NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

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DELIVERED BY HAND

June 28, 2013

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 2014 Capital Budget Application

A. 2014 Capital Budget Application

Enclosed are the original and 10 copies of Newfoundland Power Inc.'s (the "Company") 2014 Capital Budget Application and supporting materials (the "Filing").

The Filing outlines a proposed 2014 Capital Budget totaling $84,462,000 including $3,853,000 in capital expenditures approved by the Board in Order No. P.U. 31 (2012). In addition, the Filing seeks approval of a 2012 rate base in the amount of $883,045,000.

B. Compliance Matters

B.1 Board Orders

In Order No. P.U. 31 (2012) (the "2013 Capital Order"), the Board required a progress report on 2013 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. *2013 Capital Expenditure Status Report*: this meets the requirements of the 2013 Capital Order;

2. *2014 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.

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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 *2014 Capital Plan* provides a breakdown of the overall 2014 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

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Newfoundland Power Inc.
2014 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 2014 Capital Budget of $84,462,000; and
(b) fixing and determining a 2012 rate base of $883,045,000

2014 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 2014 Capital Budget of $84,462,000; and
(b) fixing and determining a 2012 rate base of $883,045,000

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 2014 Capital Budget in the amount of $84,462,000, 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 2014. 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 2014 Capital Budget are required.

4. Schedule C to this Application is a list of multi-year projects that are ongoing. The 2014 Capital Budget includes forecast capital expenditures of $3,865,000 for projects that were approved by the Board in Order No. P.U. 31 (2012).

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 2012 of $883,045,000.

7. Communication with respect to this Application should be forwarded to the attention of Ian Kelly, Q.C. 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 2014 of the improvements and additions to its property in the amount of $84,462,000 as set out in Schedules A and B to the Application; and

   (b) pursuant to Section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2012 in the amount of $883,045,000 as set out in Schedule D to the Application.

DATED at St. John's, Newfoundland and Labrador, this 28th day of June, 2013.

NEWFOUNDLAND POWER INC.

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

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

IN THE MATTER OF 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 2014 Capital Budget of $84,462,000; and
(b) fixing and determining a 2012 rate base of $883,045,000

AFFIDAVIT

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

1. That I am Vice President, Regulation and Planning 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 28th day of June, 2013:

Barrister

Peter Alteen

2014 CAPITAL BUDGET SUMMARY

Asset Class	Budget (000s)
1. Generation - Hydro[1]	$ 9,010
2. Generation - Thermal	312
3. Substations	16,865
4. Transmission[2]	5,469
5. Distribution	40,270
6. General Property	1,112
7. Transportation	2,570
8. Telecommunications	99
9. Information Systems	4,005
10. Unforeseen Allowance	750
11. General Expenses Capitalized	4,000
Total	**$ 84,462**

[1] Includes $3,495,000 in expenditures approved in Order No. P.U. 31 (2012).
[2] Includes $358,000 in expenditures approved in Order No. P.U. 31 (2012).

2014 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[3]
1. Generation – Hydro		
Facility Rehabilitation	$ 1,610	2
Hydro Plant Production Increase	1,665	4
Heart's Content Plant Refurbishment[4]	5,735	6
Total Generation – Hydro	**$ 9,010**	
2. Generation – Thermal		
Facility Rehabilitation Thermal	$ 312	10
Total Generation – Thermal	**$ 312**	
3. Substations		
Substations Refurbishment and Modernization	$ 6,023	13
Replacements Due to In-Service Failures	2,859	15
Additions Due to Load Growth	5,004	17
PCB Bushing Phase-out	2,733	19
Hardwoods Substation Feeder Termination	246	22
Total Substations	**$16,865**	
4. Transmission		
Transmission Line Rebuild[5]	$ 5,469	25
Total Transmission	**$ 5,469**	

3 Project descriptions can be found in Schedule B at the page indicated.
4 Includes $3,495,000 in expenditures approved in Order No. P.U. 31 (2012).
5 Includes $358,000 in expenditures approved in Order No. P.U. 31 (2012).

2014 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	**Budget (000s)**	**Description[6]**
5. Distribution		
Extensions	$ 11,689	29
Meters	2,755	31
Services	3,930	34
Street Lighting	2,480	37
Transformers	6,995	40
Reconstruction	3,787	42
Rebuild Distribution Lines	3,462	44
Relocate/Replace Distribution Lines for Third Parties	2,616	47
Trunk Feeders	1,261	49
Feeder Additions for Growth	1,102	51
Allowance for Funds Used During Construction	193	53
Total Distribution	**$ 40,270**	
6. General Property		
Tools and Equipment	$ 458	56
Additions to Real Property	379	59
Standby and Emergency Power – Gander Office	275	61
Total General Property	**$ 1,112**	
7. Transportation		
Purchase Vehicles and Aerial Devices	$ 2,570	64
Total Transportation	**$ 2,570**	

[6] Project descriptions can be found in Schedule B at the page indicated.

2014 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[7]
8. Telecommunications		
Replace/Upgrade Communications Equipment	$ 99	68
Total Telecommunications	**$ 99**	
9. Information Systems		
Application Enhancements	$ 1,372	71
System Upgrades	1,059	73
Personal Computer Infrastructure	420	75
Shared Server Infrastructure	833	78
Network Infrastructure	321	80
Total Information Systems	**$ 4,005**	
10. Unforeseen Allowance		
Allowance for Unforeseen Items	$ 750	83
Total Unforeseen Allowance	**$ 750**	
11. General Expenses Capitalized		
General Expenses Capitalized	$ 4,000	85
Total General Expenses Capitalized	**$ 4,000**	

[7] Project descriptions can be found in Schedule B at the page indicated.

2014 CAPITAL PROJECTS SUMMARY

2014 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 2014 Capital Project Summary provides a summary of the planned capital expenditures contained in Newfoundland Power's 2014 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
2014 Capital Projects by Definition
(000's)

Clustered	**$9,025**	**Page**
Distribution	**1,104**	
Feeder Additions for Growth	507	51
Trunk Feeders	597	49
Substations	**6,735**	
Additions Due to Load Growth	5,004	17
Substations Refurbishment & Modernization	1,485	13
Hardwoods Substation Feeder Termination	246	22
Transmission	**1,186**	
Transmission Line Rebuild	1,186	25

Pooled	**$68,747**	**Page**
Distribution	**39,166**	
Allowance for Funds Used During Construction	193	53
Extensions	11,689	29
Feeder Additions for Growth	595	51
Meters	2,755	31
Rebuild Distribution Lines	3,462	44
Reconstruction	3,787	42
Relocate/Replace Distribution Lines for Third Parties	2,616	47
Services	3,930	34
Street Lighting	2,480	37
Transformers	6,995	40
Trunk Feeders	664	49
General Property	**837**	
Additions to Real Property	379	59
Tools and Equipment	458	56
Generation-Hydro	**7,345**	
Facility Rehabilitation	1,610	2
Heart's Content Plant Refurbishment	5,735	6
Generation-Thermal	**312**	
Facility Rehabilitation Thermal	312	10
Information Systems	**4,005**	
Application Enhancements	1,372	71
Network Infrastructure	321	80
Personal Computer Infrastructure	420	75
Shared Server Infrastructure	833	78
System Upgrades	1,059	73

Pooled (continued)		**Page**
Substations	**10,130**	
PCB Bushings Phase-out	2,733	19
Replacements Due to In-Service Failures	2,859	15
Substations Refurbishment & Modernization	4,538	13
Telecommunications	**99**	
Replace/Upgrade Communications Equipment	99	68
Transmission	**4,283**	
Transmission Line Rebuild	4,283	25
Transportation	**2,570**	
Purchase Vehicles and Aerial Devices	2,570	64

Other	**$6,690**	**Page**
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	83
General Expenses Capitalized	**4,000**	
General Expenses Capitalized	4,000	85
General Property	**275**	
Standby and Emergency Power – Gander Office	275	61
Generation-Hydro	**1,665**	
Hydro Plant Production Increase	1,665	4

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 2014 the following projects are clustered:

1. The portion of the *Trunk Feeders* Distribution project involving the relocation of distribution plant in St. John's is clustered with the *Transmission Line Rebuild* project. Transmission lines 12L and 13L 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 portion of the *Substations Refurbishment and Modernization* Substations project related to Bay Roberts Substation is clustered with the *Additions Due to Load Growth* Substations project. In the 2013 Capital Plan, the refurbishment of Bay Roberts Substation was scheduled for 2015. In 2014, an additional transformer will be added to Bay Roberts 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 is clustered with the *Additions Due to Load Growth* and *Hardwoods Substation Feeder Termination* Substations projects. In 2014, the existing 25 MVA 66/25 kV transformer at Hardwoods Substation will be replaced with a 50 MVA unit to accommodate customer load growth. The termination of a new feeder at Hardwoods Substation and the construction of the new feeder are necessary to service the growth in customer load. These items are inter-dependent, and are therefore clustered.

4. The *Feeder Additions for Growth* Distribution project is clustered with the *Additions Due to Load Growth* Substations project. In 2014, the existing 4 MVA 66/12.5 kV transformer at Marble Mountain Substation will be replaced with an existing 6.7 MVA unit to accommodate customer load growth. The extension of MMT-01 feeder to transfer load from Pasadena Substation is necessary to service the growth in customer load. These items are inter-dependent, and are therefore clustered.

Summary of
2014 Capital Projects by Classification
(000's)

Normal Capital	**$78,692**	**Page**
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	83
Distribution	**40,270**	
Allowance for Funds Used During Construction	193	53
Extensions	11,689	29
Feeder Additions for Growth	1,102	51
Meters	2,755	31
Rebuild Distribution Lines	3,462	44
Reconstruction	3,787	42
Relocate/Replace Distribution Lines for 3rd Parties	2,616	47
Services	3,930	34
Street Lighting	2,480	37
Trunk Feeders	1,261	49
Transformers	6,995	40
General Expenses Capitalized	**4,000**	
General Expenses Capitalized	4,000	85
General Property	**1,112**	
Additions to Real Property	379	59
Tools and Equipment	458	56
Standby and Emergency Power – Gander Office	275	61
Generation-Hydro	**7,345**	
Facility Rehabilitation	1,610	2
Heart's Content Plant Refurbishment	5,735	6
Generation-Thermal	**312**	
Facility Rehabilitation Thermal	312	10
Information Systems	**2,633**	
Network Infrastructure	321	80
Personal Computer Infrastructure	420	75
Shared Server Infrastructure	833	78
System Upgrades	1,059	73
Substations	**14,132**	
Additions Due to Load Growth	5,004	17
Replacements Due to In-Service Failures	2,859	15
Substations Refurbishment & Modernization	6,023	13
Hardwoods Substation Feeder Termination	246	22
Telecommunications	**99**	
Replace/Upgrade Communications Equipment	99	68

Normal Capital (continued)		**Page**
Transmission	**5,469**	
Transmission Line Rebuild	5,469	25
Transportation	**2,570**	
Purchase Vehicles and Aerial Devices	2,570	64

Justifiable	**$3,037**	**Page**
Generation-Hydro	**1,665**	
Hydro Plant Production Increase	1,665	4
Information Systems	**1,372**	
Application Enhancements	1,372	71

Mandatory	**$2,733**	**Page**
Substations	**2,733**	
PCB Bushings Phase-out	2,733	19

Summary of
2014 Capital Projects by Materiality
(000's)

Large – Greater than $500	**$81,759**	**Page**
Unforeseen Allowance	**750**	
Allowance for Unforeseen Items	750	83
Distribution	**40,077**	
Extensions	11,689	29
Feeder Additions for Growth	1,102	51
Meters	2,755	31
Rebuild Distribution Lines	3,462	44
Reconstruction	3,787	42
Relocate/Replace Distribution Lines for 3rd Parties	2,616	47
Services	3,930	34
Street Lighting	2,480	37
Transformers	6,995	40
Trunk Feeders	1,261	49
General Expenses Capitalized	**4,000**	
General Expenses Capitalized	4,000	85
Generation-Hydro	**9,010**	
Facility Rehabilitation	1,610	2
Hydro Plant Production Increase	1,665	4
Heart's Content Plant Refurbishment	5,735	6
Information Systems	**3,264**	
Application Enhancements	1,372	71
Shared Server Infrastructure	833	78
System Upgrades	1,059	73
Substations	**16,619**	
Additions Due to Load Growth	5,004	17
Replacements Due to In-Service Failures	2,859	15
Substations Refurbishment & Modernization	6,023	13
PCB Bushings Phase-out	2,733	19
Transmission	**5,469**	
Transmission Line Rebuild	5,469	25
Transportation	**2,570**	
Purchase Vehicles and Aerial Devices	2,570	64

Medium - Between $200 and $500	2,411	Page
General Property	**1,112**	
Additions to Real Property	379	59
Tools and Equipment	458	56
Standby and Emergency Power – Gander Office	275	61
Generation-Thermal	**312**	
Facility Rehabilitation Thermal	312	10
Information Systems	**741**	
Network Infrastructure	321	80
Personal Computer Infrastructure	420	75
Substations	**246**	
Hardwoods Substation Feeder Termination	246	22
Small – Under $200	**$292**	**Page**
Distribution	**193**	
Allowance for Funds Used During Construction	193	53
Telecommunications	**99**	
Replace/Upgrade Communications Equipment	99	68

GENERATION - HYDRO

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

Project Cost: **$1,610,000**

Project Description

This Generation Hydro project is necessary to improve the efficiency and reliability of various hydro plants or to replace plant 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 project includes the following items:

- Refurbishment of 2 intake structures;
- Refurbishment of 2 hydro dams and spillways; 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 2014 proposed expenditures are included in ***1.1*** *2014 Facility Rehabilitation*.

Justification

The Company's 23 hydroelectric plants range in age from 14 to 113 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 generation facility would require approximately 683,000 barrels of fuel annually. At an oil price of $105.80 per barrel, this translates into approximately $72 million in annual fuel savings.

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.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2014 and a projection of expenditures through 2018.

Table 1
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$1,309	-	-	-
Labour – Internal	74	-	-	-
Labour – Contract	-	-	-	-
Engineering	174	-	-	-
Other	53	-	-	-
Total	**$1,610**	**$1,425**	**$4,470**	**$7,505**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2009	2010	2011	2012	2013F
Total	$2,519[1]	$1,301	$1,450	$1,616	$1,400

1 Includes protection and control system upgrades at Horse Chops plant.

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: **Hydro Plant Production Increase (Other)**

Project Cost: **$1,665,000**

Project Description

In 2008, Newfoundland Power conducted a study into alternative ways to improve the efficiency and energy production of existing hydroelectric plants.[1] The study reviewed 14 hydro developments identifying 31 potential projects with levelized costs of energy ranging from 2.29¢ per kWh to 23.67¢ per kWh. This project undertakes work coming out of the 2008 study.[2]

In 2014, Newfoundland Power will undertake to increase the capacity of La Manche Canal in the Tors Cove/Rocky Pond hydroelectric development. The Tors Cove/Rocky Pond hydroelectric development is composed of two plants, Tors Cove and Rocky Pond.

The Tors Cove plant was placed into service in 1940 followed by La Manche Canal and Rocky Pond plant in 1943. The combined normal annual energy production at both plants is approximately 39.0 GWh or approximately 9% of the total hydroelectric production of Newfoundland Power. Increasing the capacity of La Manche Canal will provide an additional 5.54 GWh of energy production at a cost of 2.19¢ per kWh.

Details on the proposed expenditures are included in ***1.3** Hydro Production Increase – La Manche Canal.*

Justification

The Hydro Plant Production Increase project is justified on the basis of displacing higher cost energy production with lower cost production. Increased energy production at Newfoundland Power's existing hydroelectric plants would displace energy produced at Hydro's Holyrood Thermal Generating Station.[3]

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1 A copy of this study was filed as Attachment A to the response to Request for Information PUB-NP-09 in the Company's 2010 Capital Budget Application.

2 At the end of 2013, 6 of these potential projects will have been completed. Another 3 projects are included in the 2014 to 2018 Capital Plan. Included in the 31 potential projects are 9 projects involving the construction of small hydro plants and another 13 that are not considered viable on either economic terms or because of environmental regulations.

3 The avoided cost of fuel at the Holyrood Thermal Generating Station is estimated at 16.8¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.80 per barrel for 2013 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated April 12, 2013.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2014 and a projection of expenditures through 2018.

Table 1

Projected Expenditures (000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$1,380	-	-	-
Labour – Internal	85	-	-	-
Labour – Contract	-	-	-	-
Engineering	115	-	-	-
Other	85	-	-	-
Total	**$1,665**	**$1,400**	**$1,660**	**$4,725**

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: Heart's Content Plant Refurbishment (Pooled, Multi-year)

Project Cost: $5,735,000

Project Description

This Generation Hydro project involves a major refurbishment of electrical and mechanical systems at Heart's Content Plant.[4] The components requiring replacement or refurbishment include the plant controls, governor controls, electrical protection, power cables, station service, battery bank, charger and switchgear. The project also includes the rewind of the generator stator, re-insulation of the rotor and the rewind of the exciter.

Details on the proposed expenditures for the refurbishment of the electrical and mechanical systems are included in ***1.2*** *Heart's Content Hydro Plant Refurbishment*.[5]

Justification

The Heart's Content Plant, located on the Avalon Peninsula near the community of Heart's Content, was commissioned in 1960 with a capacity of 2.4 MW.[6] The normal annual production at Heart's Content is 8.3 GWh or 1.9% of the total hydroelectric production of Newfoundland Power.

Engineering assessments of 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 Heart's Content Plant has determined the levelized cost of energy from the plant over the next 50 years to be 6.27¢ per kWh, which is significantly less than the cost of replacement energy at the Holyrood Thermal Generating Station.[7]

4 The replacement of the 579 metre long penstock at Heart's Content Plant was approved in Order No. P.U. 31 (2012) as a multi-year project. The $3,495,000 estimate for the replacement of the penstock in 2014 is included in the $5,735,000 estimated expenditure for this year's project.

5 Expenditures for the replacement of the Heart's Content Plant penstock were included in Newfoundland Power's 2013 Capital Budget Application. The proposed 2014 plant refurbishment costs were identified in the feasibility analysis contained in ***1.2*** *Heart's Content Hydro Plant Penstock Replacement*, which was the report filed in support of the penstock replacement.

6 The plant commissioned in 1960 replaced the original plant commissioned in 1918.

7 The avoided cost of fuel at the Holyrood Thermal Generating Station is estimated at 16.8¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.80 per barrel for 2013 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated April 12, 2013.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2014 and a projection of expenditures through 2018.

Table 1
Projected Expenditures (000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$4,958	-	-	-
Labour – Internal	271	-	-	-
Labour – Contract	-	-	-	-
Engineering	249	-	-	-
Other	257	-	-	-
Total	**$5,735**	**-**	-	**$5,735**

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

The penstock replacement is a multi-year project, approved in Order No. P.U. 31 (2012). The complete multi-year project expenditure is included in Schedule C. Table 2 details the complete multi-year project expenditure for the replacement of the penstock. The penstock expenditure for 2014 is also included in Table 1 above.

Table 2
Multi-Year Projected Expenditures (000s)

Cost Category	2013F	2014B	Total
Material	$25	$3,269	$3,294
Labour – Internal	25	25	50
Labour – Contract	-	-	-
Engineering	125	103	228
Other	25	98	123
Total	**$200**	**$3,495**	**$3,695**

The multi-year project is proceeding on schedule, with no anticipated changes to the project budget.

