structures.[15]

Recommendation

The transmission line has reached a point where continued maintenance is no longer feasible and has to be rebuilt using 559.5 AASC conductor to continue its safe, reliable operation.

Based on the deteriorated condition of this line, it is recommended that 11 km of H-Frame (400L) and 1.2 km of single pole line (404L) be rebuilt in 2015 at an estimated cost of $1,920,000 and the remaining 11 km section of H-Frame line (400L) be rebuilt in 2016 at an estimated cost of $1,807,000.

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[14] The 266.8 ACSR conductor used on 400L has also experienced corrosion issues on other sections of transmission lines on the Port-au-Port Peninsula. A section of transmission line 410L from Berry Head Substation to Lower Cove Mine Substation constructed with the 266.8 ACSR conductor has been replaced previously and another 1 km section is planned for replacement in 2014. See Figures 33 & 34 of Appendix C for photographs of corrosion of 266.8 ACSR conductor. Figure 35 shows a corroded in-service conductor on 400L.

[15] Pictures of the deteriorated pole cribs can be found in Figure 39 to Figure 42 of Appendix C.

3.0 Concluding

In 2015, the Company will rebuild sections of 14L, 15L, 30L, 69L and 400L. Each of these transmission lines has structures experiencing deterioration of the poles, crossarms, hardware, and conductor. Recent inspections and engineering assessment have determined the transmission lines have reached a point where continued maintenance is no longer feasible and they have to be rebuilt to continue providing safe, reliable electrical service.

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

Appendix A
Transmission Line Rebuild Strategy Schedule

Transmission Line Rebuilds 2015 – 2019 ($000s)						
Line	**Year**	**2015**	**2016**	**2017**	**2018**	**2019**
014L SLA-MUN	1950	243				
015L SLA-MOL	1958	350				
069L KEN-SLA	1951	727				
030L RRD-KBR	1959	590	511			
400L BBK-WHE	1967	1,920	1,807			
032L OXP-RRD	1959		352			
057L BRB-HGR	1958		1,491	1,518		
041L CAR-HCT	1958			1,350	1,043	
101L GFS-RBK	1957			1,750	2,221	
302L SPO-LAU	1959			1,474	1,616	1,976
124L CLV-GAM	1964					2,825
	Total	**3,830**	**4,161**	**6,092**	**4,880**	**4,801**

Appendix B
Maps of Transmission Lines
14L, 15L, 30L, 69L and 400L

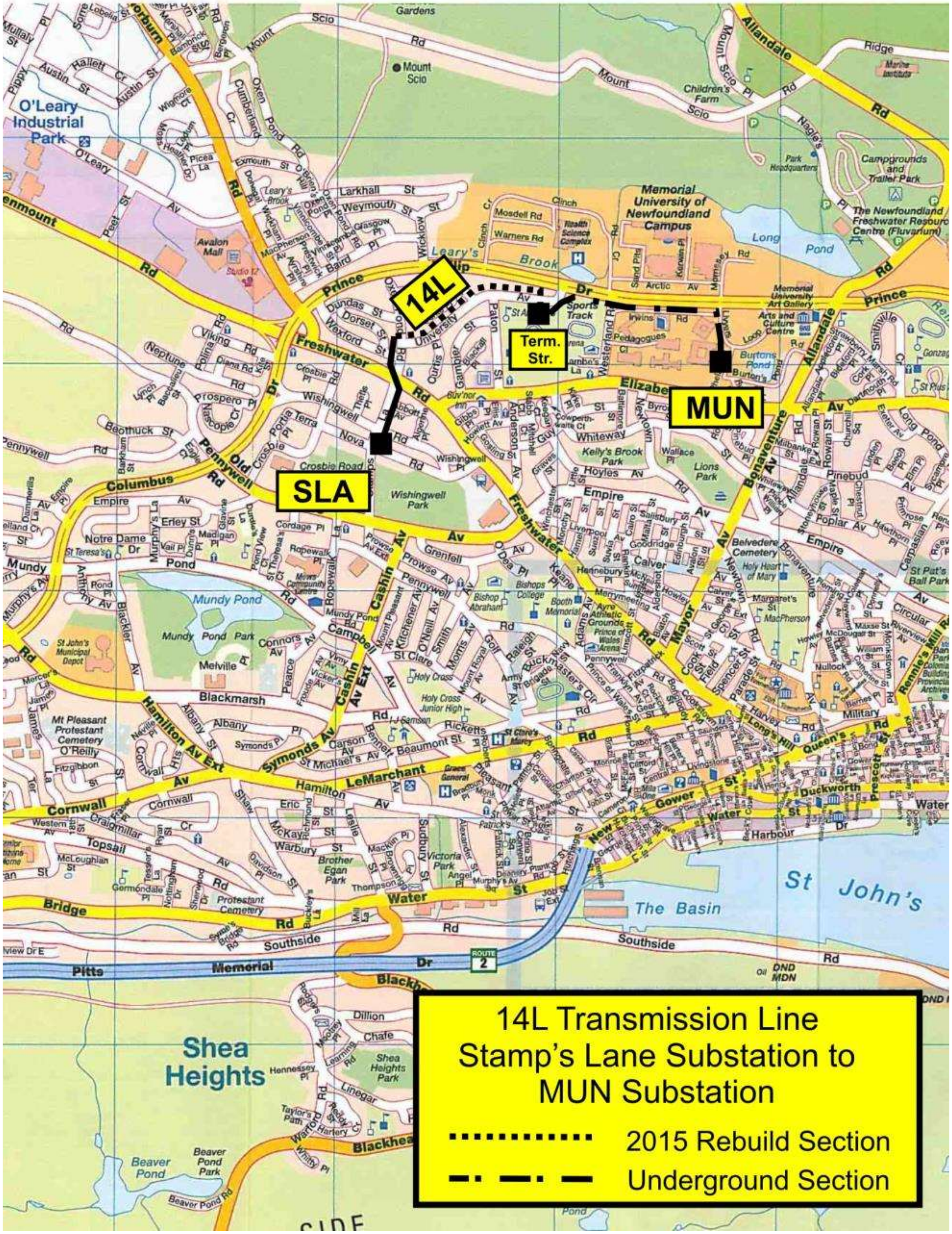

Figure 1 – Map of 14L Route

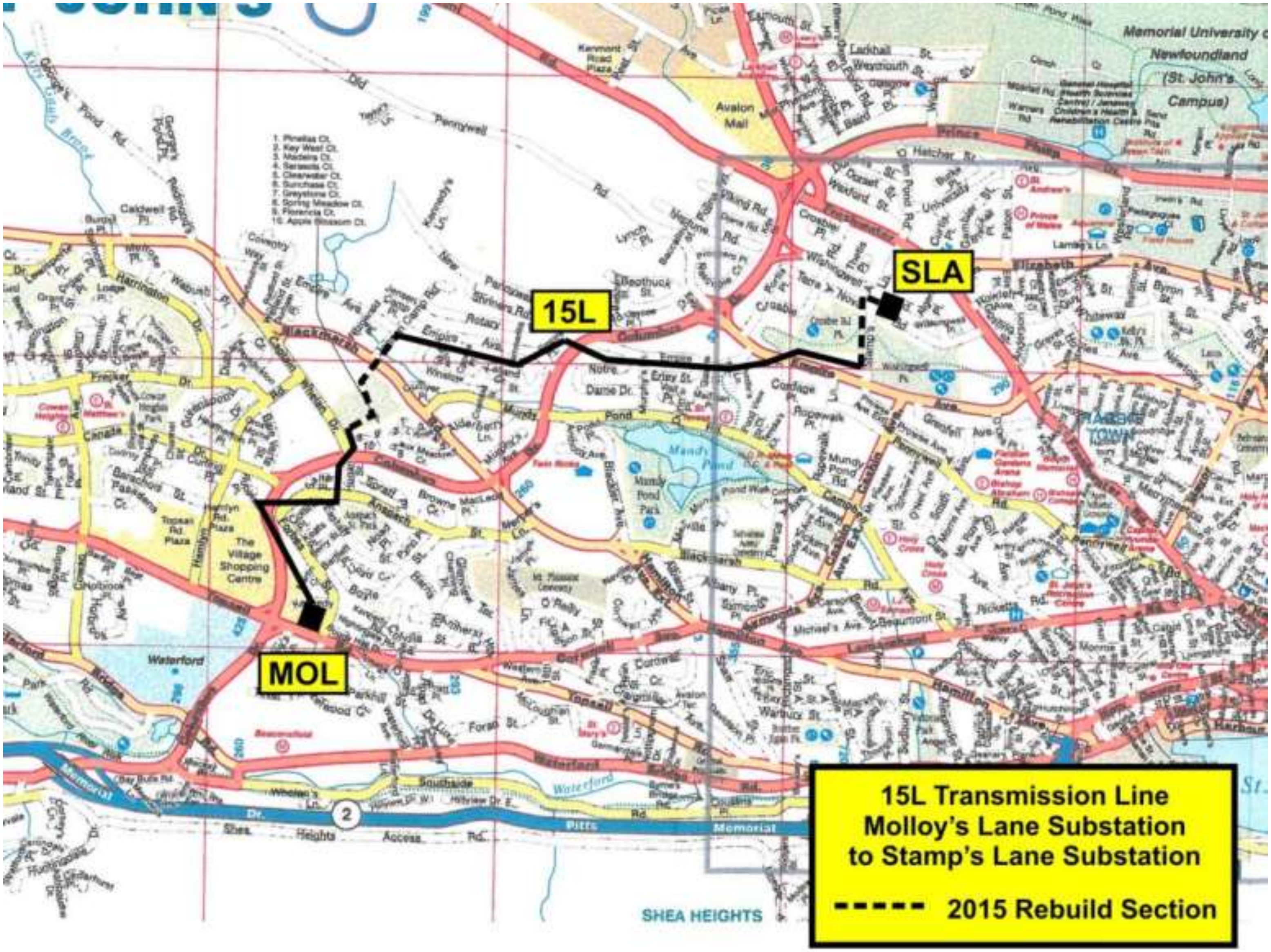

Figure 2 – Map of 15L Route

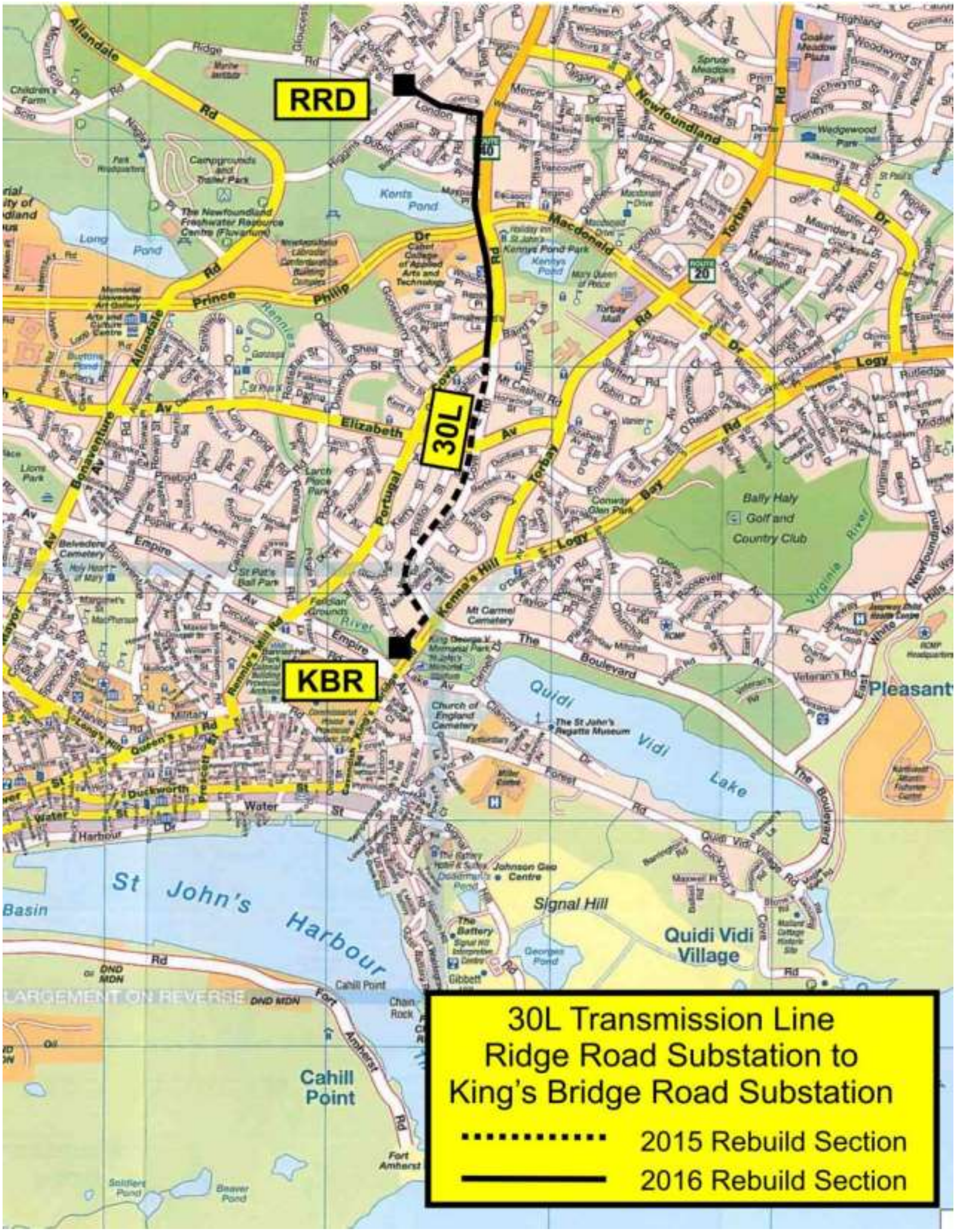

Figure 3 – Map of 30L Route

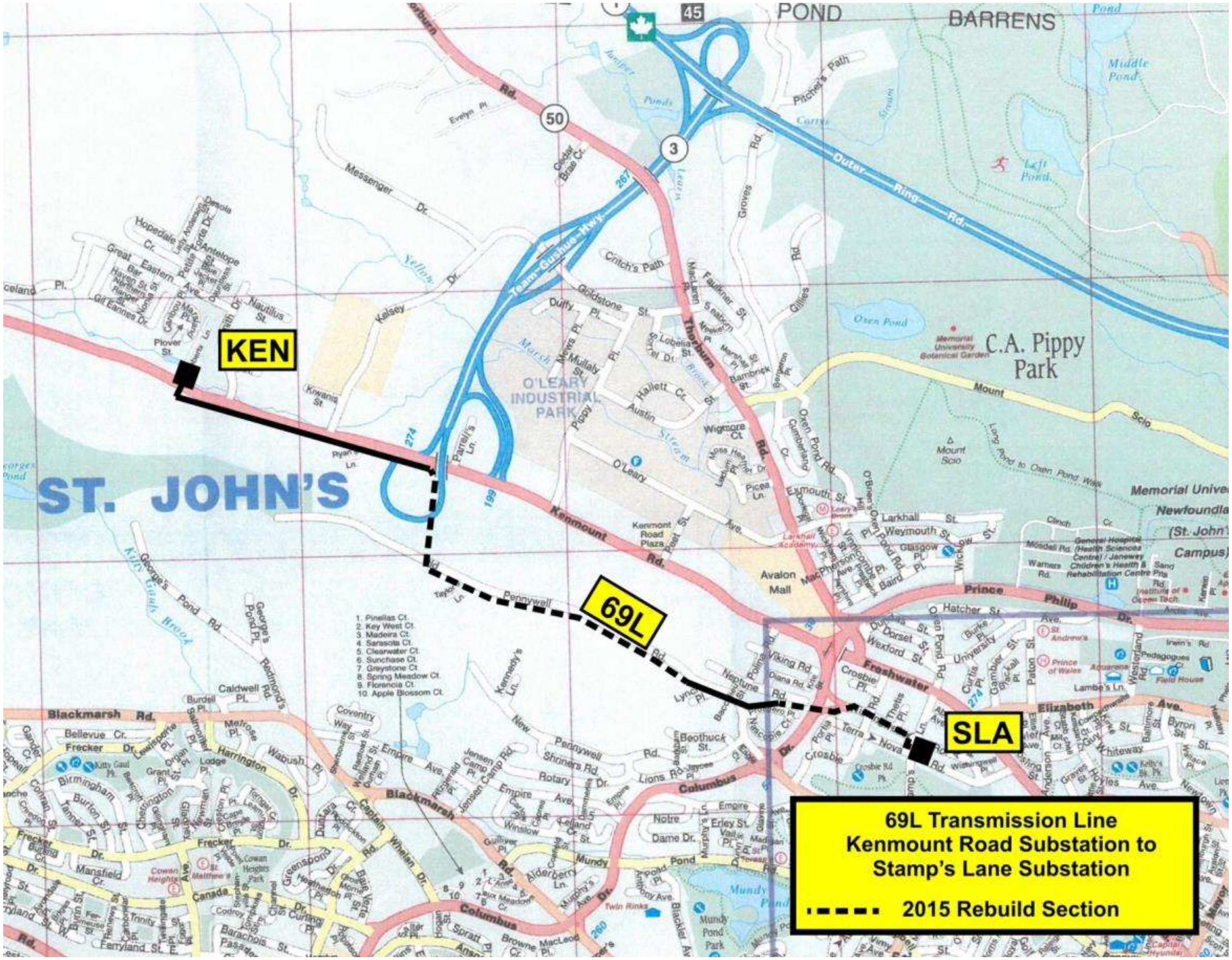

Figure 4 – Map of 69L Route

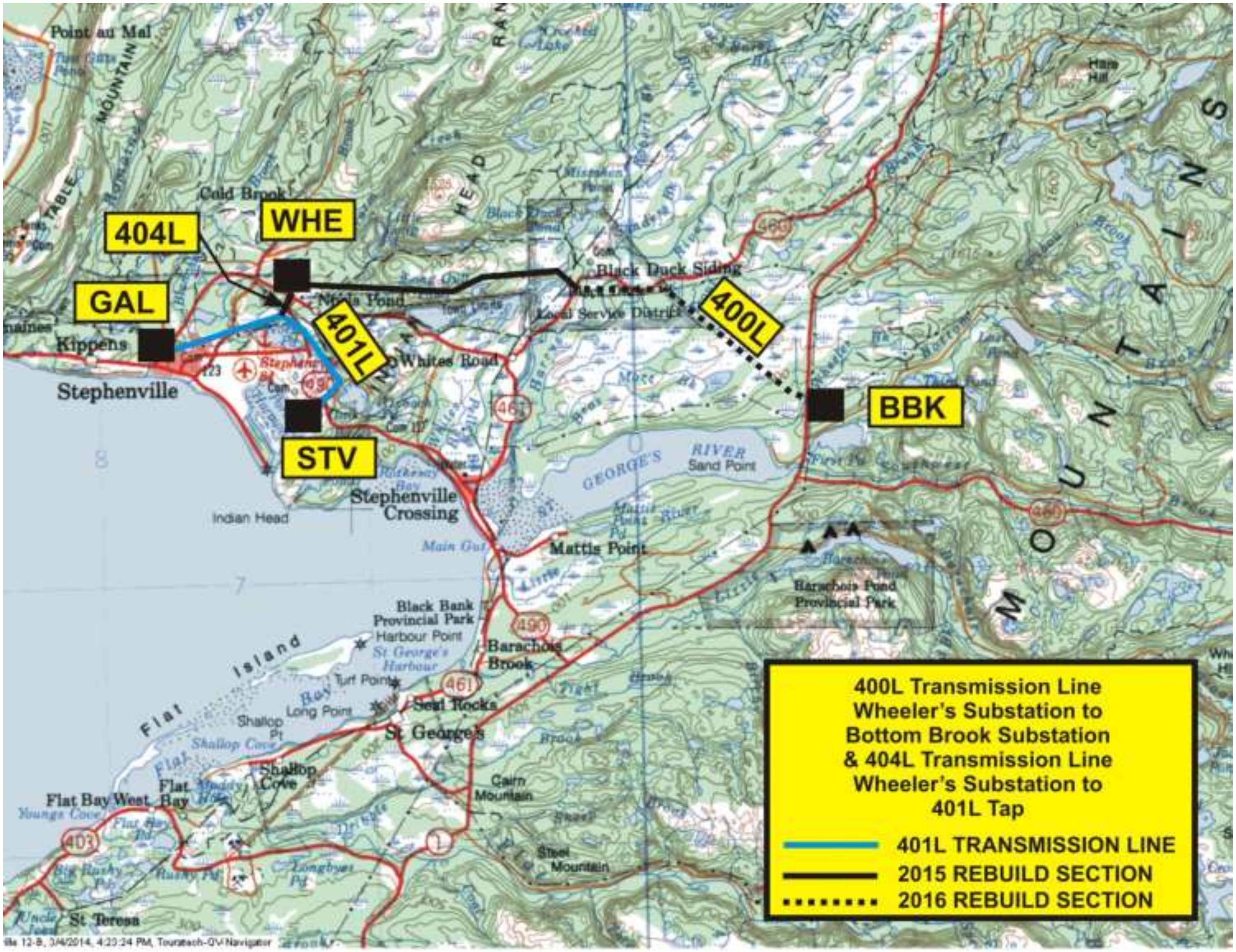

Figure 5 – Map of 400L Route

Appendix C
Photographs of Transmission Lines
14L, 15L, 30L, 69L and 400L

<u>Transmission Line 14L</u>

Figure 1 – Severe Checking in Pole

Figure 2 – Deteriorated Pole

Figure 3 – Pole Checking and Deteriorated Crossarm

Figure 4 – Pole Shell Damage

Transmission Line 15L

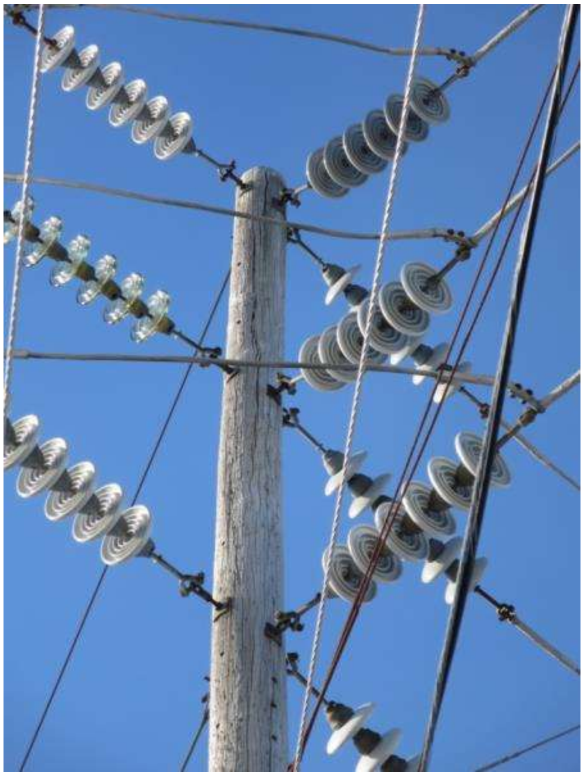

Figure 5 – Split Pole Top and Checking on Dead-End Structure

Figure 6 – Damaged Pole

Figure 7 – Deteriorated Pole Top

Figure 8 – Split Crossarms

Transmission Line 30L

Figure 9 – Pole Checking

Figure 10 – 1950's Vintage Insulators and Hardware

Figure 11 – Pole Damage

Figure 12 – Burned Pole

Figure 13 – Split Crossarm

Figure 14 – Bolts Provide Temporary Repairs to Damaged Pole

<u>Transmission Line 69L</u>

Figure 15 – Pole Checking and Original Vintage Insulators

Figure 16 – Conductor Corrosion

Figure 17 – Pole Damage

Figure 18 – Damaged Crossarm

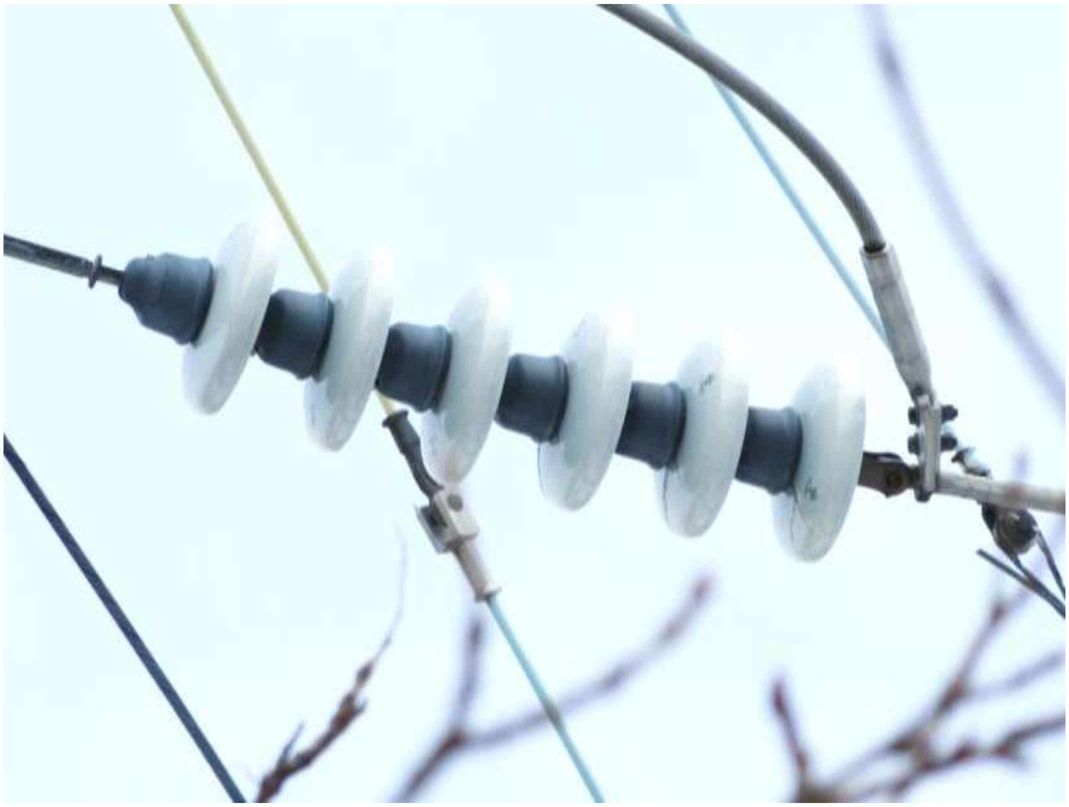

Figure 19 – Hairline Cracks in Insulators

Figure 20 – Deteriorated Pole

Transmission Line 400L

Figure 21 – Pole and Hardware Damage at Guy Wire Attachment

Figure 22 – Pole Shell Separation

Figure 23 – Significant Pole Checking Due To Shell Separation

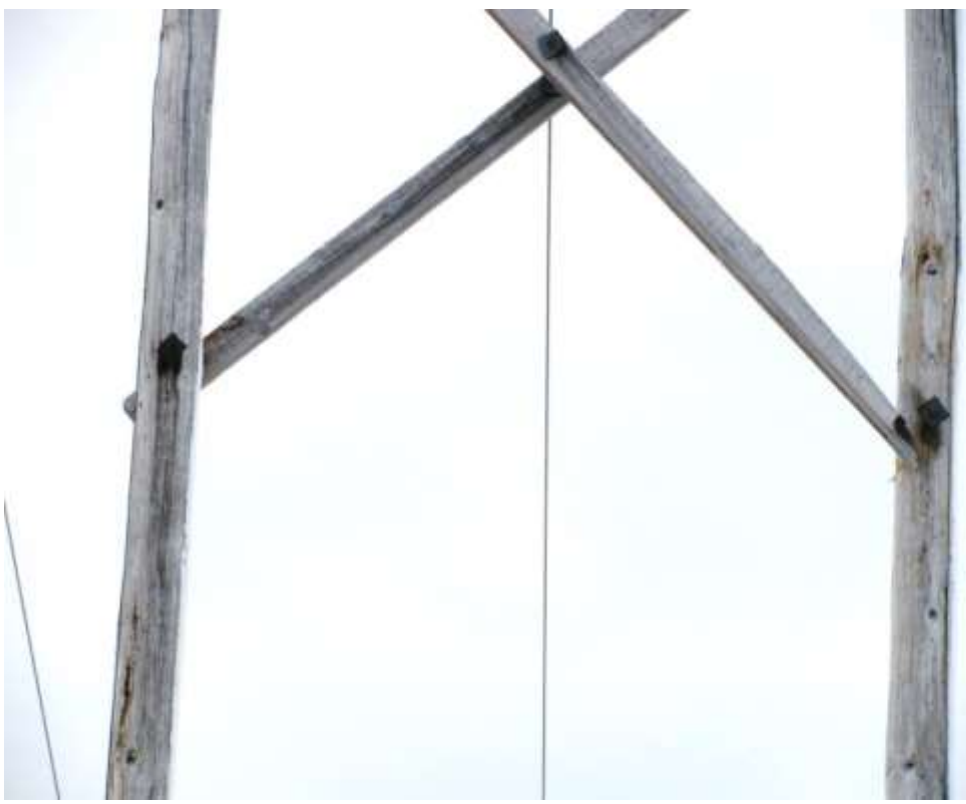

Figure 24 – Crossbrace Damage

Figure 25 – Severe Pole Checking Due to Shell Separation

Figure 26 – Split Pole Top and Checking

Figure 27 – Repairs to Conductor Due to Phase Contact Damage

Figure 28 – Pole Shell Separation Showing Exposed Inner Wood

Figure 29 – Deep Checking Due to Shell Separation

Figure 30 – Pole Shell Separation

Figure 31 – Deep Pole Checking

Figure 32 – Exposed Inner Wood

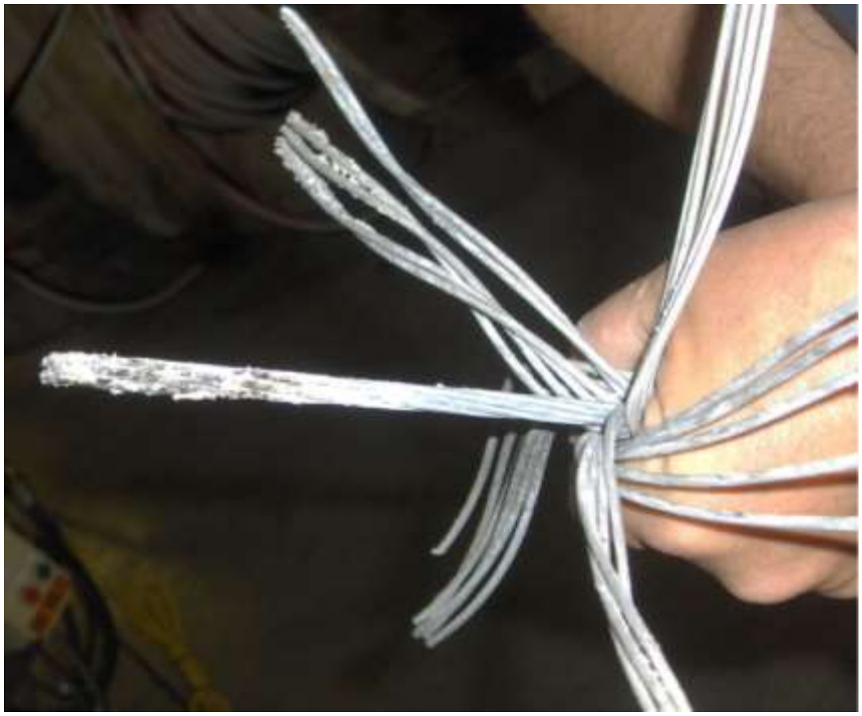

Figure 33 – Oxidization and Corrosion of 266.8 ACSR Steel Core

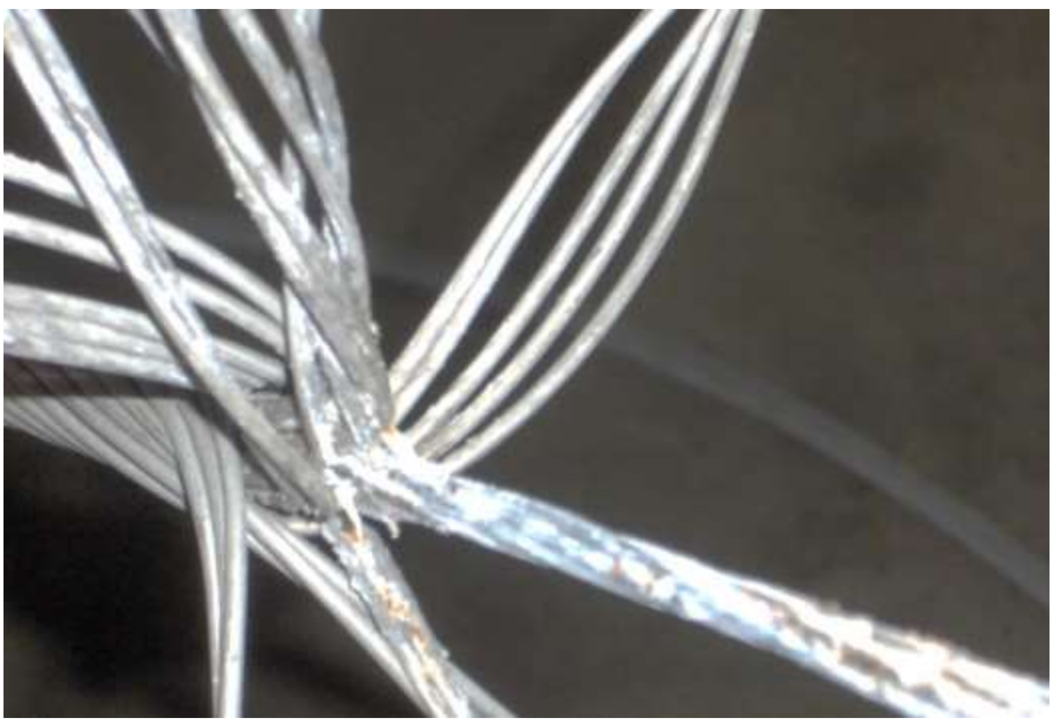

Figure 34 – Oxidization and Corrosion of 266.8 ACSR Conductor

Figure 35 – Corroded Conductor in Foreground

Figure 36 – Deteriorated Crossarm

Figure 37 – Bolts Keeping Broken Pole Together

Figure 38 - Bolts Keeping Broken Pole Together

Figure 39 – Deteriorated Pole Crib

Figure 40 – Deteriorated Pole Crib Timber

Figure 41 – Rock Ballast No Longer Contained

Figure 42 – Deteriorated Pole Crib Timber

Figure 43 – Bent Structure

Figure 44 – Broken Crossarm

Figure 45 – Bolt No Longer Securing Cross Brace

Figure 46 – Broken Crossarm

Figure 47 – Cracks in COB Type Insulator

Figure 48 – Cracks in OB Type Insulator

Distribution Reliability Initiative

June 2014

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1.0 Introduction

The Distribution Reliability Initiative is a capital project focusing on the reconstruction of the worst performing distribution feeders. Customers on these feeders experience more frequent and longer duration outages than the majority of customers.

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 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 complete 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 upon the engineering assessments completed as part of the process.

2.0 Background

Previously 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 the overall system condition.[2] SAIDI and SAIFI are used to rank the reliability performance of distribution feeders on the impact outages have on individual customers. However, it is recognised that relying solely on these indices to identify worst performing feeders can lead to overlooking smaller feeders with chronic issues.[3]

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").[4] 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 two 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] Over the period 1999 to 2011 Newfoundland Power spent approximately $17.5 million on Distribution Reliability Initiative projects almost exclusively in rural areas of its service territory.

[3] Smaller feeders will have fewer customers than larger feeders and as a result outages of similar duration will involve less customer minutes of outage.

[4] 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.

infrastructure condition and better identify issues associated with shorter feeders. Similar to SAIDI and SAIFI, CHIKM and CIKM are used to rank worse 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's has incorporated CIKM and CHIKM into its reliability analysis in this report.[5] Appendix A contains the 5-year average distribution reliability data, excluding significant events, for the 15 worst performing feeders based on data for 2009 to 2013 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 proposed on 2 St. John's distribution feeders, KBR-10 and MOL-09.

A detailed engineering assessment of each distribution feeder is included in Appendix C and Appendix D to this report.

Table 1 summarizes the reliability data for each of the 2 distribution feeders.

Table 1
Distribution Interruption Statistics
5-Years to December 31, 2013

Feeder	Customers	SAIFI	SAIDI	CHIKM	CIKM
KBR-10[6]	950	1.21	2.20	313.0	172.3
MOL-09[7]	1,930	1.73	2.13	403.4	327.2
Company Average	**-**	**1.12**	**1.68**	**57.3**	**44.5**

Table 1 clearly demonstrates that distribution feeders KBR-10 and MOL-09 are not outliers from the Company average for SAIDI and SAIFI. When you consider customer interruptions and circuit length it is clear that these 2 distribution feeders are outliers from the Company average

5 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.

6 KBR-10 is ranked 6th in terms of CHIKM and 12th in terms of CIKM. The condition of the aerial cables along Kings Bridge Road and the complexity associated with replacement following an in service failure is the basis of the decision to upgrade this section of KBR-10 in 2015.

7 MOL-09 is ranked 1st in terms of CHIKM and 3rd in terms of CIKM.

for CHIKM and CIKM. An analysis of the outage data reveals that equipment failure has been the cause of most of the outages experienced. Both feeders are constructed from some of the oldest poles and related infrastructure in service in the City of St. John's.[8]

4.0 Project Cost

The estimate to complete all work associated with the 2015 Distribution Reliability Initiative project is $863,000. Table 2 provides a detailed breakdown of the total project cost by distribution feeder.

Table 2
Project Cost

Description	KBR-10	MOL-09	Total
Engineering	15,000	43,000	58,000
Labour - Contract	56,000	211,000	267,000
Labour - Internal	57,000	137,000	194,000
Material	33,000	107,000	140,000
Other	50,000	154,000	204,000
Total	**211,000**	**652,000**	**863,000**

[8] The average age of poles that comprise these 2 distribution feeders is 47 years for KBR-10 and 37 years for MOL-09. The average age of poles for the entire Company is 27 years. The poles on these 2 feeders are significantly older than the average pole used throughout the Company.

Appendix A
Distribution Reliability Data: Worst Performing Feeders

Unscheduled Distribution Related Outages Five-Year Average 2009-2013 Sorted By Customer Minutes of Interruption				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
DLK-03	2,532	466,006	1.95	5.98
KEN-04	6,186	456,537	2.41	2.96
KEN-03	5,694	443,433	2.09	2.72
GLV-02	2,284	425,622	1.53	4.74
DOY-01	3,582	417,383	2.13	4.14
GBY-03	3,209	388,540	4.17	8.42
CHA-02	4,981	379,453	2.11	2.68
DUN-01	1,890	366,002	1.91	6.18
SUM-01	3,591	363,405	1.99	3.35
RRD-09	4,221	362,935	2.23	3.20
HWD-07	4,503	362,328	1.74	2.34
GFS-02	4,937	360,067	3.06	3.73
BOT-01	2,560	355,644	1.52	3.51
GFS-06	3,709	337,154	2.12	3.21
LEW-02	1,889	324,545	1.29	3.69
Company Average	**918**	**82,398**	**1.12**	**1.68**

Unscheduled Distribution Related Outages Five-Year Average 2009-2013 Sorted By Distribution SAIFI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
GBY-03	3,209	388,540	4.17	8.42
GBY-02	2,831	201,360	3.10	3.68
GFS-02	4,937	360,067	3.06	3.73
MSY-03	4,294	303,488	3.05	3.59
FER-01	1,806	170,049	2.82	4.43
GIL-01	2,737	245,803	2.71	4.06
LAU-01	1,830	140,962	2.63	3.37
CAB-01	3,294	248,357	2.61	3.29
MOB-01	3,741	156,372	2.58	1.79
GBY-01	1,565	156,097	2.53	4.20
KEN-04	6,186	456,537	2.41	2.96
HUM-09	1,283	160,593	2.23	4.65
RRD-09	4,221	362,935	2.23	3.20
DOY-01	3,582	417,383	2.13	4.14
MOL-06	2,903	312,687	2.13	3.82
Company Average	**918**	**82,398**	**1.12**	**1.68**

Unscheduled Distribution Related Outages Five-Year Average 2009-2013 Sorted By Distribution SAIDI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
GBY-03	3,209	388,540	4.17	8.42
DUN-01	1,890	366,002	1.91	6.18
DLK-03	2,532	466,006	1.95	5.98
SUM-02	636	205,189	1.05	5.65
SCR-01	4	321,685	1.23	5.54
LGL-02	1,091	197,685	1.73	5.23
RVH-02	175	46,712	1.14	5.06
GLV-02	2,284	425,622	1.53	4.74
HUM-09	1,283	160,593	2.23	4.65
FER-01	1,806	170,049	2.82	4.43
GBY-01	1,565	156,097	2.53	4.20
BUC-02	135	40,260	0.85	4.19
DOY-01	3,582	417,383	2.13	4.14
ABC-01	1,373	193,747	1.76	4.14
NCH-02	739	162,430	1.11	4.08
Company Average	**918**	**82,398**	**1.12**	**1.68**

Unscheduled Distribution Related Outages **Five-Year Average** **2009-2013** **Sorted By Distribution CHIKM**	
Feeder	**Annual Distribution CHIKM**
MOL-09	403.4
MOL-04	357.2
KBR-02	326.3
KBR-01	325.3
SLA-09	317.2
KBR-10	313.0
KEN-03	306.9
GFS-02	275.2
KEN-04	269.3
HWD-07	241.6
MOL-06	234.4
MOL-08	232.6
PEP-01	197.4
HUM-09	194.9
RRD-09	186.9
Company Average	**57.3**

Unscheduled Distribution Related Outages Five-Year Average 2009-2013 Sorted By Distribution CIKM	
Feeder	**Annual Distribution CIKM**
RRD-09	582.0
GFS-02	452.8
MOL-09	327.2
KEN-03	236.4
KEN-04	218.9
KBR-01	192.1
KBR-02	185.2
MOL-04	180.3
HWD-07	180.1
SLA-09	178.5
RVH-02	175.0
KBR-10	172.3
MOL-08	171.5
KBR-04	167.3
GOU-01	156.1
Company Average	**44.5**

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 related event in February 2010 and a faulted lightning arrestor in 2010. There was also a sleet related incident in 2011. No work is required at this time.
BOT-01	Reliability statistics in 2010 were poor due to damage caused by a vehicle accident. In 2013 trees falling across the line during a wind storm contributed to poor reliability. No work is required at this time.
BUC-02	Reliability problems in 2008 were due to 3 insulator failures in 2008. Insulators were replaced in 2009. There were 2 incidents of broken conductor in 2011 and a problem with a tree contacting the line in 2013. No work is required at this time.
CAB-01	Reliability was poor in 2012 principally due to 2 separate tree related incidents. A wind storm in 2013 also contributed to poor reliability. No work is required at this time.
CHA-02	Reliability statistics were driven by a single broken insulator event in June 2009. No work is required at this time.
DLK-03	Reliability statistics were driven by a broken conductor in November 2009, a single weather related event in 2011 and several incidents of trees contacting the line in 2013. 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 average statistics are also driven by weather related events in each of 2009, 2010 and 2012. Work is planned under the 2014 Feeder Additions for Load Growth project to address the single-phase taps issue. No further work is required at this time.
DUN-01	Poor reliability statistics were driven by a broken pole in 2009. Reliability improved greatly in 2010 and 2011. Poor reliability in 2012 was due to vegetation issues. No work is required at this time.
FER-01	Reliability statistics were driven by a tree related event in 2009. No work is required at this time.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
GBY-01	GBY-01 has had good reliability over the years. A lightning related event resulted in poor overall reliability in 2012. In addition a tree contacted the line in late 2013. No work is required at this time.
GBY-02	GBY-02 has had good reliability over the years. A wind related event resulted in poor overall reliability in 2012. No work is required at this time.
GBY–03	Reliability statistics were driven by isolated weather related events in each of 2009, 2010, 2011 and 2013. This feeder had significant upgrades as part of the 2011 Rebuild Distribution Lines project. No work is required at this time.
GFS-02	Reliability statistics were driven by a tree related event in October 2009 and storm damage in November 2013. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. An engineering assessment is required to determine if this feeder should be included for rebuilding in a future capital budget.
GFS-06	Reliability problems relate to vegetation issues in 2009 and 2011. A storm in November 2013 also contributed to reduced reliability statistics. No work is required at this time.
GIL-01	Reliability statistics were driven by a tree related event in October 2010 and blizzard conditions in December 2013. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. An engineering assessment is required to determine if this feeder should be included for rebuilding in a future capital budget.
GLV-02	Poor reliability statistics in 2010 were due to problems accessing the line through Terra Nova Park in response to a tree related event. A sleet storm in 2012 impacted reliability as well as a vegetation related incident in 2013. No work is required at this time.
GOU-01	Reliability statistics were driven by a wind related event in 2010 and broken conductor in December 2013. No work is required at this time.

Worst Performing Feeders **Summary of Data Analysis**	
Feeder	**Comments**
HUM-09	Reliability statistics were driven by a tree related event in 2010 and a failed lightning arrestor in 2013. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. An engineering assessment is required to determine if this feeder should be included for rebuilding in a future capital budget.
HWD-07	Reliability statistics were driven by a failed cut-out in 2010 and issues related to high winds in February 2013 and December 2013. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. An engineering assessment is required to determine if this feeder should be included for rebuilding in a future capital budget.
KBR-01	Reliability statistics were driven by a wind related outage in 2009 and a broken pole caused by a vehicle accident in 2011. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. An engineering assessment is required to determine if this feeder should be included for rebuilding in a future capital budget.
KBR-02	Reliability statistics were driven by 3 incidents of equipment failure over the 2009 to 2013 period. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. An engineering assessment is required to determine if this feeder should be included for rebuilding in a future capital budget.
KBR-04	Reliability statistics were driven by 2 tree related incidents, one in 2010 and one in 2013. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. An engineering assessment is required to determine if this feeder should be included for rebuilding in a future capital budget.
KBR-10	Over the period 2009 to 2013 this feeder has had 6 feeder level outages due to equipment failure. The condition of the aerial cable along Kings Bridge Road is of particular concern. An engineering assessment determined work is required in 2015.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
KEN-03	KEN-03 has had good reliability over the years. A sleet storm in 2009, a broken insulator in 2012 and issues which occurred with a new pole installation in 2013 led to reduced reliability. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. An engineering assessment is required to determine if this feeder should be included for rebuilding in a future capital budget.
KEN-04	KEN-04 has had good reliability over the years. Two events, a pole hit by a vehicle and a lightning strike resulted in poor overall reliability in 2012. No work is required at this time.
LGL-02	Reliability statistics were driven by wind in 2010, salt spray and a broken conductor in 2013. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. An engineering assessment is required to determine if this feeder should be included for rebuilding in a future capital budget.
LEW-02	Reliability statistics were impacted by fallen trees contacting lines in 2009 and 2011. A pole hit by a vehicle resulted in poor reliability statistics in 2013. No work is required at this time.
MOB-01	MOB-01 has had good reliability over the years. Broken conductor in 2011 and a broken pole and crossarm as a result of a vehicle accident in 2013 were the prime reasons for the poor reliability statistics experienced in recent years. No work is required at this time.
MOL-04	MOL-04 has had good reliability over the years. Several weather events resulted in poor overall reliability in 2012. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. An engineering assessment is required to determine if this feeder should be included for rebuilding in a future capital budget.
MOL-06	MOL-06 has had good reliability over the years. Trees contacting the line caused problems in 2009 and 2013. Broken conductor caused an extended outage in 2011. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. An engineering assessment is required to determine if this feeder should be included for rebuilding in a future capital budget.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
MOL-08	Broken conductor in 2009 and 2010 and a broken insulator in 2012 were the only significant issues on MOL-08. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. An engineering assessment is required to determine if this feeder should be included for rebuilding in a future capital budget.
MOL-09	Over the period 2009 to 2013 this feeder has had 6 feeder level outages due to equipment failure. The feeder also had multiple outages to long taps due to equipment failure. An engineering assessment determined work is required in 2015.
MSY-03	Reliability statistics were driven by a broken conductor event in each of 2012 and 2013. No work is required at this time.
NCH-02	Reliability statistics were driven by vegetation related event in 2011 and problems during a wind storm in 2013. No work is required at this time.
PEP-01	Reliability statistics were driven by broken conductor in September 2010. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. An engineering assessment is required to determine if this feeder should be included for rebuilding in a future capital budget.
RRD-09	Reliability problems were due to broken conductor in 2011. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. An engineering assessment is required to determine if this feeder should be included for rebuilding in a future capital budget.
RVH-02	Reliability problems were due to 2 events; a blizzard and a broken crossarm in 2011. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. An engineering assessment is required to determine if this feeder should be included for rebuilding in a future capital budget.
SCR-01	Reliability statistics were driven by a wind related event in November 2011 and a tree contacting the line in 2013. No work is required at this time.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
SCT-02	Reliability problems were due a tree contacting the line in 2010. No work is required at this time.
SLA-09	Poor overall reliability is due to an underground cable fault in 2011. This feeder is one of the Company's worst performing from an interruption per kilometer perspective. An engineering assessment is required to determine if this feeder should be included for rebuilding in a future capital budget.
SUM-01	Three events, one involving salt spray and the other broken conductor resulted in poor overall reliability in 2012. In 2013 an issue occurred with a broken insulator. No work is required at this time.
SUM-02	Reliability statistics were driven by 2 tree related events in May and December 2011 and a weather event in 2012. No work is required at this time.

Appendix C
Kings Bridge KBR-10 Feeder Study

June 2014

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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 2015 Distribution Reliability Initiative identified the KBR-10 feeder as one the *worst performing feeders* on Newfoundland Power's distribution system. An engineering evaluation of the feeder was carried out in early 2014. This report summarizes the findings of that evaluation and presents a plan to improve reliability on the feeder.

2.0 KBR-10 Feeder

The KBR-10 feeder is one of 12 distribution feeders originating from Kings Bridge Substation ("KBR"). The feeder has ties to 3 other St. John's feeders making it a critical feeder for transferring load between feeders when needed in the east end of the City.[1]

KBR-10 is a 12.5 kV distribution feeder that was originally constructed in the early 1960's serving approximately 950 customers. The feeder leaves the substation located on Kings Bridge Road between Empire Avenue and Winter Avenue and extends south along Kings Bridge Road then splits to supply the east end of Gower Street and the east end of Water Street including Signal Hill and the Battery. KBR-10 exits the substation underground with 750 MCM cross-linked polyethylene ("XLPE") cable before transitioning to overhead aerial cable on Kings Bridge Road.[2] The first 700 meter section of the main trunk along Kings Bridge Road and Ordinance Street is aerial cable. KBR-10 is 1 of 4 aerial cable feeders that are all attached to a single pole line along Kings Bridge Road.[3]

The 600 meter 3-phase section extending down Gower Street as far as Prescott Street is constructed using 1/0 copper conductor. The approximate 1.0 km section along Water Street and heading up Signal Hill through the Battery is also constructed using 1/0 copper conductor.

All of the poles comprising KBR-10 are installed in the sidewalk immediately behind the curb. Due to the age of this part of the City of St. John's, the homes and buildings along these streets are constructed along the edge of the sidewalk. This has required the use of alley-arm

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[1] Load is transferred between feeders during planned work and during unplanned emergencies to minimize the frequency and duration of customer outages.

[2] Aerial cable is an insulated cable assembled from 3 separate single-phase cables bundled together around a messenger wire. Aerial cables have wind and ice loading factors much larger than bare aluminum cable requiring larger poles with shorter span length. Most of the Company's aerial cable is more than 40 years old and is no longer a standard design for distribution feeders.

[3] Appendix C-1 includes a map showing the areas served by distribution feeder KBR-10.

construction for sections of the open wire 3-phase line to maintain clearance to homes and buildings.[4]

3.0 Engineering Assessment

Inspections have identified deterioration due to decay, splits and checks in the poles and crossarms, as well as deficiencies with guys, anchors, hardware and insulators on the feeder. Due to the proximity to the road, damage to the outer layers of the poles from vehicles and snowplows has impacted the structural integrity of the support structures. In addition 2-piece insulators are still in use on the main trunk section of the feeder. The 2-piece insulators have a documented high failure rate related to cement growth and are a particular concern on a heavily loaded urban feeder.[5] Due to the age and condition of the support structures they are susceptible to damage when exposed to severe wind, ice and snow loading. This distribution feeder was built to weather loading criteria that are less than the standard currently used for new construction.

The most critical reliability issue with this feeder in recent years has been the aerial cable running along Kings Bridge Road and Ordinance Street. The aerial cable has faulted twice in the past 3 years.[6] The age and physical condition of the aerial cable makes it highly likely that there will be further cable faults experienced.

The 1/0 copper conductor running along Gower Street as far as Prescott Street and along Water Street and heading up Signal Hill through the Battery is nonstandard and showing signs of deterioration.[7]

Table 1 summarizes the reliability data for KBR-10 distribution feeder for the most recent 5-year period.

Table 1
KBR-10 Distribution Interruption Statistics
5-Years to December 31, 2013

	Customers	SAIFI	SAIDI	CHIKM	CIKM
	950	1.21	2.20	313.0	172.3
Company Average	**-**	**1.12**	**1.68**	**57.3**	**44.5**

---

4 Alley-arm construction is when a crossarm and bracing is placed on one side of a pole to provide clearance from a building or vegetation. The alley-arm structure appears to be an inverted “L”. Appendix C-2, Figure 1 includes a photograph of an alley-arm structure showing nonstandard framing and clearances.

5 Since the 1960’s 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 that fails in tension by cracking.

6 The condition of the aerial cable is such the refurbishment of KBR-10 should take place in advance of other distribution feeders with worse reliability indices. Figure 2 of Appendix C-2 is a photograph of a faulted section of the KBR-10 aerial cable.

7 Newfoundland Power no longer uses 1/0 copper conductor in new construction.

Table 1 clearly demonstrates that distribution feeder KBR-10 is not an outlier from the Company average for SAIDI and SAIFI. Considering customer interruptions and circuit length it is clear that this distribution feeder is an outlier from the Company average for CHIKM and CIKM. Distribution feeder KBR-10 is constructed from some of the oldest poles and related infrastructure in service in the City of St. John's. 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 KBR-10 feeder is a critical part of the Company's distribution system in the east end and downtown areas of St. John's. The majority of the reliability issues on this line are due to aging and substandard infrastructure and particularly the aerial cable running along Kings Bridge Road and Ordinance Street.

To improve the performance and reliability of this feeder, it is recommended that:

- The pole line along Kings Bridge Road and Ordinance Street be upgraded including the replacement of 24 deteriorated poles and 19 anchors;[8]

- The nonstandard 1/0 copper conductor be replaced. The 25 spans of standard 3-phase open wire construction will be rebuilt with 477 mcm AASC conductor and the 26 spans of single-phase line will be rebuilt with 1/0 ASC conductor;

- All remaining 2-piece insulators on the main trunk of KBR-10 feeder be replaced with 34 kV clamp top insulators and V-brace crossarms; and

- The existing aerial cable be replaced with standard 3-phase open wire construction.

It is proposed to complete the required work in 2015 at an estimated cost of $211,000.

8 There are 413 poles on this distribution feeder. The poles being replaced range in age from 26 to 47 years in service. The primary reason for replacement of the younger poles is excessive loading and damage from vehicles and snow plows.

Appendix C-1
Map Showing Areas Serviced by KBR-10


KBR Substation
KBR
Atlantic Ocean
SIGNAL HILL RD
WATER ST
KBR-10
The Battery
OUTER BATTERY RD
U S ARMY DOCK RD
LOWER BATTERY RD
BATTERY RD
KINGS RD
BARNES RD
CIRCULAR RD
FOREST RD
CAVELL AVE
GILLS COVE
QUEENS COVE
TEMPERANCE ST
ORDNANCE ST
PLYMOUTH RD
DUCKWORTH ST

Appendix C-2
Photographs of KBR-10 Feeder

Figure 1 - KBR-10 Pole with Alley Arm Type Crossarm

Figure 2 - KBR-10 Faulted Aerial Cable

Figure 3 - Pole Leaning Towards Traffic

Figure 4 - Loss of Pole Diameter at Base

Figure 5 - Guy Bent Towards Sidewalk

Figure 6 - Deteriorated Pole

Figure 7 – Aerial Cable Splice

Appendix D
Molloy's Lane MOL-09 Feeder Study

June 2014

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Page

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 2015 Distribution Reliability Initiative identified the MOL-09 feeder as one the *worst performing feeders* on Newfoundland Powers distribution system. An engineering evaluation of the feeder was carried out in early 2014. This report summarizes the findings of that evaluation and presents a plan to improve reliability on the feeder.

2.0 MOL-09 Feeder

The MOL-09 feeder is one of 8 distribution feeders originating from Molloy's Lane Substation ("MOL"). The feeder has ties to 5 other St. John's feeders making it a critical feeder for transferring load between feeders in the City's core when needed.[1]

MOL-09 is a 12.5 kV distribution feeder that was originally constructed in the early 1970's serving approximately 1,930 customers. The feeder extends from the substation located on Topsail Road just east of Columbus Drive and heads east on Topsail Road and Cornwall Avenue. The feeder also has 3-phase lines extending down Craigmillar Avenue, Hamilton Avenue and Blackmarsh Road.[2]

The main 3-phase trunk portion of MOL-09 on Topsail Road and Cornwall Avenue is approximately 1.8 km in length. The conductor on this section of line is a mixture of 397 Aluminum Conductor Steel Reinforced ("ACSR"), 4/0 Aluminum Alloy Stranded Conductor ("AASC") and 477 Aluminum Stranded Conductor ("ASC").

There are 2 long 3-phase taps on Craigmillar Avenue, Hamilton Avenue and Blackmarsh Road. The Craigmillar Avenue section is approximately 1.0 km in length and has a tie point with SJM-11 distribution feeder. This entire section has 1/0 copper conductor.

The Hamilton Avenue/Blackmarsh Road section is approximately 1.1 km in length. There is 1/0 copper conductor on Hamilton Avenue and 477 ASC on Blackmarsh Road. There is a tie point with distribution feeder MOL-08 at the Hamilton Avenue and Blackmarsh Road intersection and a tie point with distribution feeder SJM-13 on Blackmarsh Road.

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[1] Load is transferred between feeders during planned work and during unplanned emergencies to minimize the frequency and duration of customer outages.

[2] Appendix D-1 includes a map showing the areas served by distribution feeder MOL-09.

There are also various sections of single-phase construction throughout the distribution feeder, half of which are within the first 0.9 km of the MOL-09 feeder.

3.0 Engineering Assessment

Inspections have identified deterioration due to decay, splits and checks in the poles and crossarms, as well as deficiencies with guys, anchors, hardware and insulators on the feeder. Due to the proximity to the road, damage to the outer layers of the poles from vehicles and snowplows has impacted the structural integrity of the support structures. In addition 2-piece insulators are still in use on the main trunk section of the feeder. The 2-piece insulators have a documented high failure rate related to cement growth and are a particular concern on a heavily loaded urban feeder.[3] Due to the age and condition of the support structures they are susceptible to damage when exposed to severe wind, ice and snow loading. This distribution feeder was built to weather loading criteria that are less than the standard currently used for new construction.

The poles along the Topsail Road and Cornwall Avenue section of the line are heavily loaded. This heavy loading is a significant concern for failure along this section given the extent of the deterioration identified on some of the poles and importance of the line as a tie point with other feeders in the area.

The 1/0 copper conductor running along Hamilton Avenue to Blackmarsh Road is substandard and showing signs of deterioration. In addition to reliability concerns the substandard conductor impairs load transfer capability.

Table 1 summarizes the reliability data for MOL-09 distribution feeder for the most recent 5-year period.

Table 1
MOL-09 Distribution Interruption Statistics
5-Years to December 31, 2013

	Customers	SAIFI	SAIDI	CHIKM	CIKM
	1,930	1.73	2.13	403.4	327.2
Company Average	**-**	**1.12**	**1.68**	**57.3**	**44.5**

Table 1 clearly demonstrates that distribution feeder MOL-09 is not an outlier from the Company average for SAIDI and SAIFI. Considering customer interruptions and circuit length it is clear that this distribution feeder is an outlier from the Company average for CHIKM and CIKM. Distribution feeder MOL-09 is constructed from some of the oldest poles and related

[3] Since the 1960's 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 that fails in tension by cracking.

infrastructure in service in the City of St. John's. 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 MOL-09 feeder is a critical part of the Company's distribution system in the west end of the City of St. John's. Over the past 5 years the majority of the reliability issues on this line have been due to aging and substandard infrastructure and heavy loading.

To improve the performance and reliability of this feeder, it is recommended to:

- Re-conductor the 0.5 km section of line from Hamilton Avenue to Blackmarsh Road with 477 ASC (Aluminum Stranded Conductor).

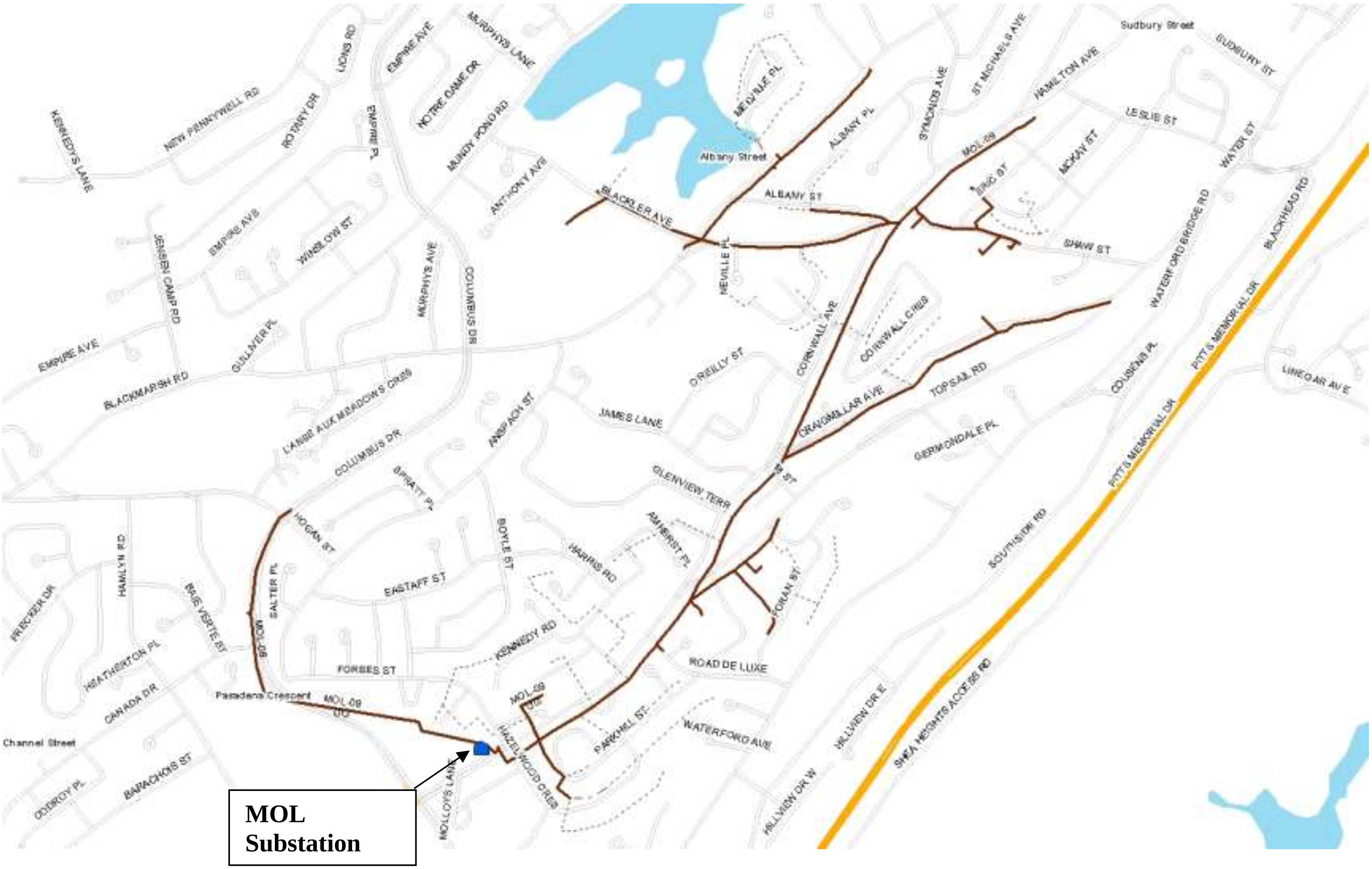
- Upgrade 71 deteriorated or overloaded poles and 33 anchors throughout the feeder.[4]

- Replace remaining 2-piece insulators on the main trunk portion of MOL-09 feeder with 34 kV clamp top insulators and V-brace crossarms.

It is proposed to complete the required work in 2015 at an estimated cost of $652,000.

[4] There are 358 poles on this distribution feeder. The poles being replaced range in age from 36 to 64 years in service. The primary reason for replacement of the younger poles is excessive loading and damage from vehicles and snow plows.

Appendix D-1
Map Showing Areas Served by MOL-09


MOL
Substation
MOL-09
Albany Street
ALBANY ST
BLACKLER AVE
NEVILLE PL
SHAW ST
LESLIE ST
Sudbury Street
SUDBURY ST
HAMILTON AVE
ST MICHAELS AVE
SYMONDS AVE
ALBANY PL
MCKAY ST
WATER ST
BLACKHEAD RD
WATERFORD BRIDGE RD
PITTS MEMORIAL DR
LINEGAR AVE
COUSENS PL
TOPSAIL RD
CRAIGMILLAR AVE
CORNWALL AVE
CORNWALL CRES
O'REILLY ST
JAMES LANE
GERMONDALE PL
GLENVIEW TERR
AMHERST PL
HARRIS RD
FORAN ST
ROAD DE LUXE
WATERFORD AVE
PARKHILL ST
HAZELWOOD CRES
MOLLOYS LANE
KENNEDY RD
FORBES ST
Pasadena Crescent
EASTAFF ST
BOYLE ST
SPRATT PL
HOGAN ST
SALTER PL
COLUMBUS DR
L'ANSE AUX MEADOWS CRES
ANSPACH ST
MURPHYS AVE
GULLIVER PL
BLACKMARSH RD
EMPIRE AVE
JENSEN CAMP RD
WINSLOW ST
NEW PENNYWELL RD
KENNEDYS LANE
ROTARY DR
LIONS RD
EMPIRE PL
NOTRE DAME DR
MUNDY POND RD
ANTHONY AVE
MURPHYS LANE
HAMLYN RD
BAIE VERTE ST
HEATHERTON PL
CANADA DR
Channel Street
GODROY PL
BARACHOIS ST
SOUTHSIDE RD
HILLVIEW DR E
HILLVIEW DR W
SHEA HEIGHTS ACCESS RD

Appendix D-2
Photographs of MOL-09 Feeder

Figure 1 – MOL-09 Pole Damage

Figure 2 - Pole Damage at Base

Figure 3 - Pole Damage

Figure 4 - Outer Shell Damage

Figure 5 – Pole Damaged by Vehicles

Figure 6 – Pole Damage near Base

Figure 7 – Pole Deteriorated at ground line

Figure 8 - Broken Crossarm, Leaning Pole, and Pole Replacement in Progress

Feeder Additions for Load Growth

June 2014

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1.0 Introduction

As load increases on an electrical system, the components of the system can become overloaded. These overload conditions 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.

This report identifies 4 overloaded conditions to be addressed as part of the 2015 Capital Budget. One situation will be addressed by increasing capacity on the overloaded section of conductor on the distribution feeder. The second and third situations will be addressed by upgrading overloaded single-phase lines to 3-phase. The fourth situation will be addressed by constructing a new distribution feeder to provide load transfer capability to adequately distribute the load on adjacent existing feeders.

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.

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;

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[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.

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.

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

MOB-01 Feeder Upgrade ($785,000)

Mobile Substation ("MOB") is located on the Southern Shore Highway ("Route 10") in the community of Mobile. There are two 12.5 kV distribution feeders terminated at MOB substation serving approximately 2,200 customers. MOB-01 distribution feeder leaves MOB substation and extends northward along Route 10 serving approximately 1,500 primarily residential customers in the communities of Mobile, Witless Bay and Bay Bulls. MOB-02 distribution feeder extends southward along Route 10 to serve approximately 700 primarily residential customers in the communities of Mobile and Tors Cove.

Two separate sections of the main trunk of distribution feeder MOB-01 are overloaded.[3] Each overloaded section identified was evaluated using all 4 available alternatives identified in section 2.2. The first overloaded section extends 3.0 km from the MOB substation to Carey's Road in the Town of Witless Bay. The conductor in this section is #4/0 AASC and is rated for 356 amps per phase. The balanced 2015 forecasted peak loads on each of the phases in this section are 407 amps per phase.[4]

---

[3] The MOB-01 distribution feeder map is included in Appendix B.
[4] The 407 amps amount to a 14% overload condition.

The second overloaded section extends 2.0 km from the intersection of Witless Bay Line and Route 10 in the Town of Witless Bay to Southside Road in the Town of Bay Bulls. The conductor in this section is #4 CU and is rated for 153 amps per phase. The balanced 2015 forecasted peak loads on each of the phases in this section are 228 amps per phase.[5]

The overload condition on MOB-01 can be attributed to residential subdivision growth in the Town of Witless Bay and the Town of Bay Bulls. Continued growth is expected as development of future phases of these subdivisions are planned or are currently under construction.

Feeder balancing is not an option for either of these overload conditions due to the fact that the combined forecasted peak currents exceed the total capacity of the three phase conductors. There is a tie point to a second distribution feeder from MOB substation through MOB-02 feeder, however due to the routing of each feeder and the available capacity of MOB-02, the tie point does not allow for the offloading of the MOB-01 feeder to resolve the overload condition. The tie point only allows for backup of a portion of MOB-01 feeder in the event of an unplanned outage or planned maintenance. There are no other existing tie points that would allow load to be transferred. Therefore, it is recommended that the first section be upgraded to 477 ASC conductor with a rating of 590 amps per phase and the second section be upgraded to #4/0 AASC conductor with a rating of 356 amps per phase.

2.4 Overloaded Single-Phase Lines

The capacity of a single-phase line is limited by the performance of feeder protection back on the 3-phase trunk feeder. A heavily loaded single-phase tap can result in unbalanced loads on the three phases of a feeder, and subsequent undesirable operation of the feeder protection at the substation.[6] This results in unnecessary outages to customers and extended time for restoring service. The unbalanced load condition can occur during peak load, cold load pickup or when a protection fuse operates on the single-phase tap. Eliminating the unbalanced condition caused by growth on the single-phase feeder taps will result in a more reliable distribution system.

Analysis of the Company's distribution feeders was completed using a distribution feeder computer modelling application to identify single-phase lines that may be overloaded.[7] Where necessary, load measurements were taken to verify the results of the computer simulation. Analysis has identified two locations where upgrades are required.

SCV-01 Feeder Upgrades ($259,000)

Two single-phase lines in the community of Upper Gullies are overloaded. The single-phase lines serving Scott's Road South and Lawrence Pond Road both exceed the Company's planning

[5] The 228 amps amount to a 49% overload condition.

[6] To detect faults, such as when a conductor breaks and falls to the ground, protection schemes are based on the measurement of differences between the current levels on each of the three phases on a distribution feeder. To maximize the chance that a line-to-ground fault is detected, the protection settings on a feeder are designed based on a minimal amount of difference, or unbalanced current.

[7] Overloaded single-phase taps typically start out as only a few spans in length, but over time can grow into much larger feeder extensions. The growth is most often occurs in new subdivisions, where a large number of customers requiring single-phase service are added over time.

criteria for maximum current on a single-phase distribution line.[8] Recent load growth on these 2 single-phase lines can be attributed to ongoing subdivision developments in the area. There are no adjacent distribution lines that could be extended to offload these single-phase lines. Therefore, it is recommended that approximately 1.5 km of single-phase distribution line on Scott's Road South and approximately 2.0 km of single-phase distribution line on Lawrence Pond Road be upgraded to 3-phases. This will improve overall reliability of the SCV-01 distribution feeder.

RBK-01 Feeder Upgrade ($386,000)

The single-phase line servicing the Sandy Point area in Central Newfoundland is overloaded. Sandy Point was once part of the community of Norris Arm South but because of population decline and out migration it has become more of a seasonal cottage area. Recent load growth on this single-phase line can be attributed to new residential construction by former residents permanently relocating back to the area for year round living. The single-phase line that serves this area exceeds the Company's planning criteria for maximum current on a single-phase distribution line.[9] There are no adjacent distribution lines that could be extended to offload this single-phase line. Therefore, it is recommended that approximately 6.0 km of single-phase distribution line on RBK-01 be upgraded to 3-phase. This will improve overall reliability of RBK-01 distribution feeder.

3.0 KEN-05 New Feeder Construction ($254,000)

Customers in the Kenmount Road area of St. John's are served from Kenmount Substation ("KEN"). KEN substation consists of two 25 MVA distribution power transformers that are used to convert a transmission level voltage of 66 kV to a distribution level voltage of 25 kV which is supplied to customers through 4 KEN distribution feeders. An engineering study has been completed on the distribution system alternatives that best meet the electrical demands of the Kenmount Road area.[10]

The study examined alternatives to determine the least cost approach to deal with the forecast overload conditions in the Kenmount Road area. Each alternative included the installation of new feeder capacity from KEN substation and was evaluated using a 20 year load forecast. Based on net present value calculations, the least cost alternative was selected.

The study identifies a project to be included in the Company's 2015 Capital Budget Application. The project involves replacement of an existing 25 MVA, 66 kV/25 kV power transformer with a new 50 MVA, 66 kV/25 kV power transformer at KEN substation and the addition of a 5th distribution feeder from KEN substation.[11]

The new distribution feeder will exit the rear of the substation and proceed north through Kenmount Terrace subdivision and interconnect with existing feeders KEN-02 and KEN-04.

---

8 The 2015 forecast load on the 2 single-phase lines is 111 and 101 amps respectively.

9 The 2015 forecast load on the single-phase line is 105 amps.

10 The study is included as Attachment D to the report ***2.2*** *2015 Additions Due to Load Growth* filed with this 2015 Capital Budget Application.

11 The new feeder will be designated KEN-05.

This new distribution feeder will be used to offload portions of KEN-02 and KEN-04 feeders.[12] These permanent load transfers will adequately distribute the existing load on the feeders and provide capacity for the continued load growth forecast for this area.

The KEN-05 new feeder item of the *Feeder Additions for Load Growth* project is clustered with the *Substation Feeder Termination* substation project and the Kenmount substation item of the *2015 Additions Due To Load Growth* substation project.

4.0 Project Cost

Table 1 shows the estimated project costs for 2015.

Table 1
Project Costs

Description	Cost Estimate
MOB-01 Feeder Upgrade	$785,000
SCV-01 Feeder Upgrades	$259,000
RBK-01 Feeder Upgrades	$386,000
KEN-05 Feeder Addition	$254,000
Total	**$1,684,000**

5.0 Concluding

The *Feeder Additions for Load Growth* project for 2015 includes distribution system upgrades to:

- Upgrade 5.0 km section of MOB-01 feeder,
- Upgrade two overloaded single-phase lines on SCV-01 feeder to 3-phase,
- Upgrade overloaded single-phase line on RBK-01 feeder to 3-phase, and
- Construct new KEN-05 distribution feeder at Kenmount substation.

The estimated cost to complete this work in 2015 is $1,684,000.

12 KEN-02 feeder services approximately 679 primarily commercial customers and has a peak load of 19.5 MVA. KEN-04 feeder services approximately 2,553 primarily residential customers and has a peak load of 15.4 MVA.

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

1 The winter rating is based on ambient conditions of 0ºC and 2ft/s wind speed.

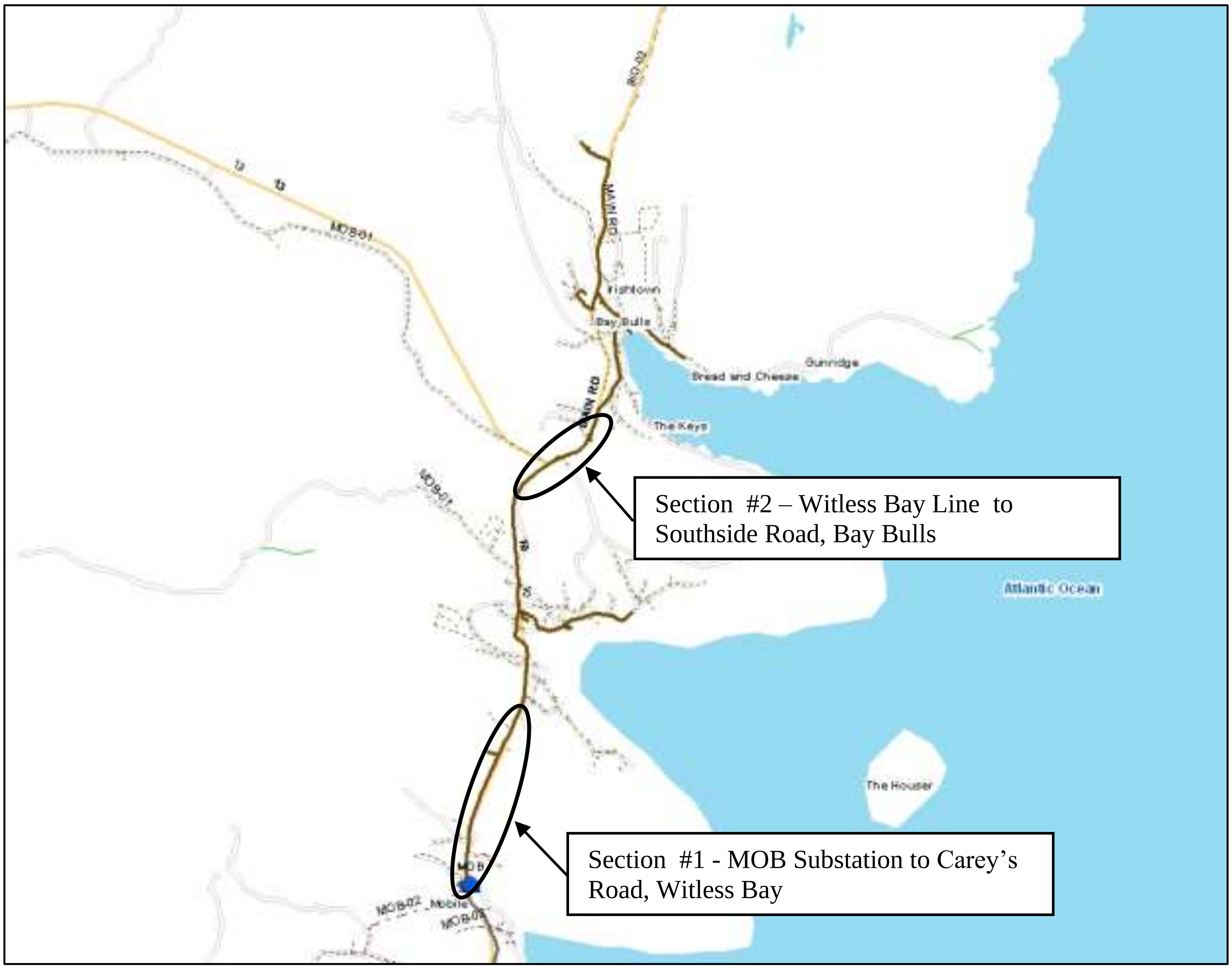
2 The summer rating is based on ambient conditions of 25ºC and 2ft/s wind speed.

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
MOB-01 Distribution Feeder Map



Section #2 – Witless Bay Line to Southside Road, Bay Bulls
Section #1 - MOB Substation to Carey's Road, Witless Bay
Atlantic Ocean
Bay Bulls
Bread and Cheese
Gunridge
The Keys
The Houser
Fishtown
MOB-01
MOB-02
MOB
MAIN RD

Vault Refurbishment and Modernization

June 2014

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1.0 Vault Refurbishment and Modernization Plan

Newfoundland Power (the "Company") has 19 electrical distribution vaults within the City of St. John's.[1] These vaults are an essential part of the Company's electrical distribution system and are primarily located inside customer owned buildings in the Water Street and Duckworth Street areas of St. John's. These vaults are typically located in the basement of a building and contain high voltage electrical equipment that converts primary voltages from the existing underground distribution system to secondary voltages. This electricity is then distributed to serve the building occupied by the vault, and in some cases adjacent buildings in the area.

Most of the existing vaults in downtown St. John's are at least 40 years old and were initially constructed when underground electrical service was established in the buildings in which they are located. Throughout the years, as standards have changed, operational issues associated with these vaults has required the Company to develop new procedures which in most cases requires that the electrical equipment in the vaults and associated buildings be de-energized prior to entry.

In the 2014 Capital Budget Application the Company submitted a *Vault Refurbishment and Modernization* plan (the "Vault Plan") which identified the need to refurbish and modernize these vaults to comply with the current versions of the Canadian Standards Association Z462-08 Arc Flash Standard, the Canadian Electrical Code, National Building Code of Canada and the Company's own operational procedures.

The Vault Plan identified 3 vault locations to be refurbished in 2014.[2] The Company has engaged AMEC Americas Limited ("AMEC"), an engineering consulting firm with expertise in the applicable codes and standards, to assist with the engineering assessment of the vaults.

The Company has selected 3 vaults to be upgraded in 2015.

2.0 2015 Vault Refurbishment and Modernization Projects

For 2015 the Company has identified 3 locations where refurbishment and modernization of existing vaults will take place. They are vaults located at Atlantic Place on Water Street; the Neal building on Harbour Drive; and the Imperial Optical building on Duckworth Street.

At both the Neal and Imperial Optical buildings there is adequate space outdoors in the vicinity of the vault to eliminate the vault entirely. This can be achieved by replacing the exposed high voltage equipment in the vault with standard pad mount or pole mount equipment located outdoors. The Atlantic Place vault on Water Street does not have adequate space outdoors in the vicinity and therefore the vault will be refurbished.

[1] The Canadian Electrical Code (CSA C22.1-12) defines a vault as "an isolated enclosure, either above or below ground, with fire-resisting walls, ceilings, and floors for the purpose of housing transformers and other electrical equipment".

[2] Newfoundland Power's approved 2014 Capital Budget Application included refurbishment and modernization of vaults located at Park's Canada building on Signal Hill, Templeton's Building, and Eclipse Building.

Table 1 identifies the 2015 Vault Refurbishment and Modernization estimated expenditures for 2015.

Table 1
2015 Vault Refurbishment and Modernization

Project	Budget
Atlantic Place (SJM-V7)	$308,000
Neal Building (SJM-V3)	120,000
Imperial Optical (SJM-V8)	45,000
Total	**$473,000**

2.1 Atlantic Place – SJM-V7 ($308,000)

The electrical vault at Atlantic Place is located within the building's parking garage at 215 Water Street. Access to the vault can be gained through the building's loading bay off Ayres Cove or through the parking garage entrance on Harbour Drive.

Figure 1: Atlantic Place Vault Location

The Atlantic Place vault has a combination of exposed high voltage electrical equipment and high voltage electrical equipment contained in metal-clad switchgear. There are 7 cubicles within the switchgear unit. The Company owns all of the exposed electrical equipment and the electrical equipment contained in 5 of the switchgear cubicles. Electrical equipment contained in the remaining switchgear cubicles is owned by Atlantic Place.

The following is a list of electrical equipment within the vault:

- High voltage power cables,
- Metal-clad switchgear unit housing 7 high voltage switches,
- Pole mount cutouts,
- 7.2 kV to 120/240 volt pole mount distribution transformers, and
- Insulated secondary conductor.

Figure 2: Atlantic Place Exposed Electrical Equipment

Figure 3: Atlantic Place Switchgear Cubicles

A 12.5 kV power cable supplies the vault from St. John's Main Substation ("SJM") located on Southside Road and enters the vault through an underground conduit. The power cable feeds a high voltage switch housed inside the first cubicle of the metal-clad switchgear. The remaining cubicles are interconnected via bus work inside the switchgear modules. The 12.5 kV power cable exits the 2nd cubicle through a conduit in the vault floor and travels to a high voltage pad mount switch located on Prescott Street. The third switch supplies 3 pole mount cutout switches and then onto three 7.2 kV-120/240 volt pole mount distribution transformers located in the vault. The 120/240 volt secondary cable exits the room through a conduit system to serve customers along Water Street.

The 4th switch contained in the switchgear provides a means to disconnect the customer owned equipment from the main trunk of the SJM Feeder. A 12.5 kV power cable leaves both cubicles 5 and 6 to supply customer owned transformers located on the 8th floor of the building. The remaining cubicle contains a spare disconnect switch that connects de-energized backup power cables to Scotia Centre and the Newfoundland and Labrador Credit Union building located on Water Street.

The Company has engaged AMEC for the purpose of providing consulting and engineering services necessary to complete an engineering assessment and cost estimate to refurbish and modernize the Atlantic Place electrical vault.[3] The assessment identified non-conformances associated with current versions of applicable electrical, building and fire prevention codes and standards, as well as with the Company's operational procedural requirements.

[3] The AMEC report is included as Attachment A.

The assessment has identified the following 3 major deficiencies:

- Lack of proper spill containment for the pole mount transformers,
- Exposed high voltage electrical equipment that could result in arc flash and electrical contact, and
- Lack of proper ventilation.

Due to electrical contact and arc flash hazards associated with the exposed high voltage equipment located in the vault, personnel must wear arc flash personal protective equipment and maintain a minimum approach distance of 30 inches from the exposed high voltage equipment while inside the vault.

Since there is insufficient space outdoors in the vicinity of Atlantic Place, the vault will be refurbished. The major components of the refurbishment work required are as follows:

- Install a 12.5 kV to 120/240 volt dry-type pad mount transformer to eliminate the pole mount transformers,
- Install 12.5 kV power cables from the existing 3rd switchgear cubicle to a new 12.5 kV high voltage pad mount switch that will replace the pole mount cutouts, and
- Ventilation equipment replacement and upgrades.

The total estimated cost of $308,000 to complete the refurbishment and modernization of the Atlantic Place vault includes the construction estimate of $224,000 identified in AMEC's report plus $84,000 for engineering and internal labour costs.[4]

[4] Engineering and internal labour costs include detailed engineering design, tendering, project management and internal trade labour for the switching, disconnection and isolation of the high voltage electrical equipment being refurbished.

2.2 Neal Building - SJM-V3 ($120,000)

The Neal Building vault is located in the building's bottom floor at 50 Harbour Drive. All of the equipment within the vault is owned by Newfoundland Power.

Figure 4: Neal Building Vault Location

The following is a list of electrical equipment within the vault:

- High voltage power cables,
- Pole mount cutouts,
- 7.2 kV to 347/600 volt pole mount distribution transformers, and
- Insulated secondary conductor.

The 12.5 kV power cable supplies the vault from a pad mount switch located on Prescott Street and enters the vault through an underground conduit. The power cables feed 3 pole mount cutout switches and then onto three 7.2 kV to 347/600 volt pole mount distribution transformers. The 347/600 volt secondary cable exits the room through a conduit system to the customer's electrical service.

Figure 5: Neal Building Vault Transformers

A review of the vault has identified the following:

- Lack of proper spill containment for the pole mount transformers,
- Exposed high voltage electrical equipment that could result in arc flash and electrical contact, and
- Lack of adequate ventilation.

Due to electrical contact and arc flash hazards associated with the exposed high voltage equipment located in the vault, personnel must wear arc flash personal protective equipment and maintain a minimum approach distance of 30 inches from the exposed high voltage equipment while inside the vault.

Since there is adequate outdoor space in the vicinity of the vault it is feasible to eliminate the vault by installing the electrical equipment outside. The work required to complete this is as follows:

- Install a 12.5 kV to 347/600 volt pad mount transformer,
- Install 12.5 kV power cable from an existing switch on Prescott Street to the new 12.5 kV pad mount transformer, and
- Install 347/600 volt cable to customer owned main disconnect switch in the building's electrical room.

2.3 Imperial Optical Building – SJM-V8 ($45,000)

The Imperial Optical Building vault is located on the building's bottom floor at 220 Duckworth Street. All of the equipment within the vault is owned by Newfoundland Power.

Figure 6: Imperial Optical Building Vault Location

The following is a list of electrical equipment within the vault:

- High voltage power cable,
- Pole mount cutout,
- 7.2 kV to 120/240 volt pole mount distribution transformer, and
- Insulated secondary conductor.

Figure 7: Imperial Optical Vault Transformer

A review of the vault has identified the following:

- Lack of proper spill containment for the pole mount transformer,
- Exposed high voltage electrical equipment that could result in arc flash and electrical contact, and
- Lack of adequate ventilation.

Due to electrical contact and arc flash hazards associated with the exposed high voltage equipment located in the vault, personnel must wear arc flash personal protective equipment and maintain a minimum approach distance of 30 inches from the exposed high voltage equipment while inside the vault.

Since there is adequate outdoor space in the vicinity of the vault it is feasible to eliminate the vault by installing the electrical equipment outside. The work required to complete this is as follows:

- Install a 12.5 kV to 347/600 volt pole mounted transformer, and
- Install 347/600 volt secondary service conductors to customer owned main disconnect switch in the building's electrical room.

4.0 Capital Plan

The capital plan was developed based on a number of factors including physical condition of equipment, impact of failures on service to customers, room size, vault design and compliance with current codes, standards and operational procedures.

The continued refurbishment and modernization of the Company's vaults will require upgrading the designs to comply with all current standards of the Canadian Standards Association, Canadian Electrical Code, National Building Code of Canada and the Company's own operational procedures.[5] To assist in the detailed engineering and execution of these refurbishment and modernization projects the Company plans to engage an engineering firm with the necessary expertise in the applicable standards and codes.[6]

Table 2 details the expenditures included in the 5-year capital plan.

Table 2
Vault Refurbishment and Modernization
5-Year Capital Plan

2015	2016	2017	2018	2019
$473,000	$500,000	$512,000	$525,000	$537,000

The vaults are located on customer premises and are essential to the delivery of electricity to the customer and in some cases to customers in the same or adjacent buildings. The Company will work with the affected customers to plan and schedule the work to minimize the impacts on their businesses.

5 A complete list of the Company's vaults is available in report ***4.3*** *Vault Refurbishment and Modernization* filed with the Company's 2014 Capital Budget Application.

6 As a result of the engineering assessment and cost estimates completed by AMEC for the refurbishment and modernization of the Atlantic Place vault, the 5-year capital plan costs estimates have increased compared to the original estimates included the Vault Plan filed in approved 2014 Capital Budget Application.

5.0 2015 Project Cost

Table 3 is a summary of the 2015 expenditures associated with the Vault Refurbishment and Modernization project.

Table 3
2014 Project Expenditures

Cost Category	Expenditure
Material	$189,000
Labour - Internal	47,000
Labour - Contract	118,000
Engineering	95,000
Other	24,000
Total	**$473,000**

6.0 Concluding

The Vault Refurbishment and Modernization work for 2015 includes the following:

- Refurbishment and modernization of the Atlantic Place vault,
- Replacement and relocation of vault equipment to outdoor locations for the Neal Building vault, and
- Replacement and relocation of vault equipment to outdoor locations for the Imperial Optical vault.

The estimated cost to complete this work in 2015 is $473,000.

Appendix A
AMEC Report – Atlantic Place

VAULT REFURBISHMENT AND MODERNIZATION REPORT
ATLANTIC PLACE
215 WATER STREET

Prepared for:

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Date: **April 2, 2014**

AMEC Ref. No.: **175752-0000-CD10-RPT-002**

REPORT

FOR

VAULT REFURBISHMENT AND MODERNIZATION REPORT
ATLANTIC PLACE
215 WATER STREET

FOR

NEWFOUNDLAND POWER INC.

A	Apr. 2, 2014	Issued for Review	RS/ RS NS	DR/ MH	RS/RS NS	
REV.	DATE	REVISION(S)	PREPARED BY	CHECK	APP	CLIENT

	REPORT FOR VAULT REFURBISHMENT AND MODERNIZATION REPORT ATLANTIC PLACE 215 WATER STREET	AMEC JOB NO. 175752	
		REPORT NO. 175752-0000-CD10-RPT-002	REV. A
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1.0 INTRODUCTION

This report summarizes the findings of a recent assessment of the electrical vault in Atlantic Place Building, at 215 Water Street, St. John's. In accordance with Newfoundland Power Work Authorization 09-058-WA-010, AMEC conducted site investigations during which the vault and its equipment were documented. This data was used to determine the deficiencies, alternative equipment configurations, and to prepare a preliminary construction cost estimate to refurbish and modernize the vault and its equipment.

AMEC has analyzed the structure's compliance with current national and local codes and standards. These analyses include electrical, building and fire codes, electrical workplace safety standards, and Newfoundland Power Operational Procedures and Distribution Standards.

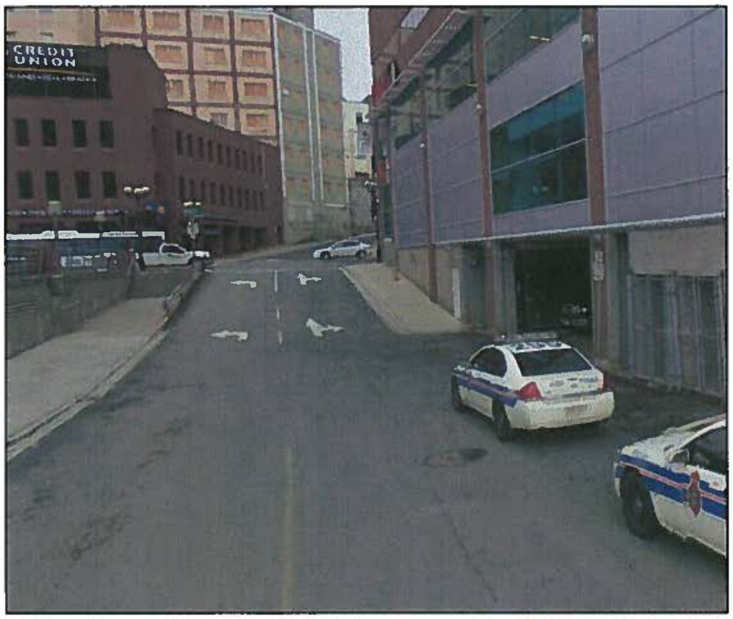
Atlantic Place is a nine level, 40,100 m^2 building constructed in the mid-1970's. ProDesCo were the architects and engineers for the building and constructors of the structure. The building is serviced by a 105 car parking garage, which occupies most of its lower level. The electrical vault is located in the northwest corner of this floor plate, adjacent to some of the building's utilities, including another electrical service room, a trash compactor, and a 4 bay loading dock. Access to these utility areas is available through stairs and a passageway off Ayre's Cove.

The front doors of Atlantic Place are located on Water Street and function as public's principle access to its food courts, restaurants, escalators and elevator lobby. Business occupancies of the first floor also include two banks, a travel agency, and a newsstand. The first floor can also be accessed from the parking garage by elevators or stairs. The eight floors above house mostly professional, administrative and financial businesses. There is a fitness centre on the second floor and Provincial Courts on the third floor.

In summary, this report will identify code deficiencies, which AMEC found with the vault and its mechanical and electrical systems; it will recommends improvements and concludes with a preliminary construction cost estimate for necessary work to undertake the refurbishment and modernization.

2.0 DESCRIPTION

Access to vault is through the Atlantic Place parking garage. The parking garage can be accessed from Habour Drive or through a four bay receiving area off Ayre's Cove. The receiving area is in close proximity to the vault.



Picture 1: Ayre's Cove access to vault

Picture 2: Access through parking garage

Two vault walls are formed by the Atlantic Place exterior walls on corner of Water Street and Ayre's Cove. The others are masonry block. A storage room abuts to vault's southern wall. The vault is an interior L-shaped room of 61.2 m^2. The largest section measures 8 m x 6.5 m and the smaller section measures 2.7 m x 3.3 m. The vault is approximately 3.2 m high except where steel and concrete beams project into the room. See Appendix A for a sketch of the First Level and the vault. The parking garage is in the northwest corner of the building.

The vault has two entrances. The largest entrance is located in the larger room section and consists of a set of double, self-closing doors with a center non-removable mullion. The doors are 812 mm x 2032 mm. The door frame reduce the opening by approximately 25 mm. Large HV equipment would not pass through the existing doorways. Both doors swing into the parking garage. One door has a lever-handle, non-locking passage set. The door is equipped with a hasp latch and a Newfoundland Power Best padlock. The hasp latch is attached on the parking garage side of the door. The other door is equipped with a round handle lockable passage set for which there is no key. This door has a deadbolt on the vault side of the door. The bolt has been in the closed position during AMEC site visits. There are Danger High Voltage, Arc Flash Warning and vault identification signs affixed to the doors. The doors have a fire resistance rating of 1.5 hr.

Picture 3: Double door entrance.

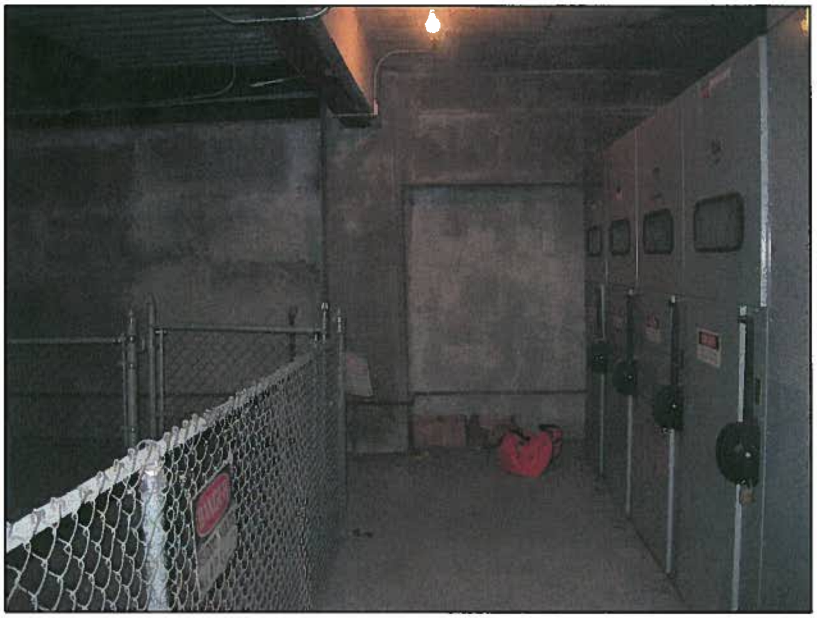
The second entrance is located in the smaller room section. The self-closing door swings into the parking garage. The door is 812 mm x 2032 mm and is equipped with a lockable, round handle entrance set, for which there is no key, and a hasp latch with a Newfoundland Power Best padlock. The latch is on the parking garage side of the door. Affixed to the door is a Danger High Voltage Sign but there is no Arcflash Warning signs. This door has a ¾ fire resistance rating.

There is a parking stall in front of each vault entrance. When a stall is occupied, the egress path may be restricted.

Picture 4: Single door entrance

The vault floor, walls, ceiling are in good condition with no signs of deterioration. Visual observation and ground penetrating radar testing (see Appendix B, Ground Penetrating Radar Report) indicates:

- The north vault wall (Water Street) and the west wall (Ayre's Cove) are 200 mm thick poured-in-place concrete.
- The south and west walls are 250 mm thick solid masonry walls.
- The floor is a 125 mm to 178 mm thick poured-in-place concrete.
- The ceiling is 254 mm to 280 mm thick poured-in-place concrete.



Picture 5: Vault wall condition. Note the Ayre's Cove wall is shown and fence.

The ceiling has what appears to be a poured-in place structural concrete section. The other section of the ceiling is poured-in-place concrete on steel exposed decking supported on exposed wide flanged steel beams. There is no fireproofing on this section of the ceiling.

Picture 6: Ceiling without fireproofing

The fire resistance rating of the solid masonry or poured-in-placed components is 3 hours.