The refurbishment of electrical and mechanical systems at Heart's Content Plant is not a multi-year project.

GENERATION - THERMAL

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

Project Cost: **$312,000**

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 2014 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 $211,000 is estimated to be the cost of refurbishment or replacement of thermal plant structures in 2014.

The 2014 project also includes refurbishment of the weather-tight enclosure of the Company's Mobile Gas Turbine. This will involve replacing sections of deteriorated cladding along with doors, door frames, and locks that no longer operate reliably. Based upon an engineering estimate, the cost in 2014 is forecast to be $101,000.

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 2014 and a projection of expenditures through 2018.

Table 1
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$200	-	-	-
Labour – Internal	45	-	-	-
Labour – Contract	-	-	-	-
Engineering	45	-	-	-
Other	22	-	-	-
Total	**$312**	**$216**	**$672**	**$1,200**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2009	2010	2011	2012	2013F
Total	$202	$196	$252	$117	$284

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: **$6,023,000**

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*** *2014 Substation Refurbishment and Modernization*.

The Company has 130 substations ranging in age from 11 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 2014, this project will refurbish and modernize the following substations:

- Bay Roberts Substation[8]
- Carbonear Substation
- Holyrood Substation
- Massey Drive Substation
- Springdale Substation

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.

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

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2014 and a projection of expenditures through 2018. Appendix A of ***2.1*** *2014 Substation Refurbishment and Modernization* details the work planned for each year.

Table 1
Projected Expenditures
(000s)

Cost Category	**2014**	**2015**	**2016 - 2018**	**Total**
Material	$4,614	-	-	-
Labour – Internal	164	-	-	-
Labour – Contract	-	-	-	-
Engineering	1,067	-	-	-
Other	178	-	-	-
Total	**$6,023**	**$4,844**	**$19,049**	**$29,916**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	**2009**	**2010**	**2011**	**2012**	**2013F**
Total	$4,153	$4,101	$2,208	$2,279	$4,452

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: **$2,859,000**

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 2014 and a projection of expenditures through 2018.

Table 1
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$1,885	-	-	-
Labour – Internal	609	-	-	-
Labour – Contract	-	-	-	-
Engineering	277	-	-	-
Other	88	-	-	-
Total	**$2,859**	**$2,941**	**$9,242**	**$15,042**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2009	2010	2011	2012	2013F
Total	$2,329	$2,388	$2,689	$3,327	$2,685

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 cost estimates and 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

This is not a multi-year project.

Project Title: **Additions Due To Load Growth (Clustered)**

Project Cost: **$5,004,000**

Project Description

This Substations project includes:

1. The replacement of the existing 66/25 kV 25 MVA substation transformer with a new 66/25 kV 50 MVA substation transformer to accommodate load growth in the Paradise area. This area includes customers served from Hardwoods (HWD), Chamberlains (CHA) and Kenmount (KEN) substations. This item is clustered with the HWD-09 item in the *Feeder Additions for Growth* Distribution project and the *Hardwoods Substation Feeder Termination* Substations project. ($2,399,000)

2. The installation of a new 66/12.5 kV 25 MVA substation transformer at Bay Roberts Substation to accommodate load growth in the Conception Bay North area. This area includes customers served from Bay Roberts (BRB) and Springfield (SPF) substations. This item is clustered with the Bay Roberts Substation item in the *Substations Refurbishment and Modernization* Substations project. ($2,320,000)

3. The installation of an existing 66/12.5 kV 6.7 MVA substation transformer at Marble Mountain Substation to accommodate load growth in the Humber Valley area. This area includes customers served from Marble Mountain (MMT) and Pasadena (PAS) substations. ($285,000)

Details on the proposed expenditures are contained in ***2.2*** *2014 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 Paradise, Conception Bay North and Humber Valley 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 a new 50 MVA substation transformer at Hardwoods Substation to replace the existing 25 MVA substation transformer, a new 25 MVA substation transformers at Bay Roberts Substation and relocation of an existing 6.7 MVA substation transformer to Marble Mountain 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 2014 and a projection of expenditures through 2018.

Table 1

Projected Expenditures (000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$4,484	-	-	-
Labour – Internal	113	-	-	-
Labour – Contract	-	-	-	-
Engineering	327	-	-	-
Other	80	-	-	-
Total	**$5,004**	**$12,087**	**$11,908**	**$28,999**

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

Project Cost: **$2,733,000**

Project Description

This Substations project is proposed to facilitate the identification and phase-out of polychlorinated biphenyls (“PCB”) from bushings and instrument transformers with concentrations of greater than 500 parts-per-million (“ppm”).

In September 2008, regulations made under the *Environment Protection Act (Canada)* were amended by the Government of Canada. The new *PCB Regulations* have effectively accelerated the schedule that Canadian utilities previously were operating under in addressing the phase-out of PCBs contained in substation equipment.

Expenditures related to this ongoing program apply to the Company’s substation transformer bushings and bulk oil circuit breaker bushings. Details on the *PCB Bushing Phase-out* project were included in the 2011 Capital Budget Application in ***2.3*** *2011 PCB Removal Strategy*, and in the 2012 Capital Budget Application in ***2.3*** *2012 PCB Removal Strategy*.

By the end of 2013, the bushings on all 167 substation transformers will have been tested.[9] By the end of 2013, bushings on 47 substation transformers will have been replaced; and in 2014, bushings will be replaced on 21 additional transformers. Table 1 summarizes the results of the testing completed and scheduled.

Table 1

Substation transformer Bushing Testing & Replacement Schedule

Year	**Tested / To Be Tested**	**Replaced / To Be Replaced**
2010 & Prior	23	2
2011	52	3
2012	53	13
2013	39	29
2014F	0	21
Total	**167**	**68**

[9] The remediation strategy for substation transformer bushings is to replace bushings that (1) test at 500 ppm or more or (2) that cannot be tested. To minimize costs and customer outages, in situations where one or more of a transformer’s bushings test at 500 ppm or more, all bushings that test at 50 ppm or more will be replaced at the same time.

By the end of 2013, bushings on all 185 bulk oil circuit breakers will have been tested.[10] There are no oil circuit breaker bushings to be tested in 2014. By the end of 2013 there will be 27 breakers replaced and in 2014 only one breaker remains to be replaced under this program. Table 2 summarizes the results of the testing completed and scheduled.

Table 2

Bulk Oil Circuit Breaker Bushing Testing & Replacement Schedule

Year	Tested / To Be Tested	Replaced / To Be Replaced
2010 & Prior	27	2
2011	90	5
2012	66	4
2013	2	16
2014F	0	1
Total	**185**	**28**

Actual failure rates for transformer and breaker bushings tested under the program have been slightly less than forecast. However there were more bushings classified as failures than forecast due to the inability to obtain oil samples for testing.[11] This has resulted in a higher number of both transformer bushings and breakers being replaced. Even though the number of replacements has been higher than forecast, there has been lower project expenditures than originally forecast due to lower than forecast costs incurred during projection execution.[12]

By the end of 2013, PCB testing will be completed on the Company's potential and current transformers, metering tanks, and station service transformers. All required replacements of units with PCB concentrations of 500 ppm or more will be completed before the end of 2014.[13]

The Company estimates that, in 2014, there will be approximately 480,000 customer-minutes of outage required to complete the testing and replacement of equipment.

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10 Whenever the bushings on a bulk oil circuit breaker test at 500 ppm or more, the complete breaker will be replaced.

11 Oil samples could not be obtained from bushings that did not have a test port or where the test port was seized due to years of inactivity.

12 The 2011 Capital Budget Application estimated expenditure over the period from 2011 to 2014 at $14.5 million. Actual and forecast expenditures included in the 2014 Capital Budget Application over the period from 2011 to 2014 are estimated at approximately $8.7 million.

13 In 2013, the Company will test the final 30 potential and current transformers, metering tanks, and station service transformers. The original Extension Application identified 79 items to be tested.

Justification

The project is justified on the requirement to meet the new Government of Canada *PCB Regulations*. Newfoundland Power has been granted an end-of-life date extension to December 31, 2014 in accordance with subsection 17(2) of the *PCB Regulations*.

Projected Expenditures

Table 3 provides a breakdown of the proposed expenditures for 2014 and a projection of expenditures through 2018.

Table 3
Projected Cost
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$2,114	-	-	-
Labour – Internal	193	-	-	-
Labour – Contract	-	-	-	-
Engineering	363	-	-	-
Other	63	-	-	-
Total	**$2,733**	**$984**	**$3,205**	**$6,922**

Costing Methodology

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.

Beyond the end-of-life extension date of December 31, 2014, expenditures will be required to address the phase-out of PCBs in equipment with PCB concentrations greater than 50 ppm and less than 500 ppm. Government regulations require equipment with PCB concentrations in that range to be removed from service by 2025. Expenditures related to the testing and, if necessary, removal of such equipment will be presented in future Capital Budget Applications.

Project Title: **Hardwoods Substation Feeder Termination (Clustered)**

Project Cost: **$246,000**

Project Description

This Substations project involves the termination of new 25 kV feeder at the Hardwoods Substation.

This project is clustered with the *Additions Due to Load Growth* Substations project to replace the existing 25 MVA transformer at the Hardwoods Substation with a new 50 MVA substation transformer (Schedule B, page 17 of 89) and with the *Feeder Additions for Growth* Distribution project to install a new 25 kV feeder (Schedule B, page 53 of 89).

Details on proposed 2014 expenditures are included in ***4.2** Feeder Additions for Load Growth*.

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 electrical system within recommended guidelines.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2014 and a projection of expenditures through 2018.

Table 1

Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$198	-	-	$198
Labour – Internal	5	-	-	5
Labour – Contract	-	-	-	-
Engineering	39	-	-	39
Other	4	-	-	4
Total	**$246**	**-**	**-**	**$246**

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: **$5,469,000**

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 2014 transmission line rebuilding work will take place on transmission lines 12L, 13L, 18L, 35L and 68L. Transmission line 12L operates between Kings Bridge Substation and Memorial University Substation in St. John's.[14] Transmission line 13L operates between St. John's Main Substation and Stamp's Lane Substation in St. John's. Transmission line 18L operates between Goulds Substation and Glendale Substation in Mount Pearl. Transmission line 35L operates between Kenmount Substation and Oxen Pond Substation in St. John's. Transmission line 68L operates between Carbonear Substation and Harbour Grace Substation in Conception Bay North.

   Details on the proposed 2014 rebuilds are included in ***3.1*** *2014 Transmission Line Rebuild* ($3,170,000).

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 ($2,299,000).

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.

[14] The rebuild of transmission line 12L was approved as a multi-year project in Order No. P.U. 31 (2012).

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2014 and a projection of expenditures through 2018. Appendix A of ***3.1*** *2014 Transmission Line Rebuild* details the transmission line rebuilds planned for each year.

Table 1
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$1,610	-	-	-
Labour – Internal	551	-	-	-
Labour – Contract	2,494	-	-	-
Engineering	378	-	-	-
Other	436	-	-	-
Total	**$5,469**	**$5,363**	**$21,669**	**$32,501**

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	2009	2010	2011	2012	2013F
Total	$4,520	$6,409[1]	$3,732	$4,694	$5,371

[1] Includes actual expenditures of $3,161,000 approved in Order No. P.U. No. 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 line 12L is a multi-year project.[15] In 2013, approximately 1.2 kilometres of aerial single-pole transmission line will be rebuilt; in 2014, approximately 1 kilometre of aerial single-pole transmission line will be rebuilt. Table 3 details the complete multi-year project expenditure for the transmission line 12L multi-year project.

Table 3
Multi-Year Projected Expenditures
(000s)

Cost Category	2013F	2014B	Total
Material	$101	$97	$198
Labour – Internal	114	87	201
Labour – Contract	80	98	178
Engineering	51	56	107
Other	34	32	66
Total	**$380**	**$370**	**$750**

The project is proceeding on schedule, with a modest increase in the project's 2014 budget of $12,000 over the original estimate.

[15] The rebuild of transmission line 12L was approved as a multi-year project in Order No. P.U. 31 (2012).

DISTRIBUTION

Project Title: **Extensions (Pooled)**

Project Cost: **$11,689,000**

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 2014 and a projection of expenditures through 2018.

Table 1
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$3,648	-	-	-
Labour – Internal	3,438	-	-	-
Labour – Contract	2,752	-	-	-
Engineering	1,475	-	-	-
Other	376	-	-	-
Total	**$11,689**	**$11,829**	**$36,210**	**$59,728**

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 2014.

Table 2
Expenditure History and Unit Cost Projection

Year	2009	2010	2011	2012	2013F	2014B
Total (000s)	$ 12,892	$ 14,616	$ 11,420	$ 11,321	$ 12,376	$ 11,689
Adjusted Costs (000s)[1,2]	$ 12,679	$ 14,123	$ 12,173	$ 11,667	-	-
New Customers	5,051	5,300	4,909	5,286	5,070	4,685
Unit Costs ($/customer)[2]	$ 2,510	$ 2,665	$ 2,480	$ 2,207	$ 2,441	$ 2,495

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.
2 2013 Dollars.

The project cost for the connection of new customers is calculated on the basis of historical data.[16] 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.

16 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: **$2,755,000**

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 2014.

Table 1
2014 Proposed Meter Acquisition

Program	Number of Meters
Energy Only Domestic Meters	24,835
Other Energy Only and Demand Meters	3,277

The expenditures for individual meters are not interdependent. However, because the individual expenditure items are similar in nature and justification, they have been pooled for consideration as a single capital 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 2014 and a projection of expenditures through 2018.

Table 2
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$2,425	-	-	-
Labour – Internal	275	-	-	-
Labour – Contract	55	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$2,755**	**$2,745**	**$7,393**	**$12,893**

Costing Methodology

Table 3 shows the annual expenditures for the most recent five-year period, as well as a projection for 2014.

Table 3
Expenditure History and Unit Cost Projection

Year	2009	2010	2011	2012	2013F	Avg	2014B
Meter Requirements							
New Connections	5,051	5,300	4,909	5,286	5,070		4,685
GROs/CSOs	14,188	10,284	13,671	15,257	20,255		19,271
Other	1,097	7,494	8,366	7,130	4,156		4,156
Total	20,336	23,078	26,946	27,630	29,841		28,112
Meter Costs							
Actual (000s)	$1,962	$1,872	$1,763	$2,557	$2,889		$2,755
Adjusted[1] (000s)	$2,124	$2,019	$1,851	$2,599	$2,889		
Unit Costs[1]	$ 104	$ 88	$ 95[2]	$ 94[2]	$ 98	$ 96	$ 98

[1] 2013 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: **$3,930,000**

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 2014 and a projection of expenditures through 2018.

Table 1
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$1,067	-	-	-
Labour – Internal	2,273	-	-	-
Labour – Contract	199	-	-	-
Engineering	343	-	-	-
Other	48	-	-	-
Total	**$3,930**	**$4,166**	**$12,850**	**$20,946**

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 2014.

Table 2

Expenditure History and Unit Cost Projection
New Services

Year	2009	2010	2011	2012	2013F	2014B
Total (000s)	$2,828	$3,255	$3,887	$3,351	$3,323	$3,091
Adjusted Costs (000s)[1]	$3,169	$3,573[2]	$4,147	$3,456	$3,053	-
New Customers	5,051	5,300	4,909	5,286	5,070	4,685
Unit Costs ($/customer)[1]	$ 627	$ 674	$ 845	$ 654	$ 655	$ 660

1 2013 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 2014.

Table 3

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

Year	2009	2010	2011	2012	2013F	2014B
Total	$410	$1,083	$795	$1,157	$652	$839
Adjusted Costs[1]	$459	$ 903[2]	$848	$1,193	$652	

1 2013 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: **$2,480,000**

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 2014 and a projection of expenditures through 2018.

Table 1
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$1,253	-	-	-
Labour – Internal	824	-	-	-
Labour – Contract	344	-	-	-
Engineering	35	-	-	-
Other	24	-	-	-
Total	**$2,480**	**$2,591**	**$7,733**	**$12,804**

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 2014.

Table 2

Expenditure History and Unit Cost Projection
New Street Lights

Year	**2009**	**2010**	**2011**	**2012**	**2013F**	**2014B**
Total (000s)	$1,805	$1,781	$1,461	$1,588	$1,612	$1,491
Adjusted Costs (000s)[1]	$1,992	$1,940	$1,548	$1,627		
New Customers	5,051	5,300	4,909	5,286	5,070	4,685
Unit Costs ($/cust.)[1]	$ 394	$ 366	$ 315	$ 308	$ 318	$ 318

1 2013 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 2014.

Table 3

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

Year	**2009**	**2010**	**2011**	**2012**	**2013F**	**2014B**
Total	$683	$797	$750	$776	$785	$989[2]
Adjusted Costs[1]	$752	$868	$795	$796	$785	

1 2013 dollars.
2 Additional replacement of temporary overhead street light service wires with permanent underground wiring.

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: **$6,995,000**

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 2014 and a projection of expenditures through 2018.

Table 1

Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$6,995	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$6,995**	**$7,167**	**$22,426**	**$36,588**

Costing Methodology

Table 2 shows the annual expenditures for the most recent five-year period, as well as an estimate for 2014.

Table 2

Expenditure History and Budget Estimate (000s)

Year	**2009**	**2010**	**2011**	**2012**	**2013F**	**2014B**
Total	$6,909	$6,588	$7,196	$6,565	$7,983	$6,995[2]
Adjusted Costs[1]	$7,425	$7,080	$7,530	$6,650		

1 2013 Dollars.
2 2014 budget adjusted to reflect reduced replacement transformer requirement and 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: **$3,787,000**

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 2014 and a projection of expenditures through 2018.

Table 1
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$896	-	-	-
Labour – Internal	1,525	-	-	-
Labour – Contract	855	-	-	-
Engineering	383	-	-	-
Other	128	-	-	-
Total	**$3,787**	**$3,917**	**$12,385**	**$20,089**

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 2014.

Table 2
Expenditure History and Budget Estimate
(000s)

Year	2009	2010	2011	2012	2013F	2014B
Total	$4,123	$5,202[2]	$3,967	$3,463	$3,499	$3,787
Adjusted Costs[1]	$4,129	$2,894[3]	$4,228	$3,569	$3,499	

[1] 2013 dollars.
[2] Includes actual expenditures of $996,000 approved under P.U. No. 17 (2010) for work associated with the March 2010 ice storm and $1,167,000 approved under 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.[17] 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.

[17] 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: **$3,462,000**

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 2014 will be performed on the following 43 of the Company's 305 feeders:

CAR-01	LOK-01	TRP-02	KBR-01	PEP-03	GAM-02
COL-01	MKS-01	WAV-01	KBR-03	PEP-04	ROB-02
DUN-01	MSY-01	WAV-02	KBR-07	RRD-09	STG-02
DUN-02	NWB-02	GOU-01	KBR-08	BHD-01	TWG-01
HCT-01	RVH-01	GOU-02	KBR-12	BOT-01	BVS-01
HGR-03	SPO-03	HWD-02	MOB-01	BOT-03	BVS-03
LLK-03	SUN-03	HWD-08	MOB-02	COB-02	FRN-02
BIG-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 9,300 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 2014 and a projection of expenditures through 2018.