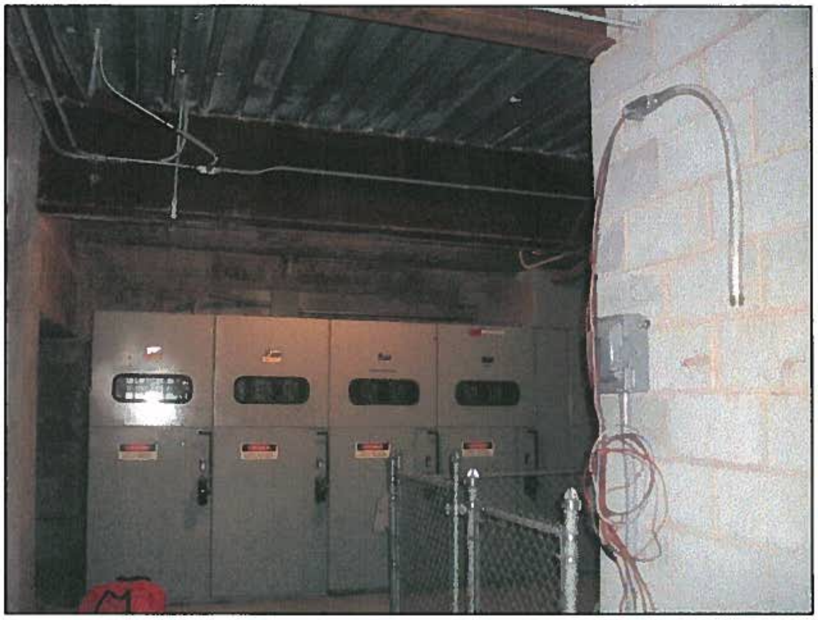
There are gaps between the masonry walls and poured-in-place concrete which occur at the penetrations of structural steel, electrical conduit and exhaust ducts. These gaps are not filled with mortar or fireproofing sealant.

Picture 7: Conduit penetrations without fireproofing sealant.

At least 15 conduit runs, which are not directly involved in the operation of the vaults electrical system, enter and exit the vault.

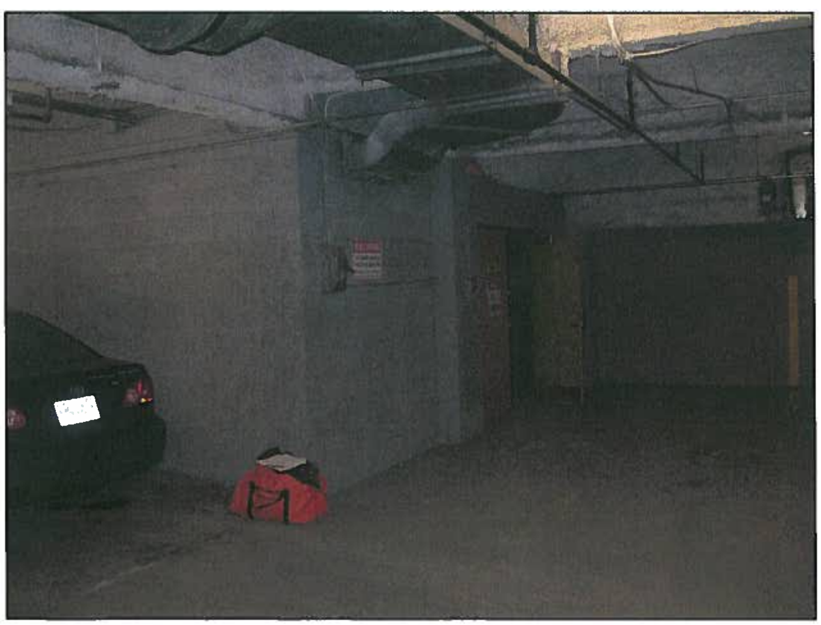
Electrical boxes, over the air intake and by the double doors, are a missing covers and have exposed wiring.

There is a 30A 240VAC disconnect switch mounted on the east wall in the small section. The switch appears to be supplied by a circuit running under the floor from the secondary terminals of single phase, pole type, oil-filled, bushing transformers. The circuit terminates in the switch. Close to the switch are 6 disconnected wires hanging from a piece of conduit.



Picture 8: Unfinished Electrical Work. Note ceiling without fireproofing.

The 6 wires run through the wall to an old 30 A 600VAC disconnect switch in the parking garage beside the double doors. This unused switch supplied the exhaust ventilation fan and fire stat sensor. There is also a circuit from the old switch to the uncovered box inside the vault by the double doors. The source circuit for the switch is disconnected. The switch is in the open position, is not locked and is accessible to the general public.



Picture 9: 30A 600 VAC switch by double doors.

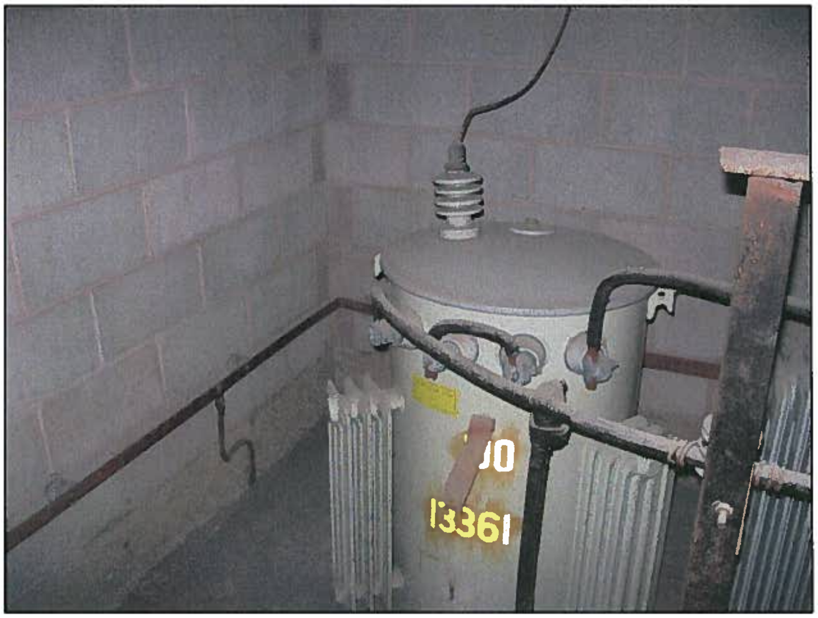
While there is one grounding type 120 V receptacle inside the vault near the double doors, it is not functional. It's supply wiring is unconnected and coiled on the other side of the wall in the parking garage.

Picture 10: Disconnected receptacle wiring

It would appear work was undertaken at some time in the past, on the vault ancillary AC electrical system but it was not completed.

The vault is lit with 5 incandescent bare lamps controlled by a light switch inside the vault at the double door entrance. There was only one lamp functioning during AMEC site inspections. It is doubtful that the 5 lamps provide adequate illumination when lit. There is no emergency lighting in the vault.

The vault grounding system consists of 38 mm copper bar on small stand-off porcelain brackets. The bar is mounted approximately 450 mm above the floor. The bus bar is connected to the building grounding system in at least 11 locations. The bus bar stops at each doorway so it is not continuous round the room. Each section has at least two connections to the building grounding system.



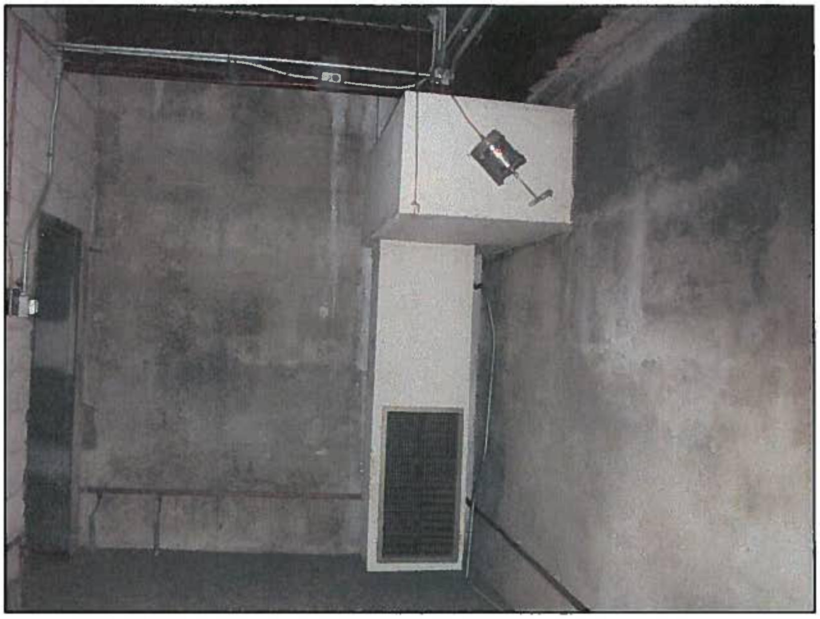
Picture 11: Vault grounding system

The switchgear was not opened to check its ground connections.

There is a fire alarm pull station and fire bell mounted in the parking garage to the side of the double doors. A fire sensor, which is mounted on the ceiling roughly in the middle of the vault, is tied into the building fire alarm system through the same electrical box as the pull station.

The vault ventilation system has an insulated fresh air intake located in the Ayre's Cove exterior wall. The intake has a pneumatic thermostatically controlled damper. The operation of the damper was not verified. The exhaust section of the ventilation system consists of open duct with a fire damper to the right of the double doors. The duct originating from the vault passes through the parking garage and exhausts outdoors in the receiving area off Ayre's Cove. The intake and exhaust ducting appear to be in good condition. The exhaust duct contains an axial fan but the fan motor is missing. According to the long-term building manager, the motor has been missing for his 34 year tenure. The exhaust duct is equipped with a Fire Stat. This device would deactivate the exhaust ventilation system in case of a fire. Control of the exhaust ventilation could not be traced but appears to be by an electrical thermostat in the small section of the room, near the intake thermostat.

There is no heating system in the vault.



Picture 12: Fresh air intake. Note ceiling without fireproofing.

Picture 13: Exhaust ventilation duct opening. Note missing grille and grouting for fireproofing

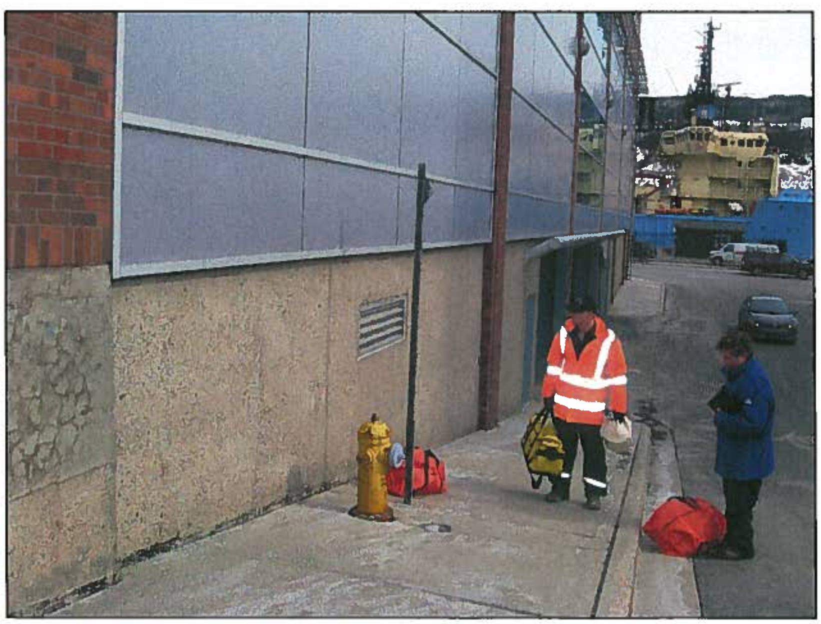
Picture 14: Ventilation exhaust duct

Picture 15: Exhaust ventilation axial fan with empty motor bracket. Note disconnected motor wiring.

The oil spill containment around the bushing transformers consists of two vault walls, vault floor and a concrete curb, approximately 160 mm high. These components are in good condition with no signs of where possible leakage would occur. In the containment area, there are four fibre ducts. The ducts do not extend above the curb. Each duct is damaged and are effectively open at the floor level which would allow spilled oil to flow into the duct.

Picture 16: Fibre duct conduit in spill containment

In the corner of the containment area is a floor drain, which according to the original drawing, is connected to a 880 litre tank buried under the sidewalk near the vault ventilation intake louver on Ayre's Cove. The original drawing indicates that it is a single wall tank. There is an access cover in the sidewalk for a 100 mm pipe which is connected to the tank to remove spilled oil. The vent pipe for the tank is located by the intake duct inside the vault. The condition of the tank was not determined.



Picture 17: General location of spill containment tank. Note fresh air intake grille.

The vault contains a 7 cubicle switchgear lineup for the 12.5 kV system, in the large section of the room. The cubicle closest to Water Street accepts SJM-03 feeder directly from St. John's main substation and is connected to SJM-03-M disconnect switch. This cubicle also receives a fibre optic cable which is not owned by Newfoundland Power. The fibre optic cable leaves the switchgear by a conduit run which proceeds out of the vault by the double doors and through the parking garage.

Picture 18: Fibre Optic conduit leaving switchgear.

In the next cubicle, the eastern end of SJM-03 from the Prescott Street S&C Vista switchgear is connected to the WO1-N-1 disconnect switch. The third cubicle supplies the bushing transformers through an unlabeled disconnect switch. The fourth cubicle contains a tie switch to last three cubicles. The fifth and sixth cubicles, owned by Atlantic Place, contain disconnect switches and power fuses supplying customer owned equipment on the 8th floor. The final cubicle is owned by Newfoundland Power and contains a disconnect switch which is connected to back-up 1/0 cables to Scotia Tower and Newfoundland & Labrador Credit Union Building. The switch is normally open. There are no high voltage fault protection devices in any Newfoundland Power cubicles. Protection is provided by the substation breakers used to supply Atlantic Place.

From the third cubicle, three concentric neutral, 1/0 XLPE cables pass through 150 mm steel conduit located under the floor and up the south wall behind the bushing transformers. Approximately 2800 mm from the floor, the cables exit the conduit and proceed along the masonry wall. The concentric neutrals are attached to the slip-on cable terminations and to a bond wire which is connected to the building grounding system. The bond wire appears to be #6 copper but its size needs to be confirmed.

Picture 19: Connection of concentric neutrals to bond wire to vault grounding system

The cables are attached to fused disconnect switches. The tops of these switches are approximately 2,600 mm from the floor and the energized connections at the bottom of the disconnect switches are approximately 1950 mm from the floor. The fused disconnects are equipped with noise suppression fuses.

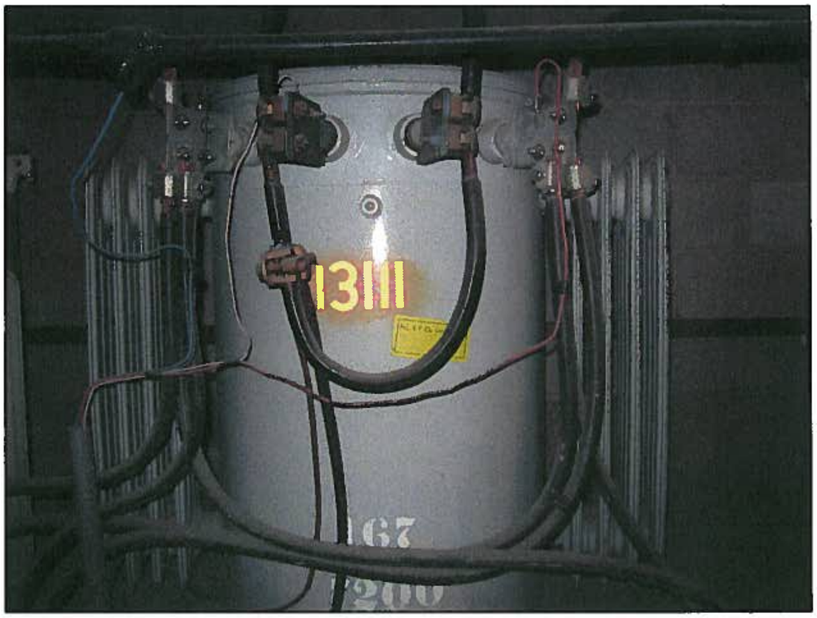
From the bottom connections on each fused disconnect there is exposed energized conductor connected to a 7200-240 V single high voltage bushing transformer. The primary windings of the transformers are connected in wye-grounded configuration. The secondary windings are connected in delta configuration with a high leg configuration to supply Water Street customers who require single phase 208 V.

A #4 copper conductor bonds the transformer tanks pole brackets to the grounding bar. AMEC could only see one connection of the bonding to the grounding bar.

The transformers do not have H2 bushings. The two side transformers have the ground straps removed from the X2 bushing but the boss for the X2 ground strap bushing is not connected to the system neutral.

Picture 20: Left side transformer X2 ground boss.

The middle transformer's secondary winding is centre tapped to ground to provide 120/240V supply. The X2 bushing of the centre transformer does not have the ground strap installed.



Picture 21: Centre transformer unconnected X2 grounding. Note #10 AWG wiring.

The transformers do not have PCB identification stickers.

From the secondary bushings of the transformers 8 insulated conductors and a bare system neutral enter 3 of the conduits to provide 120/240V and 120/208V for the Newfoundland Power customers supplied from Atlantic Place. From the bushings, a #10 AWG copper system neutral enters one of the 25 mm PVC conduits. The conductors are thought to supply the 30 A 120/240V switch on the vault's south wall.

Access to the transformers and fused disconnect switches is restricted by a 1200 mm high chain link fence. There are Danger High voltage warning signs on the fence. The distance from the bushings and switches to the fence exceeds Newfoundland Power's shock hazard distance of 813 mm.

Recent data from Newfoundland Power indicates that 19 customers are supplied from these bushing transformers. Seventeen are serviced at 120/240V and two at 120/208V. Of these19 customers, 3 are three phase customers. Assuming a 10 kVA demand for the small residential customers, the estimated non co-incident demand is approximately 230 kVA. Newfoundland Power is gathering information on additional customers supplied from Atlantic Place.

3.0 CODE REVIEW

With information obtained from the site investigation, AMEC consulted CSA C22.1-12 Canadian Electrical Code (CEC), Newfoundland and Labrador Fire and Life Safety Guidance Document (NLFSGD), National Fire Code of Canada 2010 (NFCC), National Building Code of Canada 2010 (NBC), NFPA 101 Life safety Code (NFPA), CSA Z462 Workplace Electrical Safety (CSA), Newfoundland Power Distribution Standards (NPDS) and Newfoundland Power Operational Procedures (OPR) to determine conformance of the vault and its equipment with these documents.

Below are details about the codes which is provided as background information.

The Newfoundland and Labrador Fire and Life Safety Guidance Document (NLFSGD) adopted the NBCC, NFCC and NFPA to govern fire safety. The NLFSGD requires existing Occupancies to meet the requirements of the NFCC and the NLPA.

CEC Rule 26-012 requires that "dielectric liquid-filled, indoor equipment containing more than 23 L of liquid in one tank or more that 69 L in a group of tanks shall be located in an electrical equipment vault". CEC Rule 26 246 Subrule (2) allows transformers which contain non-propagating liquid with a flash point of less than 275°C and meet other listed conditions, to be located outside an electrical equipment vault. The transformers in the Atlantic Place vault contain propagating oil with a flash point of 145°C and therefore, had to be installed in the Electrical Equipment Vault.

CEC Rule 26-354 construction states "Every electrical equipment vault, including doors, ventilation and drainage, shall be constructed in accordance with the applicable requirements of the National Building Code of Canada".

As the NBC details the construction of Electrical Equipment Vaults in NBC Section 3.6 Service Facilities. Electrical Equipment Vaults are a sub classification of Service Rooms in NBC Section 3.6. As such, a number of the requirements, e.g. emergency lighting, are also applicable to the vault.

The NFCC and NFPA are utilized by the Newfoundland and Labrador Fire Commissioner to evaluate buildings. These codes establish the type of occupancy and the level of risk for fire hazards. Atlantic Place has multiple occupancies of "Existing Assembly" and "Existing Business". The requirements of each occupancy were reviewed. When the same building condition produced a deficiency in more than one occupancy, the information below only shows one deficiency with the two rules noted.

The existing vault is a High Hazard Contents Area, as defined in NFPA 6.2.2.4, as it has contents which are "likely to burn with extreme rapidity or from which an explosion is likely".

3.1 DEFICIENCIES

Below are the NBC, CEC and NFPA deficiencies found by AMEC:

3.1.1 Architectural

1. NBC 3.3.1.13 Sentence 3) requires "door release hardware shall be operable by one hand and the door shall be openable with not more than one releasing operation". One of the double doors cannot be opened with open releasing operation due to the presence of a deadbolt and an entrance set on door. (See item 6)

2. NBC 3.6.2.7 Sentence 2) requires the vault to "be separated from the remainder of the building by a fire separation of solid masonry or concrete construction having a fire resistance rating of not less than a 3 hours if the vault is not protected by an automatic fire extinguishing system". Without fireproofing for the exposed beams and metal decking, the vault does not have a fire resistance rating. The doors fire resistance rating is inadequate for a room required to have a 3 hour fire resistance rating.

3. NBC 3.6.2.7 Sentence 4) requires "Only pipes or ducts necessary for the fire protection of the proper operation of the electrical installation shall penetrate the fire separation". There are electrical and fibre optic conduits in the vault which are not required for the proper electrical operation of the vault. These conduits contravene the rule's intent to reduce unnecessary infrastructure in the vaults.

4. NBC 3.6.2.7 Sentence 7) requires that the vault ventilation system “shall be separate from the system for the remainder of the building and be designed to automatically shut off for a fire in the vault”. Fire dampers were not found during visual inspection.

5. NBC 3.6.2.7 Sentence 8) requires the vault floor to be liquid tight and surrounded by liquid tight walls. The fibre duct in spill containment area is open at floor level which could allow an oil spill to enter the duct rather than being contained. The unknown condition of the underground spill containment tank raises concern with respect to conformance with this rule.

6. NFPA 7.13.3.4 requires a minimum clear path of egress of 710 mm. Cars in the parking stalls in front of a vault entrance may impinge on that path way’s width.

7. NFPA 7.2.1.5.3 requires for doors that “Locks, if provided, shall not require the use of a key, a tool, or special knowledge or effort for operation from the egress side.” The use of hasps locked with a Best padlock creates a situation when the locks are not removed, the locked door cannot be opened to obtain egress. Also, even with the lock removed, if the hasp moved to the closed position while a person was in the vault, it is possible that hasp may jam if a person tried to leave the room trapping the person inside the room.

8. NFPA 8.3.5.1 requires penetrations in a fire separation to be sealed with a fire stop material. There are many penetrations in the vault walls and ceiling which are not sealed with a fire stop material

9. NFPA 13.3.2.1 requires rooms with large transformers to have a minimum 1 hour fire resistance rating or be protected by an automatic extinguishing system. Without fireproofing for the exposed beams and metal decking and fire stop material around the wall penetrations, the vault does not have a fire resistance rating.

10. NFPA 39.3.2.2 requires High Hazard Content Area to be protected by an automatic extinguishing system. Atlantic Place has a sprinkler system but the vault is not covered by the system.

3.1.2 Electrical

1. CEC 26-356 requires adequate lighting which is controlled by a switch near the vault entrance. CEC also requires a grounding-type receptacle in or near the vault. Lighting is expected to be inadequate and there is no functional receptacle.

2. CEC 36-110 requires live parts and exposed conductors to be isolated by elevations as defined in CEC Table 32 or by barriers. There is exposed energized 12.5 kV conductor, connectors and switches are not at the required elevation of 2.9 m but access to them is restricted by a fence.

3. CEC 2-300 requires "all operating electrical equipment shall be kept in safe and proper operating condition". There is exposed 120, 240 or 208 wiring and some electrical boxes are without covers in the vault and around its ventilation system.

4. NBC 3.6.2.7 Sentence 6) requires the vault shall be "provided with ventilation designed in accordance with Part 6 to prevent the ambient temperature in the vault from exceeding 40°C". It is not known if the ventilation was designed to meet this requirement. But as the system is not functional, this item has been listed as a deficiency.

5. NBC 3.2.7.3 requires service rooms to have emergency lighting and an emergency power source. There is no emergency lighting in the vault.

6. NPDS 14-17 requires "On single bushing transformers with no H2 and the X2 ground straps removed, connect the spade or boss used for the X2 ground strap to the neutral". The two side transformers are not in conformance with this requirement. The standard also shows that the transformer with the system neutral connected to the X2 bushing shall also have the ground strap installed from the ground strap boss to the X2 bushing. The middle transformer is not in conformance with this requirement. The standard requires the system neutral to be connected directly to X2 bushing. The system neutral is connected to a jumper between the X2 and X3 bushing.

7. OPR 108.04 5.3.8 requires "Arc flash hazard warning signs identifying specific arc flash boundaries, incident energy levels, shock hazard and personal protective equipment requirements will be installed on all vault doors". The single entrance door does not have Arc flash warning signs installed.

8. OPR 200.01 requires PCB testing, removal of Newfoundland Power oil-filled equipment (other than pole mounted equipment) with greater than 500 PPM PCB contaminated oil by December 31, 2009 and the labeling of oil filled equipment with less than 500 PPM PCB contamination. As the transformers do not bear PCB labels they are not in conformance with the OPR.

OPR 200.09 deals with petroleum storage so the OPR cannot be used to judge the single wall spill containment tank and its piping for conformance. OPR states "Single wall underground petroleum storage tank systems shall not exist within Newfoundland Power's system". The OPR has particular installation requirements for underground piping. Newfoundland Power may wish to consider if the spirit of the OPR should be applied to the vault tank and associated piping.

There is only a single ground bar bonding connection for the transformer supply cables' concentric neutrals. Also there is only a single ground bar bonding connection of the transformer tanks' pole brackets. AMEC would recommend the installation a looped bonding wire to provide two connections for both situations.

4.0 MODERNIZATION AND REFURBISHMENT

In its 2014 Capital Budget Application, Newfoundland Power stated it would upgrade vaults to meet current codes, eliminate exposed energized connections, oil-filled equipment and open air cutouts from vaults.

The refurbishment and modernization of Atlantic Place vault can be realized by combining upgrades of the vault structure and changes to equipment in the vault.

AMEC recommends that Newfoundland Power remove the oil-filled, bushing transformers and install equipment which is not required to be housed in an Electrical Equipment Vault to comply with CEC. This action would change the room designation from a "vault" to a "service room" and eliminate the NFPA High Hazard Contents Area deficiencies.

4.1 ELECTRICAL

The exception granted electric utilities in CEC Section O Scope for utility installations or equipment has not been applied in the following actions. The actions outlined below are CEC compliant. As such these actions may result in measures not normally undertaken by Newfoundland Power.

4.1.1 Transformer

The oil-filled bushing transformers can be replaced with a 3 phase dry-type transformer or a 3 phase transformer, filled with non-propagating dielectric liquid that has a flash point over 275 °C. Such a liquid is natural ester fluid (vegetable oil), thereby avoiding harming the environment if there was a spill of the dielectric.

In discussions, a transformer manufacturer stated there is no significant difference in the cost of dry type and natural ester dielectric-filled transformer. Using higher cost natural ester dielectric eliminates the cost advantage oil-filled transformers has over dry type transformers.

CEC 26-246 requires liquid dielectric-filled transformers to have spill containment. The installation of a dielectric-filled transformer would require alteration of the spill containment. The floor drain would have to be sealed and the curb height increased, if required. Collars would have to be installed around the fibre duct conduits to ensure spilt dielectric would not flow into the conduit.

CEC 26-246 requires pressure relief vent for transformers with a capacity greater than 37.5 kVA. CEC 26-246 also requires the pressure relief vent be dusted to the outdoors in “poor ventilation areas”. The CEC does not define poor ventilation. If the thermostatically controlled mechanical ventilation is off, the ventilation is poor. Therefore AMEC would recommend dedicated pressure relief venting to the outdoors. Outdoor venting options are limited to expelling hot gas and oil on Water Street or Ayre’s Cove or on the Atlantic Place roof. None of these options are acceptable.

The cost of both types of transformers are comparable. The use of a dry-type transformer eliminates the safety hazard of expulsion of hazardous substances and the need to improve the spill containment. Therefore, AMEC recommends replacing the oil-filled transformers with dry type transformation.

Manufacturers indicate they can produce a 3 phase transformer with a 208 V high leg configuration. AMEC is waiting for confirmation of ability to produce this transformer and budgetary prices. Presently, there is a $75,000 transformer allowance in the Preliminary Refurbishment and Modernization Construction Cost Estimate. Included in the allowance is $15,000 for freight, transportation and installation. The $75,000 does not include any allowance for transformer testing.

CEC 2-320 requires adequate ventilation to ensure that ambient air temperature does not exceed that which is “normally permissible” for the equipment. The existing ventilation system is not functional and AMEC expects certain parts to have failed or be beyond their usable life. Based upon visual inspection, the ventilation duct is usable but AMEC recommends the control system and the active/interface components be replaced, e.g. replace the axial fan complete with motor, provide new exhaust grille and fire dampers. A ventilation allowance of $35,000 is included in the Preliminary Refurbishment and Modernization Construction Cost Estimate.

AMEC does not foresee any problem with accommodating a new transformer in the room.

4.1.2 Isolation and Loop Switching

Presently, transformer isolation and protection is accomplished by 3 wall-mounted fused disconnect switches. These switches have exposed energized connections and are a source of arc flash. These hazards can be eliminate by routing the 12.5 kV cables, from the 3rd cubicle, into arc resistant switchgear, equipped with switches and fault interruption capability. Workers are then protected against accidental contact with energized connections and arcflash energy and by-products by the construction of the switchgear and associated switchgear venting to the outdoors. Expelling hot gases, severe noise and other arc flash products directly unto Water Street and Ayre's Cove is not acceptable. Venting would have to be done at an elevation whereby the public would not be affected. This would result in alterations of Atlantic Place on at least the first floor.

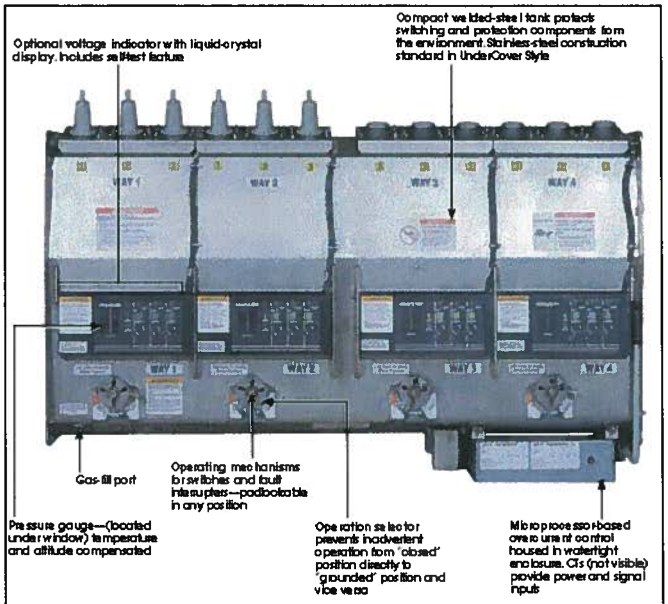
Removing the fused disconnect switches also removes the transformer protection. New switchgear would provide this protection through power fuses, breakers or relay controlled fault interrupters.

The replacement switchgear would also have to provide switches with visible isolation gaps and cable grounding features to allow the fulfillment of Newfoundland Power Worker Protection Code requirements.

Most switchgear is designed to handle higher currents and more complex bus arrangements and is relatively large. S&C Vista switchgear is compact and provides load-rated, gang-operated switches with overcurrent protection and fault interruption capability for the transformer. The switch has closed, isolated and grounded positions and a viewing port. The compact design would facilitate the installation of that switchgear in Atlantic Place. Newfoundland Power already uses Vista switchgear in the Water Street underground system. While time permits, AMEC will continue to explore the use of other switchgear but at this time, AMEC recommends the installation of S&C Vista Switchgear.

To further increase safety, AMEC recommends the installation of an S&C Portable Motor Operator, with a 15 m control cable, to allow operation of the switchgear from outside the room or the arc flash zone.

The compact design of the Vista switchgear is accomplished by the use of vacuum bottle technology and SF_6 gas. The gas, the vacuum bottles and switches are enclosed in a metal tank.



Picture 22: Example of Vault Mount S&C Vista Switch [1]

Vista switchgear will contain certain levels of arcflash without suffering a tank failure. If the arcflash is severe, before the tank ruptures a pressure relief valve will vent the unit. Like other switchgear, this venting has to be ducted to the outdoors.

When an arc is formed in SF_6, gas small quantities of lower order gases and some solids are formed. Some of these by-products are toxic and can cause irritation to eyes and respiratory system. The venting location would have to be located to ensure the dispersion of arc flash energy, noise and products do not to pose a hazard to the people.

[1] S&C Vista Underground Distribution Switchgear, descriptive Bulletin 680-30, Page 4

S&C is preparing a budgetary quote for S&C Vista 2 way 201 model switchgear. There is an allowance of $32,000 for the equipment and $20,000 for the arcflash venting included in the Refurbishment and Modernization Preliminary Estimate.

4.1.3 Cables

A preliminary design review indicates only a small amount of conduit and tray plus small amount of cable will be required to connect the new equipment. A $10,000 allowance is included in the Refurbishment and Modernization Preliminary Estimate for this work.

4.1.4 Vault electrical infrastructure

AMEC recommends the installation of a second fire detector on the opposite side of the beam which is in the middle of the room. There is a $500 allowance included in the Refurbishment and Modernization Preliminary Estimate for this detector. In the Refurbishment and Modernization Preliminary Estimate, there is a $2,000 allowance for emergency lighting, a $1,000 allowance for the lights and receptacle and a $2,500 allowance for the removal of existing electrical infrastructure no longer needed.

4.2 ARCHITECTURAL

Due to the public nature of the parking garage and the relative open access of the garage to the public, AMEC recommends Newfoundland Power continue utilizing the secure nature of the "vault" to prevent unauthorized access to its equipment.

CEC Section 0, Definitions (Page 10) defines a Service Room as "a room or space provided in a building to accommodate building service equipment and constructed in accordance with the National Building Code of Canada". As the "vault" would contain some of building service equipment, it would be considered a Service Room.

NBC 3.6.2.1 (Sentence 6) requires a Service Room to be separated from the remainder of the building by a fire separation having a fire resistance rating not less than 1 hour. The existing concrete and masonry structure of the room has a 3 hour fire resistance rating. By installing 2 hour fireproofing on the exposed steel beams and floor decking, fire stopping sealants on the fire separation penetrations, appropriate fire resistance-rated, self-closing doors and ensuring the ventilation system is fire damper-equipped, in AMEC's opinion would satisfy this requirement and eliminate the need to extend the sprinkler system into the room. Unless required by the Provincial Fire Commissioner or St. John's Life Safety Fire Inspectors, the room should not need to have sprinklers installed. There is a $5,000 allowance for fire proofing and fire stopping, $6,000 allowance for door replacement, in the Refurbishment and Modernization Preliminary Estimate.

Other deficiencies and safety hazards can be eliminated removing the door hasps locked with Best padlocks, installing entrance sets keyed for Best padlock keys and installation of removable bollards in the purkins stalls in front of the entrance.

In the Refurbishment and Modernization Preliminary Estimate there is a $4,500 allowance for architectural work for the S&C switchgear venting, a $2,000 allowance for spill curb removal and drain sealing and a $2,000 allowance fir installation of bollards.

4.3 PRELIMINARY REFURBISHMENT AND MODERNIZATION CONSTRUCTION COST ESTIMATE

The table below shows the preliminary construction cost estimate for the refurbishment and modernization of the Atlantic Place vault. A 30% contingency is included as there are items like the type of ventilation/air conditioning which can impact the final design.

Item	Cost
Transformer	$75,000
S&C 321 Switch (Inc. load break elbows)	$32,000
Arc Flash Venting	$4,500
Conduit, tray & cable	$10,000
Removal of existing electrical equipment	$2,500
Fireproofing and fire stopping	$5,000
Doors, doorframes	$6,000
Parking Bollards	$2,000
Additional fire detector	$500
Lighting & receptacle	$1,000
Spill curb removal & sealing drain	$2,000
Ventilation	$30,000
Emergency Lighting	$2,000
Contingency 30%	$51,750
Total (not including HST)	**$224,250**

Table 1. Refurbishment and Modernization preliminary construction cost estimate.

This estimate does not include work by Newfoundland Power such as project planning, procurement, construction management, protection analysis, termination of 12.5 kV cables in the building and S&C switchgear and commissioning of the S&C switchgear. Costs arising from bonding, insurance, permits, fees are not included in the estimate.

5.0 SUMMARY

For a cost of $224,250, the Atlantic Place vault and its associated Newfoundland Power equipment can be refurbished and modernized. Improvements would result in a safer work location for Newfoundland Power personnel. It would increase the safety of Atlantic Place building for its owners and occupants, while eliminating the environmental risk from oil-filled equipment.

APPENDIX A

SKETCH OF FIRST LEVEL AND VAULT

Drawing to be provided.

APPENDIX B

GROUND PENTRATING RADAR TESTING

Concrete Scanning Services

Client: AMEC
St. John's, NL

Work Site: Atlantic Place
Water St.
St. John's, NL

ATI
Date: Mar 17, 2014
Job: 1084-01

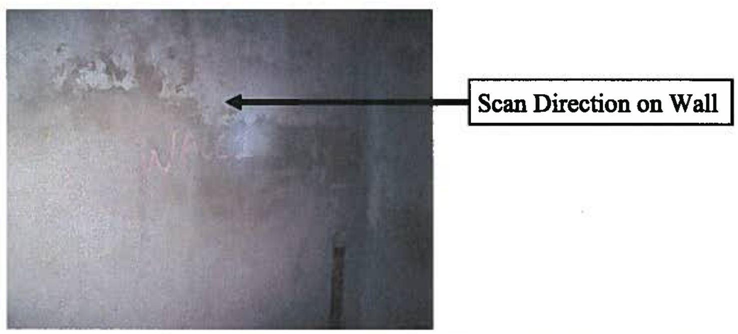
Advanced Thermal Imaging, Inc
P.O. Box 14182, C.B.S, NL
A1W 3J1
Phone: 728-2999
advancedti@bellaliant.net

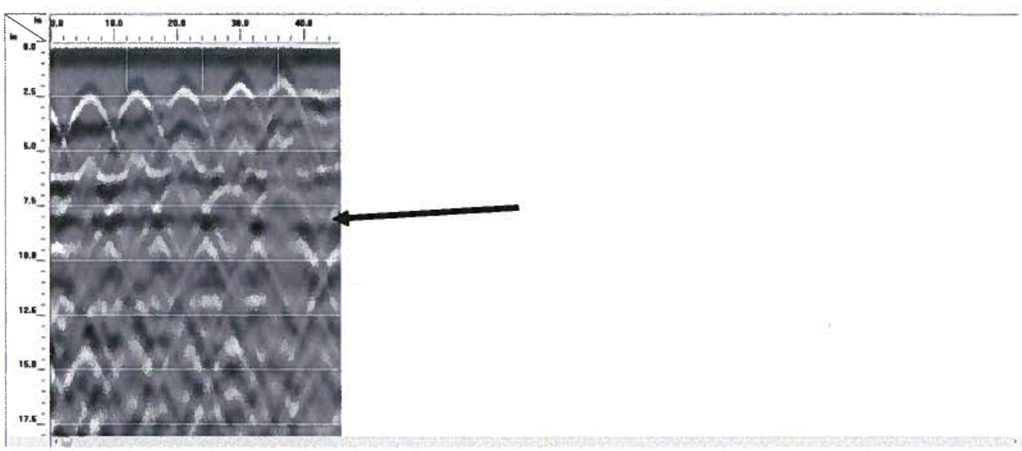
Client P.O. #
754

Concrete Scanning Service
Atlantic Place

Advanced Thermal Imaging Inc was contracted by AMEC to perform concrete scanning services in several areas of Atlantic Place, St. John's, NL. The scope of the concrete scanning service was to help determine the approximate thickness of slabs and walls in the structure. ATI personal (Anthony Walsh) performed concrete scanning as outlined and directed by Don Rideout. Scanned images can only provide approximate thickness or depth of a concrete structure. Drilling and measuring or edge measuring (where possible) can provide true thickness or depth of a concrete structure.

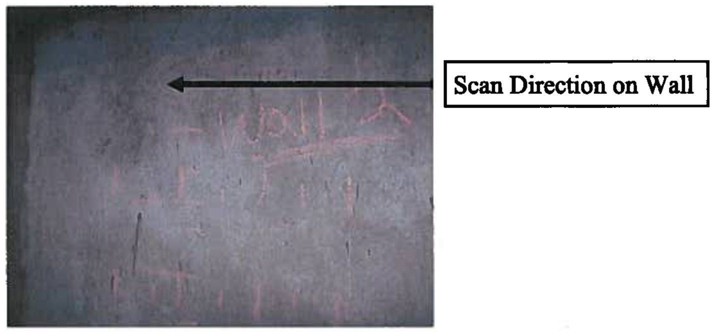
Location 1
Basement Vault
Concrete Wall

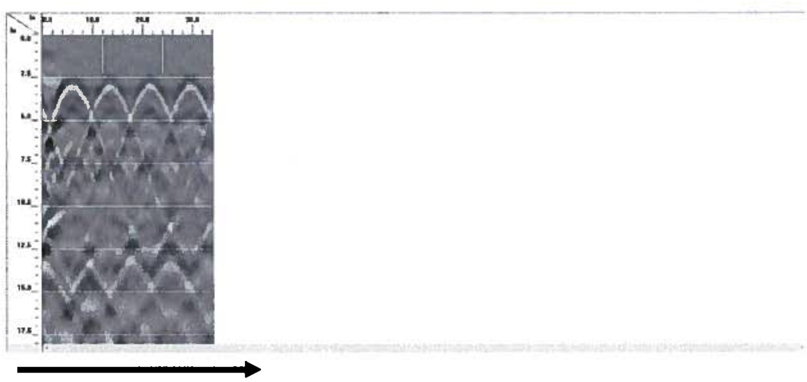




Concrete wall (opposite double doors into vault and left of main support) in vault appears to be approximately 8 inches, or more, in thickness for the main interior wall. There is a second concrete structure on the exterior of this wall (same wall as on page 2).

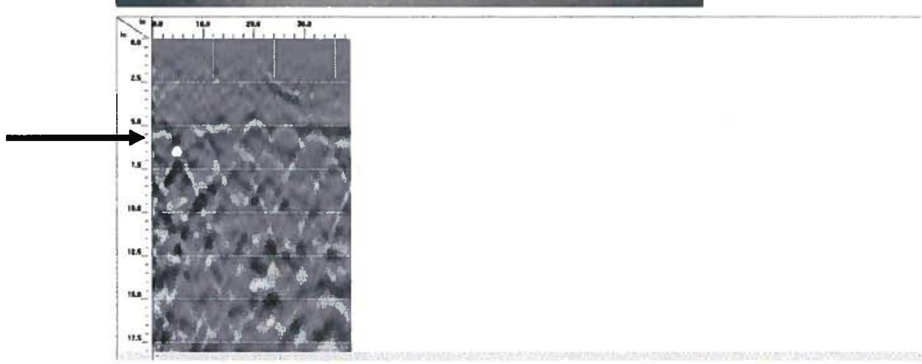
Location 2
Basement Vault
<u>Concrete Wall 2</u>





This is an image to the right of wall on page 1 (opposite double doors into vault and left of main support). The approximate thickness of wall is undetermined as there is no clear visible indicator of the back of the wall but the GPR signal appears to extend further than 8 inches. This is the same wall as in image on page 1 and uniformity of the structure appears to be the same so it can be assumed that this wall has the same thickness throughout its length.

Location 3
Basement Vault
Concrete Floor

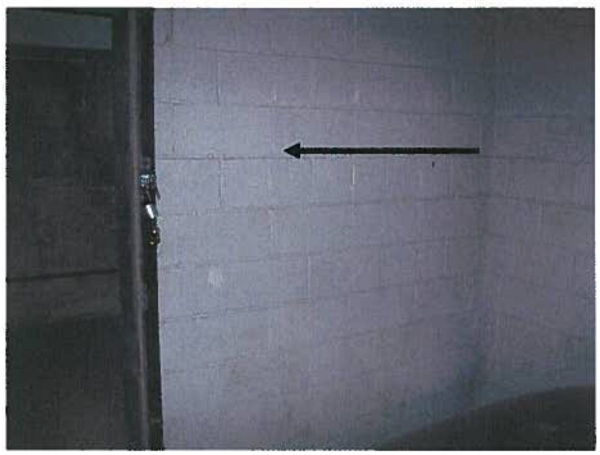


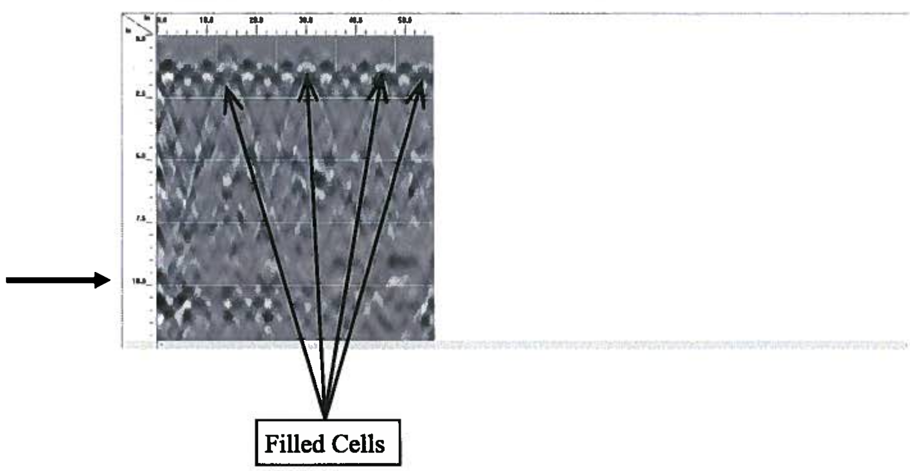
Concrete floor close towards back wall in vault. Bottom appears to be at approximately 5 — 6 inches.

Location 4
Basement Vault
Concrete Floor 2

Image of same floor as on page 3. Image shows slab thickness at 6—7 inches. Concrete floor will always have differences in uniformity (thickness will rise and fall) across the structure.

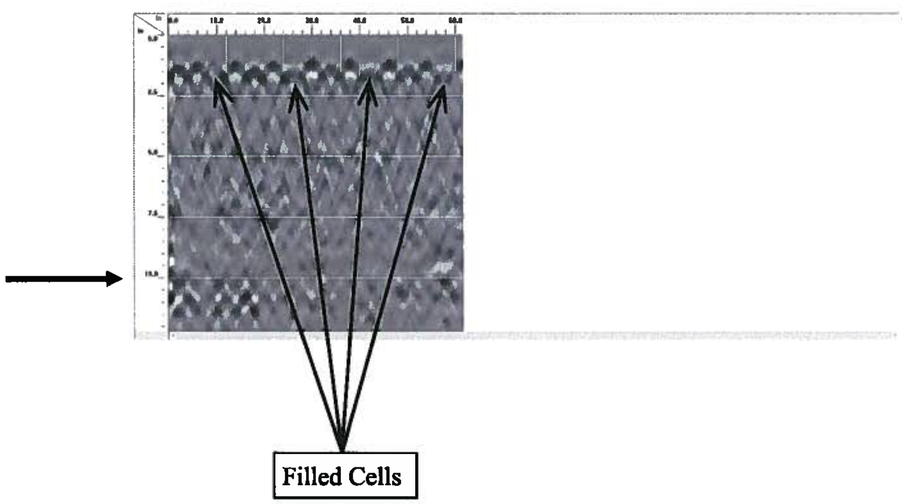
Location 5
Masonry Wall
Garage Area





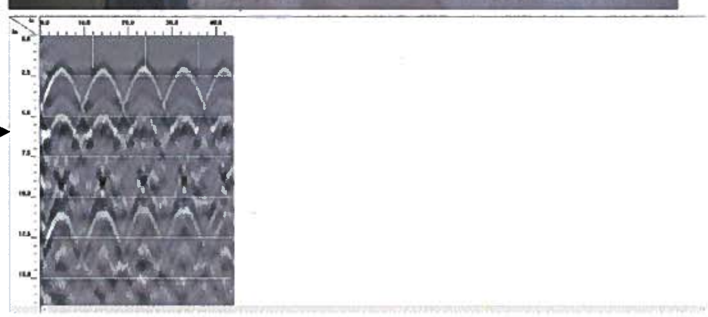
Masonry wall in garage area. Structure appears to be approximately 10 inches thick. Blocks appear to be filled but image does not indicate if reinforcements is present.

Location 6
Masonry Wall
<u>Garage Area</u>



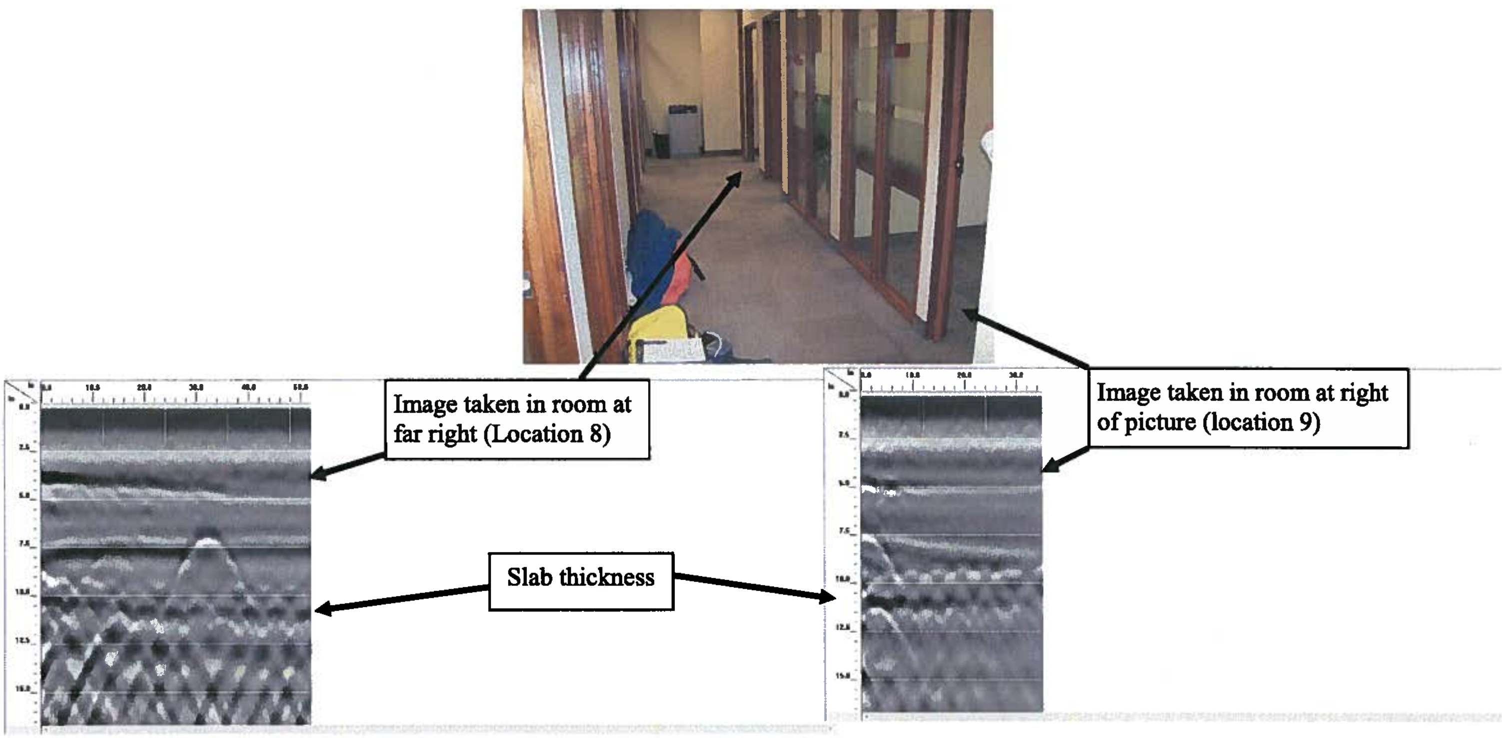
Masonry wall just right of masonry wall on page 5 (Location 5). Wall appears to be about 10 inches thick. Blocks appear to be filled but image does not indicate if reinforcements is present.