Table 1
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$1,454	-	-	-
Labour – Internal	1,593	-	-	-
Labour – Contract	208	-	-	-
Engineering	35	-	-	-
Other	172	-	-	-
Total	**$3,462**	**$3,570**	**$11,247**	**$18,279**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2009	2010	2011	2012	2013F
Actual	$1,608	$1,268	$2,413	$3,723	$2,997
Adjusted[1,2]	$1,580	$1,230	$2,559	$3,819	

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 2009 and 2010 expenditures reflect higher customer-driven, third party and storm-related work in those years.

2 2013 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 2014 are ongoing throughout 2013. Complete inspection data will not be available until late 2013; therefore the 2014 budget estimate is based on average 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

This is not a multi-year project.

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

Project Cost: **$2,616,000**

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 2014 and a projection of expenditures through 2018.

Table 1
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$917	-	-	-
Labour – Internal	836	-	-	-
Labour – Contract	550	-	-	-
Engineering	267	-	-	-
Other	46	-	-	-
Total	**$2,616**	**$2,698**	**$8,505**	**$13,819**

Expenditures in recent years have been reflective of increased activity by the various telecommunications companies. In particular, over the 2011 to 2013 period, expenditures have increased as a result of the Bell Aliant FibreOp build out.

Costing Methodology

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

Table 2

Expenditure History
(000s)

Year	**2009**	**2010**	**2011**	**2012**	**2013F**
Total	$2,077	$2,363	$2,863	$2,195	2,554
Adjusted Costs[1]	$2,302	$2,580	$3,039	$2,253	

[1] 2013 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: **$1,261,000**

Project Description

This Distribution project includes:

1. The relocation of distribution plant from structures shared with transmission line 12L. Transmission line 12L is a 66 kV line running between King's Bridge Substation on King's Bridge Road and Memorial University Substation. Constructed in 1950, 12L runs alongside Empire Avenue, Rennies Mill Road, Long Pond Road and Strawberry Marsh Road. The transmission line consists of 59 single-pole structures, all of which have distribution lines sharing the same poles.[18] The rebuild of the aerial section of transmission line 12L is planned for completion in 2013 and 2014. The distribution lines sharing the poles with transmission line 12L will be relocated at the same time as the support structures are replaced on transmission line 12L. ($397,000)

2. The relocation of distribution plant from structures shared with transmission line 13L. Transmission line 13L is a 66 kV transmission line running between St. John's Main Substation on and Stamp's Lane Substation. Constructed in 1962, 13L runs through residential areas in St. John's. The transmission line consists of 81 single-pole structures, *most* of which have distribution lines sharing the same poles.[19] The rebuild of the aerial section of transmission line 13L is planned for completion in 2014. The distribution lines sharing the poles with transmission line 13L will be relocated at the same time as the support structures are replaced on transmission line 13L. ($200,000)

3. 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.* ($397,000)

4. The replacement of manhole covers in the St. John's underground distribution system. Access to the manholes is governed by the confined space entry provisions in the *Occupational Health and Safety Regulations*. This project involves the installation of new manhole covers that are marked to indicate a confined space and allow for insertion of gas detector probes without lifting the cover as required by the regulations. ($267,000)

[18] A description of the project to refurbish transmission line 12L can be found in ***3.1** 2014 Transmission Line Rebuild.*

[19] A description of the project to refurbish transmission line 13L can be found in ***3.1** 2014 Transmission Line Rebuild.*

For 2014, the Trunk Feeders project is clustered with the *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 12L and 13L.

Justification

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

Inspections of transmission lines 12L and 13L 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 and the replacement of the manhole covers will bring this infrastructure into compliance with current standards.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2014 and a projection of expenditures through 2018.

Table 1
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$503	-	-	-
Labour – Internal	292	-	-	-
Labour – Contract	156	-	-	-
Engineering	135	-	-	-
Other	175	-	-	-
Total	**$1,261**	**$2,511**	**$11,202**	**$14,974**

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: **$1,102,000**

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 2014, the following proposed expenditures are required in the Clarenville area, the Codroy Valley, the Town of Paradise and the Humber Valley:

1. The upgrading of conductor on Clarenville Substation feeder CLV-03 to address overloaded conductor on this distribution feeder. ($268,000)

2. The upgrading of Doyle's Substation feeder DOY-01 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. ($327,000)

3. The construction of a new feeder originating at Hardwoods Substation to accommodate growth in customers and load in the Town of Paradise, including new phases of existing subdivisions and continued development of the Octagon Pond Business Park. ($357,000)

4. The 0.6 kilometre extension of Marble Mountain Substation feeder MMT-01 in order to transfer load from Pasadena Substation feeder PAS-01 to Marble Mountain Substation. ($150,000)

For 2014, the *Feeder Additions for Growth* Distribution project is clustered with the *Additions Due to Load Growth* Substations project, since the extension of MMT-01 feeder to transfer load from Pasadena Substation is dependent upon the additional transformer capacity being added to Marble Mountain Substation, and the installation of a new 25 kV feeder at Hardwoods Substation is dependent upon the additional transformer capacity being added to Hardwoods Substation.

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 2014 and a projection of expenditures through 2018.

Table 1
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$365	-	-	-
Labour – Internal	322	-	-	-
Labour – Contract	159	-	-	-
Engineering	93	-	-	-
Other	163	-	-	-
Total	**$1,102**	**$545**	**$2,172**	**$3,819**

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: **$193,000**

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 2014 and a projection of expenditures through 2018.

Table 1

Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	-	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering		-	-	-
Other	$193	-	-	-
Total	**$193**	**$197**	**$615**	**$1,005**

Costing Methodology

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

Table 2
Expenditure History and Budget Estimate
(000s)

Year	2009	2010	2011	2012	2013F
Total	$172	$172	$181	$192	$189

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: **$458,000**

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 ($113,000)*: 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 ($25,000):* 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.[20]

[20] 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 2014 and a projection of expenditures through 2018.

Table 1
Projected Expenditures (000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$458	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$458**	**$467**	**$1,456**	**$2,381**

Costing Methodology

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

Table 2
Expenditure History (000s)

Year	2009	2010	2011	2012	2013F
Total	$384	$383	$428	$449	$389

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: **$379,000**

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 2014 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 $279,000 is required for 2014. 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 2014. 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 2014 and a projection of expenditures through 2018.

Table 1
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$314	-	-	-
Labour – Internal	25	-	-	-
Labour – Contract	-	-	-	-
Engineering	25	-	-	-
Other	15	-	-	-
Total	**$379**	**$285**	**$890**	**$1,554**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	**2009**	**2010**	**2011**	**2012**	**2013F**
Total	$244	$219	$311[1]	$300	$238

[1] Excludes cost of security camera upgrades ($49,000) and Duffy Place office renovations ($63,000).

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 – Gander Office (Other)**

Project Cost: **$275,000**

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 Gander 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.

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 consist 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 in central Newfoundland would require technology and communications infrastructure located in the Gander area operations building. The uninterruptible power supply ("UPS") system that is currently located at the Gander 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.

Details on the proposed expenditures are included in ***5.1*** *Standby and Emergency Power – Gander Office*.

Justification

This project is necessary to ensure electrical service at the Company's Gander 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 2014 and a projection of expenditures through 2018.

Table 1

Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$250	-	-	-
Labour – Internal	10	-	-	-
Labour – Contract	-	-	-	-
Engineering	10	-	-	-
Other	5	-	-	-
Total	**$275**	**$275**	**$175**	**$725**

Costing Methodology

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

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

Future Commitments

This is not a multi-year project.

TRANSPORTATION

Project Title: Purchase Vehicles and Aerial Devices (Pooled)

Project Cost: $2,570,000

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 2014.

Table 1
2014 Proposed Vehicle Replacements

Category	No. of Units
Heavy fleet vehicles	6
Passenger vehicles[1]	30
Off-road vehicles[2]	9
Total	**45**

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

The Company has 72 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 2009 to 2013, the Company replaced 31 heavy fleet vehicles, an average of 6 heavy fleet vehicles per year. In 2014, 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 2009 to 2013, the Company replaced 133 passenger vehicles, an average of approximately 27 passenger vehicles per year. In 2014, the Company has identified 30 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 2014 and a projection of expenditures through 2018.

Table 2
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$2,570	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$2,570**	**$2,629**	**$8,206**	**$13,405**

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

Table 3
Expenditure History
(000s)

Year	2009	2010	2011	2012	2013F
Total	$2,087	$2,287	$2,272	$2,514	$2,950

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 determined that each unit proposed for replacement has reached the end of its useful life.

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: **$99,000**

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 2014 and a projection of expenditures through 2018.

Table 1

Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$73	-	-	-
Labour – Internal	4	-	-	-
Labour – Contract	-	-	-	-
Engineering	18	-	-	-
Other	4	-	-	-
Total	**$99**	**$102**	**$318**	**$519**

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	**2009**	**2010**	**2011**	**2012**	**2013F**
Total	$105	$149	$88	$100	$124
Adjusted Costs[1]	$113	$160	$92	$101	$124

[1] 2013 dollars

The process of estimating the budget requirement for communications equipment is based on a historical average. Historical annual expenditures related to upgrading and replacing communications equipment over the most recent five-year period, including the current year, 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.

In 2013, the Company will replace its Mobile Radio System. The forecast expenditures for the years 2014 to 2018 shown in Table 1 have been reduced to reflect the expected lower failure rates associated with 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: **$1,372,000**

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 2014 include enhancements to the Company's human resources, financial management and financial forecasting applications and Customer Service Internet and Energy Conservation Website enhancements.

The application enhancements proposed for 2014 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*** *2014 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*** *2014 Application Enhancements*.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2014 and a projection of expenditures through 2018.

Table 1
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$170	-	-	-
Labour – Internal	959	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	243	-	-	-
Total	**$1,372**	**$1,200**	**$4,350**	**$6,922**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2009	2010	2011	2012	2013F
Total	$1,444	$945	$1,003	$1,102	$1,380

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 (Pooled)**

Project Cost: **$1,059,000**

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 2014, the project includes upgrades to the Company's business applications including engineering load flow software and technical work request application, Contact Centre email management and desktop software tools, and an upgrade of the Company's SharePoint environment.

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* of the 2012 Capital Budget.

Details on proposed expenditures are included in ***6.2*** *2014 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 2014 and a projection of expenditures through 2018.

Table 1

Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$365	-	-	-
Labour – Internal	509	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	185	-	-	-
Total	**$1,059**	**$1,725**	**$4,655**	**$7,439**

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	2009	2010	2011	2012	2013F
Total	$630	$1,000	$853	$1,363	$1,177

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 for 2014 for the Microsoft Enterprise Agreement, which was approved as a multi-year project in Order No. P.U. 26 (2011). This is not otherwise a multi-year project.

Project Title: Personal Computer Infrastructure (Pooled)

Project Cost: $420,000

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 2014, a total of 143 PCs will be purchased, consisting of 79 desktop computers and 64 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 2012 and 2013, as well as the proposed additions and retirements for 2014.

Table 1
PC Additions and Retirements
2012 – 2014

	2012			**2013F**			**2014B**		
	Add	**Retire**	**Total**	**Add**	**Retire**	**Total**	**Add**	**Retire**	**Total**
Desktop	85	85	458	52	52	458	79	79	458
Mobile	45	37	303	44	44	303	64[21]	64	303
Total	**130**	**122**	**761**	**96**	**96**	**761**	**143**	**143**	**761**

[21] Total mobile computers include the replacement of 25 ruggedized mobile computers purchased in 2009 as part of the Vehicle Mobile Computing Infrastructure project.

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 2014 and a projection of expenditures through 2018.

Table 2
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$260	-	-	-
Labour – Internal	120	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	40	-	-	-
Total	**$420**	**$500**	**$1,400**	**$2,320**

Costing Methodology

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

Table 3
Expenditure History
(000s)

Year	2009	2010	2011	2012	2013F
Total	$459	$449	$423	$401	$380

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 (Pooled)**

Project Cost: **$833,000**

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 2014, 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 2014 include:

1. The replacement of shared multifunction printer devices that have reached the end of their service life;
2. Infrastructure upgrades required for the Contact Centre technology, SharePoint environment and Technical Work Request environment;
3. Enhancements to the Company's remote connectivity infrastructure;
4. Upgrade of wireless network security monitoring software; and
5. The addition of encryption infrastructure for mobile devices.

The shared server infrastructure requirements for 2014 are not inter-dependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Details on proposed expenditures are included in ***6.3*** *2014 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 2014 and a projection of expenditures through 2018.

Table 1
Projected Expenditures
(000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$425	-	-	-
Labour – Internal	273	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	135	-	-	-
Total	**$833**	**$750**	**$1,850**	**$3,433**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2009	2010	2011	2012	2013F
Total	$632	$577	$941	$687	$877

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: **$321,000**

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 2014, 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 2014 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 2014 and a projection of expenditures through 2018.

Table 1

Projected Expenditures (000s)

Cost Category	2014	2015	2016 - 2018	Total
Material	$190	-	-	-
Labour – Internal	96	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	35	-	-	-
Total	**$321**	**$200**	**$675**	**$1,196**

Costing Methodology

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

Table 2

Expenditure History (000s)

Year	2009	2010	2011	2012	2013F
Total	$115	$148	$158	$429	$200

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.

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: **$4,000,000**

Project Description

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

Justification

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

Costing Methodology

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

Future Commitment

This is not a multi-year project.

Newfoundland Power Inc.
2014 Capital Budget
Multi-Year Projects

Class	Project Description	CBA Board Order		Expenditure (000s) 2012	2013	2014	Total
Substations	Additions Due To Load Growth[1]	2012 CBA P.U. 26 (2011)	Budget	$1,156	$3,974		$5,130
			Actual/Forecast	$1,195	$3,974		$5,169
Substations	Substation Additions Portable Substation[2]	2012 CBA P.U. 26 (2011)	Budget	$879	$3,621		$4,500
			Actual/Forecast	$192	$3,121		$3,313
Generation	Heart's Content Plant Refurbishment[3]	2013 CBA P.U. 31 (2012)	Budget		$200	$3,495	$3,695
			Forecast		$200	$3,495	$3,695
Transmission	Transmission Line Rebuild[4]	2013 CBA P.U. 31 (2012)	Budget		$380	$358	$738
			Forecast		$380	$370	$750

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* (12L MUN to King's Bridge).

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

	2012	2011
Net Plant Investment		
Plant Investment	1,439,646	1,371,771
Accumulated Amortization	(602,616)	(576,019)
Contributions in Aid of Construction	(31,006)	(29,013)
	806,024	766,739
Additions to Rate Base		
Deferred Pension Costs	100,113	97,628
Credit Facility Costs	239	270
Cost Recovery Deferral – Seasonal/TOD Rates	93	228
Cost Recovery Deferral – Hearing Costs	-	253
Cost Recovery Deferral – Regulatory Amortizations	3,320	1,642
Cost Recovery Deferral – 2012 Cost of Capital	1,766	-
Cost Recovery Deferral – Conservation	227	454
Customer Finance Programs	1,446	1,527
	107,204	102,002
Deductions from Rate Base		
Weather Normalization Reserve	4,804	5,020
Adjustment – 2010 Hearing Costs	-	6
Other Post Employment Benefits	14,617	7,199
Customer Security Deposits	851	695
Accrued Pension Obligation	4,020	3,778
Accumulated Deferred Income Taxes	2,504	862
Demand Management Incentive Account	558	1,252
	27,354	18,812
Year End Rate Base	885,874	849,929
Average Rate Base Before Allowances	867,902	861,681
Rate Base Allowances		
Materials and Supplies Allowance	5,332	5,012
Cash Working Capital Allowance	9,811	9,663
Average Rate Base at Year End	883,045	876,356

2014 Capital Plan

June 2013

Table of Contents

1.0 Introduction

Newfoundland Power's 2014 Capital Plan provides an overview of the Company's 2014 Capital Budget together with an outlook for capital expenditure through 2018.

Newfoundland Power's 2014 Capital Budget totals $84,462,000.

The Company's 2014 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 $91 million. This level of annual expenditure is broadly consistent on an inflation adjusted basis with that in the period 2009 through 2013.[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 84% of expenditures over the next 5 years. This composition is broadly consistent with Newfoundland Power's capital budgets over the previous 5 years.

In 2013, Newfoundland Power commenced the examination of some longer term aspects of Capital Budget composition, particularly for Distribution assets.[3] In 2014, the Company will also make a comprehensive assessment in relation to its Customer Service System which has been a critical component of the Company's interface with its customers since 1992.[4] The potential impact of these assessments is not fully reflected in the 2014 Capital Plan.[5] The results of the assessments may increase certain future capital expenditures from those indicated in the 2014 Capital Plan. Whether or not any such increased future capital expenditures serve to increase overall annual capital expenditure requirements is currently uncertain.[6]

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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 In the 2013 Capital Plan which was filed with the Company's 2013 Capital Budget Application, the Company indicated it was assessing its distribution pole replacement practices. Current relatively low levels of pole replacement may be inconsistent with maintaining current levels of system reliability and long-term capital budget stability. This assessment has commenced, and it is expected it will take a year or two to complete. See 2013 Capital Plan, page 1.

4 The Customer Service System cost in excess of $10 million by the time its phased implementation was complete in 1993. The cost to replace this system can be expected to be material.

5 The 2014 Capital Plan does not include all capital expenditures the Company will be required to make through 2018. For example, material capital expenditures may be required following major weather events such as ice storms. To the extent they can be reasonably estimated, capital expenditures related to asset failures are included in the Company's capital plans. See, for example, the *Distribution: Reconstruction* and *Substations: Replacements Due to In-Service Failures* projects. However, this is not always possible. For example, the Bell Island submarine cable system, which is a critical component required to serve customers on Bell Island, experienced two faults in January and April 2012. Ongoing engineering studies and assessment of this system may lead to a Supplemental Capital Budget Application to replace and/or reinforce it.

6 One aspect of this uncertainty stems from forecast demographic trends in Newfoundland Power's service territory. Forecast population decline and accelerated aging in the Company's service territory could result in reduced capital expenditure requirements related to serving increased numbers of customers and electricity load. This could, for example, serve to offset increased capital expenditure requirements related to Distribution asset replacements.

2.0 2014 Capital Budget

Newfoundland Power's 2014 capital budget is $84,462,000.

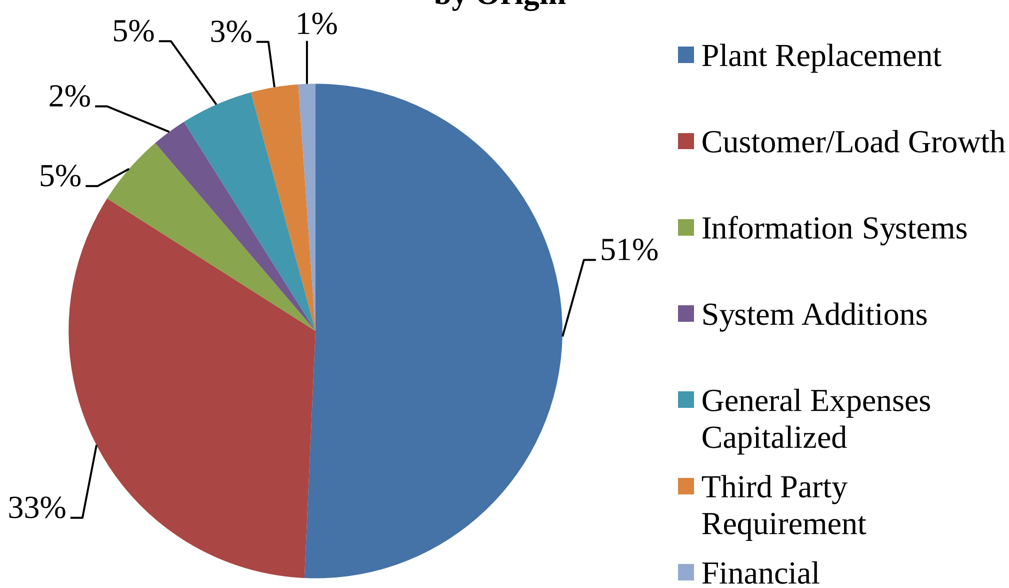
This section of the 2014 Capital Plan provides an overview of the 2014 capital budget by origin (root cause) and asset class. In addition, this section summarizes 2014 capital projects by the various categories set out in the Board's October 2007 Capital Budget Application Guidelines.