Location 7
Basement
<u>Concrete Wall</u>



Electrical room concrete wall by door. Wall appears to be approximately 6 – 7 inches in thickness.

Location 8 & 9
CIBC Bank
<u>Office Space</u>



Thickness of concrete floor in office area appears to be approximately 10—11 inches.

Burin AMR Project

Prepared By:

Byron Chubbs, P. Eng.

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NEWFOUNDLAND POWER
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1.0 Introduction

Newfoundland Power (the "Company") regularly evaluates meter reading technology to ensure meter reading is completed effectively and at least cost to customers. For more than a decade the Company has been using automated meter reading ("AMR") technology to improve safety and operational efficiency.[1] Technology improvements and reduced deployment costs have resulted in the Company purchasing only AMR meters for new service installations and meter replacements since 2013.

In 2015, the Company will pilot a new mobile collector technology in its Burin operating area ("Burin"). In addition to meter replacements required to meet Measurement Canada regulations, safety and accessibility as outlined in the Company's 2013 metering strategy, the remaining 4,000 non-AMR meters in the area will be replaced with AMR meters.[2] With 100% penetration of AMR meters in Burin the Company will read these meters using the new mobile collector device exclusively. This will allow the Company to gain further operational experience with using the new technology in a rural operating environment. This will also increase the efficiency of meter reading operations in Burin, consistent with the Company's commitment to providing least cost, reliable service to customers.

2.0 Background

2013 Metering Strategy

As part of the 2013 Capital Budget Application, the Company provided an update to its metering strategy. The strategy outlined key changes to Measurement Canada regulations governing revenue meters and provided justification for expanding the deployment of AMR meter reading technology. More specific, the strategy stated that that the Company would:

- Continue with the objectives outlined in the 2006 Metering Strategy with respect to accuracy and timeliness, cost management, worker safety and ratemaking.
- Implement the recommended transition strategy to comply with changes to Measurement Canada regulations.
- Proceed with purchasing only AMR meters for all meter replacements and new installations. and,
- Maintain focus on route optimization in order to achieve productivity improvements through AMR and reduce costs.

As outlined in the strategy, the Company focuses on route optimization to achieve productivity improvements. In some cases, specific projects are identified in which targeted meter replacements are justified by reduced meter reading costs.

[1] Automated Meter Reading ("AMR") technology enables a meter to be read remotely via a handheld receiver, eliminating the need for a meter reader to approach the meter for a visual read.

[2] These additional 4,000 AMR meter installations represent an accelerated meter replacement in the Burin area from what was forecast in the 2013 metering strategy.

Mobile Collector Technology

The Company currently uses handheld devices to collect meter readings in the field. The readings are entered manually into the handheld device for non-AMR meters, and are collected via a radio frequency signal for AMR meters. At the end of the shift all readings are downloaded from the handheld device into the Company's meter reading database for archiving and billing purposes.

Figure 1: Handheld meter reading device (left) and mobile collector unit (right)

In 2013, the Company began testing a mobile collector unit for gathering AMR meter readings. This technology uses a vehicle mounted dock and external antenna to increase the range of the handheld device. As a result, AMR meters can be read at a greater distance than had previously been achieved with the handheld device alone.

Early results using the mobile collector technology have shown an increase in range of 2 to 3 times that of the regular handheld device.[3] The increased range results in reducing the amount of time spent reading individual meters thereby increasing the number of meter readings that can be collected per shift.

3.0 Project Justification

The Burin operating area covers the entire Burin Peninsula, extending north along Highway 210 as far as the community of Terrenceville. Serving approximately 11,000 customers, Burin has the fewest number of customers of the Company's 8 operating areas. However, geographically the area is large, extending approximately 200 km from the north to the southern tip of the Peninsula. As a result, Burin is a suitable area for evaluating the mobile collector technology in a rural operating environment.

There are currently 26 meter reading routes required to read the 11,000 meters in Burin area.[4] The average route size in the area is 430 meters per route, ranging from as few as 280 meters in a route to as many as 1,030 meters in a route.[5]

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[3] The handheld unit has a range of up to 750 m. When used in conjunction with the mobile collector unit, the range increases up to 2,000 m. The range of each technology varies depending on the location of the meter (mounted inside or outside), availability of line-of-sight (trees or buildings), and landscape (hills or flat land).

[4] One meter reading "route" represents the volume of work that can be completed by one meter reader during a regular 8 hour shift.

[5] The number of meters in a route varies depending on factors such as:
- the density of meters in the route (urban routes typically have more meters than rural routes)
- penetration of AMR meters in the route
- driving time to and from the route
- number of commercial customers in the route (high commercial routes typically have fewer meters than high residential routes)

The 2013 operating cost for meter reading in Burin area was $131,000.[6] This cost includes monthly meter reading labour, as well as labour to complete other metering functions such as final readings, checking meter seals and checking stopped meters.[7]

It is forecast that by the end of 2015, approximately 7,000 meters in the Burin area will use AMR technology.[8] The cost to replace the remaining 4,000 non-AMR meters with AMR meters in 2015 is approximately $385,000.[9]

By replacing the remaining 4,000 non-AMR meters with AMR meters and utilizing the new mobile collector technology, the average route size in Burin area will increase to approximately 3,000 meters per route. As a result, the number of meter reading routes required to read all 11,000 meters will reduce to 4 routes. This will provide an annual operating savings of approximately $88,000 per year.[10]

An analysis of capital costs and operating savings shows that replacing the remaining 4,000 non-AMR meters with AMR meters will have a payback period of approximately 6 years.

4.0 Project Cost

Table 1 summarizes the cost associated with the Burin AMR Project.

Table 1
Burin AMR Project
2015 Project Cost
($000s)

Cost Category	**Cost**
Material	339
Labour – Internal	46
Labour – Contract	-
Engineering	-
Other	-
Total	**385**

6 The cost also includes approximately $109,000 for labour, $6,000 for non-labour, $11,000 for fuel and $5,000 for vehicle maintenance.

7 The 2013 labour cost of $109,000 for meter reading in Burin area is less than the 2012 labour cost of $126,000. This is due to efficiencies achieved in 2013 as a result of AMR installations and route optimization, as outlined in the 2013 Meter Strategy included in the Company's 2013 Capital Budget Application.

8 See Table 5 on page 7 of the 2013 Meter Strategy filed as part of the Company's 2013 Capital Budget Application.

9 The average unit cost per meter installation is approximately $96. This includes both the material cost to purchase the AMR meter and the labour cost for installation.

10 Meter reading labour and non-labour costs will reduce by approximately $76,000 annually. Vehicle maintenance and fuel costs will reduce by approximately $12,000 annually.

5.0 Concluding

Over the past decade, AMR technology has helped to improve safety and efficiency in the Company's meter reading operations. In 2015, the Company will increase meter reading efficiency in the Burin area by replacing all remaining non-AMR meters with AMR meters. Combined with the new mobile collector technology, this project will reduce overall meter reading costs in the area.

This project will also allow the Company to evaluate the new mobile collector technology as it gains further operational experience with the technology in a more rural environment. This evaluation may lead to accelerating the use of AMR technology beyond the current plan outlined in the 2013 meter strategy.

Company Building Renovations
Duffy Place Facility

June 2014

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NEWFOUNDLAND POWER
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1.0 Introduction

The Duffy Place Building (the "Facility") is Newfoundland Power's (the "Company") primary operations facility for the St. John's Region (the "Region").[1] The Region serves approximately 102,000 customers, 42% of all customers served by the Company. The Region's service territory extends from Cappahayden in the south to Cape St. Francis in the north and from Cape Spear in the east to Holyrood in the west. The Facility is adjacent to the Team Gushue Highway in St. John's providing access to the Northeast Avalon Peninsula highway system.

The Facility houses employees and equipment necessary to support operations throughout the Region's service territory.[2] This includes line crews, line inspectors, work dispatchers, regional engineering, meter reading and associated support and management staff. In addition, the Facility houses corporate functions such as stores warehouse, metering, customer service, information services, production center, generation maintenance, transportation and dispatch functions. The Facility is unique due to the diverse nature of the functions it supports.

The Facility is now 26 years old and has reached an age where capital improvements are necessary to ensure it continues to provide safe and reliable service to employees and the public. This multi-year project includes $2,792,000 in estimated capital expenditures associated with the replacement and refurbishment of the Facility's heating, ventilation and air conditioning systems ("HVAC"), building envelope, building interior, lighting and parking lot.[3] Improvements are required in 2015 and 2016 to replace building components that have reached the end of their useful service life and to make improvements to the existing building layout to reflect changes that have occurred in the Company's operation over the last 25 years.

2.0 Building Condition Assessment

A condition assessment has been completed for the Facility's primary building components. Overall the building is in good condition. However several components require capital improvements to ensure the Facility continues to provide safe and reliable service to employees and the public.

Figure 1 – Damage as a Result of Roof Leakage

Building Envelope

Overall, the roof at the Facility is assessed to be in good condition however localized areas of deterioration are present. Leakage has been identified in two areas; (i) at the intersection of the built-up office area roof and standing seam

1 The Facility is located on 6 hectares of property. The building is approximately 8,100 square metres, with 4,500 square metres of office space. The remaining 3,600 square metres comprises the stores warehouse and various workshops.

2 Approximately 233 employees work from the Facility.

3 Engineering, procurement and installation of the HVAC system is estimated to take approximately 65 weeks to complete. The duration of the HVAC replacement necessitates the multi-year schedule for the overall project.

warehouse roof, and (ii) at the edges of the standing seam warehouse roof. Upgrades are required at this time to prevent the leaks from damaging the interior of the building.

Figure 2 - Corroded Siding

The building's exterior siding is in good condition with the exception of the area near the base. The deterioration in this area is accelerated due to its exposure to de-icing salt. As shown in Figure 2 the siding at the base has corroded through and is no longer weather tight. In areas where the siding has been exposed to de-icing salt the removal and replacement of existing corroded siding is required. Siding is corroded and will be replaced on approximately 200 linear meters of the building's exterior walls.[4]

The Facility's overhead and personnel doors vary in condition. The original overhead doors in the line truck bays have been replaced due to corrosion. Overhead shipping and receiving doors are original and are in fair condition. The overhead door used by forklifts traveling to and from the storage yard is corroded and requires replacement. The Facility's personnel doors are largely original and have significant corrosion, including on the door frame, where exposed to de-icing salts. Deterioration has reached a point where visible gaps are evident between the door and frame. Replacement of 11 deteriorated personnel doors and frames is required.

Figure 3 - Corroded Door Frame

Figure 4 - Corroded Overhead Door

Figure 5 - Corroded Frame
(NOTE: Air gap between door and frame)

[4] To facilitate proper installation, siding is to be replaced from the base to the first siding support.

Building Interior

The interior finishes on the walls of the Facility consist of painted concrete block and drywall. Overall the interior finishes vary in condition from poor to good. The floor coverings are in fair to good condition with the exception of the carpet which is in poor condition. The carpet throughout the building is original to the Facility's 1988 construction, is at the end of its service life and due for replacement. Areas of deteriorated wall finishes will be refurbished along with window coverings that no longer function properly.

Figure 6 - Deteriorated Carpet

Office furniture is largely cubicles constructed from modular panels. The majority of the panels are in good condition. Damaged panels will need to be replaced as required. Replacing cubicle modules at the same time as replacing the carpet reduces overall project cost as the cubicles must be disassembled and reassembled to facilitate the removal of old carpet and installation of new.

Since construction the number of employees based from the Facility has increased by 37%.[5] This is largely the result of adding several corporate functions such as the Customer Contact Centre, the meter shop, offsite computer server room, backup control center and most recently, province wide crew dispatch. Also, the customer growth experienced in recent years has resulted in an increase in the number of technical, line and support staff.

These significant changes have been accommodated over the years within the existing building footprint with some modifications to the building layout being completed. Additional minor modifications within the building footprint are required to improve the functionality of several work spaces. The modifications should take place prior to replacing the original HVAC system to avoid potential future HVAC modifications.[6]

HVAC System

The HVAC system consists of 4 main air handling systems that service the majority of the Facility along with 8 smaller air conditioning systems serving designated areas.[7] The 4 main air handling systems were part of the original building construction while the 8 smaller air conditioning systems range in age from approximately 2 to 26 years.

[5] Originally the Facility accommodated approximately 170 employees. Today there are approximately 233 employees working from the Facility.

[6] These minor modifications to the building layout have resulted in poor balancing of the HVAC system as it currently operates. For further information please refer to Appendix A, page 5.

[7] The Facility's small air conditioning systems are used in areas with specialized cooling requirements such as computer server room and print shop areas as well as office areas where cooling could not be provided by the primary systems.

Due to the age, condition, and operational issues with the HVAC system, Newfoundland Power retained Core Engineering Inc ("Core") in 2012 to provide an overall HVAC system assessment and report.[8] The report is presented in Appendix A.

The main deficiencies of the HVAC system described in the report are as follows:

(i) The system is in poor general condition.
(ii) Current ASHRAE fresh air standards are not currently being achieved.[9]
(iii) The variable air volume (VAV) boxes are dumping boxes, which are not recommended for the large areas that are present in the Facility.[10]
(iv) The current control system is obsolete and should be replaced for efficiency and maintenance reasons.
(v) System is not properly balanced due to past architectural changes to the building.
(vi) The washroom exhaust system is original and does not have the efficiency of current designs.
(vii) 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.[11]

The report concludes the system is at the end of its useful service life and requires replacement.

Electrical
The building electrical service and standby generation is adequate to meet the current needs of the Facility. The standby generator at the Facility was replaced in 2006 with a larger unit and is in good condition. In 2014, the uninterruptable power supply at the Facility will be replaced.[12] The combination of standby generator and uninterruptable power supply will provide adequate emergency power to the Facility for the foreseeable future.

The condition of the lighting system throughout the building varies significantly. A survey of lighting levels has revealed several areas of concern. Lighting levels measured along the exit path in the truck bay do not meet National Building Code requirements.[13] In general, lighting levels in the truck bay and some locations throughout the stores warehouse are below Occupational Health and Safety Regulations. In addition the existing metal halide lights in the truck bay take approximately 10 minutes to warm up and reach full power.

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8 Core Engineering is an Electrical and Mechanical Engineering Consultant specializing in Electrical and Mechanical Building Systems.

9 ASHRAE (American Society of Heating, Refrigerating and Air Conditioning Engineers) publish widely adopted standards for HVAC design.

10 VAV boxes are used to control the flow of heated or cooled air into a space. A dumping box VAV is an older inefficient style that, when air is not required in a space, rather than reducing supply, releases the air to the ceiling cavity to be returned to the air handling unit,

11 Hydrochlorofluorocarbons ("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.

12 Approved under Board Order P.U. 31 (2012).

13 See Division B 3.2.7.1 of the National Building Code of Canada 2010 Volume 2.

In office areas, lighting levels at work surfaces are adequate however parabolic fluorescent fixtures cause shadowing in selected areas.[14] The control system for the office and exterior lighting forms part of the existing HVAC control system. As noted in the HVAC section, the control system is obsolete and requires replacement. The existing lighting control system was designed to switch the lights on and off on a pre-set schedule. Due to technical obsolescence there are limits to the changes that can be made to the schedule and configuration of the existing system. These deficiencies lower overall system efficiency. In addition, spare parts are difficult to source. A replacement lighting control system is required at this time.

Warehouse Equipment

The Central Stores warehouse in the Facility is the primary materials storage facility for the Company. Exterior transformer racks were placed in service in 2008 and are in good condition. The majority of the warehouse's internal storage racks predate the original 1988 construction as they were relocated from the O'Leary Avenue warehouse.[15] Overall the racking is in good condition however isolated deficiencies have been identified throughout. Typical deficiencies include damage to the support frame legs, damaged welds on cross bracing, bent cross bracing and re-welding of load bearing beams. Replacement of deteriorated sections of racking is required to ensure the continued safe operation of the warehouse.

Figure 7 - Typical Racking

Figure 8 - Damaged Support

Figure 9 - Bent Cross Bracing

The shipping and receiving area of Central Stores utilizes dock levelers at 4 of its truck bays to allow loading and offloading of various height trucks. The dock levelers are in good condition. However the mechanical system used to adjust the height of the dock levelers has deteriorated and is in poor condition. In recent years, 2 of the 4 levelers were retrofitted, replacing the original mechanical system with hydraulic systems. The mechanical systems on the remaining two dock levellers are in poor condition and require replacement.

Figure 10 - Truck Bay Loading Dock

14 Parabolic fluorescent light fixtures were commonly used at the time of construction of the Facility. Parabolic refers to the type of shade whose purpose was to direct light in such a way as to eliminate screen glare. A consequence of this type of fixture is shadowing, particularly on the ceiling and walls. The Newfoundland Occupational Health and Safety Regulations, 2012 , Section 36 state that an artificial light source or reflective surface shall be positioned, screened or provided with a shade to prevent glare or discomfort or the formation of shadows that cause eyestrain or a risk of accident or injury to workers.

15 Prior to relocating to the Facility, the Region and Central Stores occupied a property on O'Leary Avenue.

Parking Areas and Storage Yard

The Facility includes parking space for customers', employees' and Company vehicles. Space is provided in 2 lots outside the security fence for employees and customers, and throughout the interior of the security fence for Company vehicles.

Figure 11 - Mews Place Parking Lot

The condition of the parking areas vary from poor to good. The Mew's Place parking lot is in poor condition and requires immediate resurfacing. Resurfacing of the remainder of the Facility's parking lots is anticipated within 5 and 10 years.

No problems have been experienced with the Facility's water and sewer services. Prior to the resurfacing of the Mew's Place parking lot a detailed inspection of underground services will be completed to ensure any work required on the underground services is completed prior to the new asphalt being laid. Similarly, the resurfacing of the parking lot will be coordinated with the drilling of the wells required for the ground source heat pump system.[16]

Storm drainage appears to be functioning well with only 1 noted problem. Water pools at a low point near the shipping and receiving loading dock. This problem will be addressed when the pavement in that area is replaced in 5 to 10 years.

Figure 12 - Damaged Curbs

The curbs are generally in fair to good condition however there are areas in poor condition primarily as a result of snow clearing activities.[17] Sidewalks are generally in good condition. Curb and sidewalk deficiencies will be addressed as adjacent pavement is replaced.

Exterior lighting is provided in both the parking lot and storage areas. The age of the lighting varies from 2 to 24 years. All exterior lighting is in good condition and considered adequate.

Out Buildings

The Facility's secondary building is located adjacent to the main building. The building was constructed with 8 truck bays and a small office area. Originally, the secondary building housed the vehicle service center in 3 bays with the remaining bays being used for storage as well as outdoor property maintenance equipment. In 1998 the building was modified to accommodate the generation maintenance group with 1 bay being converted to office space and 2 used for

[16] The existing HVAC systems will be replaced with an energy efficient ground source heat pump system. Details on the HVAC system replacement can be found in section 3 and Appendix A.

[17] Figure 12 shows isolated curb damage associated with snow clearing.

generation equipment and materials storage.[18] The vehicle service center remains largely unchanged and the remaining 2 truck bays are used for equipment storage by the Region.

Figure 13 - Secondary Building

Figure 14 - Corroded Door and Frame

Like the main building, this Facility's secondary building is largely in good condition however there are isolated areas of deterioration. The personnel doors are significantly corroded and several windows are no longer properly sealed. Some leaks have been noted in isolated areas. Problem areas will be addressed as similar work is completed on the main building.

3.0 Multi-year Project Description

Based upon the comprehensive assessment of the Facility, the following capital expenditures are required at the Facility in 2015 and 2016 to replace components that have reached the end of the service life.

HVAC Replacement (2015 - $1,000,000, 2016 - $600,000)
Replacement of the existing HVAC system is planned for 2015 and 2016. Based on an economic analysis of 3 alternatives provided by Core Engineering, it is recommended that the Duffy Place HVAC system be replaced with a ground source closed loop heat pump system.[19] This system is the overall least cost alternative and will reduce the total building energy consumption by 550,000 kWh annually. The detailed economic analysis can be found in Appendix B. The duration of the project including engineering and procurement is estimated to be 65 weeks.

[18] Generation maintenance includes electricians, millwrights and technologists that maintain the Company's generation assets.

[19] The 3 alternatives were (i) upgrade the existing system, (ii) install a new closed loop heat pump ("CLHP") system and (iii) install a new ground source (geothermal) closed loop heat pump ("GSHP") system. A detailed description of each alternative is located in Appendix A.

Building Envelope Refurbishment (2015 - $288,000)
Replacement and refurbishment of deteriorated building envelope components are required at this time to ensure the building remains weather tight. Replacement of corroded personnel doors, including those in the secondary building, along with one overhead door in the warehouse is required. Replacement of corroded siding along with localized refurbishment of the roof is also required.

Building Interior (2015 - $182,000, 2016 - $124,000)
In advance of the HVAC project, interior reconfiguration focused on improving the functionality of space will be completed in 2015. Since HVAC design and configuration is very much dependant on building layout, it is necessary to complete modifications to the building layout in conjunction with an HVAC replacement.

The carpet in the office areas is original to the 1988 building construction and is in poor condition. Window treatment and wall coverings are also deteriorated. Replacement of both is planned for 2016. Installation will be completed after any planned architectural, HVAC and lighting upgrades.

Lighting Upgrade (2015 - $177,000)
Replacement of the metal halide truck bay lights as well as the replacement and retrofitting of various other lights throughout the Facility is required to address low and shadowy light conditions. A control system replacement is required as the current system is obsolete. Lighting upgrades are planned for 2015.

Warehouse Improvements (2015 - $55,000)
Warehouse improvements are required in 2015 including replacement of damaged sections of the pallet racking system along with improvements to the dock-levelers.

Parking Lot Improvements (2015 - $366,000)
The Mews Place parking lot is in poor condition and resurfacing is required in 2015.[20] This includes addressing curb and sidewalk deficiencies as adjacent sections of pavement are replaced.

[20] Wells for the ground source closed loop heat pump system will be drilled in the area of the employee parking lot. The installation of the wells will be coordinated with the resurfacing of the employee parking lot.

4.0 2015/2016 Project Costs

Table 1 provides a breakdown of the proposed expenditures for 2015 and 2016.

Table 1
Planned Capital Expenditures – By Item
($000s)

Description	2015	2016
Building Envelope Refurbishment	288	-
Building Interior	182	124
HVAC Replacement	1,000	600
Lighting Upgrade	177	-
Warehouse Improvements and Racks	55	-
Mews Place Parking Lot	366	-
Total	**2,068**	**724**

Table 2 provides a breakdown of the proposed expenditures for 2015 and 2016 by cost category.

Table 2
Projected Expenditures – By Cost Category
($000s)

Cost Category	2015	2016
Material	1,824	601
Labour – Internal	10	10
Labour – Contract	-	-
Engineering	112	58
Other	122	55
Total	**2,068**	**724**

5.0 Concluding

The Facility is now 26 years old. In 2015 and 2016 capital improvements are necessary to replace deteriorated building components and systems to ensure it continues to provide safe and reliable service to employees and the public. In addition, the increase in the number of employees working from the Facility requires minor modifications to the building layout that must be completed before the HVAC system is replaced.

Appendix A
HVAC System Analysis
Duffy Place

HVAC Systems Analysis

Newfoundland Power
Duffy Place, St. John's

Prepared by:

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REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
HAROLD E. FOWLER
SIGNATURE
June 19/14
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PROVINCE OF NEWFOUNDLAND

Client:

NEWFOUNDLAND
POWER
A FORTIS COMPANY

Date:
Updated June 2014

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1.0 INTRODUCTION

Core Engineering Incorporated(Core) was retained by Newfoundland Power to evaluate the heating, ventilation and air-conditioning (HVAC) systems at the Duffy Place office building. The scope of this report includes capital cost estimates and energy consumption estimates for various replacement options. This evaluation will also outline the existing equipment and systems, their condition, and provide recommendations detailing upgrades based on cost, energy, and comfort.

Harold Fowler, P. Eng., from Core has visited the site on several occasions and has reviewed drawings that were available. This report will also provide the Owner with an update as to the operation of the various systems and their conditions. Replacing the existing system components will be discussed and options for replacing the entire HVAC system with a much more energy efficient model will also be evaluated.

The Duffy Place office building was built in 1988 as a two storey structure, consisting of a first floor and partial second floor and warehouse section. The total building contains approximately 4500 square meters of space excluding the stores warehouse area. The areas served by the air handling equipment is divided as such: system 1 serves the office space on the first floor, system 2 serves the shop areas adjacent to the warehouse, system 3 serves the office space on the second level while system 4 serves the locker area adjacent to warehouse. There are approximately eight other air conditioning/ventilation systems which serve different parts of the building. These systems range in age from two years old to approximately 10 years old.

2.0 DESCRIPTION

2.1 Existing H.V.A.C. System

The majority of the existing building consists of four main air-handling systems, which provides a combination of ventilation and/or air-conditioning for the majority of the complex. There are eight separate air conditioning/ventilation systems which serve dedicated areas throughout the facility which will be spoken of briefly. These systems are as follows:

1. First Floor System office area(Air handling system – HVAC #1) - Installed in 1988.
2. First Floor Shops area(Ventilation only – HRU #1) – Installed in 1988.
3. Second Floor System office area(Air handling system – HVAC #2) - Installed in 1988
4. First Floor locker area(Ventilation only – HRU #2) – Installed in 1988.
5. Main Lobby 1002 and 2001 – Supply/Return fan with heating coil, installed in 1988.
6. Server room area – Liebert cooling split system.
7. Stationary area – Package rooftop unit.
8. Print shop area – Package rooftop unit.
9. Telecommunications area – Package rooftop unit.
10. Metering area – Samsung mini-split unit.
11. New office area – Packaged rooftop unit, installed in 2011.
12. Mezzanine area – Packaged rooftop unit.

2.2 First Floor Office System

The system designed for the original building in 1988 is commonly known as a variable air volume VAV system, which consists of an air-handling unit, complete with a supply air fan, heating coil, cooling coil, return air fan, filters, mixing box, humidifier and associated controls system. The system heating is generated using an electric heating coil and the cooling is obtained from what is generally referred to as a DX (Direct Expansion) system using refrigerant gas, compressors, condensers and cooling coils.

A VAV system is designed to control multiple zones in a building in which each zone has their own terminal supply box feed from the main air handling unit system. The terminal supply box is capable of modulating airflow to the zone to meet the desired space temperature. A temperature controller (thermostat) in a particular zone will call for either cooling or heating. This will operate a damper system in the terminal box to supply more air or less air to the zone.

A return fan located in the mechanical room pulls air from the ceiling space, exhausts a small portion and returns the remainder through the air handling unit.

The controls for this system is an older Direct Digital Control (DDC) computerized control system which controls the HVAC systems. The control system for this unit utilizes what is referred to as a free cooling option. This option allows outside air to be used to provide free cooling when needed provided outside conditions will allow it. The space control temperature has thermostats controlling VAV boxes which will vary the air flow from a maximum position on a call for cooling to a minimum position on a call for heating. However, on a call for heating, a second stage of control will energize an electric baseboard heater in a particular zone.

As part of the ventilation system, the first floor washrooms are exhausted through the Heat Recovery Unit #1 system located above room 1016 serving the shops area. There is also a supply and return fan which serves to ventilate the main lobby.

2.2 First Floor Shops System

The shops, printing, telecommunication and surrounding areas have ventilation air provided to them from a heat recovery unit located above room 1016. The unit consists of fresh air supply fan, filter, heat recovery core, electric heating coil and exhaust air fan. The unit provides 100% fresh air and returns the air from areas noted above. The heat recovery core recovers the heat from the return air and then exhausts it to the outside. The heat from the return air is transferred to the incoming fresh air via the heat recovery core. The supply air is then brought up to the final supply air set point through an electric duct mounted heating coil.

2.3 Second Floor Office System

The system consist of an indoor built-up air handling unit with supply fan, electric heating coil, chilled water cooling coil, filters, mixing box, humidifier, return fan and control systems. The system heating is generated using an electric heating coil and the cooling is obtained from what is generally referred to as a DX (Direct Expansion) system using refrigerant gas, compressors, condensers and cooling coils.

The conditioned air from these units supplies air to VAV boxes located throughout the space for various zones. They are positioned to vary the air flow. However, as these boxes are controlled in a minimum position, the static pressure in the duct system rises. As the static pressure increases, a static pressure controller will decrease the air flow from the air-handling unit.

This floor also has; dedicated exhaust fan for washrooms which exhaust directly to the outdoors and a supply/return fan which serves the lobby on the second level.

2.4 First Floor Locker System

The first floor locker area has ventilation air provided from a heat recovery unit located in room 2043. The unit consists of fresh air supply fan, filter, heat recovery core, electric heating coil and exhaust air fan. The unit exhausts 100% of the locker area and provides 100% fresh air make-up. The heat recovery core recovers the heat from the return air and then exhausts it to the outside. The heat from the return air is transferred to the incoming fresh air via the heat recovery core. The supply air is then brought up to the final supply air set point through an electric duct mounted heating coil.

2.5 Miscellaneous Air Conditioning

There are a number of miscellaneous air conditioning units identified above which have been installed since the construction of the main building in 1988. They range in age from approximately two year old to approximately 10 years old. The majority of the systems provide cooling or ventilation air to one area or a combination of areas with similar requirements.

3.0 OPERATIONAL OBSERVATIONS

3.1 First/Second Floor Office Systems

The system serving this space is a 24-year-old air-handling/VAV system as described earlier. Below are the main issues surrounding this system:

- The VAV boxes are dumping boxes, which are not recommended for large areas because they tend to cause cool pressurized ceiling spaces. This system is often responsible for comfort problems due to cold air dropping through return grilles and openings in the ceiling.

- Controls system is in need of being updated to a newer modern system for efficiency, maintenance and reasons. The Honeywell system currently installed is obsolete.

- The distribution of supply and return grilles, the zone airflows, and the number of VAV boxes are not ideally balanced within the spaces because of changes to the building layouts that have occurred since the initial installation.

- Minimum fresh air standards of 8.5 l/s per person are likely not being achieved with this system. ASHRAE Standard “Ventilation for Acceptable Indoor Air Quality” requires that the above minimum fresh air levels be maintained.

- The washroom exhaust system as discussed is 24 years old and likely does not have the efficiency of newer modern systems.

- The lobby 1002 and 2001 supply and return system as discussed is 24 years old and likely does not have the efficiency of newer modern systems.

- The cooling system is operated using Freon R-22 refrigerant which is not considered an environmentally friendly refrigerant agent. This refrigerant is due to be phased out of commercial air conditioning equipment by the year 2020. While this refrigerant will not be used in a new equipment, replacement refrigerant will be available until 2020 before 99.5% phase-out and eliminating completely the manufacturing of R-22 by 2030

- Humidifier for first floor system is original to the building and operation is likely sporadic and is at the end of it’s useful life and should be replaced.

- This system is at/near the end of it’s useful life and is generally in poor condition. It is expected that maintenance costs and reliability will cause problems in the near future.

3.2 First Floor Shops and Locker area Systems

These systems are built-up heat recovery as described earlier and are approximately twenty four years old. We have identified a few items with these systems which are as follows; current fresh air standards of 8.5 l/s per person should be supplied by these systems. ASHRAE Standard “Ventilation for Acceptable Indoor Air Quality” requires that the above minimum fresh air levels be maintained. The age of the equipment may soon cause operational issues.

3.3 Miscellaneous Air Conditioning Systems

These systems, as described earlier, range in age from approximately two year to ten years old. All misc. systems were found to be in excellent to good working condition with few issues to report. Only notable item with the misc. units is with unit serving printing/stationary area. Unit distribution should be reviewed as equipment loads/location has been modified over the years and cooling issues have been reported.

4.0 RECOMMENDATIONS

The existing systems as described are at or very close to the end of their useful lives and we would recommend replacement in the next couple of years. Several system options are available for replacement and upgrading of this building which are underlined below. Energy consumption for various systems will also be estimated using efficiencies of systems in conjunction with existing power bills provided by Newfoundland Power. These energy consumption rates can then be used to see differences in energy consumption based on the options provided.

Three system options are considered in the following analysis. Each of these options have some unique features from the other, especially with energy consumption considerations. The three options we offer for consideration are as follows:

- Upgrade the existing systems utilizing the V.A.V. system approach.
- Install a new Closed Loop Heat Pump System - conventional
- Install a new Ground Source Closed Loop Heat Pump System

4.1 Upgrade the Existing System (Option 1)

The recommended upgrades to the existing system will address problems and concerns that were raised in our observations and it will also bring the system up today's indoor air quality standards.

- Replacing the air-handling unit for the first/second floor.
- Add a new condensing units for both units.
- Revamp the duct system with upgrading of the air distribution system and additional VAV boxes.
- Adjust air flow from VAV boxes to meet Ashrae-62 requirements.
- Add variable frequency drive fan speed controllers to minimize energy consumption.
- Add a heat recovery unit for all washroom exhaust systems.
- Replace/update existing control system and add CO_2 sensors to control fresh air introduced to the building by the HVAC systems.

4.2 Closed Loop Heat Pump System (Option 2)

An energy efficient system suited to this application is a closed loop heat pump system (CLHP). This system operates on the principle of moving heat around a building. If a space needs cooling because of equipment loads or solar loads, the heat from these areas is transferred to other areas needing heating. The transfer is achieved using water piping connecting water-to-air heat pumps strategically located throughout the ceiling space. Each heat pump would be considered a zone for a particular office or group of offices, and it supplies a constant volume of air flow to the space. If additional heat is needed in the system (winter), than duct mounted electric heating coils located in each zone will provide the additional heat and conversely if heat must be rejected (summer), then a cooling tower will remove excess heat from the system.

This system will provide both the heating and cooling system demands for the building. The fresh air will be achieved using a heat recovery system. The heat recovery unit will introduce 100% outside air into the ceiling space at or near the heat pumps. The return air will be extracted from the washrooms or from general areas to be exhausted through the heat recovery unit. The heat recovery unit will extract approximately 60% of the heat from the exhaust air.

4.3 Ground Source Heat Pump System (Option 3)

This system is very similar to the CLHP system described in 4.2, but the key difference lies in the heat source and heat sink. Piping installed in drilled wells provides the needed heat in winter and also provide the means to reject heat in the summer. Even though the temperature of the ground wells is 7.2°C there is sufficient heat available to heat the building. The low ground temperature also provides almost free cooling throughout the summer regardless of the outdoor temperatures. To prevent freezing an environmentally friendly food grade anti-freeze solution is used in the circulation loop between the building and the multiple wells. A heat exchanger will transfer the heat gained from the wells to the building loop where the heat pumps will then operate to cool or heat the spaces.

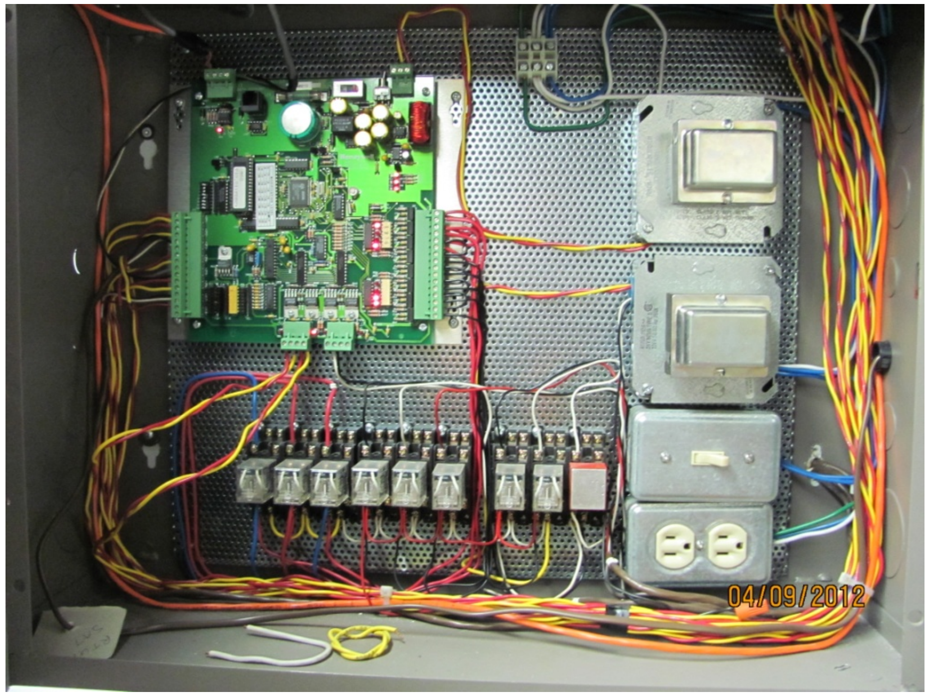
This system has the lowest energy consumption of all conventional building heating and cooling systems and is a proven system. There are numerous buildings throughout the city, which are served by a ground source heat pump system. Another advantage is the reduction in the building connected electrical load as the ground source heat pump requires only one unit of electrical energy to produce 3 units of heat output.

5.0 CAPITAL COSTS AND ENERGY CONSUMPTION

The estimated energy consumption and budget capital costs for a VAV, CLHP and ground source systems are provided in the table below. The electric energy consumption calculated are based on existing power bills. The energy consumptions given below are estimates as described in section 5.0. The maintenance costs associated with each system is also be considered and provided in the analysis table.

Component	New V.A.V./HRU Systems	C.L.H.P.	Ground Source Heat Pumps
LEVEL 1 AND 2 AHU/HRU SYSTEMS			
Est. Demolition Costs	$45,000	$45,000	$45,000
Est. Construction Costs	$760,000	$1,125,000	$1,250,000
Est. Engineering Costs	$83,600	$123,750	$137,500
Contingency 10%	$76,000	$112,500	$125,000
Total Est. Capital Costs	**$964,600**	**$1,406,250**	**$1,557,500**
TOTAL Annual energy based on existing bills provided by NF Power	**2,300,000 kwh**	**2,000,000 kwh**	**1,750,000 kwh**
Estimated Annual Maintenance Costs	**$10,500**	**$20,880**	**$19,620**

Attachment A
Existing Equipment



Existing DDC Control Panels

Existing Motor Starters

Existing First Floor Return Fan

Existing First Floor Office Space, Supply Fan and Cooling Coil

Existing First Floor Humidifier

Existing Shops/Printing Area HRU System

Existing Metering Mini-Split A/C Unit

Existing Locker Room Built-Up HRU Unit

Existing Locker Room Built-Up HRU Unit

Existing Second Level Humidifier

Existing Second Level AHU

Existing Server Room Roof Mounted Condensing Unit

Existing AHU Unit Roof Mounted Condensing Unit

Existing Packaged A/C Units Serving: Stationary, Print Shop and Telecommunications

Existing Mini-Split Condensing Unit and Packaged A/C Units Serving: Metering, Newly Added Offices and Mezzanine

Appendix B
HVAC Economic Analysis
Duffy Place

Economic Analysis Summary

An economic analysis was completed to determine the most feasible alternative for the replacement of the building HVAC system. The capital and annual operating costs used in the analysis for each alternative were provided by Core Engineering and are based on their research and experience in designing and installing these types of systems. The net present value ("NPV") for each system was determined based on estimated capital expenditures with annual maintenance cost included in the calculation. The results are provided in Table 1 below.

Table 1
Net Present Value of the 3 HVAC System Options
(000s)

Cost Category	VAV[1]	CLHP	GSHP[2]
Material	$843	$1,249	$1,388
Labour – Internal	$15	$15	$15
Engineering	$55	$55	$55
Other	$87	$131	$142
Total Capital Cost	$1,000	$1,450	$1,600
Annual Maintenance	$10,500	$20,880	$19,620
NPV @ 25 Years	**$1,282**	**$1,932**	**$1,796**

The 25 year NPV shown in Table 1 does not include the benefit of energy savings gained by the CLHP and GSHP systems. The CLHP and GSHP systems are both more energy efficient than the VAV system and can save an estimated 300 and 550 MWh per year of energy respectively.

Further evaluation of the economic analysis benchmarks the energy savings compared to the additional replacement cost of the standard VAV system. The additional capital expenditure required for each of the heat pump systems is amortized over the 25 year expected life of each system and compared to the expected energy savings. The results are shown in Table 2.

1 VAV refers to variable air volume type of HVAC system.
2 The ground source heat pump qualifies for accelerated depreciation under CCA 43.2 (50% CCA) which has a positive benefit shown below in Table 1.

Table 2
NPV CLHP and GSHP Energy Savings Compared with VAV System

	CLHP	**GSHP**
Additional Cost (NPV)	$650,000	$514,000
Annual Payment	$55,025	$43,512
Annual Energy Savings (kWh)	300,000	550,000
Levelized Cost (¢/kWh)	18.34	7.91

The levelized costs of the annual energy savings (¢/kWh) for the closed loop heat pump and ground source heat pump systems are 18.34 and 7.91 respectively.

Alternative No.1
VAV System
Present Worth Analysis

Weighted Average Incremental Cost of Capital 6.85%
PW Year 2014

YEAR	HVAC	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net benefit	Present Worth	Cumulative Present Value	Present Worth of Sunk Costs	Total Present Worth
						Benefit +ve	Benefit +ve		Benefit +ve
	25 Yrs								
	4% CCA								
2015	700,000	72,755	10,500	0	-83,255	-77,917	-77,917	-1,063,688	-1,141,606
2016	306,000	116,851	10,710	0	-127,561	-111,730	-189,647	-961,340	-1,150,986
2017	0	119,872	10,924	0	-130,796	-107,219	-296,866	-863,076	-1,159,941
2018	0	116,518	11,143	0	-127,660	-97,939	-394,805	-773,685	-1,168,490
2019	0	113,200	11,343	0	-124,544	-89,423	-484,228	-692,407	-1,176,634
2020	0	109,918	11,556	0	-121,474	-81,628	-565,856	-618,544	-1,184,400
2021	0	106,670	11,772	0	-118,442	-74,488	-640,344	-551,460	-1,191,803
2022	0	103,455	11,988	0	-115,443	-67,947	-708,291	-490,568	-1,198,859
2023	0	100,271	12,212	0	-112,483	-61,961	-770,251	-435,334	-1,205,586
2024	0	97,117	12,443	0	-109,560	-56,482	-826,733	-385,267	-1,212,000
2025	0	93,992	12,675	0	-106,667	-51,465	-878,198	-339,918	-1,218,116
2026	0	90,895	12,912	0	-103,807	-46,874	-925,072	-298,874	-1,223,946
2027	0	87,825	13,153	0	-100,978	-42,673	-967,745	-261,759	-1,229,505
2028	0	84,780	13,399	0	-98,179	-38,831	-1,006,576	-228,228	-1,234,804
2029	0	81,759	13,650	0	-95,409	-35,316	-1,041,892	-197,965	-1,239,857
2030	0	78,762	13,907	0	-92,670	-32,103	-1,073,995	-170,679	-1,244,674
2031	0	75,788	14,165	0	-89,953	-29,164	-1,103,159	-146,108	-1,249,267
2032	0	72,835	14,432	0	-87,267	-26,479	-1,129,639	-124,007	-1,253,646
2033	0	69,904	14,702	0	-84,606	-24,026	-1,153,665	-104,156	-1,257,821
2034	0	66,992	14,979	0	-81,971	-21,786	-1,175,450	-86,352	-1,261,802
2035	0	64,099	15,259	0	-79,358	-19,739	-1,195,190	-70,408	-1,265,598
2036	0	61,225	15,545	0	-76,770	-17,871	-1,213,061	-56,156	-1,269,216
2037	0	58,369	15,837	0	-74,205	-16,167	-1,229,227	-43,439	-1,272,666
2038	0	55,529	16,134	0	-71,663	-14,612	-1,243,839	-32,117	-1,275,956
2039	0	124,267	16,437	0	-140,704	-26,850	-1,270,689	-8,403	-1,279,093
2040	0	47,053	16,745	0	-63,798	-11,394	-1,282,083	0	-1,282,083

Alternative No. 2
Closed Loop Heat Pump
Present Worth Analysis

Weighted Average Incre		**6.85%**						
Escalation Rate		**See following worksheet**						
PW Year		**2014**						

	HVAC	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net benefit	Present Worth Benefit +ve	Cumulative Present Value Benefit +ve	Present Worth of Sunk Costs	Total Present Worth Benefit +ve
	25 yrs								
	4% CCA								
YEAR									
2015	870,000	90,423	20,880	0	-111,303	-104,168	-104,168	-1,548,901	-1,653,069
2016	591,600	167,189	21,298	0	-188,486	-165,094	-269,262	-1,402,461	-1,671,723
2017	0	174,654	21,724	0	-196,377	-160,978	-430,240	-1,259,291	-1,689,531
2018	0	169,775	22,158	0	-191,933	-147,249	-577,489	-1,129,041	-1,706,530
2019	0	164,950	22,557	0	-187,507	-134,631	-712,120	-1,010,606	-1,722,726
2020	0	160,176	22,980	0	-183,157	-123,077	-835,196	-902,972	-1,738,168
2021	0	155,453	23,410	0	-178,862	-112,486	-947,682	-805,208	-1,752,891
2022	0	150,777	23,839	0	-174,615	-102,775	-1,050,457	-716,465	-1,766,921
2023	0	146,146	24,284	0	-170,430	-93,881	-1,144,337	-635,961	-1,780,298
2024	0	141,560	24,743	0	-166,303	-85,734	-1,230,072	-562,982	-1,793,054
2025	0	137,015	25,205	0	-162,220	-78,268	-1,308,340	-496,875	-1,805,215
2026	0	132,512	25,676	0	-158,188	-71,430	-1,379,770	-437,039	-1,816,809
2027	0	128,047	26,156	0	-154,203	-65,166	-1,444,936	-382,927	-1,827,862
2028	0	123,619	26,645	0	-150,264	-59,431	-1,504,367	-334,034	-1,838,401
2029	0	119,227	27,143	0	-146,370	-54,179	-1,558,546	-289,902	-1,848,448
2030	0	114,869	27,656	0	-142,525	-49,374	-1,607,920	-250,108	-1,858,029
2031	0	110,545	28,168	0	-138,713	-44,973	-1,652,893	-214,268	-1,867,161
2032	0	106,252	28,698	0	-134,950	-40,948	-1,693,841	-182,028	-1,875,869
2033	0	101,989	29,237	0	-131,226	-37,265	-1,731,106	-153,065	-1,884,172
2034	0	97,756	29,787	0	-127,543	-33,897	-1,765,003	-127,085	-1,892,088
2035	0	93,551	30,344	0	-123,895	-30,817	-1,795,820	-103,815	-1,899,636
2036	0	89,372	30,912	0	-120,284	-28,001	-1,823,821	-83,011	-1,906,832
2037	0	85,220	31,492	0	-116,712	-25,427	-1,849,248	-64,444	-1,913,693
2038	0	81,092	32,083	0	-113,175	-23,076	-1,872,324	-47,910	-1,920,234
2039	0	165,928	32,685	0	-198,613	-37,900	-1,910,225	-16,247	-1,926,471
2040	0	90,970	33,299	0	-124,269	-22,193	-1,932,418	0	-1,932,418

Alternative No. 3
Ground Source Heat Pump
Present Worth Analysis

Weighted Average Incre	**6.85%**
PW Year	**2014**

YEAR	HVAC 25 Yrs 50% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net benefit	Present Worth	Cumulative Present Value	Present Worth of Sunk Costs	Total Present Worth
2015	1,000,000	101,111	19,620	0	-120,731	-112,991	-112,991	-1,421,308	-1,534,299
2016	612,000	173,603	20,012	0	-193,616	-169,586	-282,577	-1,269,250	-1,551,828
2017	0	170,774	20,413	0	-191,187	-156,723	-439,301	-1,129,260	-1,568,561
2018	0	159,197	20,821	0	-180,018	-138,108	-577,408	-1,007,126	-1,584,534
2019	0	151,460	21,196	0	-172,656	-123,968	-701,376	-898,377	-1,599,753
2020	0	145,644	21,594	0	-167,237	-112,379	-813,755	-800,508	-1,614,263
2021	0	140,787	21,997	0	-162,784	-102,374	-916,129	-711,968	-1,628,097
2022	0	136,411	22,400	0	-158,811	-93,473	-1,009,602	-631,679	-1,641,281
2023	0	132,275	22,819	0	-155,093	-85,432	-1,095,034	-558,816	-1,653,851
2024	0	128,258	23,250	0	-151,508	-78,107	-1,173,142	-492,695	-1,665,837
2025	0	124,302	23,684	0	-147,986	-71,400	-1,244,542	-432,722	-1,677,264
2026	0	120,376	24,127	0	-144,502	-65,250	-1,309,792	-378,366	-1,688,158
2027	0	116,464	24,578	0	-141,042	-59,604	-1,369,396	-329,148	-1,698,545
2028	0	112,560	25,037	0	-137,598	-54,421	-1,423,817	-284,630	-1,708,447
2029	0	108,660	25,505	0	-134,166	-49,662	-1,473,479	-244,409	-1,717,888
2030	0	104,762	25,987	0	-130,749	-45,295	-1,518,774	-208,117	-1,726,891
2031	0	100,865	26,468	0	-127,333	-41,283	-1,560,057	-175,415	-1,735,472
2032	0	96,968	26,967	0	-123,935	-37,606	-1,597,663	-145,992	-1,743,654
2033	0	93,072	27,472	0	-120,544	-34,232	-1,631,894	-119,561	-1,751,456
2034	0	89,175	27,990	0	-117,165	-31,139	-1,663,034	-95,861	-1,758,895
2035	0	85,279	28,513	0	-113,791	-28,304	-1,691,337	-74,650	-1,765,987
2036	0	81,382	29,047	0	-110,429	-25,707	-1,717,044	-55,705	-1,772,749
2037	0	77,486	29,592	0	-107,078	-23,328	-1,740,372	-38,823	-1,779,196
2038	0	73,590	30,147	0	-103,737	-21,152	-1,761,524	-23,819	-1,785,343
2039	0	89,332	30,713	0	-120,045	-22,908	-1,784,432	-6,772	-1,791,203
2040	0	37,917	31,289	0	-69,206	-12,360	-1,796,791	0	-1,796,791

2015 Application Enhancements

June 2014

Table of Contents

1.0 Introduction

Newfoundland Power (the "Company") operates and supports over 60 computer applications. These include third party software products, such as the Microsoft Dynamics Great Plains ("Dynamics GP") financial system and the Click Software ("Click") work scheduling and dispatch system, as well as internally developed software, such as the Customer Service System ("CSS") and the Outage Management System ("OMS"). These applications help employees work more effectively and efficiently in their daily duties.

The Company's computer application enhancements can be considered in 4 broad categories: Business Support Systems, Operations and Engineering Systems, Customer Service Systems and Internet/Intranet Systems. In addition, the Company budgets for minor enhancements to respond to unforeseen requirements routinely 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 provide service to its customers at least cost.

The following report describes the application enhancements planned for 2015.

2.0 Business Support Systems Enhancements

Business Support System Enhancements include application enhancements necessary to support the Company's business applications. The information technology in this category includes the human resources application Empower, the Dynamics GP application and various other applications used to manage the financial, human resources and materials management areas of the Company.

For 2015, enhancements to the Company's inventory management applications are proposed.

Table 1 summarizes the estimated cost associated with this item.

Table 1
Business Support Systems Enhancements
Project Expenditures
($000s)

Cost Category	2015 Estimate
Material	150
Labour – Internal	179
Labour – Contract	-
Engineering	-
Other	65
Total	**394**

2.1 Inventory Management Improvements ($394,000)

Description

The purpose of this item is to implement a number of enhancements to the Company's inventory management systems. These include (i) the use of Radio Frequency Identification ("RFID") technology in the management of tools and equipment ("tools") used in field operations, (ii) improvements to the tracking of inventory leaving the warehouse via heavy fleet vehicles and (iii) enhancements to the updating of corporate applications required as a result of work completed in the field.[1]

Operating Experience

The Company manages approximately 1,000 tools used in performing electrical system construction and maintenance. Ensuring that the right complement of tools is available is critical to employee productivity and operating efficiency. As a result of normal use many of these tools require repair and maintenance in order to ensure safe and effective operation. On average, 400 tools are brought in for repair annually. Once repaired, tools are reassigned to trucks as required. Given the volume of tools in use at any given time it is no longer practical to manually track tools with regards to the truck assigned, location, and repair status. Inaccuracy regarding the status and condition of tools can result in a truck not having the required tools to perform electrical system construction and maintenance.

Company trucks are stocked with inventory required to perform electrical system construction and maintenance. This inventory includes meters, streetlights, transformers and conductor. Trucks are normally stocked based on planned work for the day, however equipment initially loaded on the truck for planned work can be used for other purposes.[2] Once inventory items move outside of the warehouse, ensuring that materials are replenished on a timely basis in order to meet planned work requirements is largely a manual process. Some materials needed overnight for emergency work may have been selected for planned jobs the following day. This situation can result in trucks arriving at the job site with incorrect (or insufficient) material.

The Company installs approximately 25,000 meters and 3,000 streetlights annually.[3] Accurate and timely installation and tracking of this material is critical to effective customer service. Currently, line crews maintain a manual record of meter and streetlight numbers installed in the field. This paperwork is then brought back to the office to be keyed by office support staff. The

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[1] Examples of tools and equipment include hydraulic wire cutters, crimpers, and chain saws. Inventory items include transformers, meters, streetlights and conductor required for line construction and maintenance. Corporate applications include the Customer Service System, Metering Equipment System and Streetlight System.

[2] Equipment can be used in response to customer reported outages, pole fires, vehicle accidents and unplanned equipment upgrades or replacements.

[3] Meters are installed to provide new service, replace failed meters or replace old meters nearing end of life as defined by Measurement Canada. Streetlights are installed at the request of customers.

project will include integrating CSS with Click to automate the dispatch of customer service work orders to field crews.[4]

Justification

This project will improve overall tool management and assignment procedures utilizing RFID technology. Improving the Company's ability to track tool location and condition ensures that crews are able to effectively perform electrical system construction and maintenance.

This project will improve inventory management processes by automatically verifying that truck inventory items such as meters, streetlights, transformers and conductor are correct as trucks leave Company supply yards. Ensuring that crews have the right materials when they arrive at the job site improves operating efficiency, reduces delays in completing the work and improves overall customer service.

Eliminating the need to key meter and streetlight installation information into Company applications such as the CSS, Metering Equipment System and Streetlight Management System will improve operating efficiency, data accuracy and completeness and in turn improve customer service.

This project has a net present value of approximately $47,000 over an expected application life-cycle of 10 years.[5]

3.0 Operations and Engineering Systems Enhancements

Operations and Engineering Systems Enhancements include 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 2015, enhancements are proposed to the Company's property management application.

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4 The integration of field work with information system applications is part of the Company's operations technology strategy.

5 The net present value calculation for this project can be found on page A-1 of Appendix A.

Table 2 summarizes the estimated cost associated with this item.

Table 2
Operations and Engineering Enhancements
Project Expenditures
($000s)

Cost Category	2015 Estimate
Material	24
Labour – Internal	92
Labour – Contract	-
Engineering	-
Other	35
Total	**151**

3.1 Property Records Management System Improvements ($151,000)

Description

The purpose of this project is to replace the application used to manage the Company's real property records with a solution that ensures property records are stored and managed in an effective and secure manner.

Operating Experience

The Company manages approximately 20,000 files related to property records. These paper-based records are currently stored in a secured vault located at the Company's head office. The files represent government registered real estate records related to easements, Company owned property and conveyances. These property records are used by employees for distribution system planning and in response to customer requests and easement disputes.

The application currently being used to manage the property records, known as *PRMS*, has been in service for over 20 years. The application allows employees to search a database for a catalog number that identifies a specific record. The original paper record must then be manually retrieved from the secured vault and an electronic or paper copy is created. The original files are then returned to the vault. Some of the records date back over 60 years and their condition has deteriorated due to repeated handling.

Justification

This project will improve efficiency by reducing the manual effort required in providing access to property records. The new application will allow employees to gain direct access to electronic versions of the required records without the requirement to physically retrieve and copy the original records. In addition, the risk associated with the loss or damage of these registered documents will be reduced with the replacement of paper files with electronic versions.

This project has a net present value of approximately $17,000 over an expected application life-cycle of 10 years.[6]

4.0 Customer Service Systems Enhancements

Customer Service Systems Enhancements include application enhancements necessary to support customer service delivery, including the various forms of communications used by customers to receive service from the Company. For 2015, enhancements are proposed in customer outage communication and notification.

Table 3 summarizes the estimated cost associated with this item.

Table 3
Customer Service Systems Enhancements
Project Expenditures
($000s)

Cost Category	2015 Estimate
Material	80
Labour – Internal	97
Labour – Contract	-
Engineering	-
Other	80
Total	**257**

4.1 Customer Outage Communication and Notification ($257,000)

Description

The purpose of this item is to provide increased choice and flexibility to customers wanting to receive information from the Company regarding outage events. For 2015, notifications related to planned outages, feeder level outages and critical customers are planned.[7] The proposed

[6] The net present value calculation for this project can be found on page A-2 of Appendix A.

[7] Within the CSS database, the Company maintains a record of the distribution feeder supplying each customer. This information will be used to notify customers of feeder level outages. As part of the Customer Connectivity item to be completed in 2015 as part of ***6.5*** *Geographical Information System Improvements* project, information about how customers are connected to the distribution network will be gathered. This information will allow customers affected by smaller outages affecting only sections of a feeder to be identified.

project will allow customers to use mobile computing devices or access a website to subscribe to a service that will send messages to the customer regarding outages affecting them.[8]

Operating Experience

The Company has experienced exponential growth in customers looking for up-to-date information during outages. In a 7 day period during January 2014, Newfoundland Power managed an unprecedented number of customer communications caused by rolling blackouts, Newfoundland and Labrador Hydro equipment failures and severe weather.[9]

The number of Newfoundland Power customers opting for an electronic means of communications continues to grow. This increase is primarily driven from the use of mobile computing devices. According to the statistics collected on the Company's website, the number of customers using a mobile device to access information from www.newfoundlandpower.com has increased from approximately 93,000 mobile device visits in 2012 to approximately 422,000 mobile device visits in 2013.

Justification

This item is justified through improved customer service. Customers expect to get information they need from their communication channel of choice, during hours that meet their needs. In addition to offering customers a variety of communication channels the Company must offer the customers a simple way to manage their communication preferences.

Customer communication flexibility will help the Company redefine the way customers interact with the utility by allowing the Company to push information to customers using proactive phone calls, emails, and text messages. This type of communication can be crucial during storms and outages, and also provides opportunities in future customer self-service initiatives.

Directing customers to self-service functions and notification tools will improve customer service. Well-designed self-service options can deflect customer contact centre traffic, resulting in reduced customer wait times, reduced busy signals and greater success providing customers the information they need from various channels.

5.0 Internet Enhancements

Internet Enhancements include enhancements to the Company's web-based applications, which provide customers convenient self-service options giving them the ability to interact with the Company 24 hours a day. The applications in this category include the Company's customer service internet website, mobile website and the takeCHARGE! website.[10]

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[8] Mobile computing devices include cell phones, smart phones and tablets.

[9] During the seven day period of January 2–8, 2014, Newfoundland Power received approximately 950,000 customer visits to www.newfoundlandpower.com and approximately 140,000 customer calls to its High Volume Call Answering Service and Customer Contact Center.

[10] The takeCHARGE! website supports the joint Newfoundland and Labrador Hydro and Newfoundland Power customer energy conservation initiative.

For 2015, both the customer service website and the takeCHARGE! energy conservation website will be enhanced to improve functionality and access for mobile devices.

Table 4 summarizes the estimated cost associated with this item.

Table 4
Internet Enhancements
Project Expenditures
($000s)

Cost Category	2015 Estimate
Material	-
Labour – Internal	188
Labour – Contract	-
Engineering	-
Other	60
Total	**248**

5.1 Customer Service Internet Enhancements ($195,000)

Description

For 2015, items proposed include energy analysis functionality to support customer high bill inquiries and extending the billing and payment self-service functionalities currently available on the Company's customer service website to the mobile website.

These improvements to the customer self-service functionality expand overall customer choice and flexibility in conducting business with the Company.

Operating Experience

In 2013, over 4,800 high bill inquiry calls were received in the Customer Contact Center. During the first quarter of 2014 over 3,900 high bill inquiry calls were received. A customer's high bill can often be explained by higher consumption due to colder than normal temperatures, higher number of reading days compared to previous month or an estimated bill.

The use of electronic communications between customers and the Company continues to increase. In 2013, the Company's website recorded over 1,000,000 site visits, up 58% over 2012. Approximately 31% of customer accounts are being managed on the website. Customers continue to leverage mobile devices to connect with the Company. In 2013, 42% of visits (approximately 422,000 customer visits) were made to the website via mobile devices, a 354% increase over 2012.

Justification

This item is justified primarily on improved customer service.

Integrating self-service functionality with mobile computing devices increases customer choice in conducting business with the Company. This enhancement will increase the customer's ability to interact with the Company independent of location, time of day or type of device used.

5.2 Energy Conservation Website Enhancements ($53,000)

Description

The purpose of this item is to enhance the Internet based functionality which supports the Company's energy conservation initiatives.

In 2015, the takeCHARGE! website will be expanded to provide customers access to energy conservation information through mobile computing devices.

Operating Experience

In 2008, Newfoundland and Labrador Hydro and Newfoundland Power launched a joint energy conservation initiative including the takeCHARGE! website. The site provides residents of Newfoundland and Labrador access to energy efficiency education and awareness information. This website is an integral part of the Company's customer energy conservation communications portfolio. The website also includes information on the various rebate programs available to customers.[11]

In 2013, the Company provided rebates to over 5,200 customers and recorded approximately 76,000 visits to the takeCHARGE! website. This is an increase of 5% and 55% respectively over 2012.

As programs and associated rebates and incentives evolve, it is necessary that the website reflect the details and functionality of these program offerings. With the ever increasing use of mobile computing devices, and the increased visits to the takeCHARGE! website, the need for enhanced customer experience through a mobile web interface is required.

Justification

This item is justified on customer service improvement. These enhancements will provide customers with energy conservation tools and information integral to the Company's customer energy conservation initiative, through their personal choice of a full or mobile website. By increasing the accessibility of information surrounding programs, rebates and incentives,

[11] Currently customers may take advantage of rebate programs such as, but not limited to, thermostat, heat recovery ventilator, occupancy sensors and high bay lighting.

customers will have relevant information available to them when considering participation in the Company's customer energy conservation initiatives.

This enhancement will increase the customer's ability to interact with the Company independent of location, time of day or type of device used.

6.0 Various Minor Enhancements ($275,000)

Description

The purpose of this item is to complete enhancements to the Company's computer 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.

Operating Experience

Examples of previous work completed under this budget item include modifications to customer and operations and engineering applications performed in response to severe weather events, employee self service functionality to improve timesheet entry, and improved customer work request functionality to include new work types.[12]

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.

[12] Improvements include customer outage communication, vehicle tracking, and outage management.

Appendix A
Net Present Value Analysis

Inventory Management System Improvements

	YEAR	New Software A	New Hardware B	Software	Hardware	Residual CCA	Total	Labour	Non-Lab	Labour	Non-Lab	Net Operating Savings F	Income Tax G	After-Tax Cash Flow H
		Capital Impacts						Operating Cost Impacts						
		Capital Additions		CCA Tax Deductions C				Cost Increases D		Cost Benefits E				
0	2015	($270,000)	($85,000)	$135,000	$23,375		$158,375	$0	($15,000)	$0	$0	($15,000)	$50,279	($319,721)
1	2016	$0	$0	$135,000	$33,894		$168,894	$0	($15,300)	$73,130	$0	$57,830	$32,208	$90,038
2	2017	$0	$0	$0	$15,252		$15,252	$0	($15,606)	$75,324	$0	$59,718	($12,895)	$46,823
3	2018	$0	$0	$0	$6,863		$6,863	$0	($15,918)	$77,584	$0	$61,665	($15,893)	$45,773
4	2019	$0	$0	$0	$3,089		$3,089	$0	($16,205)	$79,911	$0	$63,706	($17,579)	$46,127
5	2020	$0	$0	$0	$1,390		$1,390	$0	($16,509)	$82,308	$0	$65,800	($18,679)	$47,121
6	2021	$0	$0	$0	$625		$625	$0	($16,817)	$84,778	$0	$67,960	($19,527)	$48,433
7	2022	$0	$0	$0	$281		$281	$0	($17,125)	$87,321	$0	$70,196	($20,275)	$49,921
8	2023	$0	$0	$0	$127		$127	$0	($17,446)	$89,941	$0	$72,495	($20,987)	$51,508
9	2024	$0	$0	$0	$57		$57	$0	($17,775)	$92,639	$0	$74,864	($21,694)	$53,170
10	Present Value (See Note I)		@	6.05%										$47,471

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 using Newfoundland Power's Labour Escalation Rates. The non-labour costs are escalated using the GDP Deflator Index.

E is the reduced operating costs. 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.

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.

Property Records Management System Improvements

		Capital Impacts						Operating Cost Impacts						
		Capital Additions		CCA Tax Deductions				Cost Increases		Cost Benefits				
	YEAR	New Software A	New Hardware B	Software	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	2015	($147,000)	($4,000)	$73,500	$1,100		$74,600	$0	($4,000)	$15,000	$0	$11,000	$18,444	($121,556)
1	2016	$0	$0	$73,500	$1,595		$75,095	$0	($4,080)	$25,750	$0	$21,670	$15,493	$37,163
2	2017	$0	$0	$0	$718		$718	$0	($4,162)	$26,523	$0	$22,361	($6,277)	$16,084
3	2018	$0	$0	$0	$323		$323	$0	($4,245)	$27,318	$0	$23,073	($6,598)	$16,476
4	2019	$0	$0	$0	$145		$145	$0	($4,321)	$28,138	$0	$23,816	($6,865)	$16,952
5	2020	$0	$0	$0	$65		$65	$0	($4,402)	$28,982	$0	$24,580	($7,109)	$17,470
6	2021	$0	$0	$0	$29		$29	$0	($4,485)	$29,851	$0	$25,367	($7,348)	$18,019
7	2022	$0	$0	$0	$13		$13	$0	($4,567)	$30,747	$0	$26,180	($7,588)	$18,592
8	2023	$0	$0	$0	$6		$6	$0	($4,652)	$31,669	$0	$27,017	($7,833)	$19,184
9	2024	$0	$0	$0	$3		$3	$0	($4,740)	$32,619	$0	$27,879	($8,084)	$19,795
10 Yr	Present Value (See Note I)	@		6.05%										$16,682

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 using Newfoundland Power’s Labour Escalation Rates. The non-labour costs are escalated using the GDP Deflator Index.
E is the reduced operating costs. 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.
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.

2015 System Upgrades

June 2014

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

Newfoundland Power (the "Company") depends on the effective implementation and on-going operation of its business applications in order to continue to provide least cost service to customers. Over time, these applications need to be upgraded to ensure continued vendor support, to improve software compatibility, or to take advantage of newly developed functionality.

This project consists of Business Applications Upgrades and continuation of the Microsoft Enterprise Agreement.

2.0 Business Applications Upgrades ($930,000)

Business Applications Upgrades involve third party software that supports the Company's business applications. For 2015, upgrades are proposed for the Company's Customer Service System (CSS) technology, Internet (customer website) technology, Business Support System Upgrades, and Employee Self Service Upgrades.

Table 1 summarizes the cost associated with these items.

Table 1
Business Applications Upgrades
Project Expenditures
($000s)

Cost Category	2015 Estimate
Material	175
Labour – Internal	590
Labour – Contract	-
Engineering	-
Other	165
	930

Description

The upgrades to the Company's business applications ensure that these applications continue to function in a stable and reliable manner with the appropriate level of vendor support. Each year, the Company's software applications are reviewed to determine if upgrades are required.

For 2015, upgrades include:

2.1 CSS Components Upgrade ($317,000)

The CSS is an application that can store and manipulate a variety of customer data and transactions, and is central to the Company's on-going provision of responsive service to its customers. The application was developed internally in 1992 and has undergone a number of modifications, upgrades and enhancements since.[1] The system handles a large volume of customer data and transactions, including customer billing and customer inquiries.[2]

The CSS is now more than 20 years old. Given the age and critical nature of the technology, the CSS is periodically assessed for its continued appropriateness as the central information technology platform for customer service delivery. The Company's most recent assessment has determined that, with current levels of annual investment, the CSS application will remain fully functional and perform at a satisfactory level for the next 5 years.[3]

The last technology component upgrade required to ensure a sustainable level of vendor support occurred in 2010. The last technology upgrade required to ensure server hardware compatibility occurred in 2007.[4]

The item proposed in 2015 involves the upgrade of software components used to operate and maintain CSS. These components include Powerhouse and Axiant programming languages from Unicom Global, the Database Management Software from Oracle as well as the Cobol programming language and the OpenVMS server operating system from Hewlett Packard ("HP").[5] These upgrades are required in order to ensure compatibility with the CSS servers being replaced as part of the Shared Server Infrastructure project.[6] This item will enable the Company to sustain an acceptable level of support and maintenance from the vendor products used to operate and maintain the CSS.

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1 The most significant single expenditure associated with the CSS occurred in 1998. This $2 million expenditure was required to replace the technologically obsolete hardware and operating system upon which the CSS application ran.

2 Since 1992, CSS has processed approximately 280 million transactions, including approximately 50 million customer bills, and supported response to over 15 million customer telephone and internet inquiries.

3 The Company does not expect that the CSS application will face technical obsolescence over the next 5 years. Two primary technology vendors for the CSS application, Hewlett Packard and Oracle, have indicated that they will continue to support the hardware, operating system and database management system which are the foundation of the CSS application until at least 2020. A third primary vendor, Unicom Global, has indicated that it expects to continue to support the software development tools which the Company uses to maintain and modify the CSS application. The Company does not currently foresee changes in the business which will result in the CSS application becoming functionally obsolete in this period.

4 In 2007 HP ended manufacturing of Alpha server technology.

5 On December 31st, 2013 Unicom Global acquired the Cognos Application Development Tools suite (including Powerhouse and Axiant) from IBM.

6 See report ***6.3*** *2015 Shared Server Infrastructure* item 1.

2.2 Website Components Upgrade ($226,000)

This item involves an upgrade to the software components used to manage and operate the Company's external website.

During the period January 2-8, 2014, the Island Interconnected System serving the majority of Newfoundlander Power's customers came under significant distress. During this period Newfoundland Power's website was visited approximately 950,000 times. This accounted for approximately 87% of total customer contacts during this period. By comparison, Newfoundland Power received approximately 1 million visits to the Company's web site during the full year in 2013.

The current website software architecture was not designed to process the volume of website visits in the short timeframe experienced in January 2014. At brief times during this period, the Company's website was unavailable to some customers.[7]

To ensure dependable website response and availability, Newfoundland Power will upgrade software components, such as the Windows operating system, Internet Information Server, and .NET framework and will also change the approach to data storage and retrieval.

In addition, this upgrade will:

(i) Ensure an acceptable level of support and maintenance is available from the vendor products used to operate and maintain the Company's website;
(ii) Improve disaster recovery capabilities by reducing the risk associated with single points of failure; and
(iii) Enhance overall website security to ensure customer information remains effectively protected.

2.3 Business Support System Upgrade ($206,000)

The Company utilizes information technology to manage employees entering and exiting the workforce along with changing work responsibilities through requests for computer access, document management and application access management. The Company relies on information technology as part of daily operations. This reliance requires the distribution of timely and accurate security information to prevent unauthorized access to customer and corporate information.[8]

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7 The website was unavailable to some customers for 44 minutes on January 2nd, 2014 and for 13 minutes on January 5th, 2014. In both instances, the website was working to maximum capacity and displayed a message to some customers indicating the website server was too busy.

8 Corporate information includes but is not limited to financial, customer, SCADA and operational information. Access to information and other information technology assets is based on job function and is provided to employees upon hiring, revoked upon termination and potentially changed when an employee changes job functions.

The Company has established policies and procedures designed to ensure employees only have access to the corporate and customer data that is necessary for them to perform their specific job functions. Collectively these policies and procedures are referred to as the Company's corporate governance and compliance obligations.

Access control applications have been developed based on best practices for information technology general controls to meet the Company's corporate governance and compliance obligations. These software components have been improved over the years largely in response to annual audit recommendations.

The purpose of this item is to upgrade the existing software components used to manage the Company's corporate governance and compliance obligations. The workflow component of this function is no longer supported by the vendor. Upgrading the existing software will ensure necessary support from vendors and ensure the Company is able to exercise an acceptable level of control over authorized access to Company applications, computer hardware, corporate and customer data.

2.4 Employee Self Service Upgrade ($181,000)

The Employee Self-Service application provides Company employees with secured on-demand access to their demographic, payroll, attendance and other annual compensation information.[9] The application also provides supervisors with access to subordinate information related to attendance, service duration and compensation. This application has removed the need to produce and distribute paper versions of paystubs, attendance calendars and Revenue Canada T4 slips.

The current application has been in service for over 10 years and was developed using technology that is no longer supported by the vendor. The proposed upgrade will ensure employees continue to have secured access to their personnel information and an effective level of support and maintenance from the vendor.

Operating Experience

System upgrades help ensure the reliability and effectiveness of the Company's business applications and mitigate risks associated with technology related problems. The timing of the upgrades is based on a review of the risks and operational experience of the applications being considered for upgrade. System upgrades are also required to ensure compatibility with upgrades in hardware platforms that occur when shared servers are upgraded.

As well, upgrades are often completed in order to take advantage of functional or technical enhancements provided by the vendor in new versions of a software application.

[9] Other annual compensation information includes overtime reports, special payroll (if applicable) and T4 information.

Justification

Investments in Business Applications Upgrades are necessary to replace outdated technology that is no longer supported by vendors and to take advantage of newly developed capabilities provided in the most recent release of the applications. Unstable and unsupported software applications can negatively impact operating efficiencies and customer service.

3.0 The Microsoft Enterprise Agreement ($195,000)

Description

This Agreement covers the purchase of Microsoft software and provides access to the latest versions of each software product purchased under this agreement at least cost.

Through the Microsoft Enterprise Agreement, Newfoundland Power achieves overall cost savings. This is a fixed price annual agreement based on the number of eligible employees that utilize Microsoft software on Company assigned personal computers.[10] Under this agreement, the Company distributes its purchasing costs for these licenses over three years, as outlined in Schedule C.

Operating Experience

The Company has had the Microsoft Enterprise Agreement in place providing access to the latest versions of business software for over 10 years.[11] The terms of the agreements are typically of 3 years duration, with requirements reviewed and adjusted annually. The current agreement expires on May 31, 2015.

Justification

The Microsoft Enterprise Agreement is the least cost option to ensuring access to current Microsoft software products.

[10] Personal computers include desktops, laptops, tablets and other mobile computing devices.
[11] The agreement covers software applications such as Microsoft Office, Outlook, SharePoint, SQL Server and other applications used by employees in the completion of their normal duties.

2015 Shared Server Infrastructure

June 2014

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

Shared server infrastructure consists of over 100 shared servers that are used for routine operation, testing, and disaster recovery of Newfoundland Power (the "Company") business applications. The Company relies on these shared servers to ensure the efficient operation and support of its customer service, Internet, engineering and operations, and business support systems.

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.

Table 1 summarizes the cost associated with these items.

Table 1
Shared Server Infrastructure Upgrades
Project Expenditures
($000s)

Cost Category	**2015 Estimate**
Material	540
Labour – Internal	285
Labour – Contract	-
Engineering	-
Other	145
Total	**970**

For 2015, this project includes:

1. The replacement of the shared server infrastructure that hosts the Company's Customer Service System ("CSS"). The CSS server infrastructure was last replaced in 2007. The current server infrastructure, Hewlett Packard's ("HP") AlphaServer ("Alpha") is no longer manufactured by the vendor and will be replaced by HP's Integrity server technology.[1] This

[1] The HP Alpha platform was first commercially available in 1994 and has hosted the CSS since 1998. HP discontinued production of the Alpha servers in 2007.

item is clustered with the CSS Components Upgrade item in the *2015 System Upgrades* project.[2] The estimated project cost for the CSS server infrastructure is $407,000.

2. The upgrading of the Company's website server infrastructure. New infrastructure is required to support the high volume of customer visits during peak times.[3] This item is clustered with the Website Components Upgrade item in the *2015 System Upgrades* project. The estimated project cost for this Internet technology infrastructure upgrade is $124,000.

3. The replacement of server equipment that is at the end of its useful life. This item will replace server hardware that support various applications including video security recording and monitoring for Company facilities, and corporate support tools used to manage application and infrastructure environments. The estimated project cost for this item is $188,000.

4. The replacement of security infrastructure used to deliver secured communications to remote locations such as substations and power plants. This equipment has reached the end of its useful life and will be no longer supported by the vendor in 2015. The estimated cost for this replacement is $108,000.

5. The installation of new security management infrastructure to consolidate and analyze security events and enable enhanced reporting and notifications of alerts. This will improve the assessment of security events such as unauthorized authentication attempts on the corporate network. The estimated cost for this project is $143,000.

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. Shared servers are computers that support applications used by employees and customers. Management of these shared servers, and their components, is critical to ensuring that these applications are available for the Company to provide service to customers and operate efficiently.

Factors considered in determining when to upgrade, replace or add server components include: the level of support provided by the vendor; the current performance of the components; the ability of the components to meet future growth; the cost of maintaining and operating the components using internal staff; the cost of replacing or upgrading the components versus operating the current components; the criticality of the applications running on the shared server components; and the business or customer impact should the component fail.

Gartner Inc. has indicated that computer servers have a useful life of approximately 5 years.[4] By making appropriate investments in its shared server infrastructure, Newfoundland Power's experience is that the average useful life of its corporate servers is about 7 years.

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2 For details on the CSS Components Upgrade project see report ***6.2*** *2015 System Upgrades*, Section 2.1.

3 The website was unavailable to some customers for 44 minutes on January 2nd, 2014 and for 13 minutes on January 5th, 2014. In both instances, the website was working to maximum capacity and displayed a message to some customers indicating the website server was too busy.

4 Gartner Inc. is a leading provider of research and analysis on the global Information Technology industry.

In order to ensure high availability of applications, and to minimize the vulnerability of its computer systems to external interference, the Company invests in system availability and 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 damage customer and corporate information.

4.0 Justification

Shared server infrastructure is essential to maintaining the provision of least cost service to customers. 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 the shared server infrastructure has the potential to impact large numbers of employees and customers, and therefore is critical to the Company's overall operations and to the provision of least cost customer service.

Investments in shared server infrastructure are based on evaluating the alternatives of modernizing or replacing technology components and selecting the least cost alternative.

SCADA System Replacement

June 2014

Prepared by:

Jack Casey, P.Eng.

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

The Newfoundland Power's (the "Company") Supervisory Control and Data Acquisition ("SCADA") System is used by the System Control Centre ("SCC") operators to remotely monitor and control the Company's electricity system.[1] The SCADA system is a critical operational technology necessary to provide reliable least cost service to customers. The replacement of the SCADA System is being undertaken at this time due to the technical obsolescence of the operating system and server hardware platform on which the SCADA application operates. In addition, the SCADA vendor has replaced the application with another product thereby limiting the support available for the current technology. The SCADA application, operating systems and server hardware components are tightly integrated and highly dependent on each other.

The current SCADA system was originally installed in 1999.[2] The server hardware platform for the SCADA system is the Hewlett Packard ("HP") Alpha.[3] The SCADA system's operating system, referred to by the trade name Tru64, is no longer supported by the vendor.[4] The Company has maintained an annual hardware service and support agreement with HP since system installation in 1999. This existing support arrangement will be in place until 2016. However continuing without an extended hardware support and maintenance agreement beyond 2016 for this critical application presents an unacceptable risk to Company operations.[5]

In response to the onset of technical obsolescence of the operating system and server hardware the vendor released a new generation SCADA system referred to as the DNA system. The upgrade path for the existing system to the new DNA system involves the replacement of the SCADA application along with the operating system and server hardware components.[6] The SCADA system is a fully integrated solution, and changing any of the 3 major components requires the remaining components to be upgraded or replaced simultaneously. The requirement to replace all 3 components of the system presents the opportunity for the Company to consider replacing the existing SCADA systems with alternatives supplied by other vendors, ensuring provision of reliable service at least cost.

The Company engaged the services of Quatric Solutions Inc. of Montreal, Quebec (the "SCADA Consultant") to provide engineering expertise for the replacement project. The SCADA Consultant has prepared a detailed report on the SCADA replacement project that is included as Appendix C. In completing this report the SCADA Consultant developed a preliminary

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1 The SCADA system remotely monitors and controls 71 substations, 25 hydro generators, 2 gas turbines, 187 distribution feeders and 78 power transformers. In total there are approximately 40,000 individual data points monitored and controlled through the SCADA system.

2 According to Gartner, shared servers have an average service life of 5 years. Gartner, Inc. is a leading information technology research and advisory company with experience in SCADA systems.

3 HP Alpha is a server platform that supports applications that operate on the OpenVMS and Tru64 operating systems. HP discontinued manufacturing Alphas in 2007.

4 Tru64 is a Unix-based operating system developed by HP and is no longer supported for security updates.

5 Security and integrity of the Company's SCADA system must be maintained to ensure normal operations and effective electricity system control. Moving the SCADA application to a fully supported hardware platform and operating system is a critical component to sustaining a secure application.

6 The existing SCADA system also has a number of custom applications that would need to be redeveloped to function with the new DNA system.

functional specification upon which selected vendors have provided budgetary estimates in response to a request for information. In addition, the SCADA Consultant has worked with Newfoundland Power to develop a detailed project scope upon which internal labour and engineering cost estimates have been prepared.

The Company proposes to replace the SCADA system as a multi-year project starting in 2015. The project will be completed in 2 years at an estimated cost of approximately $5.7 million. The project will involve the acquisition, installation, configuration, testing and deployment of an upgraded SCADA application to ensure the system continues to support Company operations. This includes the conversion and migration of SCADA components such as databases, operator displays, reporting environment and custom applications to the new platform.[7]

2.0 Background

SCADA systems are a category of software application program that monitors and controls the electricity system through the gathering of data in real time from remote locations such as hydro plants and substations. SCADA systems include hardware and software components. The hardware gathers and feeds data into computers that have the SCADA software installed. The computer then processes this data and quickly presents it to the operators. SCADA systems also record and log all events into an application referred to as a historian for both the instantaneous presentation to the operators and for post event analysis by engineering staff. The SCADA system warns the operators when conditions become hazardous through visual changes of state on computer displays and by sounding alarms.

In 1984 Newfoundland Power installed its first SCADA system. The original Automatec SCADA system operated for a 15 year in-service life. In 1999 the Company completed a project to replace the original Automatec SCADA system by an earlier version of the current Schneider/Telvent OASyS™ SCADA system.[8] An upgrade of the 1999 SCADA technology took place in 2004 with the upgrading of the operating system and the real-time server hardware.[9]

The OASyS™ SCADA system installed in 1999 enhanced the Company's ability to monitor and control the electricity system. Since that time the Company has invested in advanced communication infrastructure, including intelligent electronic devices on distribution feeders, transmission lines, along with equipment in substations and hydro plants, including:

- Substation gateway computers
- Digital protective relays

[7] SCADA reporting environment is an application that extracts electricity system data from the SCADA application and creates a version of the SCADA database on the Company's business network. This design ensures that the security of the SCADA application is not compromised while making the necessary information available to other Company employees. Advanced applications include applications such as historical data archiving, under-frequency load shed applications, working alone application and group control application.

[8] In addition to having reached the end of its service life in 1999, the original SCADA system was not Year 2000 compliant which necessitated its replacement at that time.

[9] The capital cost associated with the 1999 OASyS™ SCADA system installation was $3.7 million. The cost to upgrade the OASyS™ SCADA system in 2004 was $1.2 million.

- Digital power meters
- Intelligent feeder reclosers
- Digital under frequency load shedding relays
- Digital tap changer controllers
- Programmable logic controllers for plant control and governors

These intelligent electronic devices collect information at the distribution feeder and transmission line level, including detailed information on the actual cause of electricity system events which result in customer outages. This advancement in technology has allowed the Company to respond more effectively to customer outages and has contributed to the improvement in overall distribution reliability performance over the past decade.

Schneider, the current SCADA system vendor, has had a new generation of SCADA system products available since 2009 referred to as the DNA system that runs on a different operating system and server hardware platform.[10] Standard support for the SCADA Tru64 UNIX operating system ended on December 31st, 2012. Alpha server hardware has not been manufactured since 2007. The vendor of the hardware has made a commitment to provide minimum support for both of these legacy systems until the end of 2016.[11] Since 2009 most utilities operating OASyS™ SCADA systems have migrated to either the DNA system or SCADA systems provided by other vendors.

Table 1 provides information for 46 Schneider SCADA customers with respect to replacement activities for the OASyS™ SCADA system.[12]

Table 1
Survey of OASyS™ SCADA Customers[13]

Customers that have migrated to the DNA SCADA technology	30
Customers migrating to the DNA SCADA technology in 2013	5
Customers that plan to migrate to the DNA SCADA technology	8
Customers that remain undecided	3

Based on the data provided in Table 1, 43 of 46 utilities have already initiated actions to address the migration of their SCADA systems from the unsupported technology to the new platform.

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10 This was primarily due to industry changes on hardware and software platforms moving away from Alpha hardware and Tru64 operating systems technologies to x86 and Windows technologies.

11 Industry research suggests that enterprise server hardware should be refreshed at every 5 years, though Newfoundland Power’s experience trends towards the 7 year average for enterprise server replacement. In 2016 the SCADA server hardware will have been in service for 12 years.

12 This data does not include former customers that replaced their OASyS™ systems with SCADA systems supplied by other vendors.

13 Appendix B contains a letter from Schneider providing the information summarized in Table 1.

3.0 SCADA System Replacement Strategy

Technical obsolescence is driving the need to replace the existing OASyS™ SCADA system. The industry has substantially moved away from the OASyS™ SCADA system currently used by the Company, and as time progresses the amount of support available to Newfoundland Power will diminish.

The transition from the existing OASyS™ SCADA system to the updated DNA SCADA system would involve more than replacement of the SCADA application, operating systems and server hardware components. There will be additional work associated with the migration of the actual electricity system database, operator displays and custom applications.[14] As a result the effort and cost associated with upgrading within the Schneider family of SCADA products is comparable to moving to another SCADA vendor's product. This provides Newfoundland Power with the opportunity to go to market for a replacement SCADA system ensuring that competitive market forces will determine the least cost replacement alternative.[15]

In 2015 Newfoundland Power will solicit requests for proposal from qualified SCADA vendors for the replacement of the existing SCADA application, operating systems and server hardware. All existing functionality will be maintained with the exception of automatic generation control and the replacement of the large mimic display monitors.[16] System improvements will involve a fully functioning historian, security upgrades, interfaces to geographic information systems and outage management systems, alarm storm suppression, encryption of the Inter-Control Centre Protocol ("ICCP") link to Hydro and the automation of the operators' diary.[17]

The scope of work for the SCADA system replacement will ensure the transition from the existing technology to the new technology is seamless. The Company's engineers and technicians will work with the vendor to transfer the point database to the new technology. The point database includes all quantities and status information for devices in the electricity system. These may be as simple as the open or closed status of a transmission line breaker, or more complex such as the calculation of MVA load of a power transformer that does not have a real-time telemetry reading associated with it. In total the existing SCADA system has a point database that includes approximately 40,000 items. Similarly, the creation of the new operator displays will involve working with the vendor in display building, verification and testing.

When the vendor's standard system has been customized with Newfoundland Power's point database and displays, the transition from the existing SCADA system to the replacement system can commence. This will involve operating the existing system and the replacement system in parallel for a period of time. During this transition period the electricity system will be

[14] These custom applications include automatic generation control, under-frequency load shedding and working alone.

[15] Budgetary quotes provided by vendors in response to a request for information issued by the SCADA Consultant suggest that other vendors will be very competitive in pricing compared to the cost of remaining with the existing vendor.

[16] Appendix C includes a functional specification for the replacement SCADA system that describes existing functionality that will be maintained.

[17] The fully functioning historian is an application that archives the real-time data from the electricity system for review following significant events. Appendix C includes a functional specification for the new functionality.

monitored closely to ensure that the integrity of the monitoring and control is not compromised during and after the transition period.

In addition to the actual customization of the system to monitor and control the Newfoundland electricity system, the project will include technical training for the Company's engineers, information technology staff, technicians and power system operators. There will also be some modernization required for the SCC control and computer rooms to accommodate the new technology. This will include desks, computers and displays for the SCADA operators and computer racks to house the SCADA system hardware.[18]

Initially there will be no requirement for the replacement system to provide advanced applications beyond the system improvements stated above.[19] The replacement SCADA system is anticipated to have an in-service life of approximately 15 years, consistent with the Company's experience with its initial 2 generations of SCADA technology. Throughout this 15 year life it is likely that the Company will deploy other operational technologies that improve electricity distribution system operations. The operational technologies that may be integrated with the replacement SCADA system include geographic information systems, outage management systems, work force management systems, automated meter reading and customer service systems. Integrating these technologies with the SCADA system has the potential to improve the Company's ability to serve its customers.

4.0 Project Description

The project involves replacement of the existing SCADA application, operating system and server hardware. All existing functionality will be maintained and some system improvements such as a fully functioning historian, security upgrades, alarm storm suppression, encryption of the ICCP link to Hydro and the automation of the operators' diary will be included. The new system will also have the ability to interface with geographic information systems, outage management systems, and other operational technologies. The Company will work with the vendor to customize a standard product offering to interface with Newfoundland Power's electricity system. Included in the SCADA replacement project are the following items:

i. Engineering design and preparation of the technical specifications
ii. Request for Proposals for the replacement SCADA system
iii. Contract award to successful vendor
iv. Purchase and install new server and workstation computers
v. Migration of SCADA database
vi. Migration of SCADA displays
vii. Testing and commissioning of SCADA system migration
viii. Training
ix. Installation of system onsite at the SCC
x. Transition to new SCADA system

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18 Recent capital projects to upgrade the SCC's standby emergency power and uninterruptible power supply will continue to be used with the replacement SCADA system.

19 The vendors will be prequalified to ensure their technology integrates with commercial Distribution Management Systems (DMS), Geographic Information Systems (GIS), and Outage Management Systems (OMS).

xi. Testing and commissioning of interface between new SCADA system and field devices

5.0 Project Execution

SCADA replacement project is a multi-year project scheduled to begin in 2015 with a 2 year duration. It is estimated that it will take approximately 8 months to prepare the technical specification, prepare the Request for Proposals, and ultimately select the vendor for the replacement SCADA system. It is estimated that the development of the system, training, testing, system integration and final cutover will take another 14 months. Starting the project in the 1st quarter of 2015 will ensure the new SCADA system is operational in the 3rd quarter of 2016. A detailed project schedule including information on the various resources needed throughout can be found on pages 4-36 through 4-38 of the *SCADA System Replacement Study* included as Appendix C. The project schedule is summarized below in Figure 1.

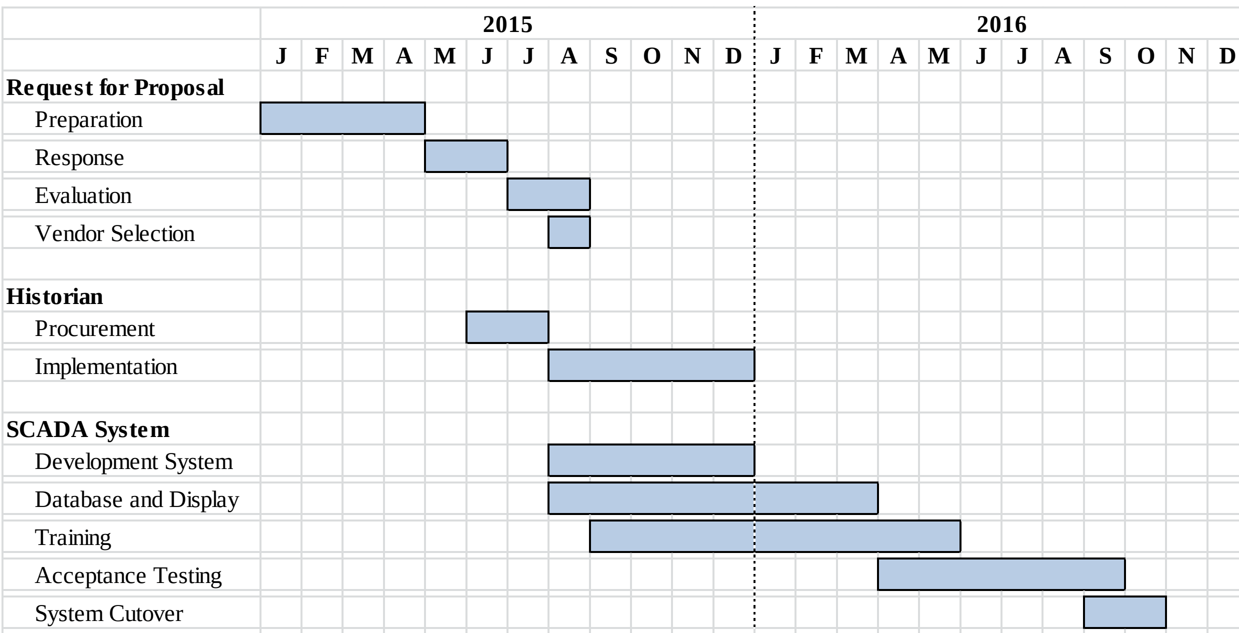

Figure 1 – Project Schedule

6.0 Project Cost Estimate

The estimate to complete all work associated with the SCADA Replacement Project is $5,675,000. Table 2 provides a detailed breakdown of the total project cost by year.

Table 2
Project Cost

Description	**2015**	**2016**
Material	$2,338,000	$2,309,000
Internal Labour	158,000	156,000
Engineering	294,000	332,000
Other	43,000	45,000
Total	**$2,833,000**	**$2,842,000**

7.0 Conclusion

The SCADA system's operating system, hardware platform and application software is no longer supported by the vendor. In response to the onset of technical obsolescence the vendor has released a new generation SCADA technology. Most of the utilities that operated SCADA technology similar to Newfoundland Power have either upgraded to the latest product available from the vendor, or moved to another vendor's SCADA system.

In 2015/2016 the Company will replace its existing SCADA application, operating system and server hardware. All existing functionality will be maintained along with some system improvements and the capability to interface with modern operational technologies such as GIS and outage management systems. Integrating these modern operational technologies with the SCADA system will improve the Company's ability to serve its customers.

Appendix A
Notice from Server and Operating System Manufacturer

United States-English

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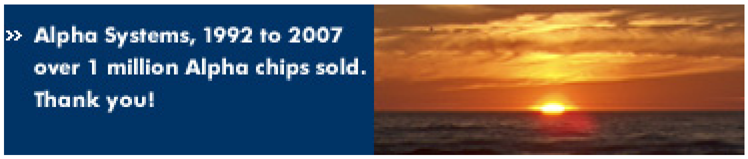
- » Services
- » Storage



- » AlphaServer roadmaps
- » AlphaServer brochure
- » Technical support
- » Alpha RetainTrust

HP AlphaServer systems with enterprise-class operating system choices of OpenVMS and Tru64 UNIX® continue to offer rock-solid reliability, application availability and performance, simplified management and flexibility. HP proudly supplied AlphaServer systems to leading business, education and government enterprises around the globe from 1992 until 2007. HP will continue to offer Service for Alpha Systems to assure reliable operation for many more years. The Alpha Retain Trust website has procedures, tools, and information about HP Services available to ease the transition from Alpha systems to other HP products.

I want to personally thank you for 15 years of loyal patronage; Ann McQuaid, General Manager, Alpha Systems Division.

News and features

October 2008: AlphaServers are still available within HP as Extended Life Products. Factory-Refurbished Systems and Options with Full Warranty are available through the HP Renew Program in EMEA, AP, and Japan, and available through Technology Value Solutions in the Americas. HP will now offer service (maintenance, repair, and advisory) for all currently selling Alpha Systems for a "minimum" of five years after last new system shipment, (or at least through 2013).

May 2007 and updated Jan 2011: HP has ceased accepting orders for new Alpha Systems as of July 25, 2008. HP will continue to offer factory-refurbished systems and options through the Technology Value Solutions (TVS) in all regions as material is available. HP will offer service (maintenance, repair, and advisory) for all shipping Alpha Systems as of July, 2008 for a minimum of five years after last system shipment, or at least through 2013. Typically, HP offers services much longer than the five year minimum commitment. HP still offers service on all Alpha Systems shipped since their original introduction in 1992.

- » February 2007: Oracle E-Business Suite R12 shipped for HP-UX on Integrity at the end of January. HP encourages customers using Oracle E-Business Suite for Tru64 UNIX on Alpha to start moving their business applications to the HP-UX/Integrity platform for capacity expansion and new installations.
- » December 2006: Oracle delivers Database 10g Release 2 for OpenVMS on Alpha. HP customers can now install Database 10g Release 2 on both OpenVMS for Integrity and Alpha, as well as Tru64 UNIX on Alpha and HP-UX for Integrity. With the up-to-date Release 2 for all operating systems on both Alpha and Integrity, Oracle Database users can more easily plan migration of their data from Alpha to Integrity systems.
- » September 2006: HP OpenVMS version 8.3 is now available providing support for the latest line of HP Integrity servers and AlphaServer systems. OpenVMS version 8.3 delivers even greater flexibility, investment protection, lower total cost of ownership (TCO), and additional virtualization capabilities for HP Integrity servers
- » January 2006: For TruCluster Server users - Symantec VERITAS cluster file system integrated HP Serviceguard clusters; shipping now for HP-UX 11i on Integrity servers

» High-end servers | » Mid-range servers | » Entry-level servers

HP Tru64 UNIX Alpha Lifecycle Chart

This chart provides notification of Tru64 UNIX discontinuance.

End of Sale: 1-October-2012

The Tru64 UNIX Operating System and Layered Products will be removed from the HP Corporate Price List (CPL) as of 31-October-2012. Many of the licenses will continue to be available for purchase through HP Financial Service with remarketed AlphaServers or sold separately.

End of Standard Support: 31-December-2012

Tru64 UNIX Standard Support will end on December 31, 2012. After December 31, 2012, customers needing continued support have two options:

(1) Purchase Mature Product Support without Sustaining Engineering (MPS w/o SE) and receive HP Technology Services support (telephone support plus existing patches). MPS is "without Sustaining Engineering Support" which means MPS w/o SE does *not* include new fixes. Under MPS w/o SE, patches for known problems are available; however, no new patches will be created.

(2) Purchase MPS w/o SE plus Tru64 UNIX Extended Engineering Support (EES) and receive all of the above support ***plus new fixes***. EES includes Sustaining Engineering and provision of new corrections. Advance notice of EES purchase is needed in order to plan EES resources. Tru64 UNIX Engineering will work to accommodate all EES requests.