2.1 2014 Capital Budget Overview

Newfoundland Power's 2014 capital budget contains 33 projects totalling $84.5 million.

Chart 1 shows the 2014 capital budget by origin, or root cause.

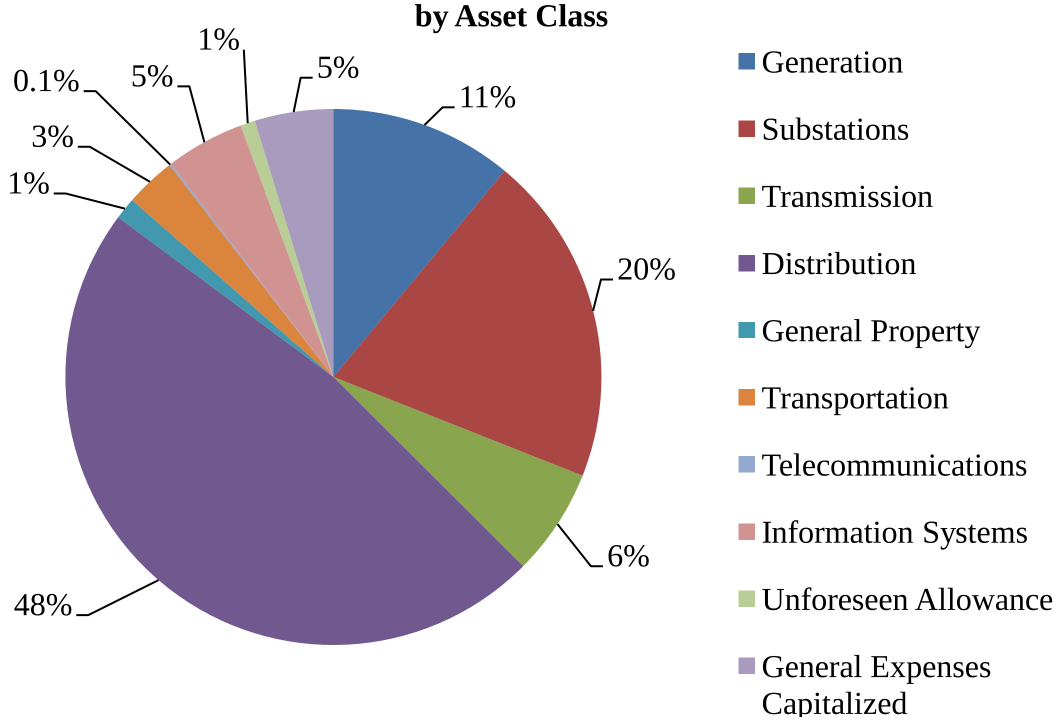
Chart 1
2014 Capital Expenditures
by Origin



Approximately 51% of proposed 2014 capital expenditure is related to the replacement of plant. A further 33% of proposed 2014 capital expenditure is required to meet the Company's obligation to serve new customers and meet the requirement for increased system capacity. The 2% of proposed 2014 capital expenditure associated with System Additions includes the projects to increase energy production at Rocky Pond and Tors Cove plants and to add a standby generator at Gander office. The remaining 14% of forecast capital expenditures for 2014 relate to information systems, general expenses capitalized, third party requirements and financial carrying costs (allowance for funds used during construction). The allocation of 2014 capital expenditures is broadly consistent with capital budgets for the past five years.

Chart 2 shows the 2014 capital budget by asset class.

Chart 2
2014 Capital Expenditures
by Asset Class



As in past years, Distribution capital expenditure accounts for the greatest percentage of overall expenditure at $40.3 million, or 48% of the 2014 capital budget. Substations capital expenditure accounts for $16.9 million, or 20% of the 2014 capital budget. Generation capital expenditure accounts for $9.3 million, or 11% of the 2014 capital budget. Transmission capital expenditure accounts for $5.5 million, or 6% of the 2014 capital budget. Together, expenditure for these four asset classes comprises 85% of the Company's 2014 capital budget.

Distribution capital expenditure is primarily driven by customer requests for new connections to the electrical system. Expenditures in 2014 are expected to be similar to recent years. Distribution capital projects that address reliability have been reduced in recent years, with no expenditures in 2014 associated with the Distribution Reliability Initiative. The reduction in capital expenditures associated with reliability is offset by inflationary increases and additional work associated with relocating distribution lines for 3rd parties.

In 2014, the Company plans to install new power transformers at Hardwoods substation in Paradise and Bay Roberts substation. Also in 2014, the Company will install a transformer from inventory at Marble Mountain substation.[7] These projects are necessary to address growth in customer load in these communities.

Changes in the regulation of polychlorinated biphenyls ("PCBs") by the Government of Canada have effectively accelerated the removal of PCBs from bushings and instrument transformers. In February 2010, Newfoundland Power was granted an extension of the December 31, 2009 end-of-use date for equipment and liquids containing PCBs to December 31, 2014. The change in regulations has resulted in a forecast capital expenditure of $8.7 million through 2014 and an additional $4.2 million in expenditures in the forecast period.[8]

Transmission lines proposed for rebuild in 2014 include 3 lines in the City of St. John's and one line each in the Mount Pearl and Conception Bay North areas. Transmission line 12L operates between Memorial University and Kings Bridge substations. Transmission line 13L operates between St. John's Main substation on Southside Road and Stamp's Lane substations. Transmission line 35L operates between Kenmount and Oxen Pond substations. Transmission line 18L operates between Goulds substation and Glendale substation in Mount Pearl. Transmission line 68L operates between Carbonear and Harbour Grace substations in Conception Bay North.

In 2014, the Company plans to upgrade the governor, generator, switchgear, protection and control systems at the Heart's Content hydro plant. The Company will complete a project to increase hydro plant production at Rocky Pond and Tors Cove in 2014.

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 2014 Capital Budget Application complies with the CBA Guidelines.

The 2014 Capital Budget Application includes 33 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 2014 Capital Budget, along with a summary of costs segmented by materiality.

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7 This substation transformer was last in service at Mobile substation. The transformer was replaced at Mobile substation by a larger unit transferred from Deer Lake substation. The project was included in the 2010 Capital Budget Application and approved on Order No. P.U. 41 (2009).

8 Expenditures forecast for years beyond the end-of-life extension date of December 31, 2014 will be to address PCB concentrations greater than 50 ppm and less than 500 ppm. Bushings and instrument transformers with PCB concentrations in this range must be removed from the power system before 2025.

2014 Capital Projects by Definition

Table 1 summarizes Newfoundland Power's proposed 2014 capital projects by definition as set out in the CBA Guidelines.

Table 1
2014 Capital Projects
By Definition

Definition	**Number of Projects**	**Budget (000s)**
Pooled	23	$58,667
Clustered[9]	6	19,105
Other	4	6,690
Total	**33**	**$84,462**

There are a total of 29 *pooled* or *clustered* projects accounting for 92% of total expenditures.

2014 Capital Projects by Classification

Table 2 summarizes Newfoundland Power's proposed 2014 capital projects by classification as set out in the CBA Guidelines.

Table 2
2014 Capital Projects
By Classification

Classification	**Number of Projects**	**Budget (000s)**
Mandatory	1	$2,733
Normal	30	78,692
Justifiable	2	3,037
Total	**33**	**$84,462**

There are 30 *normal* projects accounting for 93% of total expenditures.

9 Projects that have some components that are defined as clustered and some components that are either defined as pooled or other are included as clustered for the purpose of this table.

2014 Capital Projects Costing

Table 3 summarizes Newfoundland Power's proposed 2014 capital projects by costing method (i.e., identified need vs. historical pattern) as set out in the CBA Guidelines.

Table 3
2014 Capital Projects
By Costing Method

Method	Number of Projects	Budget (000s)
Identified Need	17	$37,698
Historical Pattern	16	46,764
Total	**33**	**$84,462**

Projects with costing method based on *identified need* account for 45% of total expenditures, while those based on *historical pattern* account for 55% of total expenditures.

2014 Capital Projects Materiality

Table 4 segments Newfoundland Power's proposed 2014 capital projects by materiality as set out in the CBA Guidelines.

Table 4
2014 Capital Projects
Segmentation by Materiality

Segment	Number of Projects	Budget (000s)
Under $200,000	2	$292
$200,000 - $500,000	7	2,411
Over $500,000	24	81,759
Total	**33**	**$84,462**

There are 24 projects budgeted at over $500,000 accounting for 97% of total expenditures.

3.0 5-Year Outlook

Newfoundland Power's 5-year capital outlook for 2014 through 2018 includes forecast average annual capital expenditure of $91.0 million. Over the five year period 2009 through 2013, the average annual capital expenditure is expected to be $76.8 million.

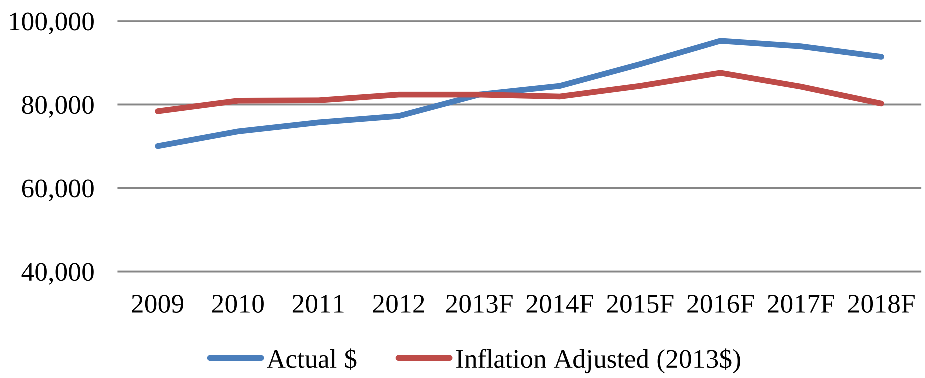
The increase in forecast annual capital expenditure reflects inflation and requirements for specific projects related to replacement of deteriorated facilities, meeting customer and load growth, maintaining compliance with federal regulations and additional portable generation. Annual expenditure through the forecast period is consistent on an inflation adjusted basis with that in the period 2009 through 2013.

3.1 Capital Expenditures: 2009-2018

The Company plans to invest $455 million in plant and equipment during the 2014 through 2018 period. On an annual basis, capital expenditures are expected to average approximately $91.0 million and range from a low of $84.5 million in 2014 to a high of $95.3 million in 2016.

Chart 3 shows actual capital expenditures for the period 2009 through 2012 and forecast capital expenditures for the period 2013 through 2018. For comparison purposes, the annual capital expenditures are also expressed in 2013 dollars to remove the effects of inflation.

Chart 3
Capital Expenditures
2009 to 2018F
($000s)



Overall planned capital expenditures for the 5-year period from 2014 through 2018 are expected to be greater than those in the 5-year period from 2009 through 2013. As shown in Chart 3 this is principally the result of inflation.[10] Forecast requirements for the 5-year period from 2014 through 2018 include additional power transformers due to load growth; the phase-out of PCB contaminated equipment, changes in meter regulations, the replacement of Pierre's Brook penstock, mobile generation and the refurbishment of gas turbines at Greenhill and Wesleyville. These additional costs are being partially offset by reduced expenditure aimed at reliability improvement.

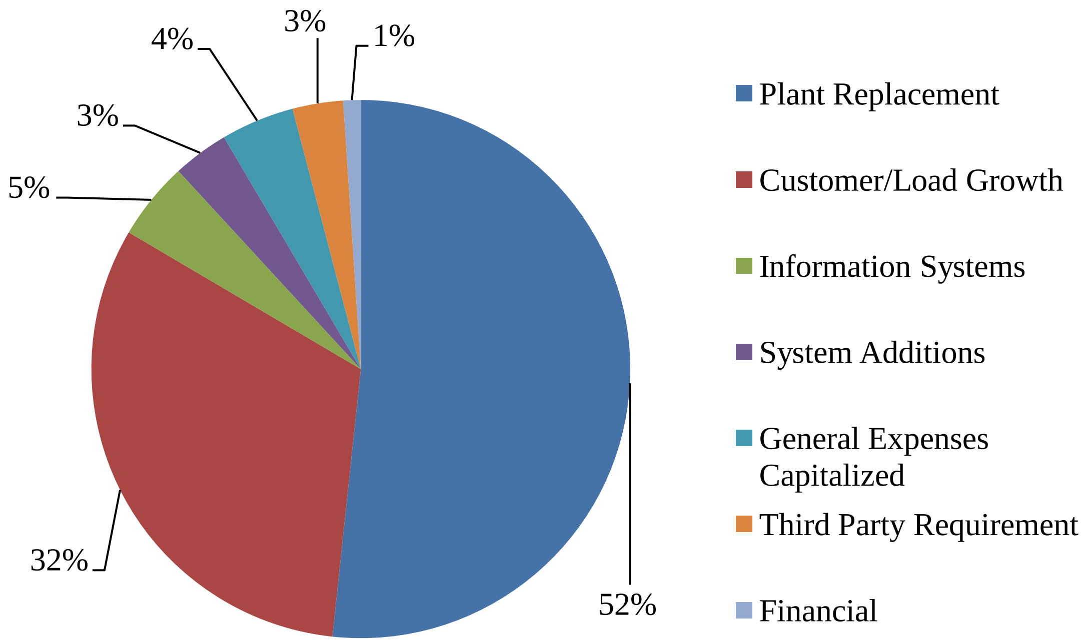
The replacement of plant has been, and will continue to be, the dominant driver of Newfoundland Power's capital budget, accounting for approximately 50% of total expenditure for the 10-year period from 2009 through 2018. Over the same 10-year period, capital expenditures to meet increased customer connections and electricity sales account for approximately 33% of total expenditures.

3.2 2014-2018 Capital Expenditures

3.2.1 Overview

Chart 4 shows aggregate forecast capital expenditures by origin for the period 2014 through 2018.

Chart 4
Capital Expenditures
by Origin
2014 to 2018



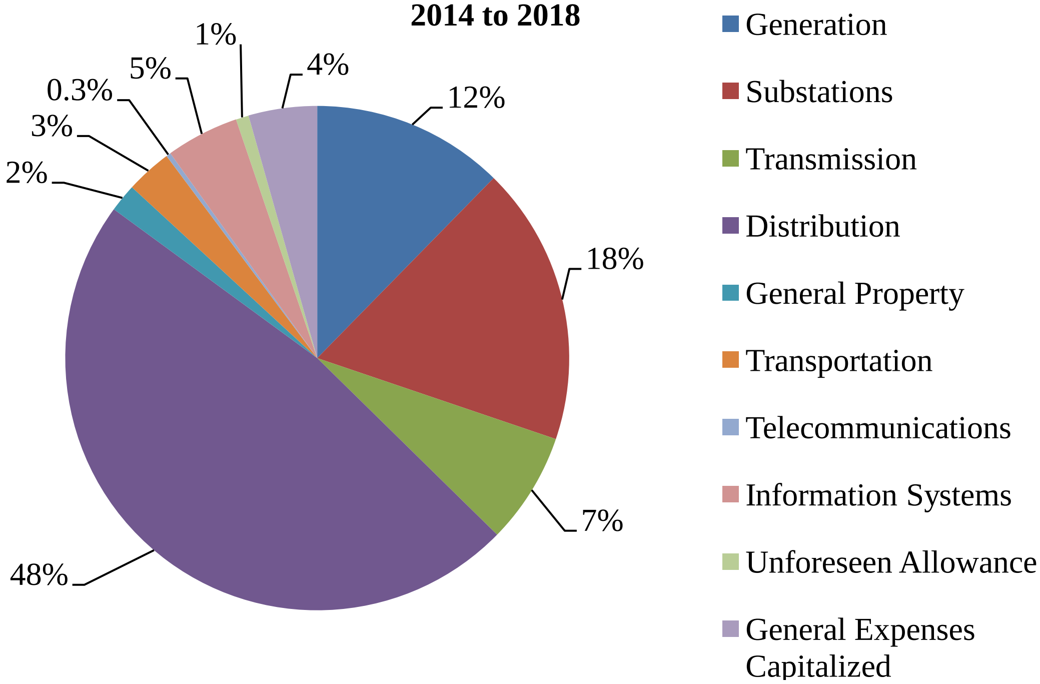
10 With the exception of 2016, the inflation adjusted curve is relatively flat. The increase in forecast capital expenditure in 2016 is attributable to the $12 million project to replace the Pierre's Brook penstock and refurbish the surge tank and plant controls.

Plant replacement accounts for 52% of all planned expenditures over the 5-year period from 2014 through 2018. This is greater than the average of 49% in the previous 5-year period from 2009 through 2013. Capital expenditure related to customer and load growth accounts for 32% of planned expenditures for this period. This is less than the average of 35% in the previous 5-year period from 2009 through 2013.

The remaining 16% of total capital expenditures for the 2014 through 2018 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 2014 through 2018 by asset class.

Chart 5
Capital Expenditures
by Asset Class
2014 to 2018



The Distribution asset class accounts for 48% of all planned expenditures over the next five years, followed by Substations (18%), Generation (12%) and Transmission (7%). The remaining six asset classes account for 15% of total capital expenditures for the 2014 through 2018 period.

Overall, planned expenditures for the period 2014 through 2018 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 2014 to 2018 is provided in Appendix A.

3.2.2 Generation

Generation capital expenditures will average approximately $11.2 million per year from 2014 through 2018, which is greater than the annual average of $7.1 million from 2009 through 2013.

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
- capital project initiatives.

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 five 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 2013 and 2014, the Company plans to refurbish the Heart's Content hydroelectric plant which includes replacing the penstock at an estimated cost of $3.7 million.[11] Also in 2014 the Company plans to refurbish the generator, governor, protection and control systems at the Heart's Content hydroelectric plant for an additional $2.2 million as described in the 2014 report ***1.2*** *Heart's Content Hydro Plant Refurbishment*.

- In 2014, the Company plans to increase the capacity of La Manche Canal at an estimated cost of $1.7 million to increase the combined production at Rocky Pond and Tors Cove plants by 5.54 GWh. Details on the project are found in the 2014 report ***1.3*** *Hydro Production Increase – La Manche Canal*.

- In 2015, 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 $1.4 million. The remaining section of woodstave penstock was replaced with a steel penstock in 1999.

- 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 $12.6 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.

[11] The multi-year project to replace the Heart's Content penstock was approved in Order No. P.U. 31 (2012).

- 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.[12]

- In 2016, 2017 and 2018, the Company plans to refurbish the turbines and wicket gates on all 3 generators at the 76 year old Tors Cove hydroelectric plant at an estimated total cost of $1.7 million.