SKU	SKU Description	Comment
	Media	
QA-054JA-H8	DIGITAL SW CDROM LIB/OSF1	
QA-6ADAA-H8	Tru64 UNIX CDROM KIT	
QA-0AFAA-H8	Digl Open3D U/A CDRM KIT	
QA-20YAA-H8	MMS RT U/A CDRM KIT	
QA-30CAA-H8	DECSNA APPC/LU6.2 RT OSF/1	
QA-4KN8A-A8	SW LP LIB U/A CDRM/NO DOC	*Not all media is available.*
QA-MT4AA-H8	Tru64 UNIX Alpha Cdrom	
QA-MT4AQ-H8	Tru64 UNIX Alpha V3 CDRM KIT	
QA-MT4AX-H8	Tru64 UNIX Alpha New HW CD	
QA-MT5AA-H8	DEV TOOLKIT U/A CDRM KIT	

Appendix B
Survey of Schneider Customers

October 7, 2013

Chris Wells
Newfoundland Power Inc.
50 Duffy Place
St. John's, NL A1B 4M5

RE: OASyS SCADA Upgrade Information

Chris,

Based on our discussion regarding the number of OASyS customers running on the latest Versions of software, I have compiled the following;

> 30 customers running DNA 7.4 or 7.5
>
> 5 customers upgrading now or just completing an upgrade this year – this is a mix of customers who upgraded from 6.XX or who decided to upgrade from 7.4 to 7.5
>
> 8 Budgeting to upgrade in 2014 or 2015 from 6.XX to DNA 7.5, including Newfoundland Power.
>
> 3 undecided but thinking about it, along with a few other very old pre OASyS systems upgrading in the future.

All of these are electric utility customers in North America and The Caribbean. We have many more OASyS systems in Europe, South America , Asia and Mexico along with other industries such as Oil and Gas, Water - Waste Water, and Transit in similar situations for upgrading.

I trust this is the information you require, please let me know if there is anything else I can help you with.

I look forward to hearing from you to assist with your future SCADA needs.

Very truly yours,

Mark Atchley
(713) 416-8059

Mark.atchley@Telvent.com

Appendix C
SCADA System Replacement Study
April 16, 2014

Newfoundland Power
SCADA System Replacement Study

April 16, 2014

Presented to:

Jack Casey
Newfoundland Power
Senior Engineer
Ref. 09-058T

8250 Décarie Blvd., Suite 210
Montréal, Québec
H4P 2P5

Document Control

Revision	Date of Issue	Author(s)	Brief Description of Change
1.0	16-Apr-2014	Ian MacCuaig	First release.
1.1	16-Apr-2014	Ian MacCuaig	Minor corrections.

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1 Executive Summary

1.1 Background

Newfoundland Power Inc., hereafter referred to as the "Owner", operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador. The Owner services approximately 86% of all electricity consumers in the province, including the Avalon, Burin and Bonavista Peninsulas and the major centres along the Trans-Canada Highway, including: Gander, Grand Falls-Windsor, Corner Brook, Stephenville, and Port aux Basques. The Owner does not service the Great Northern Peninsula, smaller communities along the coastline, and Labrador; these areas are serviced by Newfoundland and Labrador Hydro.

For over 125 years, the Owner has provided customers with safe, reliable electricity in the most cost-efficient manner possible. The Owner purchases approximately 93% of its electricity from the Crown corporation, Newfoundland and Labrador Hydro ("NL Hydro"), and generates the balance from its own smaller hydroelectric stations. The Owner's electric system is comprised of approximately:

- 252,000 customers.
- 23 hydro generating plants (32 generators) run of river under 11MW, three diesel plants (2.5MW) and three gas turbine (25, 15, 7 MW) facilities.
- 130 substations (primarily 138 kV and 66 kV).
- 11,000 km of transmission and distribution lines.
- total assets valued at over $1 billion.

The Owner currently operates a Schneider Electric (formerly Telvent), hereinafter referred to as "Current Vendor", OASyS SCADA System to monitor and control its generation, transmission and distribution system. Initially commissioned in 1999, the system has now reached the end of its service life and needs to be replaced. As a result, the Owner plans to include a capital budget request in its 2015 Capital Budget Application to the Newfoundland and Labrador Board of Commissioners of Public Utilities for a SCADA Replacement Project.

In March 2014, the Owner retained the services of Quatric Solutions Inc. ("QUATRIC") to act as the Owner's Consultant, hereafter referred to as the "Consultant", to perform an assessment of the current SCADA system and evaluate strategies for replacing the existing SCADA system. This report documents the Consultant's findings, recommended replacement strategy, project timeline, budgetary cost estimates, and recommended next steps.

1.2 Current System Assessment

The current SCADA System was commissioned in 1999 and is based on HP Alpha servers running the TRU64 UNIX operating system, and Intel-based workstations running the Windows operating system. No hardware or software upgrades have been performed on the SCADA system since 2006 and as a result the current SCADA platform is outdated, expensive to support, and failing to meet current organizational requirements. In particular, the following issues were identified:

1) **SCADA Servers:** The HP Alpha servers are now obsolete (discontinued), and spare parts are increasingly difficult to source. Now averaging more than 11 years old, the failure rate of critical server components, such as disk and memory, is expected to accelerate over the next few years.

2) **Operating System:** The TRU64 UNIX operating system was discontinued by HP and is no longer supported by HP. As a result, HP no longer provides operating system patches to correct known issues, including cyber security issues. As a result, it is not possible to follow industry best practices for cyber security while continuing to use this obsolete operating system.

3) **SCADA Software:** The OASyS DNA V6.3 SCADA software currently being used is now obsolete. The Current Vendor has replaced this product with a modern software architecture based on hardware-independent operating systems such as Linux and/or Windows. In addition, many of the core features of the current system, such as AutoCAD display editor, are no longer supported in the latest product from the Current Vendor. This has several implications:

    a) The Current Vendor cannot provide a simple upgrade to its latest product; “upgrading” to the latest version of the product requires a complete system replacement and re-development of the custom applications.

    b) The Owner must pay escalating maintenance costs for its obsolete SCADA software. Although technical support from the Current Vendor has rarely been an issue, maintenance costs have recently escalated and it is anticipated that the Current Vendor will find it increasingly difficult to maintain resources with knowledge of the current SCADA system over time.

4) **Customized Applications:** The current SCADA system includes a number of customized applications that may be difficult to replicate in a commercial, off-the-shelf SCADA product. As a result, some software developments may be required for some critical applications such as control windows and under-frequency load shedding.

5) **Historical Data:** The current use of SCADA historical data on the Corporate network is inflexible and the archive database has limited query accessibility, making it difficult for corporate users to extract the information required. In addition, since only summarized data is stored long-term, data is not always available to the level of detail required.

6) **Web Interface:** The current SCADA system provides web access for up to 20 Corporate users to view near-real-time SCADA displays, with access being granted on a first-come-first-serve basis. This constraint has prevented some corporate users, including senior management, from accessing the SCADA system displays during critical events. In addition, the web interface only runs on an obsolete, unsupported version of the web browser (Internet Explorer 7 or earlier).

7) **Control Room**: The control room work stations are positioned to face a large-screen display along the front wall. This display is no longer functional, and the Owner has acknowledged that it is no longer needed. As a result, the large screen display is occupying valuable real-estate within the control room, and the positioning of the work stations may not be optimal for day-to-day operations at the System Control Center.

1.3 SCADA Replacement Strategy

The primary objective of the SCADA System Replacement project is to update the SCADA System to a supported hardware and software environment with minimal business disruption, while at the same time improving the flow of critical power system static and historical data essential for power system analysis and information dissemination to the organization.

For the existing SCADA system, the Current Vendor cannot provide a simple upgrade to its latest product; “upgrading” to the latest version of the product requires a complete product replacement and re-development of the custom applications. As a result, the level of effort, costs, and risks with an “upgrade” will be equivalent to a product replacement from any competing vendor. In fact, of the three budgetary quotations received for the SCADA System Replacement, the budgetary quote from the Current Vendor was the most expensive. As such, an open bid process should be technically and commercially more advantageous for the Owner rather than negotiating a sole-source contract with the Current Vendor.

The SCADA Replacement Project has been divided into the following major components:

1) **SCADA System Replacement**: This component is divided into a Request for Proposals phase, followed by the project implementation phase. The Owner will need to prepare a detailed technical and commercial specification, identify qualified vendors, issue a Request for Proposals, evaluate proposal responses, perform site visits for due diligence, then negotiate a statement of work and commercial contract with the selected vendor. The general objectives of the SCADA System Replacement are to:

   a) Deliver reductions in the cost of purchasing and maintaining the SCADA hardware. Moving off the HP Alpha Server platform will ensure utilization of lower cost server hardware that is independent of the operating system and SCADA software product. The project will also deliver the opportunity to migrate to the Windows Server operating system, reducing the number of technologies that the organization will need to support, and with trained resources readily available in the marketplace.

   b) Deliver reductions in the total cost of ownership of the SCADA system. Moving to the latest version of a commercial SCADA product, and keeping current with the selected Vendor’s maintenance program, will allow the Owner to stay current with product releases and leverage product improvements financed by the selected Vendor’s user community.

   c) Provide the ability to better secure the functions performed by the SCADA system, following industry best practices, by way of integration of anti-virus, centralized account management, and patch management.

d) Provide modern, best-of-breed tools for the System Operators and support staff to allow them to continue to reliably monitor and control the Owner's generation, transmission and distribution system. This includes preserving, and possibly enhancing, some of the customizations performed on the current SCADA system, such as control windows and under-frequency load shedding.

e) Facilitate the future integration with the Outage Management System. The Owner plans to implement a commercial Outage Management System in the next 3-5 years. As such, the replacement strategy for the SCADA system should take this into consideration and ensure that the SCADA system selected follows industry standards for system integration (e.g. OPC, Multispeak, etc.) and includes the tools needed to easily integrate with a future OMS. The Owner should also evaluate the selected SCADA vendor's OMS product, if any.

2) **Commercial Historian:** The Owner should consider deploying a commercial historian in order to address the issues with historical data storage, analysis, and reporting. With the success of commercial historian products such as OSIsoft PI, SCADA vendors have invested very little research and development effort to improve their native historians, and as such the functionality and performance offered by commercial historians is far superior to native SCADA historians. A commercial historian would improve the flow of critical power system static and historical data essential for power system analysis and information dissemination to the organization, resulting in lower operating costs and improvements in productivity.

3) **Control Room Refurbishment:** Now that the large screen display at the front of the Control Room is no longer functional, there is no need for the operator work stations to remain in their current configuration. Alternate configurations should be considered that may enhance interaction amongst the operators, as well as new ergonomic work stations that will better meet the goals of occupational health and safety, and improve productivity. The Control Room should also be refurbished to remove the large screen display and reclaim this space for the operators.

1.4 Project Plan

The Owner intends to follow the following project plan:

KEY MILESTONES	
SCADA Replacement Program Start	January 2015
SCADA Request for Proposals	
SCADA RFP Start	January 2015
SCADA RFP Documents Complete	May 2015
Proposals Received from SCADA Vendors	June 2015
SCADA System Contract Award	August 2015
SCADA RFP End	August 2015

SCADA System Replacement	
SCADA System Replacement Start	September 2015
Development System Complete	December 2015
Database and Display Validation Complete	March 2016
Factory Acceptance Tests Complete	April 2016
System Installation Complete	July 2016
Site Acceptance Tests Complete	September 2016
Start of Warranty	October 2016
Post Project Activities	October 2016
SCADA System Replacement End	October 2016
Commercial Historian	
Commercial Historian Start	May 2015
Commercial Historian End	December 2015
Control Room Refurbishment	
Control Room Refurbishment Start	January 2016
Control Room Refurbishment End	May 2016
SCADA Replacement Program End	October 2016

1.5 Budgetary Cost Estimates

The following budgetary estimate is based on a detailed analysis of the activities and resources required to execute the SCADA Replacement project, as well as budgetary quotations received from potential suppliers. Estimates have been rounded up to the nearest $1000.

SCADA System Replacement	$4,300,000
Commercial Historian	$976,000
Control Room Refurbishment	$399,000
TOTAL BUDGETARY ESTIMATE (CAD)	**$5,675,000**

2 Current System Assessment

2.1 Methodology

In March 2014, the Consultant travelled to St. John's to hold a series of meetings with the Owner's operational and information technology (IT) staff in order to review the current SCADA system architecture, system interfaces, functional requirements, concerns, needs, risks, and priorities for upgrading or replacing the SCADA system. A series of meeting were held with the appropriate team members to:

1) Review the current system architecture, including system interfaces and quantity of servers / workstations in each of the production environments and locations;
2) Identify any issues or concerns with the existing system such as cyber security, system architecture, system sizing, system performance, or system stability that should be addressed in the new SCADA system;
3) Identify the major functions available on the current SCADA that must be available in the new SCADA system, and document (at a high-level) the custom applications such as the under-frequency load-shedding application, scheduled alarms application, etc.;
4) Identify any new functions that the Owner would like to introduce in the new SCADA system;
5) Identify corporate IT standards, such as preferred hardware or software platforms, that should be taken into consideration in the upgrade or replacement strategy;
6) Quantify the current maintenance and support costs, response times, and service levels.
7) Review the interface between the Owner's SCADA system and the NL Hydro SCADA/EMS system to determine any issues, constraints or opportunities that should be taken into consideration in the upgrade or replacement strategy.
8) Assess the adequacy of the existing control center facilities and backup facilities (rack space, power, air conditioning, etc.).
9) Assess integration of future technologies such as GIS, OMS, WFM, etc.
10) Analyze the Owner's capacity for deploying and maintaining the new SCADA system.

Following these meetings, the Consultant developed a high-level set of functional requirements and solicited budgetary quotations from qualified suppliers for the following major system components:

- SCADA System
- Commercial Historian
- Control Room Desks

2.2 Current System Architecture

2.2.1 System Overview

The architecture of the current SCADA system is standard within the industry, with redundant SCADA servers at the System Control Centre (SCC) and non-redundant SCADA servers at a Disaster Recovery System (DRS) that is synchronized in real-time from the primary system. SCADA data used for web displays, analysis, and reporting is replicated in near-real-time to a Decision Support System (DSS) in a demilitarized zone (DMZ) in order to isolate corporate users from the SCADA production database. Communications to systems external to the control centers are primarily to the substation RTUs / SMP Gateways using DNP3 protocol, and to NL Hydro using the ICCP protocol.

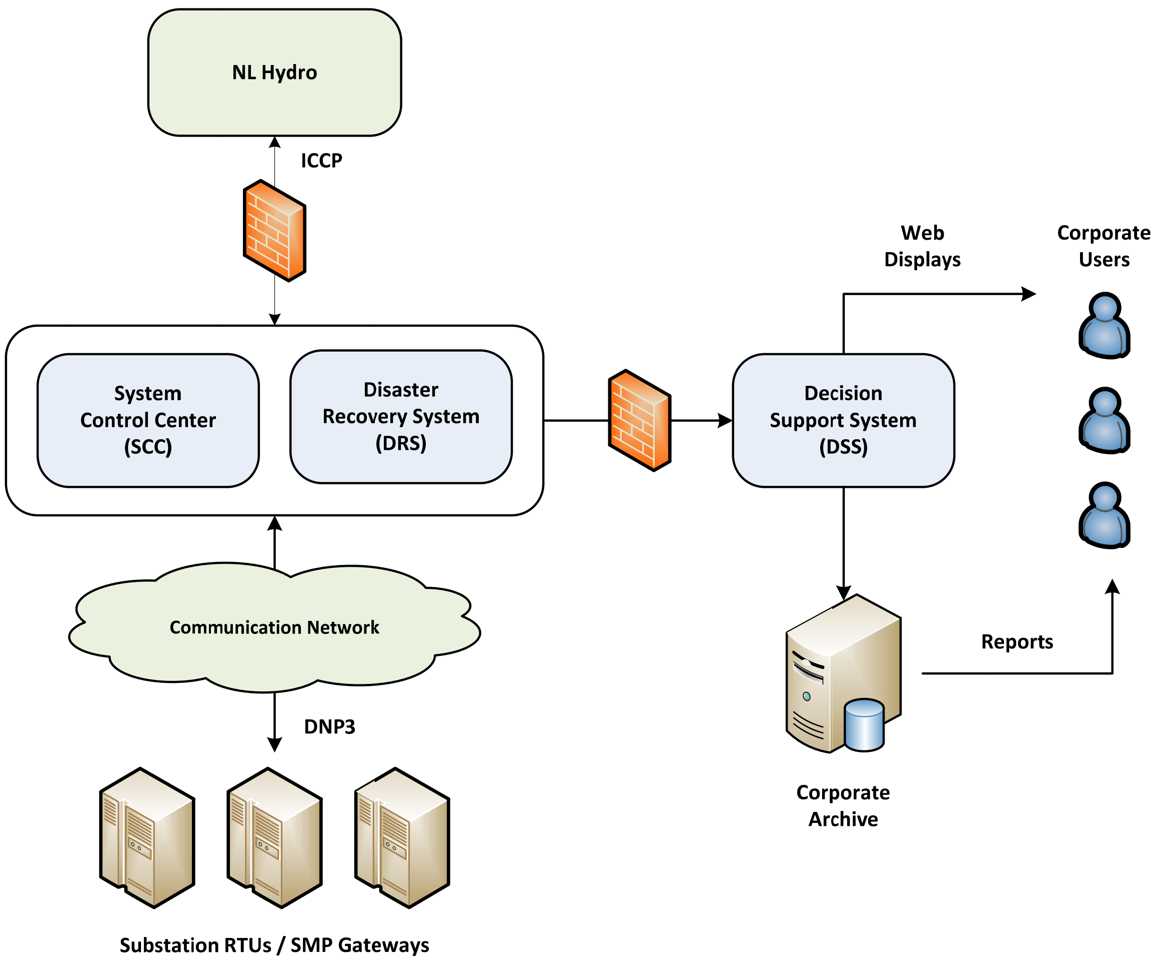


Figure 2-1: System Overview

2.2.2 System Platform

The current SCADA System is based on the HP Alpha servers running the TRU64 UNIX operating system, and Intel-based workstations running the Windows operating system. Since commissioning the system in 1999, a software upgrade was performed in 2004 and the primary SCADA servers were upgraded in 2006 following HP's decision to discontinue the Alpha Server product line. As a result, the current SCADA platform is outdated, expensive to support, and failing to meet current organizational requirements. In particular:

8) **SCADA Servers:** The HP Alpha servers are now obsolete, and spare parts are increasingly difficult to source. Now averaging more than 11 years old, the failure rate of critical server components, such as disk and memory, is expected to accelerate over the next few years.

9) **Operating System:** The TRU64 UNIX operating system is no longer supported by HP. As a result, HP no longer provides operating system patches to correct known issues, including cyber security issues. It is not possible to follow industry best practices for cyber security while continuing to use this obsolete operating system.

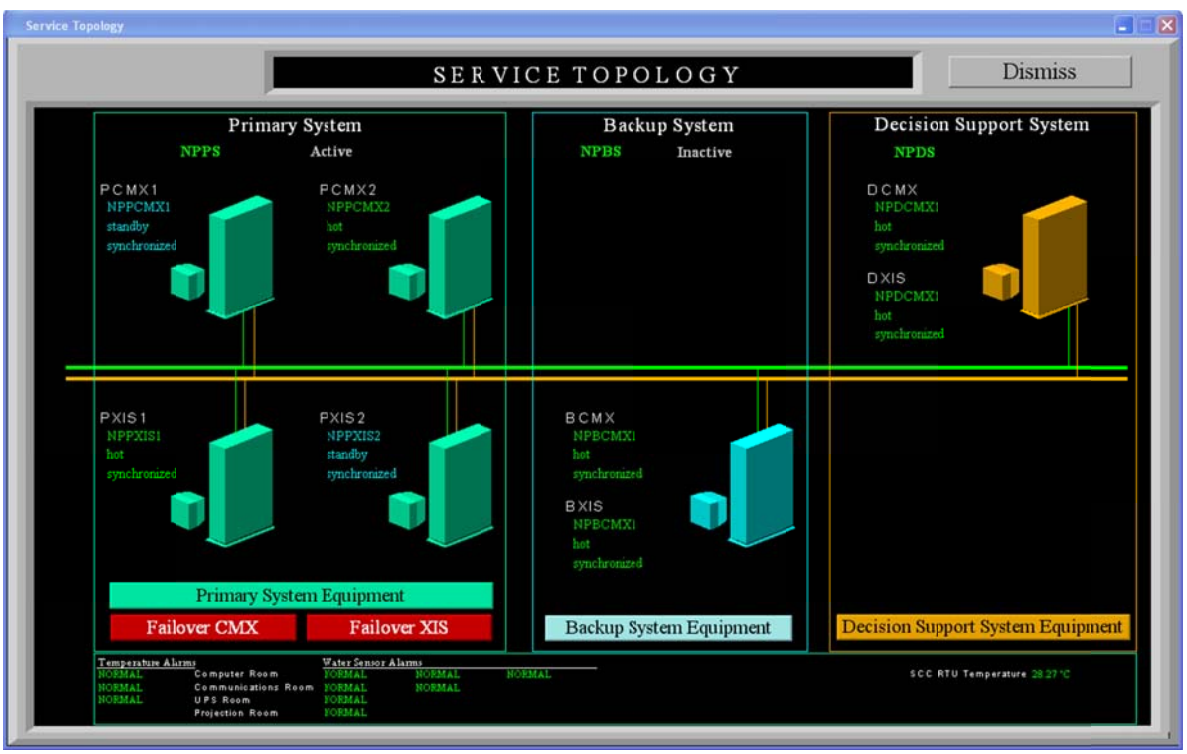


Figure 2-2: System Topology

10) **SCADA Software:** The OASyS DNA V6.3 SCADA software currently being used is now obsolete. The Current Vendor has replaced this product with a modern software architecture based on hardware-independent operating systems such as Linux and/or Windows. In addition, many of the core features of the current system, such as AutoCAD display editor, are no longer supported in the latest product from the Current Vendor. This has several implications:

   a) The Current Vendor cannot provide a simple upgrade to its latest product; "upgrading" to the latest version of the product requires a complete system replacement and re-development of the custom applications.

   b) The Owner must pay escalating maintenance costs for its obsolete SCADA software. Although technical support from the Current Vendor has rarely been an issue, maintenance costs have recently escalated and it is anticipated that the Current Vendor will find it increasingly difficult to maintain resources with knowledge of the current SCADA system over time.

2.2.3 Communications

2.2.3.1 Substations

Communications between the SCADA System and the substation RTUs / SMP Gateways is based on the DNP3 protocol using a variety of communication technologies including the Owner's fiber optic network, Bell-Aliant wide area network, Bell-Aliant digital subscriber lines (DSL/ADSL), Bell-Aliant leased circuits, Bell mobility network (EVDO/HSPA), Globalstar satellite network, and spread spectrum radio. Redundant communication circuits are provided for critical substations, and Checkpoint VPN-1 endpoint devices are used to secure internet-based connections.

No issues were identified with the communications with the substations. Communication costs were not evaluated at this time as it was beyond the scope of this study.

2.2.3.2 NL Hydro

An ICCP link is used to exchange real-time information with NL Hydro. A non-redundant LiveData ICCP server located at the System Control Center provides the interface to NL Hydro. A VPN link between the two systems is used to encrypt the data being exchanged.

2.2.4 Corporate Users

To support SCADA data analysis, reporting, and web displays by Corporate users, SCADA data is replicated in near-real-time to a separate Decision Support System (DSS) in a demilitarized zone (DMZ). This eliminates the need for Corporate users to access the SCADA production database, thereby minimizing SCADA performance issues and data security issues.

The Owner has developed a number of extract routines that move data from the DSS database to Corporate databases to facilitate corporate reporting on SCADA historical data. Various procedures move summarized hourly, daily, monthly and yearly information to an SQL Server database on the

Corporate network for end user reporting, analysis and alerts. In addition, specific subsets of "minute" data are extracted for Corporate applications such as Peak Load management and information displays. Numerous reports and templates have been provided to users on the Corporate network to allow access to specific SCADA data archives.

A number of issues were identified with the current solution:

1. **Historical Data:** The current use of SCADA historical data on the Corporate network is inflexible and the DSS database has limited query accessibility, making it difficult for corporate users to extract the information required. In addition, since only summarized data is stored long-term, data is not always available to the level of detail required.
2. **Web Interface:** The current SCADA system provides web access for up to 20 Corporate users to view near-real-time SCADA displays, with access being granted on a first-come-first-serve basis. This constraint has prevented some key personnel from accessing the SCADA system displays during critical events. In addition, the web interface only runs on an obsolete, unsupported version of the web browser (Internet Explorer 7 or earlier).

2.2.5 Control Room Facilities

System Operators monitor and control the generation, transmission, and distribution network 7 days a week, 24-hours a day from four (4) work stations located at the System Control Center. The two main System Operator workstations, located side-by-side at the front of the room, have 4 x 19" and 2 x 60" monitors connected to the SCADA system, as well as 3 x 19" monitors connected to Corporate systems. The 2 x 60" monitors are mounted from the ceiling. A Shift Supervisor workstation and Support workstation, located side-by-side behind the System Operator work stations, have 4 x 19" monitors connected to the SCADA system as well 3 x 19" monitors connected to Corporate systems (e-mail, outage management, etc.).

The work stations are positioned to face a large-screen display along the front wall. This display is no longer functional, and the Owner has acknowledged that it is no longer needed. The extended viewing area provided by the 2 x 60" displays connected to each System Operator work station is adequate for system monitoring and control.

2.3 Current System Functions

This section provides an analysis of the SCADA functions, support functions, system configuration, system capacity, and system performance constraints of the existing SCADA system.

2.3.1 SCADA Functions

The majority of the SCADA functions available on the current SCADA system are industry standard SCADA functions, though their implementation characteristics vary from one product to the next. The following sections provide descriptions of the functions that were customizations on the existing system, and may not be standard features on some SCADA products.

2.3.1.1 Control Windows

The current SCADA system provides a customized, sophisticated, and efficient user interface for executing supervisory control functions, particularly for the generating units. Figure 2-3: Control Windows provides an example for a circuit breaker and hydro plant / generator control.

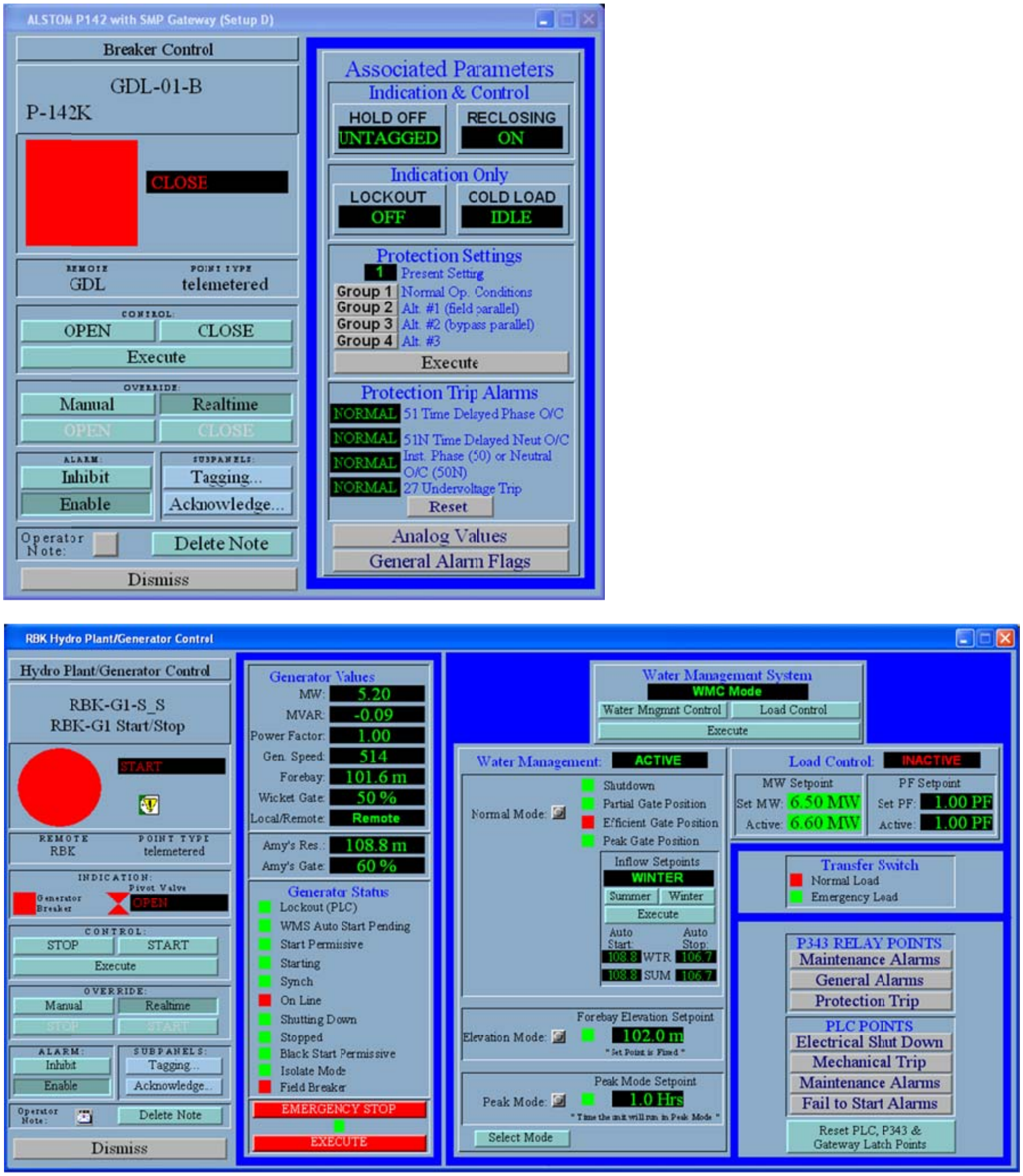


Figure 2-3: Control Windows

The control windows provide a global view of all of the parameters associated with the device selected so that the System Operator can make appropriate control decisions quickly, and with a minimum number of mouse clicks. A side panel is used to display parameters associated with the device, such as the status of the recloser, lockout status, protection settings, etc. These control windows have been customized to recognize the different types of devices in the system.

2.3.1.2 Tagging

The current SCADA system has tagging capabilities whereby tags can be added to status and analog points. Up to 4 different tag types are supported, and multiple tags of the same type can be applied to any point. Different tag types carry with them various limitations on any commands that might be issued to the tagged point, such as inhibit close, inhibit control, etc.

The current implementation is inflexible in that software changes are required to change tag type names in order to conform to the Owner's Worker Protection Code, or to add additional data fields for switching order number or work permit number.

2.3.1.3 Alarm Suppression

The current SCADA system has a functionality referred to as "Device Dependent Alarming" which will allow the delaying of an alarm based upon a prior event – typically designed for use to allow switching transients to settle before generating an alarm. For example, delaying a voltage level alarm for a pre-determined time after a transmission breaker has been opened. The "Device Dependent Alarming" functionality has a timeout period that must be defined and, while you could suppress the alarms for a defined period, they will all alarm after the timeout period expires if they are still in an alarm state.

Although the Device Dependent Alarming function is useful, the Operators require an intelligent alarming capability to suppress alarms, or reduce their priority to event status, when they are secondary alarms resulting from a commanded action. This would eliminate nuisance alarms and allow the Operators to focus on the cause of an event, rather than its side-effects.

2.3.1.4 AGC Lite

The current SCADA system includes an application called AGC Lite to automatically control the MW & MVAR output of the hydro generating units. MW and MVAR setpoints are set by the System Operator and the SCADA system continually monitors the output and issues raise and lower commands as required to keep the outputs within a pre-defined deadband of the setpoints.

Since the SCADA system was commissioned, most units have been upgraded with local PLC control and the AGC Lite application is no longer required for these units. Only 2 units currently remain on AGC Lite, and only one of these is anticipated to be outstanding after the new SCADA System is placed in service. As such, this functionality will likely not be required in the new SCADA System.

2.3.1.5 Under-Frequency Load Shed

The current SCADA system includes a customized, pre-wired, under-frequency load shedding scheme to maintain system stability at times when there is insufficient generation to support all customer load. Custom-built under-frequency load control circuit boards installed in each distribution substation RTU are connected to the feeder circuit breakers providing the ability to trip specific circuit breakers when the frequency drops to a pre-set threshold (e.g. 59.0 Hz, 58.8 Hz, 58.6 Hz, etc.). Up to four different under-frequency thresholds are supported per circuit board, and the levels are pre-programmed in the substation RTU. The Owner has currently defined seven (7) under-frequency thresholds, also called load shed groups or blocks, but more may be required in the future.

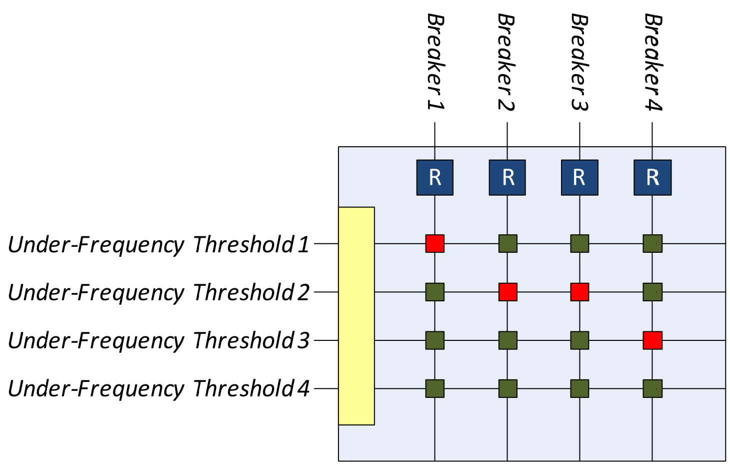


Figure 2-4: Under-Frequency Load Control Board

The current SCADA system includes a custom application to manage the digital relays that implement the multi-stage under-frequency-load shedding scheme. This includes:

- Arming the relays to respond in a controlled fashion to future load shedding events;
- Monitoring the customer load prior to, during and following the load shedding events;
- Restoring each under-frequency group following the load shedding event by issuing a single control output;
- Rotating customers through, and removal from, the different stages of under-frequency load shedding scheme following each event to minimize the outage impact on individual customers. The “rotation” is implemented manually at the SCADA level.

On the current SCADA system, each under-frequency threshold is associated with a load shed “block”. Each feeder breaker can be associated with up to 4 load shed blocks keeping in mind that the configuration of the under-frequency thresholds in the substation RTU must match those assigned at the SCADA block level. Although a feeder can be assigned to up to 4 load shed blocks, it can only be activated, or armed, on one of the blocks at any given time. This provides the ability to dynamically change the feeders affected at a particular under-frequency threshold so that it is not always the same customers affected.

The configuration of the load shed blocks is maintained at the SCADA system. Each time the configuration is changed, controls are automatically issued to the under-frequency load control boards to arm or disarm the feeder on its respective groups. The SCADA system also automatically calculates the load on each group, and historical data is collected for future reference.

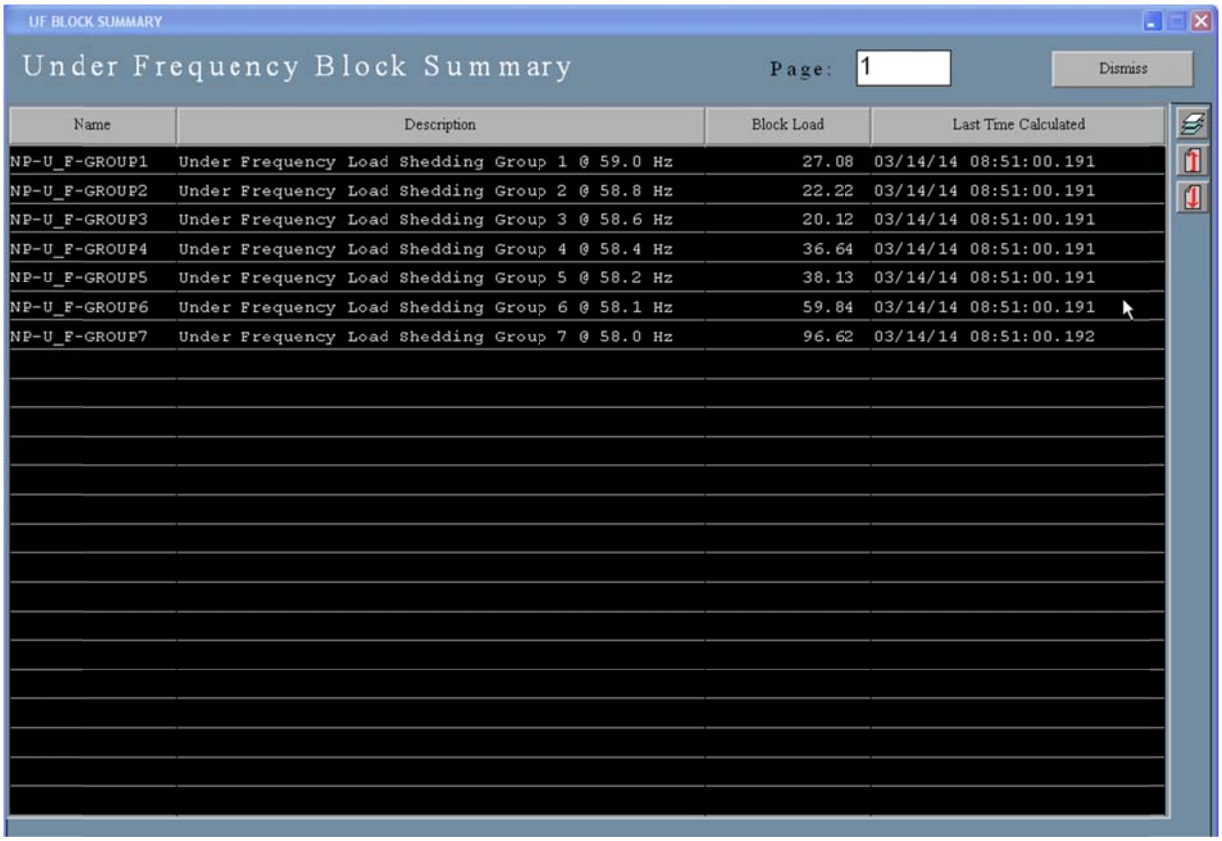


Figure 2-5: Under-Frequency Block Summary

The advantage of this under-frequency load shed scheme is that, once programmed, it will operate autonomously at the substation level, independently of the SCADA system. A disadvantage of the solution is the lack of a user-friendly interface to change the configuration of the load shed blocks.

2.3.1.6 Scheduled Alarms

The current SCADA system supports an application for added security to track employees that are working alone in a dangerous or remote location. An expiry date and time is entered and if the employee reports back before the time expires then the record is marked completed and closed. If the time expires without the employee reporting back then a SCADA alarm is generated and various procedures are followed by System Control Center staff.

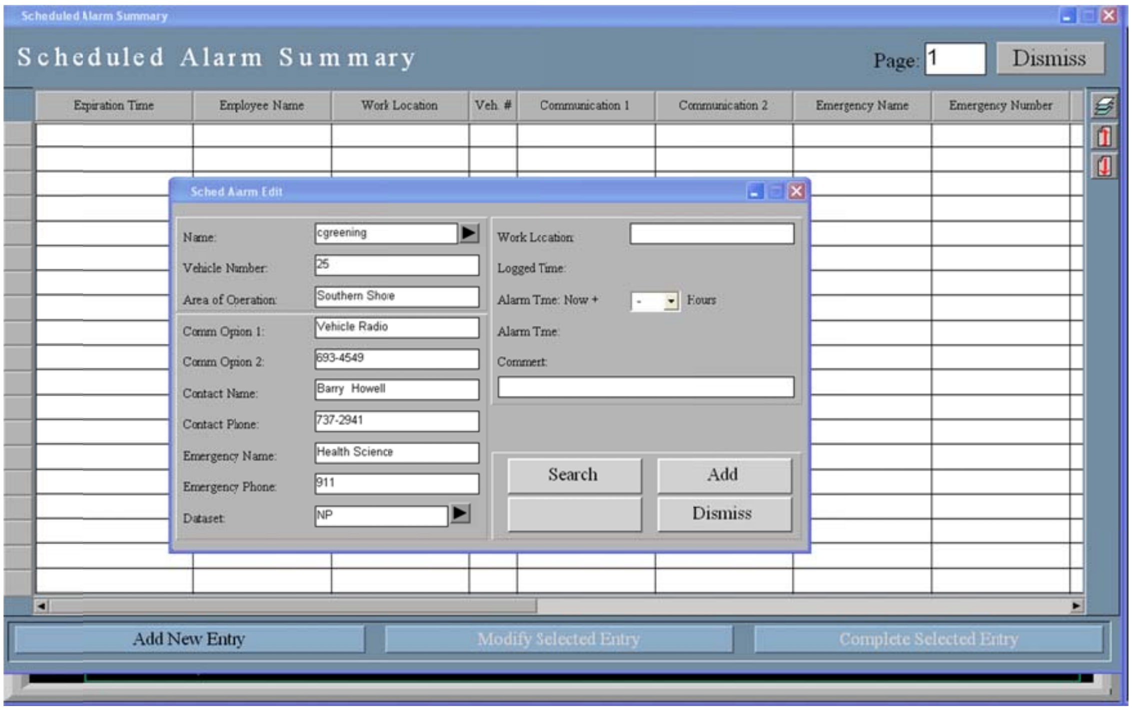


Figure 2-6: Scheduled Alarms

2.3.1.7 Operator Diary

SCADA Operators make judgments daily regarding significant events that occur during their shift. Manually, the operators maintain a chronological log of these events to report to several internal groups including senior management. The logs are individually saved and shared via email when there is time available to do so. During storms and major system events there is not always time to maintain the operator diary.

The operator diary includes free form text with no automation to help report substantial events. The logs cannot be easily searched for content, do not have a standardized method to capture data content and are individually saved on the company's network, making it very difficult to query historically for known or past events.

2.3.2 Support Functions

2.3.2.1 Database Management

The current SCADA system supports online edits that are automatically propagated to all SCADA servers without the need to failover the servers to bring the new database online. An online database editor provides the ability for users to add, modify, and delete database objects.

The Current Vendor has provided some custom scripts to simplify some database transactions, such as the ability to upload a Microsoft Excel file to modify the configuration of the under-frequency load shed groups, and the ability to extract point definitions in Microsoft Excel format on a substation basis.

2.3.2.2 Display Management

The current SCADA system uses AutoCAD as the display editor. This has provided significant advantages to the Owner, as the drawings provided to field crews for on-site work are the same drawings that are available to the System Operators on the SCADA System. In fact, the Owner's processes were streamlined to have one group responsible for maintaining the drawings, as opposed to separate groups. This has reduced costs, eliminated discrepancies, and improved productivity.

2.3.2.3 System Administration

The current SCADA system provides basic tools for system administrators to maintain the system configuration (areas of responsibility, user roles, privileges, etc.) and troubleshoot issues (protocol analyzer, database monitor, etc.)

2.3.3 System Capacity

The current SCADA system is sized to accommodate data acquisition from the existing substations, and data exchange with NL Hydro. Please refer to Table 3-2: System Capacity for a summary of the current and future system capacity.

2.3.4 System Performance

No issues were identified with the system performance and user response times with the current SCADA system.

2.4 Outage Management System

The Owner has a number of Corporate applications that support distribution system maintenance, outage logging, power restoration and customer notification during outages. Specific systems or applications helping support these functions are:

- ESRI ARC FM Geographic Information System (GIS). The Owner is in the process of deploying ESRI ARC FM. The initial phase of this project will provide a GIS-based electrical connectivity model that will maintain and support the Owner's feeder diagram process.
- Microsoft .Net-based Outage Management system, and Informer application. The Owner has designed two .Net applications that support the logging of customer outages and the posting of outage notifications to the company's website and Interactive Voice Response systems. Over time it is planned that these applications will be replaced by a commercial OMS that will integrate directly with the ESRI GIS.

Short-term SCADA requirements include integration capabilities with Microsoft .Net based applications such as the Owner's Outage Management and Informer applications, and more would be required, primarily from a data exchange perspective. The Owner expects to implement a commercial OMS solution within 3-5 years, replacing the existing Outage Management and Informer applications.

2.5 Operator Training

The Owner expects a significant number of System Operators to retire during the life time of the new system. As such, the amount of time spent training new users is expected to increase over the next few years. No specific tools are available on the current SCADA system; new users are trained on the production system.

2.6 Maintenance and Support

The Owner maintains an annual Maintenance & Support Agreement with the Current Vendor. The agreement originally provided for up to 200 hours a year in technical support, but since the Owner had no control on how the hours were spent, the agreement was modified such that the vendor has turn-key responsibility to resolve reported issues. The cost of this annual agreement has recently increased given the obsolescence of the system platform, and the unique functionality of the existing SCADA system.

3 Replacement Strategy

3.1 Objectives

The primary objective of the SCADA System Replacement project is to update the SCADA System to a supported hardware and software environment with minimal business disruption. The general objectives of the SCADA System Replacement project are to:

1. Deliver reductions in the cost of purchasing and maintaining the SCADA hardware. Moving off the HP Alpha Server platform will ensure utilization of lower cost server hardware that is independent of the operating system and SCADA software product. The project will also deliver the opportunity to migrate to the Windows Server operating system, reducing the number of technologies that the organization will need to support, and with trained resources readily available in the marketplace.
2. Deliver reductions in the total cost of ownership of the SCADA system. Moving to the latest version of a commercial SCADA product, and keeping current with the selected Vendor's maintenance program, will allow the Owner to stay current with future product releases and leverage product improvements financed by the selected Vendor's user community.
3. Provide the ability to better secure the functions performed by the SCADA system, following industry best practices, by way of integration of anti-virus, centralized account management, and patch management.
4. Improve the flow of critical power system static and historical data essential for power system analysis and information dissemination to the organization, resulting in lower operating costs and improvements in productivity.
5. Provide modern, best-of-breed tools for the System Operators and support staff to allow them to continue to reliably monitor and control the Owner's generation, transmission and distribution system. This includes preserving, and possibly enhancing, some of the customizations performed on the current SCADA system, such as control windows and under-frequency load shedding.
6. Facilitate the future integration with the Outage Management System.

3.2 General Requirements

The general requirements for the new SCADA system are:

1. **High Availability:** The SCADA system architecture must be fault tolerant so that any single hardware failure does not result in the loss of a critical function. The production SCADA must exhibit an annual system availability of 99.98%. A Disaster Recovery System (DRS) must be provided to function as the main disaster recovery site. It is not required for the equipment at the DRS to be redundant in its initial configuration. However, the system must be designed and built so the Owner can implement a redundant DRS by simply adding equipment and changing configuration parameters without having to modify software code or recompile any programs.

2. **Present Pertinent Information:** It is important that the System Operators and Engineers have access to a full range of high quality real-time and historical data, as well as the tools to interpret the data to aid the staff in performing their jobs.
3. **Compliance with Standards:** The SCADA system must conform to industry standards, especially standards relating to enterprise integration, interfacing and exchanging data between different systems.
4. **Open System Design:** The SCADA system must comply with widely accepted standards for open systems, both from standards organisations as well as de facto standards. This will enable the Owner to select the best-of-breed hardware and software solutions to meet their future needs and greatly enhance the system's ability to communicate with the enterprise systems.
5. **Expandable/Scalable:** The SCADA system hardware and software must be easily expandable and scalable and provide the capability to upgrade and/or add additional processors, disk units, remote terminal units, network plant, etc., and expand application programs or add new functions without major disruption to the operation of the SCADA system.
6. **Security:** The SCADA system must have appropriate security features that prevent unauthorised users from accessing the system and permit assigning various levels of access privilege to the authorised users. In order for the Owner to follow industry best practices for cyber security, the new SCADA system must support the NERC CIP requirements.
7. **Minimal Customisation:** To the greatest extent possible, standard applications must be used to minimise customisation to standard product(s) and thereby lower the risk of implementation schedule delays and reduce the costs of system procurement and system maintenance services.
8. **System Responsiveness:** High performance is required for user interface, data collection, and program execution times as well as the timeliness of making data available to the enterprise.
9. **Maintainability:** State of the art auditing, editing, display building, and database generation tools must be provided for maintaining the system. Ideally the new SCADA system will allow the Owner to continue to use AutoCAD as the primary display editor.
10. **Improved Operator Training:** An offline environment with Operator training tools that are fully integrated with the SCADA system and use the same databases and displays as the production system should be provided to improve Operator training.

3.3 Corporate Standards

The following table identifies the Owner's current corporate IT standards; the new system should be compatible with these standards.

Table 3-1: Corporate IT Standards

CORPORATE IT STANDARDS
Microsoft Windows 7 for workstations with standard keyboard and mouse behavior
Windows Server 2012 for Windows-based servers

CORPORATE IT STANDARDS
Red Hat Linux for UNIX-based servers
HP servers and workstations, 3 PAR SAN
3 PAR Storage Area Network (SAN)
SQL Server RDBMS (Oracle can also be supported)
Trend Micro anti-virus
Middleware (1) BizTalk Server (primarily), (2) Visual Basic .NET, (3) SQL Server SSIS
TCP/IP protocol and SNMP capable network management tools (e.g. Solar Winds)
Cisco equipment for switches, routers, and firewalls.
Ethernet, Fast Ethernet, and Gigabit Ethernet for local area networks
Tivoli Net Backup as a backup tool

3.4 System Architecture

The architecture of the new SCADA system should be similar to the existing system architecture with SCADA servers installed at the System Control Center and Disaster Recovery site. However, the Owner should consider the following enhancements to the system architecture during the SCADA system replacement:

1. **SCADA Servers:** The SCADA servers should follow Corporate IT standards as defined in Section 3.3 in order to facilitate hardware maintenance and support. High-performance server models with redundant processors, power supplies, and cooling fans should be used to maximize system availability. Commercial network management tools, independent of the SCADA System, should be used to monitor all server and workstation components.

2. **Operating Systems:** The operating system of the SCADA servers and workstations should be hardware-independent (i.e. Windows or Linux) allowing the Owner to select the best-of-breed hardware and software solutions to meet their future needs. The operating systems selected should also follow Corporate IT standards as defined in Section 3.3 in order to facilitate software maintenance and support.

3. **Redundant ICCP Servers:** Given the critical nature of the data being exchanged between the Owner and NL Hydro, industry best practice is to use redundant ICCP servers at the System Control Center, and a non-redundant backup server at the Disaster Recovery System.

4. **Pre-Production Environment:** In order to follow industry best practices for cyber security, software patches (operating system, commercial database, SCADA software, etc.) should be monitored, evaluated, and installed regularly. To minimize the risk to the production system, industry best practice is to use a pre-production system to perform regression tests prior to installing the patches on the production system.

5. **Commercial Historian:** In order to address the issues with historical data storage, data analysis and reporting, and to improve productivity, the Owner should consider deploying a commercial historian with the new SCADA system. With the success of commercial historian products such as OSIsoft PI, SCADA vendors have invested very little research and development effort to improve their native historians, and as such the functionality and performance offered by commercial historians is far superior to native SCADA historians. However, native SCADA historians may still be the best choice for short-term history and for archiving alarms and events.

6. **Interface to Outage Management System:** The Owner plans to implement a commercial Outage Management System in the next 3-5 years. As such, the replacement strategy for the SCADA system should take this into consideration and ensure that the SCADA system selected follow industry standards for system integration (e.g. OPC, Multispeak, etc.) and includes the tools needed to easily integrate with a future OMS. The replacement SCADA system must have the ability to integrate with a number of real-time interfaces to external systems including the GIS and a commercial OMS. It would be expected that the SCADA platform would support industry standard interfaces, such as OPC and MultiSpeak, for this purpose. Preference should be given to SCADA products that have an integrated OMS product available. As such, SCADA vendors were asked to provide details of their integrated Outage management System (OMS) product, if applicable, and to provide budgetary estimates for their OMS product.

7. **Operator Training Simulator (OTS):** The Owner expects a significant number of System Operators to retire during the life time of the new system. As such, the amount of time spent training new users is expected to increase over the next few years, and new tools to support this training should be evaluated. It may be better to acquire the OTS with the OMS since more functionality and training will be required with the OMS. SCADA vendors were asked to provide details of their integrated Operator Training Simulator (OTS) product, if applicable, and to provide budgetary estimates for their OTS product.

3.5 System Functions

For this Strategic Plan, the following SCADA Vendors were invited to submit budgetary quotations for the SCADA System Replacement project:

- Schneider Electric Inc., based in Houston, Texas, USA
- Open Systems International Inc. (OSII), based in Minneapolis, Minnesota, USA
- Survalent Technology Inc., based in Mississauga, Ontario, Canada.

The Owner has a preference for standard products with minimal customization in order to minimize costs and to facilitate future upgrades and maintenance. However, the system needs to include some specific functions that are critical to the Owner’s day-to-day operations (e.g. under-frequency load shed, control windows, etc.) that may not be standard software in all products. The Owner should consider alternative, standard product solutions that would provide similar functionality. Where customizations are required, the Owner should insist that the customization become part of the Vendor’s standard product in the future.

A high-level set of functional requirements was provided to the SCADA vendors. The requirements included typical SCADA functions found in modern SCADA systems as well as functions that were customized on the current SCADA system. The SCADA Vendors were requested to identify their compliance to these requirements as follows:

- Standard (included or not in price) for functions that are available in the standard product and can be enabled through configuration parameters (no software development required to enable, disable, or configure the function).
- Customization (included or not in price) if a similar function exists in the standard product, but customization will be required to support the functionality as described.
- New (included or not in price) if no similar function exists in the standard product, and the function would need to be developed.

3.5.1 SCADA Functions

The following sections provide descriptions of the functions that were customizations on the existing system, and how they should be handled in the replacement project based on feedback from the SCADA vendors. These functions should form part of the product evaluation matrix, with appropriate weights assigned to each function, during product evaluations.

3.5.1.1 Control Windows

The control windows in their current form will be difficult to replicate in the new SCADA system. The Consultant has seen demonstrations of each of the SCADA products proposed and can confirm that none of the products offer the functionality available on the current system. Nonetheless, two of the SCADA vendors indicated that this functionality is standard in their SCADA product which would indicate that they did not take the time to analyze the functionality requested, and are not willing to change their standard product to comply with the Owner's requirements. Only one SCADA vendor (Survalent) recognized that the control window functionality requested would need to be customized in their product and included it in their development efforts.

The Owner will need to carefully analyze of the capabilities of the SCADA products in order to determine the best course of action. For example, in consultation with the System Operators, the Owner could accept the functionality offered in the selected product and plan for operator training; this would likely result in a loss of productivity. Alternatively, the Owner could engage the selected Vendor to develop the control windows per the Owner's specifications. This would simplify the transition to the new system, maintain productivity, and enhance the vendor's product for other utilities.

To ensure that sufficient budget is available to support the implementation of control windows similar to the current functionality, a separate estimate was provided by the Consultant for this customization in the budgetary estimates.

3.5.1.2 Tagging

The ability to easily change tag attributes should be a standard feature in most modern SCADA systems. In fact, all of the SCADA vendors indicated that this is a standard feature of their SCADA product. The Owner should carefully analyze of the capabilities of the SCADA products to configure additional tag fields, or modify existing fields, during product evaluations.

3.5.1.3 Alarm Suppression

Most modern SCADA systems offer some form of intelligent alarm processing. In fact, all of the SCADA vendors indicated this was a standard feature of their SCADA product. The Owner should carefully analyze the intelligent alarming features of the SCADA products during product evaluations.

3.5.1.4 AGC Lite

The Owner anticipates that one generating unit may still be under the control of the existing AGC Lite application when the new SCADA System is placed in service. As such, this functionality will likely not be required in the new SCADA System, but the Owner may want to consider SCADA products that support this capability as a risk mitigation strategy. Each of the SCADA products selected for budgetary quotations have an optional AGC application that could be included with the SCADA system, if required.

To ensure that sufficient budget is available to support this option, a separate estimate was provided by the Consultant for this application in the budgetary estimates.

3.5.1.5 Under-Frequency Load Shed

The new SCADA system will need to support the customized, pre-wired, under-frequency load shedding scheme provided by the current SCADA system. Since the design is somewhat unique, some customization will be required in the new SCADA system to fully support, and possibly enhance, the existing functionality.

Each of the SCADA vendors has proposed their standard, SCADA-level, rotating load shed application in response to this requirement; this will not meet the requirements of this application. As such, some customization will be required to arm and disarm the digital relays on the under-frequency load control boards, as a minimum. The Owner should also consider automating, or at least improving the user interface, for changing the configuration of the load shed blocks.

To ensure that sufficient budget is available to support this critical application, a separate budgetary estimate was provided by the Consultant for customizing the vendor's standard product.

3.5.1.6 Scheduled Alarms

The application to track employees that are working alone in a dangerous or remote location must be supported in the new SCADA system, but may not be a standard offering. One of the SCADA vendors indicated this functionality was included in their standard product, and two included a price to customize their product to include this function. The Owner should carefully analyze the Scheduled Alarms features of the SCADA products during product evaluations.

3.5.1.7 Operator Diary

The Owner is interested in automating the operator diary function and standardizing the presentation of events. It is recognized that there will be some interaction with the operators to approve the inclusion of some items, but minimizing the operator effort is important. One of the SCADA vendors indicated this functionality was included in their standard product, and two included a price to customize their product to include this function. The Owner should carefully analyze the Operator Diary features of the SCADA products during product evaluations.

3.5.2 Support Functions

3.5.2.1 Database Management

The new SCADA system must provide tools for maintaining the system databases, including support for online edits that are automatically propagated to all SCADA servers without the need to failover the servers to bring the new database online. An online database editor must be provided for System Administrators to add, modify, and delete database objects.

All of the SCADA vendors have indicated that their SCADA product supports this functionality. In addition, each SCADA vendor claims to support user-defined fields on SCADA point definitions, and the ability to extract point definitions in Microsoft Excel format on a substation basis. The Owner should carefully analyze the Database Management features of the SCADA products during product evaluations.

3.5.2.2 Display Management

The Owner has a preference to maintain AutoCAD as the display editor for the new SCADA system, but each of the SCADA products quoted use their own proprietary display editor in order to improve graphic performance. Each of the SCADA products can import AutoCAD files to their proprietary format, but the feasibility of doing this as a standard process only seemed feasible with one of the SCADA products (Survalent). The Owner will need to carefully analyze the Display Management features of the SCADA products during product evaluations.

3.5.2.3 System Administration

The new SCADA system must provide modern, best-of-breed tools for system administrators to maintain the system configuration and troubleshoot issues. Each of the SCADA products quoted include a standard set of tools for configuring, maintaining, and troubleshooting the SCADA system. The Owner should carefully analyze the System Administration features of the SCADA products during product evaluations.

3.5.3 Cyber Security

All of the SCADA vendors have confirmed that their SCADA product complies with the NERC CIP cyber security requirements. The Owner should carefully analyze the cyber security features of the SCADA products during product evaluations.

3.5.4 Multispeak Specification

Although the SCADA vendors confirmed that their products support the Multispeak specification, all of them proposed to use a proprietary interface between their OMS product and the ESRI ARC FM product for importing the distribution network model. Only one of the SCADA vendors (Survalent) included Multispeak in their offering as a standard component, and provided compliance certificates with other products. The Owner should carefully analyze the GIS interface features of the SCADA products during product evaluations.

3.5.5 System Capacity

The Owner plans to implement some feeder automation schemes in the future and interface to an Outage Management System, so the new SCADA system should be sized with this expansion capability. The following table shows the system capacity requirements for the new SCADA system:

Table 3-2: System Capacity

SCADA Database Sizing	Current System	Future System
DNP3 IP Interfaces	150	500
DNP3 Serial Interfaces (RS232)	4	10
Telemetered Analog Points	9,000	25,000
Telemetered Digital Points	22,000	50,000
Non-Telemetered Analog Points	150	500
Non-Telemetered Digital Points	5,000	20,000
Calculated Analog Points	350	2,000
Calculated Digital Points	100	500
Secure ICCP:		
Number of Links (2 way exchange of information)	1	3
Data Values per Data Set	1,500	2,000
Control Scripts	N/A	2,500
Historical Data (all points, one year online retention)	40,000	100,000

Some of the SCADA vendors base the pricing of their product on the system sizing capacity. Only one SCADA vendor (Survalent) indicated that system sizing was unlimited, and would not affect software license pricing or support costs.

3.6 Project Implementation

3.6.1 Responsibilities

The contract should be structured as a turn-key project with clearly defined scope, deliverables, and responsibilities. In general, responsibilities should be divided between the Owner and the SCADA Vendor as follows:

1. All activities related to the installation, configuration, testing, and maintenance of the SCADA software should be the responsibility of the SCADA Vendor with support from the Owner.
2. All activities related to the procurement, installation, configuration, testing, and maintenance of the SCADA hardware should be the responsibility of the Owner, based on the SCADA Vendor's hardware specification. The hardware should comply with the Owner's corporate IT standards.
3. Activities related to the migration of the SCADA database and displays should be the responsibility of the Owner, using tools and training provided by the SCADA Vendor. The tools provided by the SCADA Vendor will need to be customized to meet the Owner's requirements.
4. Activities related to point-to-point testing and commissioning of the system interfaces (i.e. ICCP) should be the responsibility of the Owner with support from the Vendor.

3.6.2 Database and Display Conversion

The transition from the current SCADA system to the new platform will require a carefully planned migration strategy for the databases and displays to ensure their accuracy during the conversion process. The migration strategy should describe the methods, tools, and validation that will be used for the migration of the existing SCADA system databases and displays to the new platform. A Data & Display Migration Plan should be specified as a project deliverable, to be provided by the SCADA Vendor, reviewed and approved by the Owner.

Conversion of the existing SCADA database should be fairly straight-forward, but in order to take advantage of new features available with the new SCADA system, other SCADA attributes may need to be configured. A detailed analysis of the SCADA attributes will be required, and the Data & Display Migration Plan should address each attribute.

Tools provided by the SCADA Vendor to convert the existing displays will likely preserve the basic features of the displays (i.e. lines, symbols, etc.), but will almost certainly result in the loss of functionality. The current SCADA system displays includes a significant amount of custom software (OBEL code) driving specific functionality that will need to be implemented using different technology, such as control scripts, or implemented as software customizations. A detailed analysis of the displays will be required, and the Data & Display Migration Plan will need to address each customization to ensure no loss of functionality.

The System Operators should be consulted regularly throughout the database and display conversion process to ensure the new system is configured to meet their needs, and to provide an opportunity for them to "test drive" the system early on. A Development System should be provided by the

SCADA Vendor early in the project, and it should be installed at the System Control Center for easy access by the System Operators. Given the key role this Development System will have, a payment milestone should be attached to this deliverable.

During the SCADA System Replacement, the Owner will continue to use, and therefore modify, the existing databases and displays. In addition to static SCADA point definitions, dynamic point information needs to be converted prior to system cutover such as tags, notes, manually-entered values, scan overrides, etc. As a result, the migration strategy should take into consideration the fact that data conversions will occur at several key milestones in the project, and finally at system cutover.

Although each of the SCADA Vendors has included the database and display conversion as a customization in their budgetary quotations, the Consultant believes that the level of effort for display conversion has been under-estimated by the SCADA Vendors. To ensure that sufficient budget is available to support this critical item, a separate estimate was provided by the Consultant for database and display migration in the budgetary estimates.

3.6.3 System Cutover Plan

The transition from the current SCADA system to the new SCADA system must be carefully planned in order to ensure a smooth cutover to the new system. The System Cutover Plan should include a period where the new system and the current system run in parallel so that the SCADA Vendor and Owner can verify the database conversion, display conversion, and SCADA functionality prior to cutover.

The System Cutover Plan needs to consider:

- Rack space, air conditioning, and power for the new SCADA equipment running in parallel with the existing equipment for the duration of the transition period;
- Placement (and cabling) of the new workstations such that the users have access to both systems during the transition period keeping in mind that the control room facilities may be refurbished;
- Point-to-point testing of a sample of data to verify the database and display conversion, data acquisition functions, and data processing functions (alarms, events, etc.).
- Testing of system interfaces, such as the ICCP link with NL Hydro and the interface to the new commercial historian.
- Development of a detailed system cutover schedule to ensure no loss of control, real-time data, or historical data during the cutover period. This includes the migrations of dynamic SCADA data such as manually-entered values, tags, scan overrides, etc.
- Maintenance of databases and displays during the parallel run, so that the old SCADA system can be re-started quickly, without the loss of control, real-time data, or historical data, in the event of a major issue with the new SCADA system.

3.6.3.1 Dual RTU Communication Paths

All substation RTUs / Gateways are currently configured to communicate with only one master station, the existing SCADA system. In order to test the new SCADA system prior to cutover, the new SCADA system will need to communicate with the substation RTUs / Gateways in order to verify the system configuration, database conversion, display conversion, and SCADA functionality. There are two alternatives to address this issue:

1. Maintain only one communication port to each substation RTU / Gateway, and coordinate the SCADA tests such that the substation RTU / Gateways required for the tests are switched from the current system to the new system for a few hours to perform the tests. This has the advantage of being easy to configure, but has the disadvantage that the System Operators will not be able to monitor and control the substations under test during the test period, historical data during the test periods will be lost, and testing of the new SCADA system could be delayed if access to the RTUs is not available when needed.

2. Configure a second communication port at each substation RTU / Gateway so that both SCADA systems can communicate with the substation at the same time. This provides a realistic test environment for the new SCADA system and greatly simplifies the validation of the database and display conversion; the same display can be called up on both systems and visually inspected for differences that can result from conversion factors, alarm limits, and other attributes being configured differently on the two systems. Controls are normally disabled on the new SCADA system to prevent testers from operating devices inadvertently.

   The team analyzed each substation's ability to communicate with multiple SCADA masters in order to devise a strategy for the transition phase to the new SCADA system. A majority of the substations can be upgraded fairly easily using existing equipment to configure a second communications port for the new SCADA system. Some substations would require additional hardware to be installed at the substation to provide a second communications port.

   Coordination will still be required with the System Operators during specific tests, such as point-to-point testing, so that they are aware that changes coming from the substation are a result of testing, and not actual field changes. During point-to-point testing, the points assigned to the substation RTU / Gateway under test should be placed in a "TEST" area of responsibility so that the System Operators are not bothered by invalid alarms during the test period.

   Once configured, the second communication port can be configured on the new Pre-Production System in order to provide a realistic test environment for future upgrades.

The Consultant recommends the second option for the majority of the substations (non-critical substations do not need to be dual-ported), and the project plan and budgetary estimates include the activities, resources, and equipment required for the Owner to implement this solution.

3.6.3.2 Point-to-Point Testing

Detailed point-to-point testing should be conducted on a representative sample of devices covering various point types (analog, digital), device types (generators, transformers, switches, etc.), and substation communication devices (SMP Gateway, RTU). The goal of the point-to-point tests are to verify the database and display conversion process. Based on the results observed during the initial tests, the sample size can be adjusted such that the Owner has confidence in the databases and displays on the new SCADA system. The project plan includes the activities and resources required for the Owner to conduct the point-to-point testing on a representative sample of devices.

3.7 Related Projects

3.7.1 Commercial Historian

In order to improve the flow of critical power system static and historical data essential for power system analysis and information dissemination to the organization, the Owner should consider deploying a commercial historian such as the OSIsoft PI Historian. Commercial historians are increasingly being adopted by electric utilities world-wide due to their performance, ease-of-use, and reporting capabilities.

For this Strategic Plan, the following suppliers were invited to submit budgetary quotations for the supply, implementation, and maintenance of a commercial historian:

- OSIsoft Inc., based in San Francisco, California (PI Historian)
- ADM System Engineering, based in Halifax, Nova Scotia (PI deployment)
- GCM Consulting, based in Montreal, Quebec (PI deployment)

For the PI Historian from OSIsoft, the budgetary quotation includes support for 200,000 tags:

- 100,000 tags to support 100,000 SCADA point values, and
- 100,000 tags to keep the corresponding quality (good data, bad data, telemetry fail, etc.)

The PI license and maintenance costs are based on the number of tags. As a result, the Owner may want to consider the follow options with regards to the number of PI tags in order to lower the license costs and support costs:

- Determine the relative importance of keeping the point quality with the point value. Not only does it double the number of tags, but trying to use the quality information in reports and displays makes them more complex to build.
- Consider purchasing a lesser quantity of tags initially (e.g. to support 50,000 SCADA points) and adding tags in the future as the need arises. Adding tags is very easy, and non-disruptive. This would lower the initial license costs and support costs considerably.

Activities to implement the commercial historian have been included in the project plan, and the budgetary estimate includes all hardware, software, and resources required for its successful implementation.

3.7.2 Control Room Facilities

Now that the large screen display at the front of the Control Room is no longer functional, there is no need for the operator desks to remain in their current configuration. Alternate configurations should be considered that may enhance interaction amongst the operators, as well as new ergonomic work stations that will better meet the goals of occupational health and safety, and improve productivity. The Control Room should also be refurbished to remove the large screen display and reclaim this space for the operators.

Activities have been included in the project plan, and a budgetary quotation for new control desks was received from Evans Consoles, an industry leader in control room furniture.

3.8 Maintenance and Support

The installation of a new SCADA system will require a software Maintenance and Support Agreement that includes product enhancements and bug fixes, as well as ensuring appropriate maintenance is performed on a regular basis to ensure compatibility with future operating system updates. Given the criticality of the system, the new support agreement for the SCADA application must cover the system 24/7/365. Maintenance and support for the hardware infrastructure should be similar.

Each of the SCADA Vendors has provided quotations for their standard Maintenance & Support Agreements. Following is a comparison of the services offered by each SCADA Vendor:

Table 3-3: Maintenance and Support Services

Maintenance and Support Services	Schneider	OSII	Survalent
Emergency Support	24x7x365	24x7x365	24x7x365
Standard Support (bug fixes, security flaws, etc.)	8:30AM - 5PM CST	8AM - 5PM EST	24x7x365
Web-based Trouble Ticket System	Yes	Yes	Yes
Technical Support Hours (per year)	40	0	0
On-Site Visit (1-week) (T&L excluded)	No	No	Yes
System Performance Audit (yearly)	Yes	No	Yes
Upgrade License for New Releases (installation excluded)	Yes	Yes	Yes
Refresher Training	No	Yes	Yes
Users Conference	Yes	Yes	Yes

4 Project Plan

A high-level project schedule is provided on page 4-36 showing the major activities related to the following components:

1. SCADA Request For Proposals (RFP)
2. SCADA System Replacement
3. Commercial Historian
4. Control Room Refurbishment

The following sections describe the various activities, dependencies, and resourcing requirements for each component.

4.1 SCADA Request For Proposals

An open bidding process will be used to select the new SCADA product. As such, the Owner will need to prepare a detailed technical and commercial specification, identify qualified vendors, issue a Request for Proposals, evaluate proposal responses, perform site visits for due diligence, then negotiate a statement of work and commercial contract with the selected vendor.

4.1.1 Major Activities

The SCADA RFP phase will take approximately 8 months to complete, as follows:

1. Four (4) months to develop the RFP specifications;
2. One (1) month for the vendors to submit proposals;
3. Two (2) months for site visits, proposal clarifications, and selection of finalist; and
4. One (1) month for statement of work and contract negotiations.

4.1.2 RFP Specifications

The RFP specifications will capture and define the scope of work as well as the terms and conditions that will govern the work. The RFP specifications will also provide instructions to the bidders for preparing their responses so as to ensure a fair bidding environment, and to facilitate the evaluation of proposal responses.

The following sections describe the various documents generally included in the Request for Proposals specifications.

1. **Letter of Invitation**

   This document is addressed to the Sales representative of each qualified bidder inviting them to submit proposals for the scope of work specified. This document generally includes a description of the structure of the RFP package attached to the letter so that the vendor can confirm they have received all relevant documents.

2. **Part 1 - Instruction to Bidders**

   This document provides information related to the RFP process and specific instructions for bidders to follow in submitting their responses. This includes:

   a. A description of the utility and a brief description of the scope of work,

   b. Protocol for data exchange between the Customer and bidders,

   c. Form and method of proposal submissions,

   d. Deadline for proposal clarification questions,

   e. Deadline for proposal delivery,

   f. Date and venue of the Proposal Meeting (if applicable),

   g. Bonds or guarantees to be provided with proposals,

   h. Bid validity requirements, and

   i. Any other information necessary for bidders to submit a qualifying proposal.

   In order to facilitate the evaluation process, all responses should follow the same structure and format as prescribed in the Instructions to Bidders. Forms and schedules to be completed by the bidders are included in the RFP package (see item 6 below).

3. **Part 2 - Terms and Conditions**

   This document contains the commercial terms and conditions under which the products and services are to be provided. These are generally utility-specific standard terms and conditions available from the procurement department. The terms and conditions may be adjusted by the procurement department depending on the nature of the products and services requested. Bidders will be asked to submit a Table of Compliance against the terms and conditions.

4. **Part 3 - Technical Specifications**

   This document contains the technical specifications for the product and services requested. In general this document is outlined as follows, and bidders will be asked to submit a Table of Compliance against each technical requirement:

   a. Introduction

      This section will provide a high-level overview of the project and its background, the project goals and objectives, characteristics of the transmission or distribution system, related projects, preferred implementation strategy, and system maintenance strategy.

b. System Architecture

This section will describe the conceptual system architecture of the system to be delivered and specify the requirements for redundancy and failover, external system interfaces, cyber security, system sizing, system performance, system monitoring, and system availability.

c. SCADA Functions

This section will specify the requirements for data acquisition, data processing, alarms and event processing, calculated points, control scripts, data exchange with external systems, historical data processing, and mapboard interface.

d. User Interface

This section will specify the requirements for user interface functions such as login/logout, areas of jurisdiction, privileges, layouts, fonts, data quality symbols, graphic displays, alarm displays, application displays, tabular displays, display building tools, display navigation, panning, zooming, display features, supervisory controls, control windows, tagging, trending, and study mode.

e. Advanced Functions

This section will specify the requirements for advanced functions, such as load shed and restoration, automatic generation control, capacitor control, and vol-var control.

f. Project Implementation

This section will specify the requirements for project structure and governance, project controls, project schedule, key milestones, database conversion, display conversion, documentation, quality assurance, acceptance testing, system installation, system commissioning, system cutover, and final acceptance criteria. This section will also identify the specific responsibilities of each party, and provide a detailed list of deliverables.

g. Training

This section will specify the training requirements, and identify the specific training courses to be provided during the project.

h. Maintenance and Support

This section will specify the maintenance and support requirements.

5. **Part 4 – Bidder Information**

This document contains a set of questions to further define the solution being proposed by each vendor. The questions are generally structured as follows:

a. Corporate

This section will ask bidders to describe their corporate structure, financial status, primary products and services offered, research and development expenditures, and differentiators.

b. Technical

This section will ask bidders to describe the characteristics of the solution proposed, such as system architecture, cyber security, SCADA, user interface, CIM, external system interfaces, network model, advanced applications, third-party software, database maintenance tools, display maintenance tools, and software configuration management.

c. Implementation

This section will ask bidders to describe their proposed solution as it relates to project management, key personnel, database creation and validation, display creation and validation, acceptance testing, deficiency tracking, documentation, training, installation, commissioning, and software configuration control.

d. Maintenance & Support

This section will ask bidders to describe their approach to maintenance and support of their product including product roadmaps, release schedules, user groups, and forums.

6. **Part 5 – Proposal Submission Forms and Schedules**

This document contains a set of forms and schedules to be used by bidders in preparing their proposal response. The forms and schedules are generally structured as follows:

a. Proposal Submission Form (includes vendor details, proposal checklist, signatures)

b. Table of Compliance Forms (technical and commercial)

c. Price / Payment Schedule

d. Bonds / Guarantees

e. Conflict of Information Statement Form

f. Requests for Clarification Form

A short-list of qualified vendors will be produced once proposals have been received. Site visits will be performed in order to assess each short-listed SCADA system in use at another electric utility in North America, and to assess the SCADA facilities of each short-listed vendor.

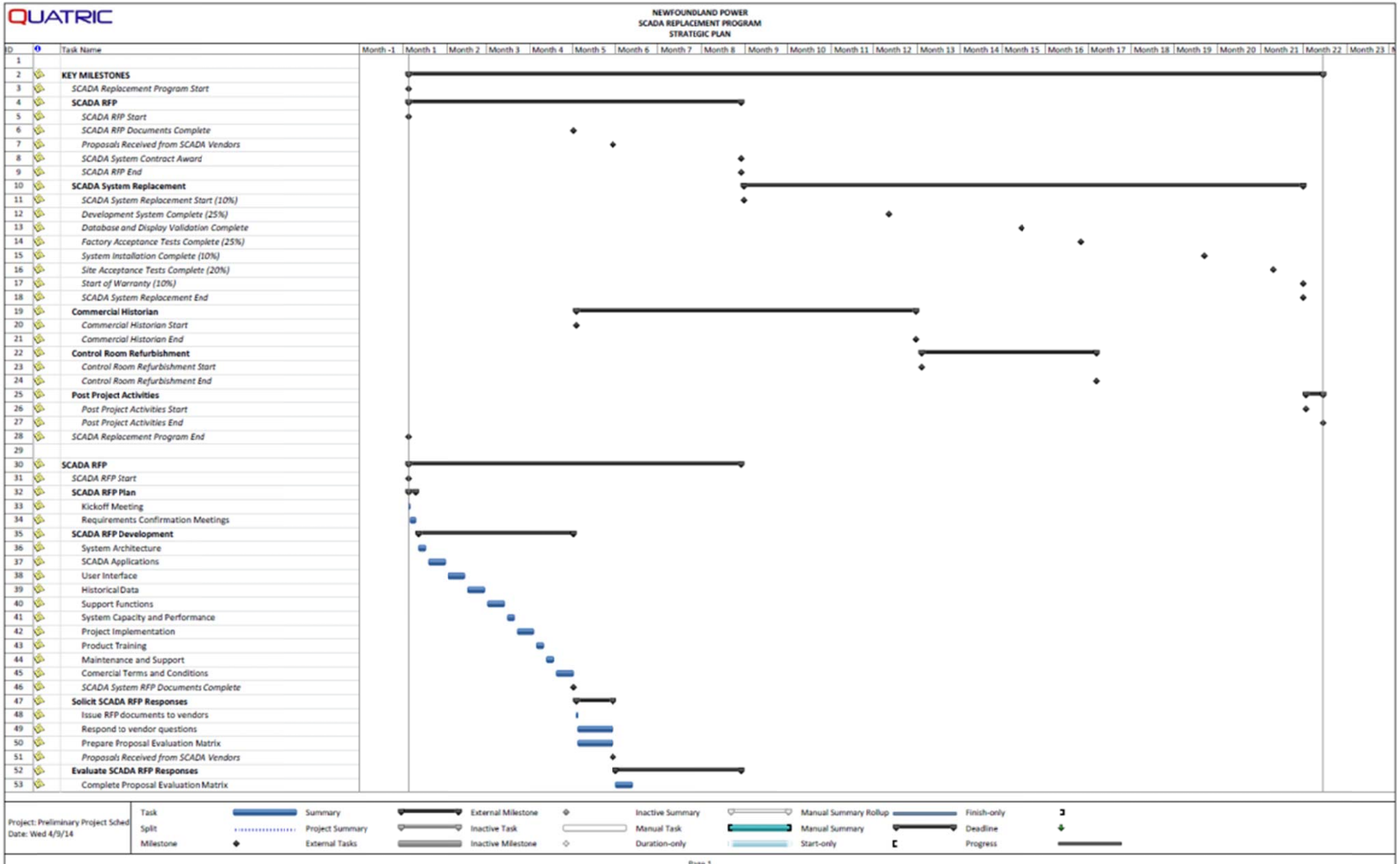
4.1.3 Resourcing

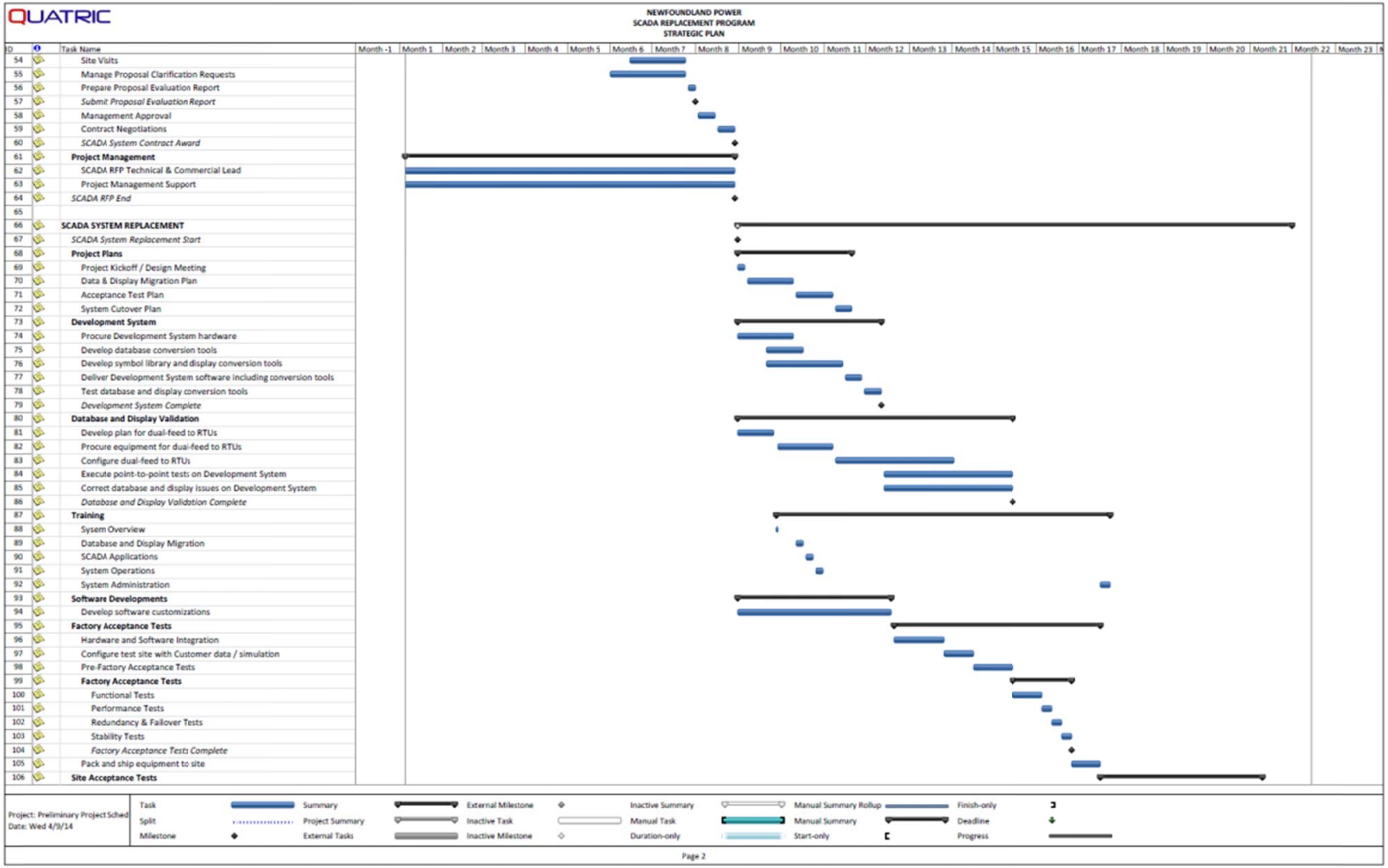
This Strategic Plan assumes that the development of the RFP specifications will be led by an external Consultant with experience developing SCADA RFP specifications, with support and input provided by the Owner's internal resources. Standard text and templates for the various specification documents will be provided by the Consultant, and will be updated to reflect the Owner's specific requirements.

The following roles will be required to support the RFP process (one person may be qualified to fulfill more than one of these roles):

1. **Project Manager**: Will be responsible for reviewing and specifying requirements for project implementation, coordinating the Owner's resources during RFP development, and negotiating the contract with the selected SCADA Vendor. Ideally this Project Manager will also manage the SCADA System Replacement once it has been awarded.
2. **SCADA Engineer**: Will be responsible for specifying and reviewing the requirements for the SCADA database, displays, configuration, and applications.
3. **System Administrator**: Will be responsible for reviewing and specifying requirements for the SCADA software installation and maintenance, including database and display conversion and maintenance.
4. **System Operator**: Will be responsible for reviewing and specifying requirements for SCADA user interface.
5. **RTU Engineer**: Will be responsible for reviewing and specifying the requirements for interfacing with the substations, including requirements for point-to-point testing.
6. **Communication Engineer**: Will be responsible for reviewing and specifying requirements for the communication network, including cyber security.
7. **Hardware Engineer**: Will be responsible for reviewing and specifying requirements for SCADA servers, workstations, SANs, operating systems, etc. to ensure that Corporate IT standards are maintained.
8. **SCADA Consultant**: Will lead the SCADA RFP development and produce the technical and commercial specifications. Will also lead the proposal evaluations, site visits, and proposal clarification questions. Will produce the Proposal Evaluation Report for review and approval by the Owner.

Figure 4-1: Project Schedule




QUATRIC
NEWFOUNDLAND POWER
SCADA REPLACEMENT PROGRAM
STRATEGIC PLAN
ID
Task Name
Month -1
Month 1
Month 2
Month 3
Month 4
Month 5
Month 6
Month 7
Month 8
Month 9
Month 10
Month 11
Month 12
Month 13
Month 14
Month 15
Month 16
Month 17
Month 18
Month 19
Month 20
Month 21
Month 22
Month 23
54 Site Visits
55 Manage Proposal Clarification Requests
56 Prepare Proposal Evaluation Report
57 Submit Proposal Evaluation Report
58 Management Approval
59 Contract Negotiations
60 SCADA System Contract Award
61 Project Management
62 SCADA RFP Technical & Commercial Lead
63 Project Management Support
64 SCADA RFP End
65
66 SCADA SYSTEM REPLACEMENT
67 SCADA System Replacement Start
68 Project Plans
69 Project Kickoff / Design Meeting
70 Data & Display Migration Plan
71 Acceptance Test Plan
72 System Cutover Plan
73 Development System
74 Procure Development System hardware
75 Develop database conversion tools
76 Develop symbol library and display conversion tools
77 Deliver Development System software including conversion tools
78 Test database and display conversion tools
79 Development System Complete
80 Database and Display Validation
81 Develop plan for dual-feed to RTUs
82 Procure equipment for dual-feed to RTUs
83 Configure dual-feed to RTUs
84 Execute point-to-point tests on Development System
85 Correct database and display issues on Development System
86 Database and Display Validation Complete
87 Training
88 Sysem Overview
89 Database and Display Migration
90 SCADA Applications
91 System Operations
92 System Administration
93 Software Developments
94 Develop software customizations
95 Factory Acceptance Tests
96 Hardware and Software Integration
97 Configure test site with Customer data / simulation
98 Pre-Factory Acceptance Tests
99 Factory Acceptance Tests
100 Functional Tests
101 Performance Tests
102 Redundancy & Failover Tests
103 Stability Tests
104 Factory Acceptance Tests Complete
105 Pack and ship equipment to site
106 Site Acceptance Tests
Project: Preliminary Project Sched
Date: Wed 4/9/14
Task
Split
Milestone
Summary
Project Summary
External Tasks
External Milestone
Inactive Task
Inactive Milestone
Inactive Summary
Manual Task
Duration-only
Manual Summary Rollup
Manual Summary
Start-only
Finish-only
Deadline
Progress
Page 2


NEWFOUNDLAND POWER
SCADA REPLACEMENT PROGRAM
STRATEGIC PLAN
ID
Task Name
Month -1
Month 1
Month 2
Month 3
Month 4
Month 5
Month 6
Month 7
Month 8
Month 9
Month 10
Month 11
Month 12
Month 13
Month 14
Month 15
Month 16
Month 17
Month 18
Month 19
Month 20
Month 21
Month 22
Month 23
107 Hardware installation
108 Software installation and configuration
109 System Installation Complete
110 Database and display conversion
111 Site Acceptance Tests
112 Site Acceptance Tests Complete
113 System Cutover
114 Final database and display conversion
115 System Cutover
116 Parallel Operation
117 Start of Warranty
118 Project Management
119 SCADA Project Manager
120 SCADA Project Consultant
121 SCADA System Replacement End
122
123 COMMERCIAL HISTORIAN
124 Commercial Historian Start
125 Procurement
126 Develop Requests for Proposals
127 Solicit Proposal Responses
128 Evaluate Proposal Responses
129 Commercial Historian Contract Negotiations
130 Commercial Historian Contract Award
131 Implementation
132 System Installation, Configuration and Training
133 Migrate existing historical data to PI
134 Develop Corporate Reports & Displays
135 Project Management
136 Commercial Historian Technical Lead
137 Project Management Support
138 Commercial Historian End
139
140 CONTROL ROOM REFURBISHMENT
141 Control Room Refurbishment Start
142 Design & Construction
143 Develop control room design
144 Solicit quotations for products and services
145 Construction
146 Project Management
147 Project Manager
148 Control Room Refurbishment End
149
150 POST PROJECT ACTIVITIES
151 Post Project Activities Start
152 Decommission old SCADA hardware
153 Project Management
154 Project Manager
155 SCADA Project Consultant
156 Post Project Activities End
Project: Preliminary Project Sched
Date: Wed 4/9/14
Task
Split
Milestone
Summary
Project Summary
External Tasks
External Milestone
Inactive Task
Inactive Milestone
Inactive Summary
Manual Task
Duration-only
Manual Summary Rollup
Manual Summary
Start-only
Finish-only
Deadline
Progress
Page 3

4.2 SCADA System Replacement

Regardless of the SCADA vendor selected, the sequence of events for the replacement of the SCADA system will be similar. This Strategic Plan is based on a 12-month schedule for the SCADA System Replacement, which is in line with the budgetary estimates provided by the SCADA Vendors which ranged from 9 months to 12 months.

4.2.1 Major Activities

The SCADA System Replacement phase is divided into the following major components:

1. **Project Plans**: Although the plans will be developed by the SCADA Vendor, the Owner's resources will be required to review and approve these critical documents.
2. **Development System**: A Development System will need to be delivered to the Owner early in the project in order to allow the Owner to verify and validate the database and display conversion. The Owner will need to work closely with the SCADA Vendor to support the development of the database and display conversion tools.
3. **Database and Display Validation**: Point-to-point testing will be performed on a subset of the SCADA points in order to assess the quality of the database and display conversion process. The Development System from item 2 will be used for this purpose, but dual feeds to the substation RTUs will need to be configured prior to running the tests. These activities will be executed primarily by the Owner's resources, with support provided by the SCADA Vendor if required.
4. **Training**: Training for the Owner's resources will be conducted in a timely manner such that the training is provided "just-in-time". For example, user training for the System Operators will be provided prior to the Factory Acceptance Tests.
5. **Software Developments**. It is recognized that some software customizations will be required to satisfy all of the Owner's requirements. This activity will be undertaken by the SCADA Vendor based on inputs received during the project planning phase.
6. **Factory Acceptance Tests**: In order to ensure that the new SCADA system satisfies all of the Owner's requirements prior to being installed on-site, a Factory Acceptance Test will be executed by the SCADA Vendor. The Owner's resources will travel to the SCADA Vendor's factory to witness the execution of the acceptance test procedures. The tests should include functional tests, performance tests, redundancy and failover tests, and stability tests.
7. **Site Acceptance Tests**: Once the system has been accepted at the SCADA Vendor's factory, the system will be shipped to the Owner's site, installed, and configured. To ensure the system functions correctly with all of the Owner's interfaces, a Site Acceptance Test will be conducted by the Owner and supported by the SCADA Vendor.
8. **System Cutover**: Once the new SCADA system has been certified in the new environment, a final database and display conversion will be performed and the system cutover. The old SCADA

system will not be decommissioned until after a stability period (parallel run), typically 10 days, of uninterrupted execution.

9. **Post Project Activities**: Once the Owner is satisfied with the operation of the new SCADA system, the old SCADA system will be decommissioned. This involves removing the servers, workstations, cables, etc. and recycling the material.

4.2.2 Resourcing

The following roles will be required to support the SCADA System Replacement (one person may be qualified to fulfill more than one of these roles):

1. **Project Manager**: Will be responsible for overall project implementation and status reporting, managing the project budget, coordinating the Owner's resources, and managing the SCADA Vendor, managing risks, and resolving conflicts.
2. **SCADA Engineer**: Will be responsible for verifying and validating the SCADA database, displays, configuration, and applications.
3. **System Administrator**: Will be responsible for verifying and validating the SCADA software installation and maintenance procedures, including database and display conversion and maintenance procedures, and point-to-point testing procedures..
4. **System Operator**: Will be responsible for verifying and validating the SCADA user interface.
5. **RTU Engineer**: Will be responsible for configuring dual ports to each substation RTU for point-to-point testing.
6. **Communication Engineer**: Will be responsible for verifying and validating the communication network infrastructure, including cyber security, and assisting the RTU Engineer to implement dual ports to each substation RTU.
7. **Hardware Engineer**: Will be responsible for verifying and validating the SCADA servers, workstations, SANs, operating systems, etc. to ensure that Corporate IT standards are maintained. Will also procure the hardware that is not provided by the SCADA Vendor.
8. **SCADA Consultant**: The SCADA Consultant will assist the project team with the implementation of the SCADA replacement. Activities will include participation in all project meetings and conference calls, reviewing project documents, participating in the acceptance tests, and providing guidance to the project team.

4.3 Commercial Historian

This Strategic Plan is based on acquiring the software licenses for the commercial historian directly from the manufacturer (e.g. OSIsoft), and using a system integrator with experience with the commercial historian to install, configure, and deploy the software for the Owner. The system integrator will also provide hands-on training for the first 10 corporate displays and reports so that the Owner can then complete the corporate reports and displays.

The Owner has a preference to implement the Commercial Historian in 2015, interfacing with the existing SCADA System initially, and then migrating the interface to the new SCADA system when it is commissioned in 2016.

4.3.1 Major Activities

The Commercial Historian phase is divided into the following major activities:

1. **Procurement**: Once the specifications for the SCADA System Replacement are complete and issued to the qualified SCADA Vendors, the RFP for the Commercial Historian can be started. The timeframe is much shorter since there are fewer requirements and fewer suppliers. Once proposals have been received, a contract will be negotiated for the agreed scope of work.
2. **Implementation**: The Owner will be responsible for procuring the hardware for the commercial historian based on the specifications from the software manufacturer (e.g. OSIsoft). The hardware will be installed directly on-site and the System Integrator will travel to the Owner's site to install and configure the historian software. The Current Vendor will be engaged to install their native interface to the commercial historian. The System Integrator will then migrate the existing historical data and provide hands-on training to the Owner's resources. The Owner will then complete the development of the corporate reports and displays.

4.3.2 Resourcing

The following roles will be required to support the Commercial Historian (one person may be qualified to fulfill more than one of these roles):

1. **Project Manager**: Will be responsible for overall project implementation and status reporting, coordinating the Owner's resources, and managing the suppliers.
2. **SCADA Engineer**: Will be responsible for reviewing the historical data migration, building and validating the corporate reports and displays.
3. **System Administrator**: Will be responsible for supporting the historical data migration, validating the software installation and configuration, and maintaining the commercial historian system.
4. **SCADA Consultant**: The SCADA Consultant will assist the project team with the selection and implementation of the commercial historian. Activities will include development of the RFP specifications and evaluation of proposals.

4.4 Control Room Refurbishment

The primary goal of the control room refurbishment is to remove the obsolete large screen display and to re-allocate and re-fresh the control room floor space to enhance interaction amongst the Operators and Dispatchers, as well as provide new ergonomic work stations that will better meet the goals of occupational health and safety, and improve productivity.

4.4.1 Major Activities

The Control Room Refurbishment phase is divided into the following major activities:

1. **Develop control room design**: A plan for the floor space will be developed in order to identify an optimal layout and to identify the materials (furniture, carpet, etc.) that will be required.
2. **Solicit quotations for products and services**: Quotes for the various products and services needed for the refurbishment of the control room will be obtained and rationalized to ensure the budget is respected.
3. **Construction**: The construction phase is expected to take approximately 6 weeks.

4.4.2 Resourcing

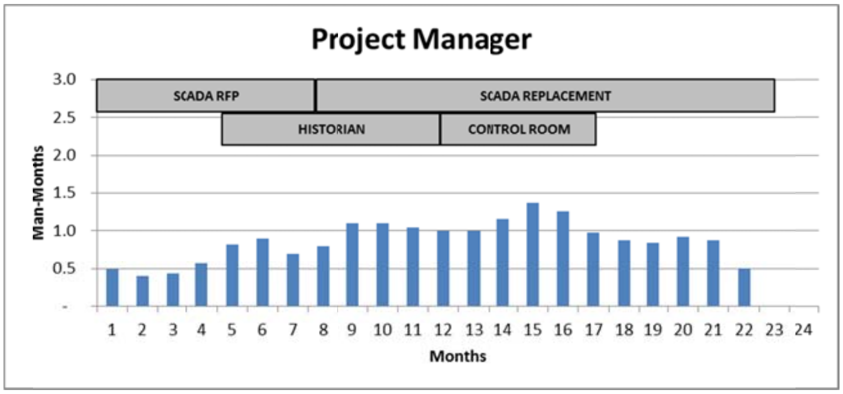
The following roles will be required to support the Control Room Refurbishment (one person may be qualified to fulfill more than one of these roles):

1. **Project Manager**: Will be responsible for overall project implementation and status reporting, coordinating the Owner's resources, and managing the suppliers.
2. **System Operators**: Will be consulted to ensure the planned refurbishment will meet their expectations and requirements.
3. **Control Room Consultant**: The Control Room Consultant will assist the project team with the design and implementation of the control room refurbishment. The Control Room Consultant will have experience designing control rooms for electric utilities, and understand the ergonomic and human factors for work space layout.
4. **Construction Contractors**: Construction contractors will be engaged to refurbish the control room. The Owner's facilities team should be consulted for recommended contractors that have done business with the Owner and have a good business relationship with the Owner.

4.5 Manloading

In order to implement the SCADA Replacement Project, the Owner will need to assign operational and IT resources to execute the various activities as outlined in this Strategic Plan. Some resources will need to devote more time to project activities than others, and as a result the Owner will need to ensure that its staffing plan will support the SCADA Replacement project. The following sections identify the various resource requirements during all phases of the project:

1. **Project Manager**: A Project Manager with SCADA experience will need to be assigned to the project full-time, and the budgetary estimate assumes that an internal resource will be used to fill this role. If an internal resource is not available, an external consultant could be used to fill this role, but the labour rate in the budgetary estimate would need to be adjusted to reflect this human resourcing strategy.

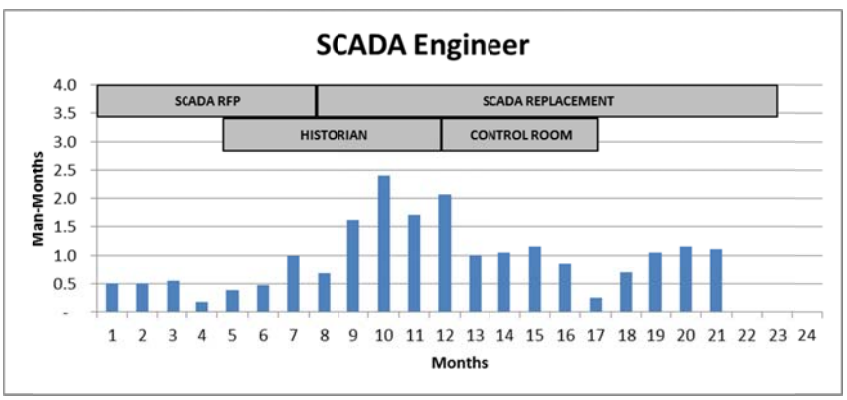


2. **SCADA Engineer**: The SCADA Engineering activities vary during the course of the project and result in the following requirements:

    a. One (1) SCADA Engineer will need to be assigned to the project on a part-time basis (half-time) for the first six (6) months to support the SCADA RFP effort. This requirement can likely be filled with existing resources.

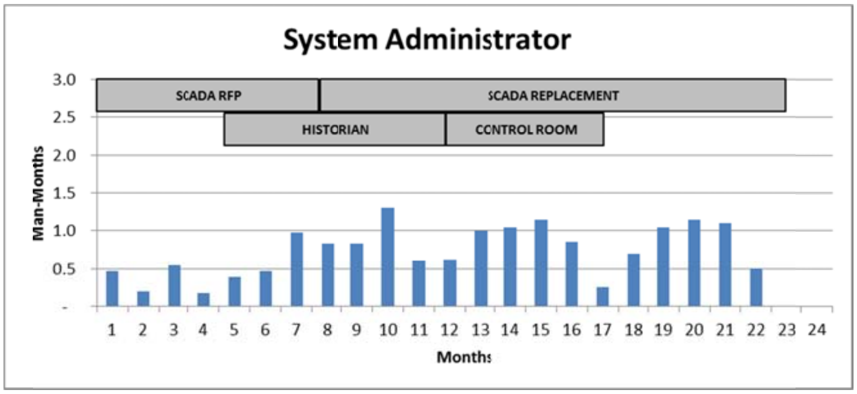
    b. Two (2) full-time SCADA Engineers will be needed months 9 through 12 for database and display conversion, and to develop the commercial historian displays and reports.

    c. One (1) SCADA Engineer will be required for the remainder of the project for acceptance testing, system installation, and commissioning.