- In 2017 and 2018, the Company plans to refurbish its gas turbines located at Greenhill and Wesleyville at an estimated total cost of $4.7 million.

- In 2018, the Company plans to refurbish the 67 year old Mobile hydroelectric plant at an estimated cost of $2.9 million.[13]

The Company will bring forward, as part of its annual Capital Budget Applications to the Board, engineering reports regarding each of these initiatives as well as economic analyses of their feasibility.

3.2.3 Transmission

Transmission capital expenditures are expected to average $6.5 million annually from 2014 through 2018 compared with $4.7 million annually from 2009 through 2013.

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 2014 Capital Budget Application.

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

[13] The Mobile hydroelectric plant refurbishment will be subject to a resolution of matters related to the termination of the Company's rights to use the waters of the Mobile river system. These matters are currently subject to litigation.

3.2.4 Substations

Substations capital expenditures are expected to average $16.3 million annually from 2014 through 2018, a material increase from the average of $11.8 million annually from 2009 through 2013. The increase in expenditure is largely attributable to the requirement for additional system capacity to serve increased customer load and compliance with revised PCBs regulations.

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 counter the continuous aging of substation assets such 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*** *2014 Substation Refurbishment and Modernization* filed with the 2014 Capital Budget Application.

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 2014 to 2018 forecast period there is a requirement to install 12 substation transformers to accommodate load growth.[14] In 2014, as a result of customer and load growth experienced over the past decade new power transformers will be required at Hardwoods and Bay Roberts substations. Also in 2014 an existing substation transformer will be relocated to Marble Mountain substation.[15] Commencing in 2015 and continuing through 2018, 6 new substation transformers will be required for the Northeast Avalon Peninsula, Grand Falls and Clarenville areas.[16] The Company will also relocate 3 transformers to substations on the Northeast Avalon

[14] By comparison, in the period 2010 through 2013, Newfoundland Power has purchased 5 new power transformers and relocated 1 power transformer 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.

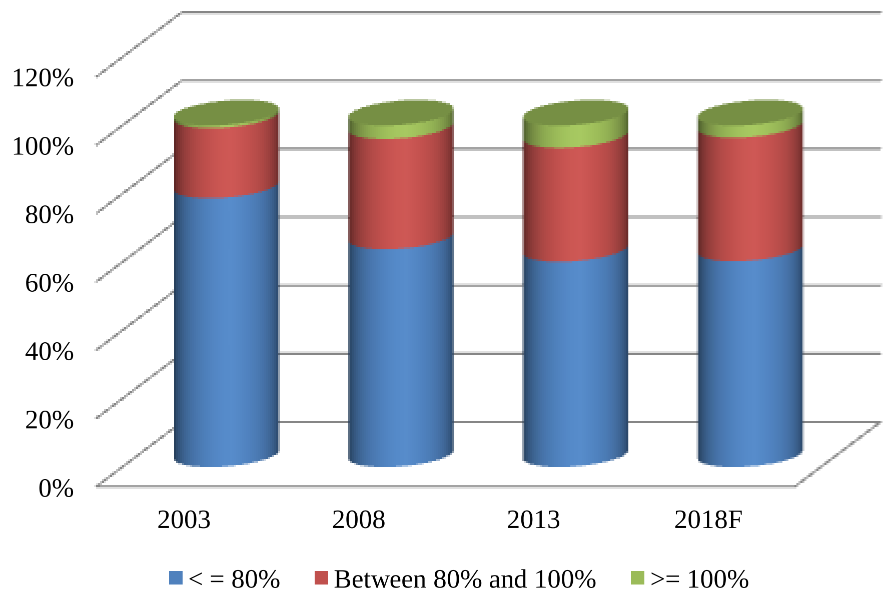
[15] Planning studies for the Bay Roberts and Marble Mountain areas are included in the 2014 Capital Budget Application report ***2.2*** *2014 Additions Due To Load Growth*. The requirement for the Hardwoods transformer was studied in the 2011 Capital Budget Application report ***2.2*** *2011 Additions 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.

Peninsula and the Codroy Valley that will become available as a result of the 6 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 2018F



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 almost doubled to 40%. 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 4 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.

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.

Regulatory changes by the Government of Canada with respect to the phase-out of bushings and instrument transformers containing PCBs have increased capital expenditures by approximately

$6.9 million over the next 5 years.[17] Detailed reports on the impact of the change in PCBs regulations were included in the 2011 and 2012 Capital Budget Applications.[18]

3.2.5 Distribution

Distribution capital expenditures from 2014 through 2018 are expected to increase to an average of approximately $43.4 million annually, compared to an average of $39.7 million annually from 2009 through 2013.

The Company operates approximately 9,300 km of distribution lines serving approximately 253,000 customers. Distribution capital expenditures are primarily driven by:

- new customers;
- third party requests;
- breakdown capital maintenance;
- distribution preventive capital maintenance;
- system load growth; and
- capital project initiatives.

Capital expenditures associated with new customer connections are forecast to decrease towards the end of the planning period. This is primarily due to a forecast decrease in new customer connections. The costs to connect new customers to the electricity system are included in several distribution projects including *Extensions*, *Transformers*, *Services*, *Meters* and *Street Lighting*.

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

Table 5
New Customer Connections

	2014	**2015**	**2016**	**2017**	**2018**
New Customer Connections	4,685	4,585	4,621	4,502	4,207
Average Cost/Connection	$4,647	$4,812	$4,923	$5,071	$5,271
Capital Expenditure (000s)	$21,770	$22,063	$22,749	$22,828	$22,177

Over the period 2014 to 2018, the expenditure associated with new customer connections is forecast to be within the range of $22 million to $23 million, or approximately 25% of the annual capital expenditures.

[17] 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. Expenditures forecast for years beyond the end-of-life extension date of December 31, 2014 will be to address PCB concentrations greater than 50 ppm and less than 500 ppm. Bushings and instrument transformers with PCB concentrations in this range must be removed from service by 2025.

[18] See Order Nos. P.U. 28 (2010) and P.U 26 (2011).

Distribution capital expenditures are required to relocate or replace distribution lines to meet third party requests from governments, telecommunications companies and individual customers. In 2014, the expenditures associated with third party requests is estimated at $2.6 million. Over the remainder of the five year period, these expenditures are forecast to remain stable and approximate an average of $2.8 million.

Capital expenditures associated with the replacement of meters are typically based upon historical expenditures. This forecast has increased over the planning period as the result of changes to Government of Canada compliance sampling regulations for electricity meters. The new regulations came into effect for digital meters in 2011 and will come into effect for electromechanical meters in 2014. In 2014 and beyond it is anticipated that an increase in electromechanical meter replacements will occur under the new regulations. A detailed description of the Company's strategy to deal with the 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.

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.

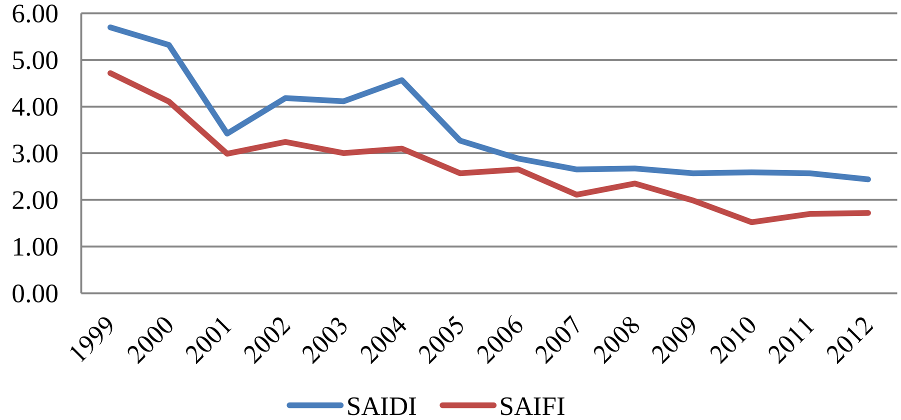
The Distribution *Reconstruction* project involves the replacement of deteriorated or damaged distribution structures and electrical equipment. The project is comprised of small unplanned projects and is estimated using the historical average of the most recent five-year period.

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 2014 through 2018 is expected to remain relatively constant though increased in comparison to the previous five years.

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*. There is no project planned for 2014. This is based upon the information provided in the report ***4.1*** *Distribution Reliability Initiative* filed with the 2014 Capital Budget Application.

Chart 7 shows SAIDI, or system average interruption duration index, and SAIFI, or system average interruption frequency index, for the years 1999 through 2012. Chart 7 has been adjusted to remove the effects of severe weather events.[19]

Chart 7
SAIDI and SAIFI
1999 - 2012



Newfoundland Power considers current levels of service reliability 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 are reduced compared to previous years.[20]

Newfoundland Power has a number of older Distribution assets in service that are critical to the safe and reliable delivery of electricity to customers. These assets would include old distribution poles, the electrical vaults on customer premises in the downtown St. John's underground distribution system, aerial power cables, and the underground primary distribution systems in Mount Pearl, Paradise and Virginia Park. The Company is assessing whether the replacement rate of these assets is sufficient to ensure both (i) continued safe and reliable service and (ii) long-term stability and predictability in capital expenditures.

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 a building and contain high voltage electrical equipment that converts primary voltages from the existing underground

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[19] Adjustments exclude the 2007 and 2010 Bonavista ice storms, Hurricane Igor in 2010, the December 2011 high wind event and Tropical Storm Leslie in September 2012. 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 and 2012 SAIDI and SAIFI would be 5.85 and 2.12 respectively.

[20] Over the 10 year period from 2000 to 2009, expenditures for the Distribution Reliability Initiative project totalled approximately $15 million.

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 2014, the Company will refurbish and modernize 3 of the 19 vaults in the St. John's downtown area. The work completed here will assist in the development of a multi-year plan for refurbishing and modernizing the remaining vaults. Details on the refurbishment and modernization of the vaults are found in report ***4.3*** *Vault Refurbishment and Modernization* filed with the 2014 Capital Budget Application.

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; and
- backup electricity generation and demand/load control equipment at Company buildings.

General Property capital expenditures are expected to average $1.6 million annually from 2014 through 2018 which is the same as the period from 2009 through 2013.

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 2014 through 2018 are expected to increase to an average of approximately $2.7 million annually, compared to an average of $2.4 million annually from 2009 through 2013. 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 2014 through 2018 is principally reflective of the number of heavy fleet and passenger vehicles expected to meet the replacement parameters over the period.

3.2.8 Telecommunications

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

Telecommunications capital expenditures are expected to decrease to an average of approximately $268,000 annually from 2014 through 2018 compared to the annual average of $368,000 from 2009 through 2013. 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.[21]

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

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.

Two of the Company's critical Information Systems, the Customer Service System ("CSS") and the SCADA system, operate on the Hewlett Packard AlphaServer hardware platform. 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. In 2013, the Company will undertake comprehensive assessments of both the CSS and SCADA systems as a result of the technical obsolescence of the AlphaServer hardware and associated operating systems.

Information Systems capital expenditures from 2014 through 2018 are expected to increase to an average of approximately $4.3 million annually, compared to an average of $3.7 million annually from 2009 through 2013. The increase is largely driven by expected system upgrades resulting from the technical obsolescence issues associated with the CSS and SCADA systems.

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 2014 through 2018.

3.2.11 General Expenses Capitalized

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

General Expenses Capitalized of $4.0 million is reflected in each year's capital budget from 2014 through 2018.

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 2014 through 2018.

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 recent losses of the Kenmount, Horsechops, Pierre's Brook and Salt Pond power transformers, will necessitate capital expenditures.[22]

Change in Government of Canada regulations regarding PCBs in equipment and meter compliance sampling will impact future capital budgets. The current 5-year forecast includes significant cost to accelerate the removal of PCBs from service. The 2011 Capital Budget Application estimated expenditures over the period from 2011 to 2014 at $14.5 million. The actual and forecast expenditures included in this 2014 Capital Budget Application over the same period are $8.7 million. The reduction in cost is the result of experience gained through project execution resulting in better estimates and lower allowances for contingencies. Also, the industry continues to consult with Environment Canada to extend the timeline associated with the removal of PCBs in substations.

The current 5-year forecast for meter replacements is based upon a transition plan as outlined in the report ***4.3** 2013 Metering Strategy* included in the 2013 Capital Budget Application. These estimates of meter replacements provided in the transition strategy may change to reflect actual test results from new compliance sampling regulations for electromechanical meters which come into effect in 2014.

In January and April 2012 the Bell Island submarine cable system experienced 2 faults that necessitated emergency repairs. Ongoing engineering studies and assessment of this system may lead to a Supplemental Capital Budget Application to replace and /or reinforce it within the 5-year plan.

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.

With the sanctioning of the Muskrat Falls project there will be associated impacts upon Newfoundland Power. The Company will be involved in supplying construction power to sites

[22] 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).

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 included any projects associated with Muskrat Falls development.

The Company has taken steps to reduce the uncertainty regarding replacement of its CSS, which has been in service since 1991.[23] These steps have included upgrades of hardware and software components and removal of technology components that posed the highest risk. Certain aspects of CSS, including the servers, have reached end of life. In 2013, the Company will begin a comprehensive assessment of upgrade and replacement strategies for CSS. The results of this assessment may 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.

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

Appendix A
2014-2018 Capital Plan

Newfoundland Power Inc.
2014-2018 Capital Plan
(000s)

Asset Class	2014	2015	2016	2017	2018
Generation	$9,322	$6,999	$15,623	$13,884	$10,308
Substations	16,865	20,856	15,631	13,778	14,145
Transmission	5,469	5,363	5,765	7,634	8,270
Distribution	40,270	42,436	44,294	45,196	44,822
General Property	1,112	1,992	1,863	1,382	1,846
Transportation	2,570	2,629	2,685	2,736	2,785
Telecommunications	99	275	304	330	332
Information Systems	4,005	4,375	4,410	4,285	4,235
Unforeseen Allowance	750	750	750	750	750
General Expenses Capitalized	4,000	4,000	4,000	4,000	4,000
Total	**$84,462**	**$89,675**	**$95,325**	**$93,975**	**$91,493**

Newfoundland Power Inc.
2014-2018 Capital Plan
(000s)

GENERATION

Project	2014	2015	2016	2017	2018
Facility Rehabilitation - Hydro	$1,610	$1,425	$1,470	$1,490	$1,510
Facility Rehabilitation - Thermal	312	216	220	224	228
Hydro Plant Production Increase	1,665	1,400	10	830	820
Heart's Content Plant Refurbishment	5,735	-	-	-	-
Pierre's Brook Penstock	-	750	11,850	-	-
Mobile Plant Refurbishment	-	-	-	-	2,885
Morris Plant Refurbishment	-	-	-	-	550
Seal Cove Plant Refurbishment	-	200	-	-	-
Tors Cove Plant Upgrade	-	508	573	575	565
Rose Blanche Plant Refurbishment	-	-	-	700	-
Petty Harbour Plant Refurbishment	-	2,500	-	-	-
Cape Broyle Plant Refurbishment	-	-	-	165	-
Horsechops Plant Refurbishment	-	-	-	-	675
Lookout Brook Plant Refurbishment	-	-	-	-	775
Purchase Portable Generation	-	-	1,500	7,500	-
Greenhill Gas Turbine	-	-	-	2,400	-
Wesleyville Gas Turbine	-	-	-	-	2,300
Total - Generation	**$9,322**	**$6,999**	**$15,623**	**$13,884**	**$10,308**

Newfoundland Power Inc.
2014-2018 Capital Plan
(000s)

SUBSTATIONS

Project	2014	2015	2016	2017	2018
Substations Refurbishment & Modernization	$6,023	$4,844	$5,042	$6,975	$7,032
Replacements Due to In-Service Failure	2,859	2,941	3,012	3,081	3,149
Additions Due to Load Growth	5,250	12,087	6,407	2,654	2,847
PCB Bushing Phase-Out	2,733	984	1,020	1,068	1,117
Plant Refurbishment	-	-	150	-	-
Total - Substations	**$16,865**	**$20,856**	**$15,631**	**$13,778**	**$14,145**

Newfoundland Power Inc.
2014-2018 Capital Plan
(000s)

TRANSMISSION

Project	2014	2015	2016	2017	2018
Rebuild Transmission Lines	$3,169	$3,763	$4,165	$6,034	$6,770
Transmission Line Reconstruction	2,300	1,600	1,600	1,600	1,500
Total - Transmission	**$5,469**	**$5,363**	**$5,765**	**$7,634**	**$8,270**

Newfoundland Power Inc.
2014-2018 Capital Plan
(000s)

DISTRIBUTION

Project	2014	2015	2016	2017	2018
Extensions	$11,689	$11,829	$12,241	$12,238	$11,731
Meters	2,755	2,745	2,588	2,640	2,165
Services	3,930	4,166	4,306	4,330	4,214
Street Lighting	2,480	2,591	2,662	2,679	2,392
Transformers	6,995	7,167	7,328	7,477	7,621
Reconstruction	3,787	3,917	4,022	4,128	4,235
Rebuild Distribution Lines	3,462	3,570	3,660	3,749	3,838
Relocate/Replace Distribution Lines For Third Parties	2,616	2,698	2,767	2,835	2,903
Distribution Reliability Initiative	-	500	512	525	537
Feeder Additions for Load Growth	1,102	545	85	625	1,462
Trunk Feeders	1,261	2,511	3,922	3,765	3,515
Allowance for Funds Used During Construction	193	197	201	205	209
Total - Distribution	**$40,270**	**$42,436**	**$44,294**	**$45,196**	**$44,822**

Newfoundland Power Inc.
2014-2018 Capital Plan
(000s)

GENERAL PROPERTY

Project	2014	2015	2016	2017	2018
Tools and Equipment	$458	$467	$477	$485	$494
Additions to Real Property	379	285	291	297	302
Renovations Company Buildings	-	965	920	600	1,050
Standby Generators	275	275	175	-	-
Total - General Property	**$1,112**	**$1,992**	**$1,863**	**$1,382**	**$1,846**

Newfoundland Power Inc.
2014-2018 Capital Plan
(000s)

TRANSPORTATION

Project	2014	2015	2016	2017	2018
Purchase Vehicles and Aerial Devices	$2,570	$2,629	$2,685	$2,736	$2,785
Total - Transportation	**$2,570**	**$2,629**	**$2,685**	**$2,736**	**$2,785**

Newfoundland Power Inc.
2014-2018 Capital Plan
(000s)

TELECOMMUNICATIONS

Project	2014	2015	2016	2017	2018
Replace/Upgrade Communications Equipment	$99	$102	$104	$106	$108
Fibre Optic Cable	-	173	200	224	224
Total - Telecommunications	**$99**	**$275**	**$304**	**$330**	**$332**

Newfoundland Power Inc.
2014-2018 Capital Plan
(000s)

INFORMATION SYSTEMS

Project	2014	2015	2016	2017	2018
Application Enhancements	$1,372	$1,200	$1,400	$1,450	$1,500
System Upgrades	1,059	1,725	1,685	1,485	1,485
Personal Computer Infrastructure	420	500	500	450	450
Shared Server Infrastructure	833	750	650	600	600
Network Infrastructure	321	200	175	300	200
Total - Information Systems	**$4,005**	**$4,375**	**$4,410**	**$4,285**	**$4,235**

Newfoundland Power Inc.
2014-2018 Capital Plan
(000s)

UNFORESEEN ALLOWANCE

Project	2014	2015	2016	2017	2018
Allowance for Unforeseen Items	$750	$750	$750	$750	$750
Total - Unforeseen Allowance	**$750**	**$750**	**$750**	**$750**	**$750**

Newfoundland Power Inc.
2014-2018 Capital Plan
(000s)

GENERAL EXPENSES CAPITALIZED

Project	2014	2015	2016	2017	2018
General Expenses Capitalized	$4,000	$4,000	$4,000	$4,000	$4,000
Total - General Expenses Capitalized	**$4,000**	**$4,000**	**$4,000**	**$4,000**	**$4,000**

2013 Capital Expenditure Status Report

June 2013

Newfoundland Power Inc.

2013 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 8 of Order No. P.U. 31 (2012).

Page 1 of the 2013 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 2013, which were approved in Order No. P.U. 31 (2012). The detailed tables also include information on those capital projects approved for 2011 and 2012 (and approved in Order Nos. P.U. 28 (2010) and P.U. 26 (2011)) that were not completed prior to 2013.

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 2013 Capital Expenditure Status Report. These variance criteria are as outlined in the *Capital Budget Application Guidelines*.

Newfoundland Power Inc.

2013 Capital Budget Variances
(000s)

	Approved by Order Nos. P.U. 31 (2012)	Forecast	Variance
Generation – Hydro	$4,450	$4,450	-
Generation - Thermal	284	284	-
Substations	17,618	17,618	-
Transmission	5,371	5,371	-
Distribution	38,740	40,180	1,440
General Property	1,737	1,737	-
Transportation	2,950	2,950	-
Telecommunications	874	874	-
Information Systems	4,014	4,014	-
Unforeseen Items	750	750	-
General Expenses Capitalized	4,000	4,200	200
Total	$80,788	$82,428	1,640
Projects carried forward from 2011 and 2012		$1,465	

2013 Capital Expenditure Status Report
(000s)

	Capital Budget				Actual Expenditures				Forecast			
	2011	2012	2013	Total	2011	2012	2013	Total To Date	Remainder 2013	Total 2013	Overall Total	Variance
	A	B	C	D	E	F	G	H	I	J	K	L
2013 Projects	$ -	$ -	$ 80,788	$ 80,788	$ -	$ -	$ 19,507	$ 19,507	$ 62,921	$ 82,428	$ 82,428	$ 1,640
2012 Projects	-	6,783	-	$ 6,783	-	4,143	247	4,390	668	$ 915	5,305	(1,478)
2011 Projects	1,281	-	-	$ 1,281	470	163	-	633	550	$ 550	1,183	(98)
Grand Total	**$ 1,281**	**$ 6,783**	**$ 80,788**	**$ 88,852**	**$ 470**	**$ 4,306**	**$ 19,754**	**$ 24,530**	**$ 64,139**	**$ 83,893**	**$ 88,916**	**$ 64**

Column A	Approved Capital Budget for 2011
Column B	Approved Capital Budget for 2012
Column C	Approved Capital Budget for 2013
Column D	Total of Columns A,B and C
Column E	Actual Capital Expenditures for 2011
Column F	Actual Capital Expenditures for 2012
Column G	Actual Capital Expenditures for 2013
Column H	Total of Columns E,F and G
Column I	Forecast for Remainder of 2013
Column J	Total of Columns G and I
Column K	Total of Columns H and I
Column L	Column K less Column D

2013 Capital Expenditure Status Report
(000s)

Category: Generation - Hydro

	Capital Budget			Actual Expenditures			Forecast				
Project	**2012**	**2013**	**Total**	**2012**	**2013**	**Total To Date**	**Remainder 2013**	**Total 2013**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	I	J	
2013 Projects											
Hydro Plants - Facility Rehabilitation	$ -	$ 1,400	$ 1,400	$ -	$ 356	$ 356	$ 1,044	$ 1,400	$ 1,400	$ -	
Hydro Plant Production Increase	-	1,128	$ 1,128	-	169	169	959	1,128	1,128	-	
New Chelsea Plant Refurbishment	-	847	$ 847	-	12	12	835	847	847	-	
Pittman's Pond Plant Refurbishment	-	875	$ 875	-	65	65	810	875	875	-	
Hearts Content Plant Refurbishment	-	200	$ 200	-	11	11	189	200	200	-	
Total - 2013 Generation Hydro	**$ -**	**$ 4,450**	**$ 4,450**	**$ -**	**$ 613**	**$ 613**	**$ 3,837**	**$ 4,450**	**$ 4,450**	**$ -**	
2012 Projects											
Rattling Brook Dam Refurbishment	$ 5,000	-	$ 5,000	$ 2,744	$ -	$ 2,744	$ 285	$ 285	$ 3,029	$ (1,971)	1
Total - Generation Hydro	**$ 5,000**	**$ 4,450**	**$ 9,450**	**$ 2,744**	**$ 613**	**$ 3,357**	**$ 4,122**	**$ 4,735**	**$ 7,479**	**$ (1,971)**	

* See Appendix A for notes containing variance explanations.

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

2013 Capital Expenditure Status Report
(000s)

Category: Generation - Thermal

Project	Capital Budget 2013 A	Capital Budget Total B	Actual Expenditures 2013 C	Actual Expenditures Total To Date D	Forecast Remainder 2013 E	Forecast Total 2013 F	Forecast Overall Total G	Variance H	Notes*
2013 Projects									
Thermal Plants - Facility Rehabilitation	$ 284	$ 284	$ 45	$ 45	$ 239	$ 284	$ 284	$ -	
Total - Generation Thermal	**$ 284**	**$ 284**	**$ 45**	**$ 45**	**$ 239**	**$ 284**	**$ 284**	**$ -**	

* See Appendix A for notes containing variance explanations.

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

2013 Capital Expenditure Status Report
(000s)

Category: Substations

Project	Capital Budget 2013	Capital Budget Total	Actual Expenditures 2013	Actual Expenditures Total To Date	Forecast Remainder 2013	Forecast Total 2013	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2013 Projects									
Substation Refurbishment and Modernization	$ 4,452	$ 4,452	$ 476	$ 476	$ 3,976	$ 4,452	$ 4,452	$ -	
Replacements Due to In-Service Failures	2,685	2,685	918	918	1,767	2,685	2,685	-	
Additions Due to Load Growth	3,974	3,974	640	640	3,334	3,974	3,974	-	
PCB Bushing Phase-out	3,386	3,386	1,063	1,063	2,323	3,386	3,386	-	
Substation Addition - Portable Substation	3,121	3,121	19	19	3,102	3,121	3,121	-	
Total - Substations	**17,618**	**17,618**	**3,116**	**3,116**	**14,502**	**17,618**	**17,618**	**-**	

* See Appendix A for notes containing variance explanations.

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

2013 Capital Expenditure Status Report
(000s)

Category: Transmission

	Capital Budget		Actual Expenditures		Forecast				
Project	**2013**	**Total**	**2013**	**Total To Date**	**Remainder 2013**	**Total 2013**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2013 Projects									
Rebuild Transmission Lines	$ 5,371	$ 5,371	$ 349	$ 349	$ 5,022	$ 5,371	$ 5,371	$ -	
Total - Transmission	**$ 5,371**	**$ 5,371**	**$ 349**	**$ 349**	**$ 5,022**	**$ 5,371**	**$ 5,371**	**$ -**	

* See Appendix A for notes containing variance explanations.

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

2013 Capital Expenditure Status Report
(000s)

Category: Distribution

	Capital Budget				Actual Expenditures				Forecast				
Project	**2011**	**2012**	**2013**	**Total**	**2011**	**2012**	**2013**	**Total To Date**	**Remainder 2013**	**Total 2013**	**Overall Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	
2013 Projects													
Extensions	$ -	$ -	$ 11,376	$ 11,376	$ -	$ -	$ 3,798	$ 3,798	$ 8,578	$ 12,376	$ 12,376	$ 1,000	
Meters	-	-	2,849	2,849	-	-	1,195	1,195	1,694	2,889	2,889	40	
Services	-	-	3,705	3,705	-	-	1,307	1,307	2,668	3,975	3,975	270	
Street Lighting	-	-	2,267	2,267	-	-	651	651	1,746	2,397	2,397	130	
Transformers	-	-	7,983	7,983	-	-	1,923	1,923	6,060	7,983	7,983	-	
Reconstruction	-	-	3,499	3,499	-	-	1,445	1,445	2,054	3,499	3,499	-	
Rebuild Distribution Lines	-	-	2,997	2,997	-	-	787	787	2,210	2,997	2,997	-	
Relocate/Replace Distribution Lines For Third Parties	-	-	2,554	2,554	-	-	566	566	1,988	2,554	2,554	-	
Trunk Feeders	-	-	117	117	-	-	-	-	117	117	117	-	
Feeder Additions for Growth	-	-	1,204	1,204	-	-	453	453	751	1,204	1,204	-	
Allowance for Funds Used During Construction	-	-	189	189	-	-	65	65	124	189	189	-	
Total - 2013 Distribution	**$ -**	**$ -**	**$ 38,740**	**$ 38,740**	**$ -**	**$ -**	**$ 12,190**	**$ 12,190**	**$ 27,990**	**$ 40,180**	**$ 40,180**	**$ 1,440**	
2012 Projects													
Trunk Feeders	$ -	$ 848	$ -	$ 848	$ -	$ 779	$ 247	$ 1,026	38	$ 285	$ 1,064	$ 216	2
2011 Projects													
Feeder Additions for Growth	$ 1,281	$ -	$ -	$ 1,281	$ 470	$ 163	$ -	$ 633	550	$ 550	$ 1,183	$ (98)	
Total Distribution	**$ 1,281**	**$ 848**	**$ 38,740**	**$ 40,869**	**$ 470**	**$ 942**	**$ 12,437**	**$ 13,849**	**$ 28,578**	**$ 41,015**	**$ 42,427**	**$ 1,558**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2011
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Column J	Total of Columns G and I
Column K	Total of Columns H and I
Column L	Column K less Column D

2013 Capital Expenditure Status Report
(000s)

Category: General Property

	Capital Budget			Actual Expenditures			Forecast				
						Total	Remainder	Total	Overall		
Project	**2012**	**2013**	**Total**	**2012**	**2013**	**To Date**	**2013**	**2013**	**Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	I	J	
2013 Projects											
Tools and Equipment	$ -	$ 389	$ 389	$ -	$ 89	$ 89	$ 300	$ 389	$ 389	$ -	
Additions to Real Property	-	238	238	-	4	4	234	238	238	-	
Company Building Renovations	-	950	950	-	310	310	640	950	950	-	
Standby Generator Duffy Place	-	160	160	-	-	-	160	160	160	-	
Total - 2013 General Property	**$ -**	**$ 1,737**	**$ 1,737**	**$ -**	**$ 403**	**$ 403**	**$ 1,334**	**$ 1,737**	**$ 1,737**	**$ -**	
2012 Projects											
Company Building Renovations	$ 935	$ -	$ 935	$ 620	$ -	$ 620	345	$ 345	$ 965	$ 30	
Total General Property	**$ 935**	**$ 1,737**	**$ 2,672**	**$ 620**	**$ 403**	**$ 1,023**	**$ 1,679**	**$ 2,082**	**$ 2,702**	**$ 30**	

* See Appendix A for notes containing variance explanations.

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

2013 Capital Expenditure Status Report
(000s)

Category: Transportation

Project	Capital Budget 2013	Capital Budget Total	Actual Expenditures 2013	Actual Expenditures Total To Date	Forecast Remainder 2013	Forecast Total 2013	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2013 Projects									
Purchase Vehicles and Aerial Devices	$ 2,950	$ 2,950	$ 247	$ 247	$ 2,703	$ 2,950	$ 2,950	$ -	
Total - Transportation	**$ 2,950**	**$ 2,950**	**$ 247**	**$ 247**	**$ 2,703**	**$ 2,950**	**$ 2,950**	**$ -**	

* See Appendix A for notes containing variance explanations.

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

2013 Capital Expenditure Status Report
(000s)

Category: Telecommunications

Project	Capital Budget 2013 A	Capital Budget Total B	Actual Expenditures 2013 C	Actual Expenditures Total To Date D	Forecast Remainder 2013 E	Forecast Total 2013 F	Forecast Overall Total G	Variance H	Notes*
2013 Projects									
Replace/Upgrade Communications Equipment	$ 124	$ 124	$ 21	$ 21	$ 103	$ 124	$ 124	$ -	
Mobile Radio System Replacement	750	750	-	-	750	750	750	-	
Total - Telecommunications	**$ 874**	**$ 874**	**$ 21**	**$ 21**	**$ 853**	**$ 874**	**$ 874**	**$ -**	

* See Appendix A for notes containing variance explanations.

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

2013 Capital Expenditure Status Report
(000s)

Category: Information Systems

Project	Capital Budget 2013	Capital Budget Total	Actual Expenditures 2013	Actual Expenditures Total To Date	Forecast Remainder 2013	Forecast Total 2013	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2013 Projects									
Application Enhancements	$ 1,380	$ 1,380	$ 427	$ 427	$ 953	$ 1,380	$ 1,380	$ -	
System Upgrades	1,177	1,177	209	209	968	1,177	1,177	-	
Personal Computer Infrastructure	380	380	101	101	279	380	380	-	
Shared Server Infrastructure	877	877	147	147	730	877	877	-	
Network Infrastructure	200	200	109	109	91	200	200	-	
Total - Information Systems	**$ 4,014**	**$ 4,014**	**$ 993**	**$ 993**	**$ 3,021**	**$ 4,014**	**$ 4,014**	**$ -**	

* See Appendix A for notes containing variance explanations.

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

2013 Capital Expenditure Status Report
(000s)

Category: Unforeseen Items

Project	Capital Budget 2013	Capital Budget Total	Actual Expenditures 2013	Actual Expenditures Total To Date	Forecast Remainder 2013	Forecast Total 2013	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2013 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 2013
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2013
Column D	Total of Column C
Column E	Forecast for Remainder of 2013
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2013 Capital Expenditure Status Report
(000s)

Category: General Expenses Capitalized

Project	Capital Budget 2013	Capital Budget Total	Actual Expenditures 2013	Actual Expenditures Total To Date	Forecast Remainder 2013	Forecast Total 2013	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2013 Projects									
Allowance for General Expenses Capitalized	$ 4,000	$ 4,000	$ 1,530	$ 1,530	$ 2,670	$ 4,200	$ 4,200	$ 200	
Total - General Expenses Capitalized	**$ 4,000**	**$ 4,000**	**$ 1,530**	**$ 1,530**	**$ 2,670**	**$ 4,200**	**$ 4,200**	**$ 200**	

* See Appendix A for notes containing variance explanations.

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Column A	Approved Capital Budget for 2013
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2013
Column D	Total of Column C
Column E	Forecast for Remainder of 2013
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:*

Budget: $5,000,000 Actual: $3,029,000 Variance: ($1,971,000)

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]

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

Distribution

2. *Trunk Feeders (2012 Project):*

Budget: $848,000 Actual: $1,064,000 Variance: $216,000

Actual Trunk Feeders expenditure was higher than the 2012 Capital Budget amount, primarily as a result of additional cost incurred to meet the requirements of municipal and federal government authorities. Additional expenditures of $188,000 are associated with the Charlottetown submarine cable project in Terra Nova National Park, including additional survey work to meet federal requirements and other work necessary to comply with Parks Canada's Environmental Protection Plan established for the project. Additional expenditures of $28,000 were incurred to replace a line in Stephenville when the Town of Stephenville required that an additional 700 metres of the line be routed underground along Massachusetts Drive.

2014 Facility Rehabilitation

June 2013

Prepared by:

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NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

The 2014 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 2014 Facility Rehabilitation project totalling $1,610,000 is comprised of Hydro Dam and Intake Structure Rehabilitation and Generation Equipment Replacements Due to In-Service Failures.

2.0 Hydro Dam Rehabilitation

Cost: $1,025,000

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 2014 includes:

1. *Topsail Forebay Refurbishment ($115,000)*
   This project involves the rehabilitation of several deteriorated components of the gate house as well as improvements to reduce flooding. The trashrack and adjacent timber

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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.

floor were replaced in 1991. Recent observations and inspections have indicated that both the trashrack and adjacent timber joists have deteriorated significantly. A new trashrack is required, as failure could cause extensive damage to the turbine. Replacement of the gatehouse deck joists is required to ensure employee safety.

During period of high inflows, such as significant rainfall events or snow melts, the water rises to, or exceeds the height of the gatehouse timber frame. The water flows through the gatehouse and floods the adjacent parking area. As a result of the timber being frequently close to or in the water, it has deteriorated significantly. During extreme flood events, high water limits access to the gatehouse. Improvements to the structure and parking lot grade are required to divert the flood waters toward the spill channel to ensure the continued safety and integrity of the structure.

Figure 1 – Deteriorated Trash Rack

Figure 2 – Deteriorated Timber Deck

Figure 3 – High Water (Above Floor Elevation)

2. *Cape Broyle Spillway ($495,000)*
   The Cape Broyle Spillway was constructed in the mid 1950's as part of the original hydro development. This project involves replacement of the existing stoplog spillway with a new concrete structure. Stability analysis indicates that the spillway does not meet requirements for overturning and the structure lacks available freeboard with the stoplogs in place. The concrete base has deteriorated in places and the right abutment is prone to washout during periods of high flow.

   Accessing the structure to remove stoplogs is critical to dam safety. Access during extreme flood conditions is difficult, and operation of this type of spillway is a safety hazard for power plant operators. In addition to dam safety deficiencies, the spillway does not meet public safety requirements. Replacing the stoplog spillway with a concrete overflow spillway without an access walkway will address dam safety deficiencies and remove a significant public and employee safety hazard.

   The deteriorated stoplogs leak considerably and this condition is expected to worsen over time. Based on field measurements, it is estimated that approximately 1.35 GWh of energy is lost annually as a direct result of the leakage. Addressing the leakage as part of the construction of a new concrete structure will save approximately $227,000 in annual purchase power cost.[3]

Figure 4 – Cape Broyle Spillway

Figure 5 – Access Walkway

[3] 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.

Figure 6 – Deteriorated Concrete and Abutment Prone to Washout

Figure 7 – Significant Leakage

Figure 8 – Concrete Deterioration

3. *West Lake Dam and Spillway ($215,000)*
   The West Lake dam and spillway are a part of the Sandy Brook plant watershed. West Lake Dam was reconstructed in 1984. This project involves replacing the existing concrete outlet structure, refurbishing the spillway and completing safety improvements. Refurbishment of the concrete outlet structure is required as it has significant vertical cracking and the wingwall concrete has eroded due to turbulence. The steel spillway cutoff has heaved vertically and as a result the spillway is no longer level. Refurbishment is required as the vertical rise has decreased spillway capacity and poses a tripping hazard to both employees and cabin owners in the area. The walkway also does not meet current public safety requirements. Improvements to walkway safety will be incorporated into the new outlet design.

Figure 9 – West Lake Dam and Spillway

Figure 10 – Deteriorated Wingwall Concrete

Figure 11 – Heaved Cutoff Wall

Figure 12 – Walkway and Gate Structure

4. *Lawn Plant: Intake Structure Rehabilitation ($200,000)*
The Lawn intake structure was constructed in the mid 1930's as part of the original hydro development. The concrete intake conduit and support structure for the intake gate at Lawn Plant requires rehabilitation. This portion of the structure has deteriorated to the point where pieces of concrete are breaking free of the intake structure and traveling through the penstock to the generator turbine. In addition, excessive flows currently migrate through the concrete that is installed on the top and sides of the gate when the gate is in the closed position. The flows have increased such that the penstock can no longer be dewatered for maintenance purposes.