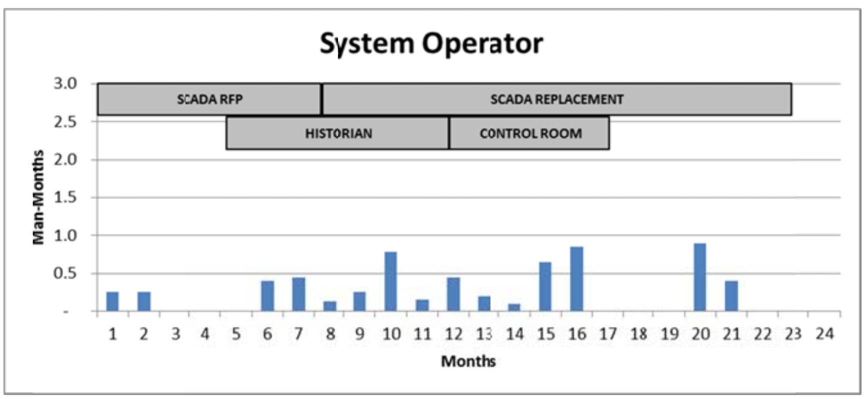


Since the current SCADA Engineer is occupied full-time on the existing SCADA System, additional resources will be needed to support the project. This is a common issue with SCADA replacement projects, and utilities often assign the existing SCADA Engineer to work on the new SCADA System, and bring in temporary resources to perform the SCADA engineering activities on the old SCADA system, and to develop corporate displays and reports. This allows the SCADA Engineer to acquire hands-on experience with the new SCADA system prior to system cutover.

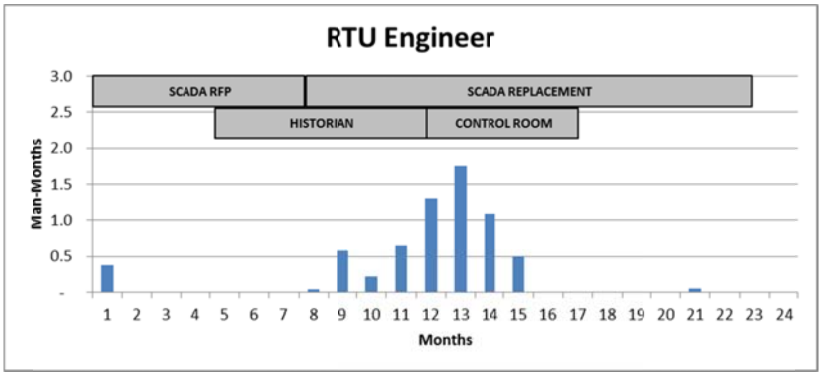
3. **System Administrator**: A System Administrator will need to be assigned to the project on a part-time basis (half-time) for the first six (6) months, averaging out to a full-time position for the remainder of the project. As with the SCADA Engineer, utilities often assign the existing System Administrator to work on the new SCADA System, and bring in a temporary resource to perform the system administration activities on the old SCADA system. This allows the System Administrator to acquire hands-on experience with the new SCADA system prior to system cutover.



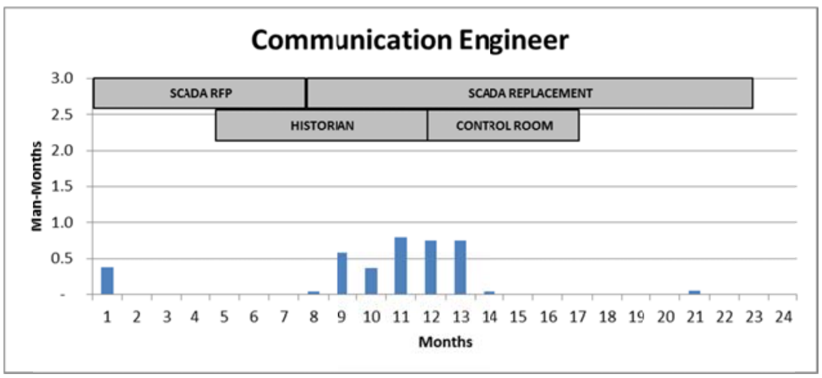
4. **System Operator**: Participation of a System Operator will be sporadic throughout the project, providing inputs during the SCADA RFP phase, and participating in the acceptance testing of the new system. These activities can be performed by existing resources.



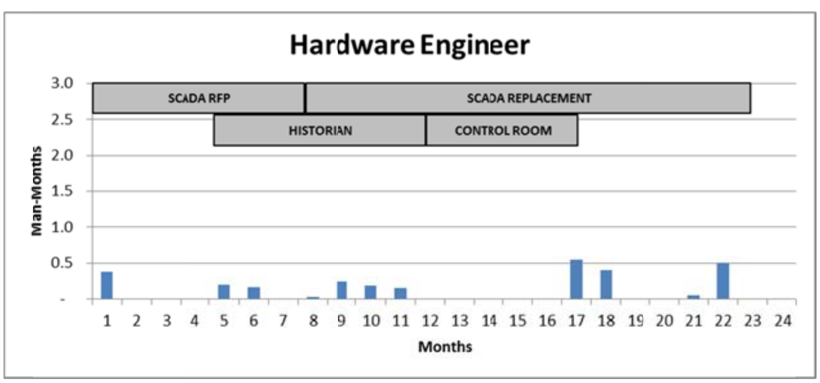
5. **RTU Engineer**: Participation of an RTU Engineer will be required briefly at the beginning to provide requirements for point-to-point testing, then concentrated in months 12 through 14 to configure dual ports on the substation RTUs. These activities can likely be performed by existing resources, provided the work is planned well in advance.



6. **Communication Engineer**: Participation of a Communication Engineer will be sporadic throughout the project, providing inputs during the SCADA RFP phase, and participating in the configuration of dual ports on the substation RTUs. These activities can be performed by existing resources.



7. **Hardware Engineer**: Participation of a Hardware Engineer will be sporadic throughout the project, providing inputs during the SCADA RFP phase, procuring hardware, acceptance testing, and decommissioning the old SCADA system. These activities can be performed by existing resources.



5 Budgetary Cost Estimates

The following budgetary estimate is based on a detailed analysis of the activities and resources required to execute the SCADA Replacement project.

SCADA System Replacement	$4,300,000
Commercial Historian	$976,000
Control Room Refurbishment	$399,000
TOTAL BUDGETARY ESTIMATE (CAD)	**$5,675,000**

These estimates are based on the following global parameters:

SCADA Project Contingency	15%
Commercial Historian Contingency	15%
Control Room Refurbishment Contingency	15%
Project Cost of Capital	6.0%
USD-CAD Exchange Rate	1.10

Details of the individual estimates is provided in the following sections. The Microsoft Excel spreadsheet and Microsoft Project schedule showing the activities, resources, and dependencies have been provided separately.

5.1 SCADA System Replacement

In order to support the estimates for the SCADA System Replacement, budgetary quotations were solicited from the following organizations:

1. Schneider Electric (Houston, Texas) – SCADA System
2. Open Systems International Inc. (OSII) (Minneapolis, Minnesota) – SCADA System
3. Survalent Technology (Mississauga, Ontario) – SCADA System

Following is a summary of the budgetary quotations received from the SCADA Vendors:

Table 5-1: SCADA Vendor Budgetary Quotations

SCADA VENDOR BUDGETARY QUOTES	Schneider	OSII	Survalent
Hardware	$497,600	$305,266	$244,000
Standard Product Licenses	$699,300	$850,000	$429,000
Standard Product Deployment	$740,000	$650,000	$190,000
Data Conversion Tools and Services	$62,000	$64,000	$40,000
Display Conversion Tools and Services	$64,000	$64,000	$50,000
Software Customizations	$115,000	$0	$80,000
Training & Workshops	$97,000	$41,125	$26,000
Travel & Living Costs	INCLUDED	$35,000	INCLUDED
Warranty	$103,000	$28,250	INCLUDED
Maintenance and Support - Year 1	$140,000	$101,250	$24,429
TOTAL	**$2,517,900**	**$2,138,891**	**$1,083,429**

Estimates were adjusted to ensure they offered comparable functionality and performance, and an average of the budgetary quotation components was used as the basis for this budgetary estimate. In addition, to calculate the cost of capital, the following payment milestones were assumed:

- SCADA System Replacement Start (10%)
- Development System Complete (25%)
- Factory Acceptance Tests Complete (25%)
- System Installation Complete (10%)
- Site Acceptance Tests Complete (20%)
- Start of Warranty (10%)

Internal efforts were estimated based on the project plan presented in Section 4, Project Plan.

Table 5-2: SCADA System Replacement Budgetary Estimate

SCADA System Replacement	Total
SCADA Request for Proposals Costs	
SCADA RFP - Engineering Labour	$99,600
SCADA RFP - Internal Labour	$42,840
SCADA RFP - Contract Labour	$0
SCADA RFP - Other Labour (Consultants)	$217,600
SCADA RFP - Travel & Living	$47,500
Subtotal SCADA Request for Proposals Costs	**$407,540**
SCADA Vendor Deployment Costs	
SCADA Vendor - Material (hardware, third-party software, etc.)	$349,000
SCADA Vendor - Standard Product Licenses	$659,500
SCADA Vendor - Standard Product Deployment	$526,700
SCADA Vendor - Data Conversion Tools and Services	$55,400
SCADA Vendor - Display Conversion Tools and Services	$59,400
SCADA Vendor - Software Customizations - Development and Deployment	$97,500
SCADA Vendor - Training & Workshops	$54,800
SCADA Vendor - Travel & Living Costs	$35,000
SCADA Vendor - Warranty	$65,700
SCADA Vendor – Maintenance & Support (Year 1)	$88,600
Subtotal SCADA Vendor Deployment Costs	**$1,991,600**
NP SCADA Deployment Costs	
NP SCADA - Material (hardware, third-party software, etc.)	$301,000
NP SCADA - Engineering Labour	$426,080
NP SCADA - Internal Labour	$178,440
NP SCADA - Contract Labour	$0
NP SCADA - Other Labour (Consultants)	$190,600
NP SCADA - Travel & Living (Project Meetings, Testing, Training)	$56,000
Subtotal NP SCADA Deployment Costs	**$1,152,120**
SCADA System Replacement Subtotal	**$3,551,260**
SCADA System Replacement Contingency	$533,400
SCADA System Replacement Cost of Capital	$214,736
SCADA SYSTEM REPLACEMENT TOTAL (ROUNDED UP)	**$4,300,000**

5.2 Commercial Historian

Budgetary quotations were solicited from the following organizations to support this estimate:

1. OSIsoft – PI Historian
2. ADM System Engineering – PI Historian Implementation
3. GCM Consulting - PI Historian Implementation

An average of the budgetary quotations received from the suppliers was used as the basis for this budgetary estimate.

Table 5-3: Commercial Historian Budgetary Estimate

Commercial Historian	Total
PI Integrator Deployment Costs	
PI Integrator - Material	$0
PI Integrator - Deployment Costs	$61,000
PI Integrator - Training & Workshops	$0
PI Integrator - Travel & Living	$12,000
Subtotal PI Integrator Deployment Costs	**$73,000**
NP PI Deployment Costs	
NP PI - Material (hardware, third-party software, etc.)	$574,368
NP PI - Engineering Labour	$92,480
NP PI - Internal Labour	$18,660
NP PI - Contract Labour	$0
NP PI - Other Labour (Consultants)	$65,200
NP PI - Travel & Living (Project Meetings, Testing, Training)	$0
Subtotal NP PI Deployment Costs	**$750,708**
Commercial Historian Subtotal	**$823,708**
Commercial Historian Contingency	$124,000
Commercial Historian Cost of Capital	$27,707
COMMERCIAL HISTORIAN TOTAL (ROUNDED UP)	**$976,000**

5.3 Control Room Refurbishment

Budgetary quotations were solicited from the following organizations to support this estimate:

1. Evans Consoles – Control Room Desks

Table 5-4: Control Room Refurbishment Budgetary Estimate

Control Room Refurbishment	Total
Control Room - Materials (furniture, desks, carpet, etc.)	$260,767
Control Room - Engineering Labour	$19,280
Control Room - Internal Labour	$2,880
Control Room - Contract Labour	$28,800
Control Room - Other Labour (Consultants, etc.)	$19,200
Subtotal Control Room Refurbishment	**$330,927**
Control Room Refurbishment Subtotal	**$330,927**
Control Room Refurbishment Contingency	$49,800
Control Room Refurbishment Cost of Capital	$17,993
CONTROL ROOM REFURBISHMENT TOTAL (ROUNDED UP)	**$399,000**

5.4 Maintenance and Support

All of the SCADA Vendors offer varying levels of software support for their product. The following tables provide the annual maintenance support costs over the first 5 years.

Table 5-5: Maintenance and Support Budgetary Estimates

Maintenance and Support Costs	Schneider	OSII	Survalent
Maintenance and Support - Year 1	$140,000	$101,250	$24,429
Maintenance and Support - Year 2	$144,200	$106,313	$24,429
Maintenance and Support - Year 3	$148,500	$111,628	$24,429
Maintenance and Support - Year 4	$153,000	$117,210	$24,429
Maintenance and Support - Year 5	$157,600	$123,070	$24,429
TOTAL MAINTENANCE AND SUPPORT COSTS	**$743,300**	**$559,471**	**$122,145**

5.5 Options

SCADA Vendors were asked to provide budgetary quotes for their Outage Management System software and Operator Training Simulator software for consideration by the Owner. The following budgetary estimates were provided:

Table 5-6: Options Budgetary Estimates

Options	Schneider	OSII	Survalent
Outage Management System	$260,000	$309,150	$250,000
Operator Training Simulator	$48,000	$101,290	$30,000
TOTAL OPTIONS	**$308,000**	**$410,440**	**$280,000**

6 Next Steps

Following are the recommended next steps for the SCADA Replacement Project:

1) Submit capital budget request in the 2015 Capital Budget Application.
2) Organize vendor presentations to review products and services. Suggested vendors include:
    a) Open Systems International (OSII) (SCADA)
    b) Schneider Electric (SCADA)
    c) Survalent Technology (SCADA)
    d) OSIsoft (PI Historian)
    e) ADM System Engineering (PI Integration)
3) Conduct site visits at other Canadian electric utilities to assess their tools (SCADA, historian, OMS, GIS, etc.), control room facilities, and support structure. Project references have been provided for the following Canadian utilities that are of similar size to the Owner:
    a) Eastern Canada
        i) Newfoundland & Labrador Hydro, St. John's, Newfoundland (OSI Monarch SCADA)
        ii) Nova Scotia Power (OSI Monarch SCADA / Schneider ADMS)
    b) Central Canada / USA
        i) Duke Progress Energy, Raleigh, North Carolina (Schneider ADMS)
        ii) PowerStream, Vaughan, Ontario (Survalent SCADA)
        iii) Austin Energy, Austin, Texas (Schneider ADMS)
    c) Western Canada
        i) ENMAX, Calgary, Alberta (Survalent SCADA)
        ii) ATCO Electric, Vegreville, Alberta (OSI Monarch SCADA)
        iii) Fortis BC, Trail, British Columbia (Survalent SCADA)
4) Review internal staffing options for key project positions.
5) Identify possible SCADA Consultants to assist the Owner with the project implementation.

Geographical Information System Improvements

Prepared By:

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NEWFOUNDLAND POWER
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1.0 Introduction

Newfoundland Power operates over 300 distribution feeders, representing over 9,500 kilometres of distribution lines. It is important that accurate records be kept of the current state of the electrical system and that this information is available to all field and technical employees at all times.[1]

The Company's geographical information system ("GIS") provides a central database for storage of distribution asset information. This enables information to be updated and available in a more efficient and timely manner, and also reduces the inherent inefficiencies that exist with maintaining multiple systems.

As part of Newfoundland Power's 2015 Capital Budget Application, the Company will complete 2 projects related to the GIS system to (i) improve how electrical system information is distributed and presented to crews in the field, and (ii) add information about customer location and electrical connectivity.

2.0 Background

In 2013, the Company completed a project to streamline the manual processes used to maintain and distribute information associated with the Company's distribution assets.[2] This project included the purchase of a GIS application, known as *ArcFM*, to store and display information about the geographic location and electrical connectivity of the Company's distribution network. Although GIS is a new technology for Newfoundland Power, it is commonly used in the electrical utility industry.[3]

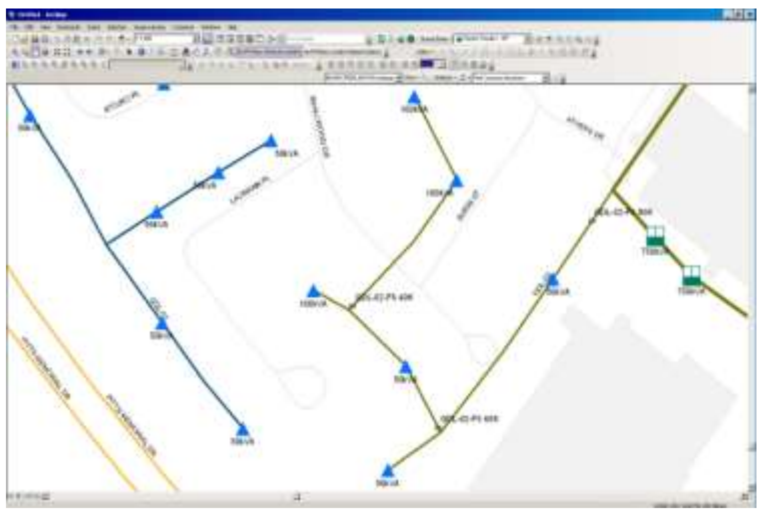

Figure 1: GIS displays primary distribution lines, protective devices and transformers.

The GIS currently stores information about distribution poles, primary conductor, switches and transformers. This information includes equipment specifications as well as geographical location.[4] The GIS system also maintains electrical connectivity information for these assets.

1 Crews responding to outages must know the current configuration of the distribution network to troubleshoot and restore power in a safe and timely manner.

2 This project was completed as part of the Company's 2013 Capital Budget Application, ***7.1** Application Enhancements*.

3 Newfoundland Power conducted a 2014 survey of CEA utilities, in which 94% of respondents use a GIS system. See Appendix A for survey results.

4 Equipment specifications stored in the GIS include pole height and classification, conductor size and materials, transformer kVA ratings, etc.

This information allows users to, for example, determine the nearest upstream isolation switch from a piece of equipment or identify downstream sections of distribution lines affected by the operation of a switch.

3.0 GIS Mobile Project *($158,000)*

There are currently 2 ways in which field staff can view information contained within the GIS database.[5] When connected to a wireless network, the data can be viewed through a web browser interface using computers in line trucks.[6] This interface displays electrical system connectivity and provides the ability to search for locations of street addresses or switching devices. As a backup to the web browser interface, field staff can view PDF representations of the GIS database when connection to the wireless network is not available.[7] These PDFs have limited functionality and do not display pole, streetlight or meter location data.

Both methods of displaying the GIS database only provide a one-directional view of the electrical distribution network. There is currently no method for crews to update the GIS database from the field. This limits the ability of field staff to make updates to the GIS database when errors are discovered, or when unplanned changes are made to the distribution network, such as during outage calls or storm events.

In 2015, the Company will improve how information about electrical system connectivity is distributed and presented to crews in the field to ensure the information is up-to-date and available at all times. Ease of access to this information through a graphical user interface increases the efficiency of work, including line patrols and electrical switching during storm situations and system events.[8] Also, this information must be available to crews at all times to ensure consistency of service under all operating conditions.

This project will include the installation and configuration of software on computers in line trucks that will provide crews with access to location data for the company's distribution network, both in a connected and disconnected state.[9] The project will also provide field staff with the ability to update GIS information in the field, increasing the timeliness of updates and reducing the manual effort required to update this data.

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5 Due to limitations in the wireless network service available throughout the Company's service territory, computers in line trucks have to operate while connected and disconnected from the wireless network.

6 Wireless network access is available in locations in Newfoundland with adequate cellular coverage. All of the Company's line trucks are equipped with a cellular modem to access the cellular network.

7 Portable Document Format ("PDF") is an open standard for electronic document exchange. Created by Adobe, it is a common file format used to present documents in a manner independent of application software, hardware, and operating systems.

8 This is particularly valuable for crews travelling between operating areas who may be less familiar with the service territory. This occurs regularly under normal system operations, and is more common when the Company is responding to storm situation and system events.

9 Viewing GIS data in a disconnected state is accomplished by storing a copy of the GIS database locally on the device. This copy will be synchronized with the master GIS database on a regular basis.

This project will provide an annual savings of approximately $32,500 due to the increased efficiency in updating the GIS. This project has a net present value of approximately $36,000 over an expected application life-cycle of 10 years.[10]

4.0 Customer Connectivity Project (*$275,000*)

The GIS currently maintains electrical connectivity information from the substation feeder breaker to the distribution transformer, as shown in Figure 2 below. The original source for this information was the Company's distribution modeling software, *CYME*.[11] Information about pole locations and specifications is provided from Bell Aliant's GIS database.[12] The majority of utilities have a GIS system which contains electrical connectivity information to the customer premise, as shown in Figure 3 below.[13] Although the Company's GIS is capable of storing information about which customers are connected to the transformer, there is no source available for this information and, therefore it must be collected from the field.[14]

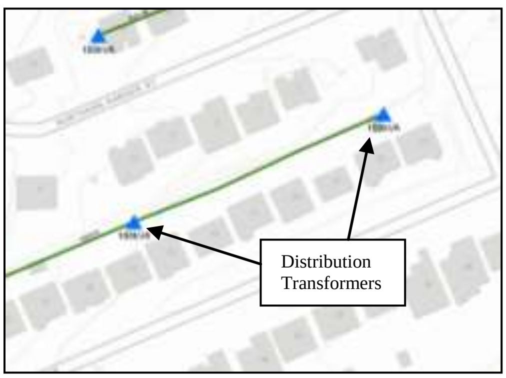

Figure 2: The Company's GIS currently stores information on primary conductor, switches and transformers.

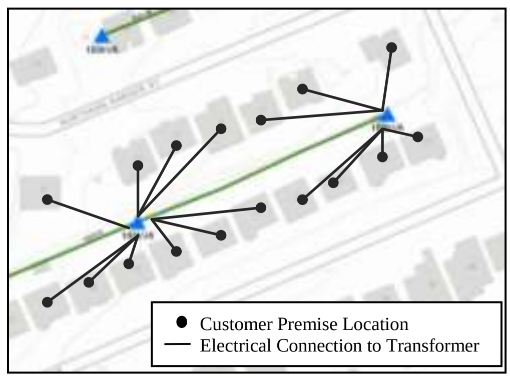

Figure 3: Customer premise locations and electrical connectivity will be added to the GIS

Electrical connectivity information provides a number of opportunities to improve overall service to customers, particularly when responding to outages. For example, when a power outage occurs affecting multiple customers, the Company will typically receive multiple reports of power outages from the affected customers and multiple outage tickets will be created. These outage tickets are grouped and dispatched to a field crew as a single job.[15] However, grouping

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10 The net present value calculation for this project can be found on page B-1 of Appendix B.

11 CYME software is a tool used to complete network modeling and load flow analysis on the electrical system.

12 Pole locations and specification information was collected in a survey completed as part of the Bell Aliant pole sale in 2012. As part of the Joint Use Agreement, Bell Aliant is responsible for storing and maintaining the pole information inside of its own GIS.

13 Newfoundland Power conducted a 2014 survey of CEA utilities in which 88% of respondents maintain electrical connectivity information to the customer premise. See Appendix A for survey results.

14 The Company's Customer Service System ("CSS") was designed over 20 years ago and predates commercial GIS applications for utilities. As a result the CSS database was never designed to store GIS type data on customer locations and electrical connectivity information.

15 Each year, approximately 4,300, or 25% of individual outage tickets are related to outages affecting multiple customers and must be manually grouped and dispatched.

outage tickets requires an understanding of the electrical system to determine which outages are related, particularly for outages not affecting the entire feeder.[16] As a result this is a manual process that requires a high degree of operational experience to complete.[17] Electrical connectivity information from a GIS can be used to visually represent which outages are related. This will reduce the amount of time it takes to analyze, prioritize and dispatch crews to an outage, which is critical in responding to customers without power.

In 2015, the Company will complete a field survey of approximately half of all customer premises and add the electrical connectivity information of its customers to the GIS database. This will also include integration between the GIS and CSS to ensure that customer information updates in CSS will automatically update the GIS and become immediately available to field staff.

The expanded use of GIS technology in field operations is principally aimed at improved customer service. The use of GIS technology by field crews will enable faster response times to customer outages, along with a reduction in the amount of time necessary to analyze the cause of these customer outages.[18] The expanded use of GIS technology in the Customer Contact Centre will provide the agent with more customer specific information regarding the customer's connection to the electricity network. Also, the GIS technology will provide the Company with the ability to customize messaging for planned and unplanned work affecting customers. This customized messaging can be communicated to customers through automated telephone technology or Internet base websites and social media.[19]

The expanded use of GIS technology will also have associated improvements in productivity. When completed, this project will provide an annual savings of approximately $73,000 as a result of increased efficiency in managing and responding to customer outages alone.[20] This aspect of the project has a net present value of approximately $21,000 over an expected application life-cycle of 10 years.[21]

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16 Within its CSS database, the Company maintains a record of the feeder that supplies each customer. This allows contact center staff to be aware if a customer calling to report an outage has been affected by a full feeder outage. However, the Company does not maintain a record of distribution protection devices that exist between the customer's location and the substation feeder breaker, or a record of which distribution transformer connects the customer to the distribution network.

17 Enhancements were made to the Company's outage management application in 2012 to simplify the process of grouping outage tickets; however it remains a manual process.

18 The visual representation of the network connectivity will assist field staff in quickly identifying the network component that is common to all customers experiencing an outage.

19 The connectivity information will also be used to support the Customer Outage Communication and Notification item included in the Information Systems Applications Enhancements project. Details can be found in the report ***6.1** Application Enhancements*. The customer outage communication and notification item allows customers to receive notifications of feeder level outages. As connectivity information is assembled in the GIS these notifications can be extended to outages affecting only sections of a feeder.

20 The operating savings includes reduced crew time responding to customer outages, during regular shifts and overtime, as well as reduced clerical time in analyzing and grouping outage tickets.

21 The net present value calculation for this project can be found on page B-2 of Appendix B. This value is, in the Company's view, quite conservative given the very long-term benefits of a GIS database. In addition, the value does not attempt to capture all future benefits. For example, the GIS database improvements will ultimately enable more efficient customer service in terms of scheduling new connections; these types of longer term efficiencies have not been valued in this analysis.

5.0 Project Cost

Table 1 summarizes the cost associated with this project.

Table 1
Geographical Information System Improvement
2015 Project Cost
($000s)

Cost Category	2015 Cost
Material	15
Labour – Internal	258
Labour – Contract	-
Engineering	50
Other	110
Total	**433**

6.0 Concluding

GIS technology will be an important tool in improving overall efficiency in the Company's field operations. Providing improved functionality to crews in the field will help improve data management, eliminate redundancies and enhance decision making.

Adding customer premise locations and electrical connectivity information, and integrating the GIS with CSS will improve overall service to customers by reducing outage response time and providing better information to customers. This information will also provide the necessary data should the Company implement a fully automated outage management system in the future, capable of automatically predicting which protective devices operated, dispatching crews and notifying affected customers.

Appendix A
Summary of GIS Survey Results

Summary of GIS Survey Results

	Responded Yes
Does your utility currently maintain a GIS?	94%
Which assets do you currently track within your GIS?	
Substations	88%
Poles	94%
Guy Wires	71%
Primary Conductors	94%
Switching Devices	94%
Transformers	94%
Underground Manholes/Duct Banks	94%
Streetlights	71%
Secondary/Service Conductors	82%
Customer Premise Locations	88%
Does your GIS maintain connectivity information through to the customer premise location?	88%

In April 2014 the Company completed a survey of CEA utilities to determine which utilities use a GIS and what asset information they store inside their GIS. In total, 17 utilities responded.

Appendix B
Net Present Value Analysis

GIS Mobile Project

		Capital Impacts						Operating Cost Impacts						
		Capital Additions		CCA Tax Deductions				Cost Increases		Cost Benefits				
	YEAR	New Software A	New Hardware B	Software	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	2015	($158,000)	$0	$79,000	$0		$79,000	$0	$0	$16,250	$0	$16,250	$18,198	($123,553)
1	2016	$0	$0	$79,000	$0		$79,000	$0	($8,160)	$33,475	$0	$25,315	$15,569	$40,884
2	2017	$0	$0	$0	$0		$0	$0	($8,323)	$34,479	$0	$26,156	($7,585)	$18,571
3	2018	$0	$0	$0	$0		$0	$0	($8,490)	$35,514	$0	$27,024	($7,837)	$19,187
4	2019	$0	$0	$0	$0		$0	$0	($8,642)	$36,579	$0	$27,937	($8,102)	$19,835
5	2020	$0	$0	$0	$0		$0	$0	($8,805)	$37,676	$0	$28,872	($8,373)	$20,499
6	2021	$0	$0	$0	$0		$0	$0	($8,969)	$38,807	$0	$29,837	($8,653)	$21,185
7	2022	$0	$0	$0	$0		$0	$0	($9,134)	$39,971	$0	$30,837	($8,943)	$21,895
8	2023	$0	$0	$0	$0		$0	$0	($9,304)	$41,170	$0	$31,866	($9,241)	$22,625
9	2024	$0	$0	$0	$0		$0	$0	($9,480)	$42,405	$0	$32,925	($9,548)	$23,377
10 Yr	Present Value (See Note I)	@		6.05%										$35,892

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 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.

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.

Customer Connectivity Project

		Capital Impacts						Operating Cost Impacts						
		Capital Additions		CCA Tax Deductions				Cost Increases		Cost Benefits				
	YEAR	New Software A	New Hardware B	Software	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	2015	($275,000)	$0	$137,500	$0		$137,500	$0	$0	$18,000	$0	$18,000	$34,655	($222,345)
1	2016	($267,500)	$0	$3,750	$0		$3,750	$0	$0	$55,620	$0	$55,620	($15,042)	($226,922)
2	2017	$0	$0	$401,250	$0		$401,250	$0	$0	$77,446	$0	$77,446	$93,903	$171,349
3	2018	$0	$0	$0	$0		$0	$0	$0	$79,769	$0	$79,769	($23,133)	$56,636
4	2019	$0	$0	$0	$0		$0	$0	$0	$82,162	$0	$82,162	($23,827)	$58,335
5	2020	$0	$0	$0	$0		$0	$0	$0	$84,627	$0	$84,627	($24,542)	$60,085
6	2021	$0	$0	$0	$0		$0	$0	$0	$87,166	$0	$87,166	($25,278)	$61,888
7	2022	$0	$0	$0	$0		$0	$0	$0	$89,781	$0	$89,781	($26,036)	$63,744
8	2023	$0	$0	$0	$0		$0	$0	$0	$92,474	$0	$92,474	($26,818)	$65,657
9	2024	$0	$0	$0	$0		$0	$0	$0	$95,248	$0	$95,248	($27,622)	$67,626
10 Yr	Present Value (See Note I)	@		6.05%										$21,104

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 Newfoundland Power's Labour Escalation Rate. The non-labour costs are escalated to current year using the GDP Deflator Index.
E is the reduced operating costs. 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.
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.

Rate Base:
Additions, Deductions & Allowances

June 2014

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1.0 Introduction

1.1 General

In the 2015 Capital Budget Application (the "Application"), Newfoundland Power seeks final approval of its 2013 average rate base. This is consistent with current regulatory practice before the Board.

Newfoundland Power's 2013 average rate base of $915,820,000 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 affect 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 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 result 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 is provided in this report. This includes two historical years, the current year and following year. The 2014 and 2015 forecast rate base additions and deductions reflect the Company's most recent forecasts and estimates. In addition, 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 2012 and 2013 and the forecast additions for 2014 and 2015.

Table 1
Additions to Rate Base
2012-2015F
($000s)

	2012	2013	2014F	2015F
Deferred Pension Costs	100,113	101,159	103,831	109,147
Credit Facility Issue Costs	239	-	-	-
Cost Recovery Deferral – Seasonal/TOD Rates	93	95	80	86
Cost Recovery Deferral – Hearing Costs	-	644	322	-
Cost Recovery Deferral – Regulatory Amortizations	3,320	2,214	1,107	-
Cost Recovery Deferral – 2012 Cost of Capital	1,766	1,177	589	-
Cost Recovery Deferral – 2013 Revenue Shortfall	-	2,252	1,126	-
Cost Recovery Deferral – Conservation	227	2,085	4,912	7,548
Customer Finance Programs	1,446	1,363	1,450	1,450
Total Additions	107,204	110,989	113,417	118,231

Additions to rate base were approximately $111.0 million in 2013. This is approximately $3.8 million more than 2012. The higher additions to rate base through 2013 reflect (i) an increase in deferred pension costs; (ii) the deferred recovery of 2013 hearing costs[1]; (iii) the deferred recovery of a 2013 revenue shortfall[2]; and, (iv) the deferred recovery of annual customer energy

[1] In Order No. P.U. 13 (2013), the Board approved the deferred recovery over a three year period, beginning in 2013, external costs related to the Company's 2013 General Rate Application.

[2] In Order No. P.U. 13 (2013), the Board approved the amortization over three years, commencing in 2013, of the 2013 revenue shortfall resulting from the implementation of new customer rates after January 1, 2013.

conservation program costs.[3]

This section outlines the additions to rate base in further detail.

2.2 Deferred Pension Costs

Table 2 shows details of changes in Newfoundland Power's deferred pension costs from 2012 through 2015.

Table 2
Deferred Pension Costs
2012-2015F
($000s)

	2012	2013	2014F	2015F
Deferred Pension Costs	100,113	101,159	103,831	109,147

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).[4]

Table 3 shows details of changes in Newfoundland Power's deferred pension costs from 2012 through 2015.

Table 3
Deferred Pension Costs
2012-2015F
($000s)

	2012	2013	2014F	2015F
Deferred Pension Costs, January 1st	97,628	100,113	101,159	103,831
Pension Plan Funding[5]	13,638	13,791	13,755	13,836
Pension Plan Expense	(11,153)	(12,745)	(11,083)	(8,520)
Deferred Pension Costs, December 31st	100,113	101,159	103,831	109,147

3 In Order No. P.U. 13 (2013), the Board approved the deferral of annual customer energy conservation program costs and the amortization of annual costs over seven years with recovery through the Rate Stabilization Account.

4 Deferred pension costs were approved for inclusion in average rate base in Order No. P.U. 19 (2003).

5 Pension funding for 2012 and 2013 includes special funding payments of $10.7 million based on the latest actuarial information. Special funding payments of $10.7 million are also expected in 2014 and 2015.

2.3 Credit Facility Costs

In Order P.U. 1 (2005), the Board approved Newfoundland Power's issue of a $100 million committed revolving term credit facility.

On March 27th, 2012, the committed credit facility was renegotiated on similar terms as the previous facility, with a decrease in pricing, and an extension to a five year term maturing in August 2017. Legal and other administration costs of $115,000 resulting from the amendment are being amortized over the life of the agreement beginning in April 2012.

In Order No. P.U. 23 (2013), the Board approved Newfoundland Power's return on rate base for 2013 and 2014, which includes credit facility issue costs.

For the 2013 and 2014 test years, the unamortized credit facility costs are included as a component of the Company's weighted average cost of capital and are therefore reflected in the rate of return on rate base for those years. Consequently, they are not included in the calculation of average rate base for 2013 and 2014.

Table 4 shows details of Newfoundland Power's amortization of deferred credit facility issue costs for 2012.

Table 4
Deferred Credit Facility Issue Costs
2012
($000s)

	2012
Balance, January 1st	270
Cost	115
Amortization	(146)
Balance, December 31st	239

2.4 Cost Recovery Deferral – Seasonal/TOD Rates

In Order No. P.U. 8 (2011), the Board approved the Optional Seasonal Rate Revenue and Cost Recovery account.

This account is charged with: (i) the current year revenue impact of making the Domestic Seasonal – Optional Rate available to customers and (ii) the operating costs associated with implementing the Domestic Seasonal - Optional and the Time-of-Day Rate Study.

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 of any balance in this account.

Table 5 shows details of the Optional Seasonal Rate Revenue and Cost Recovery account for 2012 through 2015.

Table 5
Seasonal/TOD Rates
2012-2015F
($000s)

	2012	2013	2014F	2015F
Balance, January 1st	228	93	95	80
Additions	93	95	80	86
Reductions	(228)	(93)	(95)	(80)
Balance, December 31st	93	95	80	86

2.5 Cost Recovery Deferral - Hearing Costs

In Order No. P.U. 43 (2009), the Board approved the deferred recovery over a three year period, beginning in 2010, of $750,000 in external costs related to the Company's 2010 General Rate Application. The deferred hearing costs were fully amortized in 2012.

In Order No. P.U. 13 (2013), the Board approved the deferred recovery over a three year period, beginning in 2013, of external costs related to the Company's 2013 General Rate Application. The actual external costs incurred for the 2013 General Rate Application were $965,000. The deferred hearing costs will be fully amortized in 2015.

Table 6 shows details of the changes in Newfoundland Power's deferred hearing costs from 2012 through 2015.

Table 6
Deferred Hearing Costs
2012-2015F
($000s)

	2012	2013	2014F	2015F
Balance, January 1st	253	-	644	322
Cost	-	965	-	-
Amortization	(253)	(321)	(322)	(322)
Balance, December 31st	-	644	322	-

2.6 Cost Recovery Deferral - 2010 Regulatory Amortizations

In Order No. P.U. 30 (2010), the Board approved the deferred recovery in 2011, until a further Order of the Board, of $2.4 million in costs ($1.6 million after-tax) related to the expiry of certain regulatory amortizations in 2010.

In Order No. P.U. 22 (2011), the Board approved the deferred recovery in 2012, until a further Order of the Board, of $2.4 million in costs ($1.7 million after-tax) related to the expiry of certain regulatory amortizations in 2010.

In Order No. P.U. 13 (2013), the Board approved, with effect from January 1, 2013, the amortization of these deferrals over three years using the straight-line method, commencing in 2013.

Table 7 shows the cost recovery deferral and its amortization for 2012 through 2015 related to the expiry of regulatory amortizations in 2010.

Table 7
Cost Recovery Deferral - Regulatory Amortizations
2012-2015F
($000s)

	2012	**2013**	**2014F**	**2015F**
Balance, January 1st	1,642	3,320	2,214	1,107
Cost	1,678	-	-	-
Amortization	-	(1,106)	(1,107)	(1,107)
Balance, December 31st	3,320	2,214	1,107	-

2.7 Cost Recovery Deferral - 2012 Cost of Capital

In Order No. P.U. 17 (2012) the Board approved the deferred recovery of the amount of the difference in revenue for 2012 relating to the determination of Newfoundland Power's 2012 cost of capital of $2.5 million ($1.8 million after-tax).

In Order No. P.U. 13 (2013), the Board approved, with effect from January 1, 2013, the amortization of the deferral over three years using the straight-line method, commencing in 2013.

Table 8 shows the 2012 cost of capital deferral for 2012 and its amortization for 2013 through 2015.

Table 8
Cost Recovery Deferral - 2012 Cost of Capital
2012-2015F
($000s)

	2012	2013	2014F	2015F
Balance, January 1st	-	1,766	1,177	589
Cost	1,766	-	-	-
Amortization	-	(589)	(588)	(589)
Balance, December 31st	1,766	1,177	589	-

2.8 Cost Recovery Deferral - 2013 Revenue Shortfall

In Order No. P.U. 13 (2013), the Board approved the proposed amortization over three years, commencing in 2013, of the 2013 revenue shortfall resulting from the implementation of new rates after January 1, 2013.[6]

In Order No. P.U. 23 (2013), the Board approved the revenue shortfall in the amount of $4.0 million (2.8 million after-tax).

Table 9 shows the revenue shortfall for 2013 and its amortization for 2013 through 2015.

Table 9
Cost Recovery Deferral – 2013 Revenue Shortfall
2012-2015F
($000s)

	2012	2013	2014F	2015F
Balance, January 1st	-	-	2,252	1,126
Cost	-	2,815	-	-
Amortization	-	(563)	(1,126)	(1,126)
Balance, December 31st	-	2,252	1,126	-

[6] Per Order No. P.U. 13 (2013), amortization will be from the effective date of the new rates (July 1, 2013) to December 31, 2015, using the straight-line method.

2.9 Cost Recovery Deferral - Conservation

Table 10 shows details of forecast amortization of the deferred cost recovery related to conservation for 2012 through 2015.

Table 10
Cost Recovery Deferral - Conservation
2012-2015F
($000s)

	2012	**2013**	**2014F**	**2015F**
Balance, January 1st	454	227	2,085	4,912
Cost	-	2,085	3,125	3,381
Amortization	(227)	(227)	(298)	(745)
Balance, December 31st	227	2,085	4,912	7,548

In Order No. P.U. 13 (2009), the Board approved the deferred recovery of certain forecast 2009 conservation costs. These costs totalled $948,000 on an after-tax basis in 2009.

In Order No. P.U. 43 (2010), the Board approved the after-tax recovery of 2009 deferred conservation costs evenly over a four year period beginning in 2010. The deferral will be fully amortized in 2013.

In Order No. P.U. 13 (2013), the Board approved the deferral of annual customer energy conservation program costs and the amortization of annual costs over seven years with recovery through the Rate Stabilization Account.

2.10 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 11 shows details of changes to balances related to customer finance programs for 2012 through 2015.

Table 11
Customer Finance Programs
2012-2015F
($000s)

	2012	2013	2014F	2015F
Balance, January 1st	1,527	1,446	1,363	1,450
Change	(81)	(83)	87	-
Balance, December 31st	1,446	1,363	1,450	1,450

3.0 Deductions from Rate Base

3.1 Summary

Table 12 summarizes Newfoundland Power's deductions from rate base for 2012 and 2013 and the Company's forecasts for 2014 and 2015.

Table 12
Deductions from Rate Base
2012-2015F
($000s)

	2012	2013	2014F	2015F
Weather Normalization Reserve	4,803	5,058	2,090	-
Other Post Employment Benefits ("OPEBs")	14,617	23,515	31,820	39,463
Customer Security Deposits	851	840	800	800
Accrued Pension Obligation	4,020	4,325	4,684	5,080
Accumulated Deferred Income Taxes	2,504	1,872	2,197	3,718
Demand Management Incentive Account	558	(272)	152	-
Total Deductions	27,353	35,338	41,743	49,061

Deductions from rate base were approximately $35.3 million in 2013. Newfoundland Power's deductions from rate base in 2013 have increased approximately $8.0 million from 2012. The reduction in rate base primarily reflects the amortization of the OPEB regulatory asset[7] and amortization of the employee future benefits regulatory asset[8] related to OPEBs.

This section outlines the deductions from rate base in further detail.

3.2 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.

In Order No. P.U. 32 (2007), the Board approved a five year recovery of a $6.8 million balance in the Weather Normalization Reserve beginning in 2008. This was fully amortized in 2012.

In Order No. P.U. 13 (2013), the Board approved the disposition of the annual balance in the Weather Normalization Reserve Account through the Rate Stabilization Account. The board also approved, with effect from January 1, 2013, the amortization over three years, commencing in 2013, of the 2011 year-end balance in the Weather Normalization Reserve Account of $5.0 million.

Table 13 shows details of changes in the balance of the Weather Normalization Reserve from 2012 through 2015.

Table 13
Weather Normalization Reserve
2012-2015F
($000s)

	2012	**2013**	**2014F**	**2015F**
Balance, January 1st	(5,020)	(4,803)	(5,058)	(2,090)
Operation of the reserve	1,580	(1,712)	(417)	-
Transfers to the RSA	-	(216)	1,712	417
Amortization	(1,363)	1,673	1,673	1,673
Balance, December 31st	(4,803)	(5,058)	(2,090)	-

In Order No. P.U. 11 (2014) the Board approved the December 31, 2013 positive balance of $5,058,185 in the Weather Normalization Reserve.

[7] 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.

[8] 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.

3.3 Other Post Employment Benefits

Newfoundland Power's other post employment benefits ("OPEBs") are comprised of retirement allowances for retiring employees as well as health, medical and life insurance for retirees and their dependents.

In Order No. P.U. 31 (2010), the Board approved, beginning in 2011, the adoption of the accrual method of accounting for OPEBs and related income tax. In addition, the Board approved a 15-year straight line amortization of a transitional balance starting in 2011.

In Order No. P.U. 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 14 shows details of the changes related to the net OPEBs liability from 2012 through 2015.

Table 14
Other Post Employment Benefits
2012-2015F
($000)

	2012	2013	2014F	2015F
Regulatory Asset	83,064	73,105	67,525	62,131
OPEB Liability	97,681	96,620	99,345	101,594
Net OPEBs Liability	14,617	23,515	31,820	39,463

3.4 Customer Security Deposits

Customer security deposits are provided by customers in accordance with the Schedule of Rates, Rules and Regulations.

Table 15 shows details on the changes in customer security deposits from 2012 through 2015.

Table 15
Customer Security Deposits
2012-2015F
($000)

	2012	2013	2014F	2015F
Balance, January 1st	695	851	840	800
Change	156	(11)	(40)	-
Balance, December 31st	851	840	800	800

3.5 Accrued Pension Obligation

Accrued pension obligation is the cumulative costs of Newfoundland Power's unfunded pension plans net of associated benefit payments.

Table 16 shows details of changes related to accrued pension obligation for 2012 through 2015.

Table 16
Accrued Pension Obligation
2012-2015F
($000)

	2012	**2013**	**2014F**	**2015F**
Balance, January 1st	3,778	4,020	4,325	4,684
Change	242	305	359	396
Balance, December 31st	4,020	4,325	4,684	5,080

3.6 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,[9] pension costs[10] and other employee future benefit costs.[11]

9 In Order No's. P.U. 20 (1978), P.U. 21 (1980) and P.U. 17 (1987), the Board approved the Company's use of the Tax Accrual Accounting to recognize deferred income tax liabilities associated with plant investment.

10 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.

11 In Order No. P.U. 31 (2010), the Board approved the use of tax accrual accounting to recognize deferred income taxes related to timing differences between other employee future benefits recognized for tax purposes (cash payments) and other employee future benefit expense recognized for accounting purposes (accrual basis).

Table 17 shows details of changes in the accumulated deferred income taxes from 2012 through 2015.

Table 17
Accumulated Deferred Income Taxes
2012-2015F
($000)

	2012	**2013**	**2014F**	**2015F**
Balance, January 1st	862	2,504	1,872	2,197
Change	1,642	(632)	325	1,521
Balance, December 31st	2,504	1,872	2,197	3,718

3.7 Demand Management Incentive Account

In Order No. P.U. 32 (2007) the Board approved the Demand Management Incentive Account (the "DMI Account") to replace the Purchase Power Unit Cost Variance Reserve.

Table 18 shows details of the DMI Account from 2012 through 2015.

Table 18
DMI Account
2012-2015F
($000)

	2012	**2013**	**2014F**	**2015F**
Balance, January 1st	1,252	558	(272)	152
Transfers to the RSA	(1,252)	(558)	272	(152)
Operation of DMI	558	(272)	152	-
Balance, December 31st	558	(272)	152	-

In Order No. P.U. 7 (2014), the Board approved a debit transfer to the RSA at March 31, 2014, of $383,085 equal to the balance in the DMI account for 2013 and related income tax effects.

4.0 Rate Base Allowances

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.

4.1 Cash Working Capital Allowance

The cash working capital allowance recognizes that a utility must finance the cost of its operations until it collects the revenues to recover those costs.

Table 19 shows details on changes in the cash working capital allowance from 2012 through 2015.

Table 19
Rate Base Allowances
Cash Working Capital Allowance[12]
2012-2015F
($000)

	2012	2013	2014F	2015F
Gross Operating Costs	447,918	467,036	478,166	480,353
Income Taxes	7,755	(1,999)	12,418	9,592
Municipal Taxes Paid	14,507	15,625	15,731	15,933
Non-Regulated Expenses	1,090	11,364	(1,674)	(1,851)
Total Operating Expenses	471,270	492,026	504,641	504,027
Cash Working Capital Factor	2.0%	1.73%	1.69%	1.69%
	9,425	8,512	8,528	8,518
HST Adjustment	386	(1,986)	(2,180)	(2,180)
Cash Working Capital Allowance	9,811	6,526	6,348	6,338

4.2 Materials and Supplies Allowance

Including a materials and supplies allowance in rate base provides a utility a means to reasonably recover the cost of financing its inventories that are not related to the expansion of the electrical system.[13]

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12 The cash working capital allowance for 2012 is calculated based on the method used to calculate the 2010 Test Year average rate base approved by the Board in Order No. P.U. 43 (2009). The cash working capital allowance for 2013 through 2015 is calculated based on the method used to calculate the 2013/2014 Test Year average rate base approved by the Board in Order No. P.U. 13 (2013).

13 Financing costs for inventory related to the expansion of the electrical system are recovered through the use of an allowance for funds used during construction and are capitalized upon project completion.

Table 20 shows details on changes in the materials and supplies allowance from 2012 through 2015.

Table 20
Rate Base Allowances
Materials and Supplies Allowance
2012-2015F
($000)

	2012	2013	2014F	2015F
Average Materials and Supplies	6,682	7,029	7,633	7,584
Expansion Factor[14]	20.2%	22.53%	22.53%	22.53%
Expansion	1,350	1,584	1,720	1,709
Materials and Supplies Allowance	5,332	5,445	5,913	5,875

14 The expansion factor is based on a review of actual inventories used for expansion projects. The calculation of the 2012 rate base including a materials and supplies allowance based upon an expansion factor of 20.2% was approved by the Board in Order No. P.U. 43 (2009). The calculation of the 2013 through 2015 rate base including a materials and supplies allowance based upon an expansion factor of 22.53% was approved by the Board in Order No. P.U. 13 (2013).