This project involves rehabilitation of the existing concrete intake conduit and support structure for the intake gate at Lawn Plant.

Figure 13 – Lawn Forebay Dam

Figure 14 – Concrete Removed from Turbine

Figure 15 – Gate Guide (Note: Deteriorated Concrete behind gate guide)

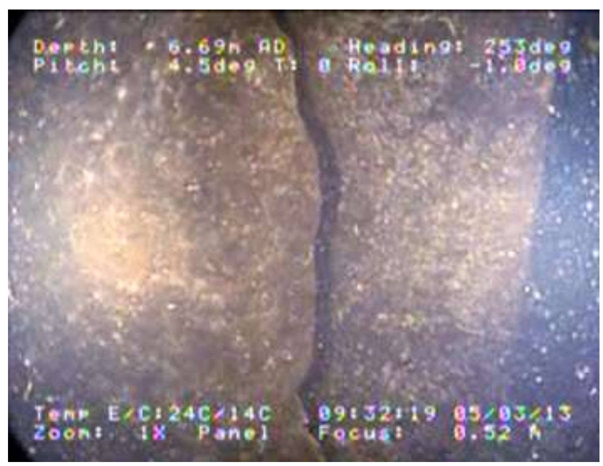


Figure 16 – Crack in intake conduit roof

3.0 Generation Equipment Replacements Due to In-Service Failures

Cost: $585,000

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 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 2008.

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

Year	2009	2010	2011	2012	2013F
Total	$475	$569[4]	$464	$523	$575

Based upon this recent historical information and engineering judgement, $585,000 is estimated to be required in 2014 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.

[4] Excludes Hurricane Igor related costs from 2010.

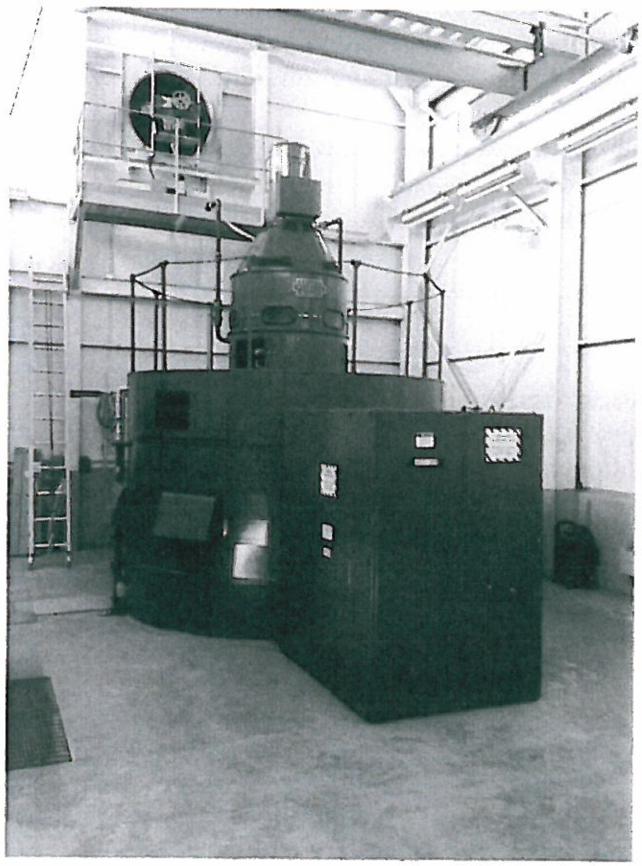
4.0 Concluding

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 2014 budget of $1,610,000 for Facility Rehabilitation is recommended as follows:

- $1,025,000 for Hydro Dam Rehabilitation;
- $585,000 for Generation Equipment Replacements Due to In-Service Failures.

Heart's Content Hydro Plant Refurbishment

June 2013



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1.0 Background

1.1 General

Newfoundland Power's Heart's Content hydroelectric development (the "Plant") is located on the Avalon Peninsula, near the community of Heart's Content, approximately 125 km west of the City of St. John's.

The Plant was placed into service in 1960 and contains one generating unit with a nameplate capacity of 2.4 MW and a rated net head of 46.9 m.[1] The Plant contains a single vertical 3,400 hp Francis turbine manufactured by Inglis (English Electric) and a 3,000 kVA Bruce Peebles & Co. Ltd. generator.[2] The Plant's normal annual production is approximately 8.3 GWh or 1.9 % of the total hydroelectric production of Newfoundland Power. The Plant has provided 54 years of reliable energy production.

The refurbishment and life extension of the Plant includes necessary work on the generator, protection and control equipment and switchgear.[3] The estimated levelized cost of energy from the Plant over the next 50 years, including the capital expenditure of $6.4 million over the next 25 years, is 6.27¢ per kWh.[4]

This report provides a summary of the engineering assessment of the Plant and the refurbishment proposed for 2014.

1.2 Previous Upgrades

There have been a number of upgrades to the original plant and equipment since commissioning in 1960.

The following is a list of the upgrades that have been completed in the past 25 years:

1989 – Controls upgraded on main inlet and bypass valves
1996 – Forebay line relocated
1997 – Main inlet valve replaced
1997 – Anti-condensation heaters added
1997 – Generator stator re-wedged
1998 – PDA system and multifunction generator protection relay added
1999 – PLC and bearing temperature monitoring added
2000 – Cooling coils and cooling water solenoids replaced
2001 – Generator circuit breaker replaced
2002 – PLC upgrades
2003 – Roof replacement

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1 The original generating station at the Hearts Content site dates back to 1918.

2 The generator is rated at 3,000 kVA at 80% power factor, which equates to a 2,400 kW load rating.

3 Associated with this project is the replacement of the penstock which was approved as a multiyear project in Order No. P.U. 31 (2012). A copy of the report describing the penstock replacement project can be found with the 2013 Capital Budget Application at ***1.2*** *Heart's Content Plant Penstock Replacement*.

4 Details of the feasibility analysis can be found in Appendix B.

2004 – Intruder and fire alarm systems added
2005 – Fisheries compensation valve added
2007 – Forebay water level system upgraded
2008 – Cooling water system upgraded and duplex filters added
2008 – Runner replaced
2008 – Garage door replaced
2008 – Two exhaust fans with dampers and hood installed
2009 – AC distribution upgraded and station service transformer replaced
2009 – Controls upgraded
2009 – 15-ton crane and trolley installed
2009 – ION 7550 revenue meter installed

2.0 Engineering Assessment

2.1 General Condition Assessment

A detailed engineering assessment has been completed and has determined that the Plant is in generally good condition.[5] Most civil and mechanical systems have been upgraded over the past 25 years and are in good condition, requiring only minor work. The engineering assessment has determined that the Plant requires the refurbishment of three major electrical systems at this time.

The overall building structure is in good condition, including the roof, entrance systems and overhead crane. The turbine runner, wicket gates and the main valve have been recently replaced. The bypass valve and mechanical sections of the governor are original to the Plant. The bypass valve does not require any work at this time and the mechanical section of the governor requires only a minor overhaul. The AC and DC electrical distribution panels are in good condition and have sufficient capacity to accommodate the necessary refurbishment. Most instrumentation, including the MegAlert system and the control of the heating and ventilating equipment, is in good condition.

The primary systems requiring refurbishment for the life extension of a plant include the generator, protection and control equipment, switchgear and some miscellaneous ancillary equipment.

2.2 Generator ($790,000)

The Plant generator was manufactured in 1959 by Bruce Peebles & Co. Ltd. and the stator and rotor windings are original to the 55 year old unit. In 1997, the stator winding was re-wedged as a result of the stator coils becoming loose.[6] Winding coils in the stator are subjected to thermal and mechanical stresses during normal operation. Electrical insulation of the rotor is subjected to similar thermal stresses as the stator due to normal operation of the generator. Mechanical stresses experienced by rotor poles are substantially higher than the stator due to centrifugal

[5] Appendix A includes a detailed engineering assessment of the Plant.
[6] Loose coils results in rapid deterioration of the insulating material encasing the coils due to increased movement caused by the mechanical forces exerted on them.

forces present during normal operation. The condition and age of the stator winding and the rotor insulation necessitates their replacement in 2014.

The pilot exciter and main exciter are the original units supplied with the generator in 1959. The pilot exciter will no longer be required when the new digital voltage regulator is installed. The exciter commutator and the slip rings are scored and require resurfacing. The condition and age of the exciter dictates that it should be rewound in conjunction with the generator rewind.

The rewinding of the stator and exciter, and the re-insulation of the rotor constitutes a major overhaul of the generator. During the course of this work other ancillary systems will be replaced and refurbished as required. Replacement of the surge protection, neutral grounding transformer and resistor are required. The generator potential transformers and current transformers, field breaker and field discharge resistor will also be replaced. All of this equipment will be located in either the generator termination cubicle or the switchgear.

The power cables between the exciter and the rotor are original to the 1959 installation. The condition and age of the cables require that they be replaced.

2.3 Protection and Control ($840,000)

The existing mechanical section of the governor including the hydraulic power piston assembly, the relay valve, hand wheel, and gate operating linkages are in good operating condition and will be retained.[7] The governor controls are antiquated and will be modernized. The control head, which initiates the movement of the power piston, will be replaced with a programmable logic controller ("PLC") based digital control system.[8] The new governor control system will facilitate the implementation of a water management system. The water management system will optimize efficiency of the plant by controlling the load on the unit based upon the amount of water available. A fibre optic cable will replace the existing figure 8 copper communications cable to transfer water level information from the forebay to the Plant.

Similar to the governor control, the balance of plant control will be transferred to an upgraded PLC system. An Allan-Bradley CompactLogix® programmable logic controller will be installed to replace the existing plant control system. The upgraded PLC will improve the local and remote monitoring and control functionality and will provide additional information about the performance of key plant components. The new unit control panel containing the upgraded PLC, and a computer based operator interface will be located in the upstairs control room. The unit control panel will also house all associated monitoring and control equipment, control switches and meters necessary to locally operate the Plant. The generator protection, voltage regulation and metering equipment is antiquated and will be replaced with digital equipment located in the unit control panel that readily interfaces to the upgraded PLC system.

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7 Reconditioning of all seals, bushings and other components that have deteriorated through the previous 54 years of service will be required to eliminate leakage and extend the life of the power piston and relay valve assemblies.

8 The fly ball governor head, pilot valve assembly, mechanical restoring linkages and permanent magnet generator used for speed sensing will be removed.

Most of the existing instrumentation in the Plant will be interfaced with the upgraded PLC system. The exceptions include speed sensing, vibration monitoring and governor condition sensing. Instrumentation for these measurements will be upgraded to interface with the PLC system.

The upgraded PLC will also integrate with the existing SCADA data concentrator to communicate with the System Control Centre for remote monitoring and control of the Plant.

2.4 Switchgear ($465,000)

The existing switchgear will be replaced with an arc flash rated assembly, equipped with an arc-flash protection system and containing a new vacuum breaker with closed-door racking capability. Higher accuracy instrument transformers for improved protection and metering will be supplied with the switchgear. The existing 3-phase station service transformer will be incorporated into the new switchgear.

The existing power cables between the switchgear and the generator will be reused. New power cables will be installed between the switchgear and the power transformer in the substation yard replacing the existing original cable and terminations. The power cables will be terminated on a new structure in the substation yard on which a disconnect switch and current transformers for the arc-flash relay system will be mounted.

2.5 Miscellaneous ($145,000)

The remainder of the work associated with the 2014 refurbishment project involves miscellaneous ancillary systems required for the safe and reliable operation of the Plant.

Both the battery bank and charger are beyond their life expectancy and will be replaced with a gel-cell battery bank and temperature compensated battery charger. The intake louvers in the west end of the building are deteriorated and will be replaced while the existing actuator will be reused. The existing generator and turbine floor heaters will be replaced with blower-type heaters.

Compressed air is used to operate the generator brakes. The existing compressor and pressure tank are 1959 vintage and lack necessary features such as an air-water separator, pressure regulator or pressure switch for low air alarm. The condition and age of the compressed air system dictates that it should be replaced.

3.0 Project Proposal

3.1 Cost Breakdown

The total project cost for the refurbishment of the Plant, excluding cost associated with the penstock replacement, is estimated at $2,240,000. Table 1 below summarizes the cost breakdown.

Table 1
Project Cost
($000s)

Cost Category	Cost
Material	1,689
Labour - Internal	246
Labour - Contract	-
Engineering	146
Other	159
Total	**2,240**

Associated with this project is the replacement of the penstock at a 2014 estimated cost of $3,495,000 which was approved as a multiyear project in Order No. P.U. 31 (2012).

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 8.3 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 $6.4 million over the next 25 years, is 6.27¢ per kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation.[9]

[9] The avoided cost of fuel at the Holyrood Thermal Generating Station is estimated at 16.8¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.80 per barrel for 2013 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated April 12, 2013.

4.0 Conclusion

A detailed engineering assessment has been completed on the Heart's Content Hydro Plant and has determined that the Plant is in generally good condition. The primary systems requiring refurbishment at this time for the life extension of the Plant include the generator, protection and control equipment, switchgear and some miscellaneous ancillary equipment.

The generator and exciter winding will be replaced during the extended outage associated with the penstock replacement. Installation of a PLC based governor control system, improved PLC based plant control system, upgraded protection and replacement of equipment that has surpassed its reliable service life are required to ensure reliable, efficient operation of the Plant and the provision of energy to the Island Interconnected system.

The feasibility analysis included in Appendix B verifies the financial viability of completing this project. The 8.3 GWh of energy that will be available from Heart's Content each year will provide 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 2014.

Appendix A
Heart's Content Hydro Plant
Engineering Assessment

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1.0 General

The following summarizes the results of the detailed engineering assessment performed on Newfoundland Power's Heart's Content Hydro Plant ("the Plant"). This assessment included an evaluation of the condition of the various components contained in the facility together with comprehensive recommendations for required refurbishment to permit life extension.

2.0 Civil

Structurally, the Plant is in good condition, the roof was replaced in 2003 and a galvanized rolling door was installed in 2008. The only civil work required during this upgrade is the installation of channel iron in the concrete floor, to which the new switchgear will be attached, and the interior of the Plant will be painted upon completion of the refurbishment.

3.0 Governor

The Woodward Type LR gateshaft governor is the original unit. It has been reliable and, except for minor oil leakage, has no outstanding maintenance issues. The original equipment manufacturer discontinued manufacturing replacement parts for these units as of July 1, 2008. A number of third party companies provide maintenance support, including parts, but these companies and the utility industry is moving towards replacing the hydraulic control portion of these governors with digital systems that provide enhanced control and feedback capabilities.[1]

The governor speed control and gate limit are motorized and can be operated remotely utilizing electromechanical relay logic to control the load on the unit. There are no gate position or gate limit setpoint transducers and therefore no feedback of these quantities for unit control or remote indication. More advanced control of the governor setpoints is required to implement a water management system in the unit control PLC to optimize the energy produced from the available water.

Figure 1 - Woodward Governor

[1] The Company has 16 Woodward gateshaft governors in service in its hydro plants. In previous capital budget applications that included hydro plant refurbishment projects, 12 of the 16 Woodward governors have been refurbished in a manner similar to what is recommended at Heart's Content.

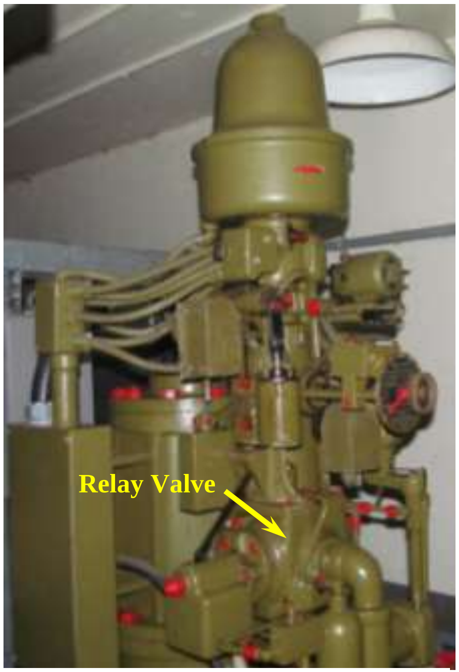


Figure 2 - Governor Control Head

The governor consists of two sections, the power piston that provides the force necessary to operate the wicket gates under load and the control head that adjusts the position of the power piston to maintain the system frequency through varying load conditions. The control head, which initiates the movement of the power piston, will be replaced down to the relay valve with a PLC based digital control system. The fly ball governor head, pilot valve assembly, mechanical restoring linkages and permanent magnet generator used for speed sensing will be removed. The new governor control system will facilitate the implementation of a water management system. The existing hydraulic power piston assembly will be retained, along with the relay valve, handwheel, and gate operating linkages. Reconditioning of all seals, bushings and other components that have deteriorated through the previous 54 years of service will be required to eliminate leakage and extend the life of the power piston and relay valve assemblies.

4.0 Generator

The generator at the Plant was manufactured by Bruce Peebles & Co. Ltd. in 1959 and the stator and rotor windings are original to the 55 year old unit. Generator winding insulation has a design life of 40 years, with the actual life dependent upon several factors including quality control during manufacture, quality control during installation and operating conditions such as loading of the generator, ambient temperature, humidity and exposure to system electrical faults.

Winding coils in the stator are subjected to thermal and mechanical stresses during normal operation. These stresses result in movement of the coils in the stator slots. This movement as well as the normal electrical stress placed on the insulation when the unit is operating, leads to degradation of the insulating material on the coils. Failure of the insulating material will result in an in service failure of the generator similar to the one experienced in 2002 on one unit at the Rattling Brook hydro plant.[2]

Insulation for the rotor is subjected to similar thermal stresses as the stator due to normal operation of the generator. Mechanical stresses experienced by rotor poles are substantially higher than the stator 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.

[2] The in service failure at Rattling Brook hydro plant occurred when the generator had been in service 43 years.

The Plant generator stator windings, which operate at 2,400 volts, are among the oldest windings remaining in service in the Company's fleet of generating plants.[3] In 1997, the stator was re-wedged as a result of the stator coils becoming loose. Loose coils results in rapid deterioration of the insulating material encasing the coils due to increased movement caused by the mechanical forces exerted on them.

The replacement of the Heart's Content intake and penstock are scheduled to be completed in 2014. It is estimated that the plant will be out of service for 20 weeks from June to October to complete this work. Completing the generator rewind at the same time would add efficiencies by eliminating the need for additional down time and lost production. It is recommended that the generator rewind be completed in conjunction with this project.

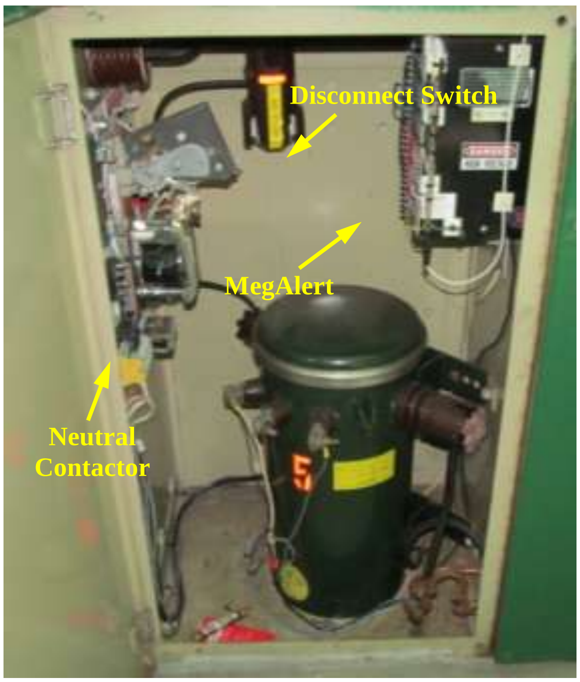


Figure 3 – Neutral Grounding Transformer

The generator neutral is high-impedance grounded through a grounding transformer, resistor, disconnect switch and neutral contactor located in the generator termination cubicle. To minimize the magnitude of fault currents, high impedance grounding is the preferred method of generator neutral to ground connection. The grounding transformer is a 1960's vintage 5 kVA oil-filled distribution unit. The resistor connected across the secondary of the grounding transformer is original. The size of the resistor required will be recalculated with the new power cables and surge capacitors. A properly sized resistor minimizes the transient overvoltage in the event of an arcing ground fault. A new dry-type neutral grounding transformer with secondary resistor will be installed in the generator termination cubicle. The neutral disconnect switch will be removed and the neutral contactor will be incorporated into the new grounding system.

The generator is shut down when there is inadequate water available for production. This usually occurs during the summer and early fall when humidity is high. As a result, moisture accumulation on the stator windings compromises the winding insulation. Energizing the generator with moisture present could result in an electrical flashover and permanent winding damage. A MegAlert® stator insulation test system provides a warning that allows prompt corrective action to be taken when the insulation value is reduced.[4] To enable the testing to be completed, the insulation testing system includes a neutral contactor to automatically disconnect

[3] Newfoundland Power currently has 16 generators operating at 2,400 volts with an average winding age of 30 years. Nine of the 16 generators have been rewound. The average age of the windings when rewound was 63 years. The Heart's Content stator windings will be 55 years old when replaced.

[4] The Company has installed MegAlert® insulation testing systems on 16 generators. The MegAlert® system continuously monitors the integrity of the insulation while the unit is shut down, ensuring it can be re-energized when required. It will also prevent re-energizing the generator should the insulation measurement fall below a safe value.

the stator windings from ground when the generator shuts down. A MegAlert® system has been previously installed at Heart's Content and will be incorporated into the new control system as part of this project.

The existing generator surge protection capacitor and lightning arresters are connected to the 2,400 volt bus in the switchgear. The three phase capacitor was installed in 1986 and the lightning arresters are the original installation. Three new two bushing capacitors and MOV type lightning arresters will be installed in the generator termination cubicle and connected to the generator leads to provide improved surge protection. The two bushing capacitors will facilitate the use of the MegAlert® stator insulation test system. The three phase capacitor will be returned to inventory.

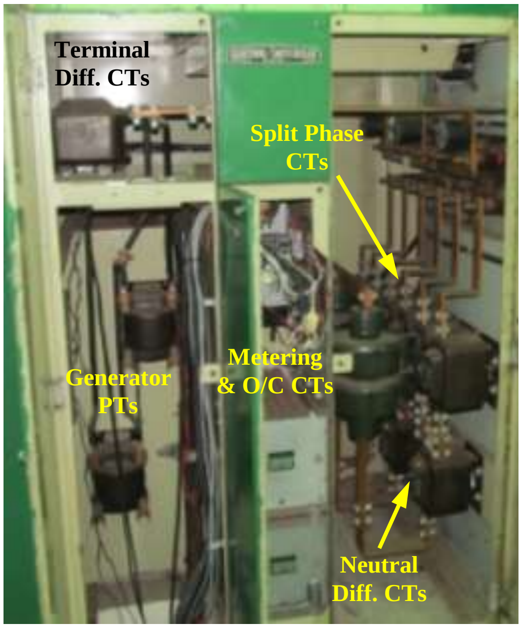


Figure 4 – Generator CTs and PTs

The generator protection and metering potential transformers (PTs) and current transformers (CTs), located in the generator termination cubicle, are original to the 1959 installation. The PTs and CTs are critical to the electrical protection of the generator and will be replaced.[5] The six 400:5 CTs used for generator split phase protection will be replaced with three 100:5 split phase CTs with a rated ampacity of 800 amps. The three neutral-side differential protection CTs and three dual-secondary overcurrent protection and metering CTs will be replaced with three protection CTs, located in the generator termination cubicle, and three revenue class metering CTs, located in the new switchgear lineup. The three terminal side differential CTs and generator PTs will be replaced with new units located in the new switchgear. The single crosscurrent compensation CT will be removed since it will not be required for the new digital voltage regulator. The CT reconfiguration will necessitate modifications to the buswork in the generator termination cubicle. The reconfiguration will also free up enough space to enable the generator surge protection to be installed in the generator termination cubicle.

[5] PTs and CTs are all critical to electrical protection of the generators, and an in-service failure of these components could result in serious damage to the generator windings.

5.0 Excitation System

The pilot exciter and main exciter are the original units supplied with the Bruce Peebles & Co. Ltd. generator in 1959. The pilot exciter will no longer be required when the new digital voltage regulator is installed. The exciter commutator and the slip rings are scored and require resurfacing. The age of the exciter dictates that it should be rewound in conjunction with the generator rewind. Infrared brush temperature sensors will be added to the commutator and slip rings.

Figure 5 – Exciter Commutator

The voltage regulator is the original Brown Boveri Model AV4/1 with mechanical operating mechanisms. These units have been discontinued for many years. The voltage regulator cannot be integrated into the upgraded control system to provide the required automated control. It will be replaced with a digital voltage regulator incorporated into the Combination Generator Control Module (CGCM) located in the unit control panel. The CGCM is designed to be easily integrated into the control system and provide improved voltage regulation under varying system conditions.

The field breaker, which is located in the generator termination cubicle, is the original ITE Model AKF-1 breaker which is no longer supported by the original manufacturer and is beyond its expected service life. A new field breaker will be installed, located either in the generator termination cubicle or in a cabinet mounted on top of the generator termination cubicle, if there is insufficient space. The power cables between the exciter and the rotor will also be replaced.

6.0 Switchgear

The switchgear is original to the 1959 English Electric installation. Several upgrades have been completed over the years. The surge protection was replaced in 1986, the generator circuit breaker was replaced with a Cutler Hammer Type VPC vacuum unit in 2001 and the power cables from the generator to the switchgear were also replaced at that time. The non-standard 27-inch switchgear cubicles greatly limited the options for replacement breakers. A three-phase, 75 kVA, 120/208V station service transformer was installed in the switchgear in 2009. The remaining equipment, including the bus potential transformers and current transformers, are original.

Figure 6 – Switchgear with Doors Open

As a result of the high energy fault levels at this location, there is a very high arc flash hazard associated with this switchgear requiring an arc flash boundary of 3 metres when all cubicle doors are fully secured and 14 meters when racking the breaker, necessitating the use of Level 3 arc flash personal protective equipment.[6]

The protective relays, meters and voltage regulator are incorporated into the switchgear doors, which greatly increase arc flash hazards for operating personnel. The high voltage compartments in the front of the switchgear are vented through the bottom of the doors. In the event of an internal fault, the electric arc and hot gases would exit the switchgear directly towards personnel.

The existing switchgear will be replaced with an arc flash rated assembly, equipped with an arc-flash protection system and containing a new vacuum breaker with closed-door racking capability. Higher accuracy instrument transformers for improved protection and metering will be supplied with the switchgear. The existing station service transformer will be incorporated into the new switchgear. The generator breaker and 3-phase capacitor will be removed from the existing switchgear and returned to inventory.[7] The protective relays, meters and voltage regulator will be located in a new unit control panel to be located in the control room upstairs, providing additional employee safety.

The existing power cables between the switchgear and the generator will be reused. New power cables will be installed between the switchgear and the power transformer in the substation yard to replace the existing original cable and terminations, which are beyond their life expectancy. The power cables will be terminated on a new structure in the yard, on which a T1-D switch and current transformers for the arc-flash relay system will also be installed.

7.0 AC Distribution System

A 75kVA, 120/208 V three phase station service transformer was installed in the switchgear in 2009. It will be relocated to the new switchgear.

A 120/208V, 250A, 84-circuit AC panel, meter and distribution system were installed in 2009. Additional circuits associated with this refurbishment will be connected to this panel. An emergency station service is included in the project design to supply plant heating and lighting in the event of a power interruption to the switchgear.

6 An arc flash study for the Heart's Content switchgear is included as Appendix C.

7 The generator breaker can be used to replace an existing breaker at 6 other Company plants. The 3-phase capacitor is a direct replacement for the unit in service at Pitman's Pond plant and could also be used at 6 other Company plants.

The generator and turbine floor lighting, heating and generator and cable tray grounding will be upgraded.

8.0 DC System

The existing GNB Exide lead-acid battery bank was installed in 1995 and the Staticon battery charger was purchased in 1977. Three cells of the battery bank were found to be defective during maintenance performed in 2011. Both the battery bank and charger are beyond their life expectancy and will be replaced. A gel-cell battery bank and temperature compensated battery charger will be installed.

The 42-circuit, 250A Siemens DC distribution panel, installed in 1996, has ten spare breakers and does not require replacement. Additional circuits associated with this refurbishment will be connected to this panel.

9.0 Protective Relaying

The generator electrical protection is provided by a Beckwith M-3420 multifunction generator protection relay, installed in 2002, and original Westinghouse electromechanical relays. The following protective elements are in service:

27	Undervoltage
32	Reverse Power
51V	Voltage Controlled Overcurrent
59	Overvoltage
59GN	Residual Neutral Overvoltage
81	Under and Over Frequency
87	Differential
87SP	Split Phase

The existing protective relaying lacks three elements of the minimum protection set.[8] Newfoundland Power has only two Beckwith M-3420 relays in service and has no spare available.[9] This relay will be removed from service, placed in inventory and replaced with a Schweitzer digital multifunction generator protection relay, rotor ground module and split phase overcurrent relay, located in the unit control panel. Improved protection reduces stresses due to electrical faults and in turn extends the life of the generator.

10.0 Plant Control

The plant is remotely monitored from the System Control Centre. Presently there is no automation with respect to water management and the setting of machine loads to optimize the use of the water resources. An Allen-Bradley Model SLC 5/04 programmable logic controller

[8] The existing generator protection does not include Rotor Ground Fault (64F), Loss of Field Fault (40), Stator Unbalance Current / Negative Sequence Fault (46) protective elements, which are recommended by the IEEE for these generators.

[9] The other unit is at Rose Blanche Hydro Plant.

was installed in 1999 to monitor bearing temperature and vibration. PLC upgrades were completed in 2002 and 2009 but the standardized Newfoundland Power remote control and water management systems were not implemented because of the type of governor control in place.

An Allan-Bradley CompactLogix® programmable logic controller will be installed to replace the existing system, which will be returned to inventory.[10] The upgraded processor will provide processing power that will greatly improve the local and remote monitoring and control functionality and will provide additional information about the performance of key plant components. It will facilitate the implementation of a variety of control modes to ensure efficient operation of the plant and utilization of available water. Standard control, protection and automation functionality will be implemented.

The existing annunciation is provided by a 15" LCD rack-mounted monitor using a Windows-XP desk-top computer and keyboard as the human-machine interface ("HMI"). This will be replaced by an Allan-Bradley PanelView Plus®. This HMI will provide enhanced alarm and event indication, plant monitoring and trending, set point management and control functionality.

A new data concentrator and network communications switch were installed in 2012 in conjunction with the upgrade of the Heart's Content substation. A high speed data link will be established in 2013 and no additional upgrading will be required as part of this project. The new control system will be integrated with this system and the communications infrastructure will permit remote administration of the PLC and digital relays by head office engineering staff that would normally require a site visit.

The new unit control panel, which will be located in the upstairs control room, will contain the processor, associated monitoring and control equipment, control switches and generator protection relays.

The following equipment will be located in the panel:

a) Allan Bradley CompactLogix® PLC
b) Allan-Bradley PanelView Plus® HMI
c) MegAlert® remote LED display and switch board meter
d) Emergency stop pushbutton (latching)
e) Start pushbutton
f) Stop pushbutton
g) Alarm reset pushbutton
h) Generator breaker control switch (ANSI device No. 52CS)
i) Field breaker control switch (ANSI device No. 41CS)
j) Speed raise/lower control switch (ANSI device No. 15CS)
k) Gate limit control switch (ANSI device No. 65CS)
l) Voltage raise/lower control switch (ANSI device No. 70CS)
m) Generator lock out relay (ANSI Device No. 86G) and blocking switches

[10] The Allan-Bradley CompactLogix® programmable logic controller will provide functionality similar to the ControLogix® programmable logic controller used in the upgrade of larger plants, but with scaled down processing power and capabilities better suited to smaller hydro plants.

n) Three position manual/local/remote control switch (ANSI Device No. 43CS)
o) Schweitzer SEL-700G1 relay with SEL-2664 rotor ground module
p) Schweitzer SEL-551 relay for split phase protection
q) Ethernet Switch
r) Combination Generator Control Module (CGCM)
s) Synchroscope
t) Automatic/manual synchronizing control switch (ANSI device No. 25CS)
u) Schneider PowerLogic® ION 7550 for revenue metering

11.0 Instrumentation

The instrumentation has been upgraded over the past number of years with stator temperature RTD's added as part of the stator rewedging in 1997, bearing temperature and vibration monitoring installed in 1999, the cooling water flow meters and a speed switch installed in 2000 and bearing oil level sensors installed in 2008.

The existing instrumentation, with the exception of the speed switch and vibration monitor, will be reused and integrated into the new control system. The speed switch will be removed and dual magnetic speed sensors installed on the existing PMG toothgear to provide analogue speed signals to the governor and unit control PLCs. The unit control PLC will perform the speed processing functions previously performed by the speed switch. The vibration sensors will be reused but the monitor will be replaced with a Rockwell Automation Entek® system, designed to be seamlessly integrated into the Allan-Bradley PLC. Brush temperature instrumentation will be added and the analog gauges on the governor oil, scroll case and braking air will be replaced with new digital gauges which will provide analog signals to the PLC.

The Schneider PowerLogic® ION 7550 revenue meter, which was installed in the switchgear in 2009, will be relocated to the new unit control panel.

12.0 Heating and Ventilation

Generator anti-condensation heaters were installed in 1997. The heat and ventilation control cabinet, installed in 2009, will be integrated with the PLC. The existing Omega HX303C thermostat/humidistat on the generator floor and a new thermostat to be installed on the turbine floor will be used by the PLC to control all heat and ventilation equipment. Intake louvers on the fan in the west end of the building are deteriorated and will be replaced. The existing actuator will be reused. The existing generator and turbine floor heaters will be replaced with blower-type heaters.

13.0 Water Level Monitoring and Control

The forebay water level system is critical to the implementation of the Water Management System in the PLC. The water level and trash rack signals are transmitted to the plant utilizing pulse width modulated signals over a copper cable. The copper cable is no longer reliable as it has experienced damage due to lightning and ground potential rise and will be replaced with a fibre optic cable. The existing communications system will be upgraded to technology compatible with the new plant control system. In addition, the forebay building will be replaced as part of the penstock upgrade which will result in the replacement of the water level probe.

The PLC will use the water level signal to control the Water Management System. High level (spill) and low level alarms will be initiated when specified water levels are reached. The Water Management System will optimize efficiency of the plant by controlling the load on the unit based upon the following water level, inflow, wicket gate position and control mode set points:

Peak Water Level	Peak Gate Position
Low Inflow Peak Water Level	Efficient Gate Position
Efficient Water Level	Partial Gate Position
Low Inflow Efficient Water Level	Gate Position Deadband
Partial Water Level	Rate of Rise (Bump)
Low Inflow Partial Water Level	Elevation Mode Water Level
Shutdown Water Level	Elevation Mode Gate Shutdown Level
Low Inflow Shutdown Water Level	Load Control Mode Voltage Level
Level Deadband	Load Control Mode Kilowatt Level
Start-up Water Level	Load Control Mode Kilowatt Deadband

14.0 Cooling Water

The cooling water system was partially upgraded in 1997 in conjunction with the main inlet valve replacement and in 2000, the bearing cooling coils and cooling water solenoids were replaced. In 2008, further upgrades including the addition of a duplex filter were completed. No upgrading will be completed as part of this project. The controls will be integrated into the new CompactLogix® PLC.

15.0 Turbine

The runner, nose cone and wicket gates were replaced in 2008 and no additional work is required at this time.

16.0 Main Inlet and Bypass Valves

The main inlet valve, installed in 1997, is a 48-inch Pratt butterfly valve with Rotork actuator. It is in good condition with no leakage observed during the most recent inspection. There has been minor leakage around the actuator gearbox but no work is required at this time. The bypass valve is the original 1960 vintage 5-inch type SMA unit with a limit torque actuator. The valve has been recently refurbished and there is no leakage across the valve seat and only minor leakage around the gate stem. The bypass valve will not be replaced or overhauled as part of this project. The controls, which were upgraded in 1989, will be integrated into the new CompactLogix® PLC.

17.0 Compressor

Figure 8 – Compressor

Compressed air is used to operate the generator braking system. The compressor motor was replaced in 2004 but the compressor and pressure tank are 1959 vintage. The unit does not have an air-water separator, pressure regulator or pressure switch for low air alarm. The age of the 80-gallon J.B Bairid pressure vessel dictates that the compressor should be replaced.

18.0 Overhead Crane

A new 15-ton crane and trolley were installed in 2009 and no additional work is required.

Appendix B
Heart's Content Hydro Plant
Feasibility Analysis

Table of Contents

1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Heart's Content hydroelectric plant (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2014.

With investment required in 2014 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
Heart's Content Hydroelectric Plant
Capital Expenditures

Year	**($000s)**
2014	$5,736
2029	20
2033	275
2038	180
2039	200
Total	**$6,411**

The estimated capital expenditure for the Plant over the next 25 years is $6.41 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 $57,750[1] per year. 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 hydro plant generation/output. This charge is reflected in the historical annual operating costs for the Heart's Content plant.

[1] 2013 dollars.

Penstock maintenance and issues surrounding ice have accounted for a large portion of the operating costs of this plant in recent years. Future operating costs have been estimated at $47,750 to include a reduction of $10,000 per year to reflect the penstock and intake replacement project.

4.0 Benefits

The maximum output from the Plant is 2,400 kW. The Plant normally operates at an efficient load of 2,100 kW to maximize the energy from the water.

The estimated long-term normal production of the Plant under present operating conditions is 8.3 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 6.27¢ per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Heart's Content 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 Heart's Content guarantees the availability of low cost energy to the Province. Otherwise, the projected annual production of 8.3 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 16.8¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.80 per barrel for 2013 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated April 12, 2013.

Attachment A
Summary of Capital Costs

Heart's Content Feasibility Analysis Summary of Capital Costs ($000s)					
Description	**2014**	**2029**	**2033**	**2038**	**2039**
Civil					
Dam, Spillways and Gates			50		
Penstock & Intake	3,495				200
Powerhouse				180	
Mechanical					
Governor Overhaul	12		15		
Air Compressor	7				
Heat and Ventilation	8				
Electrical					
Generator Rewind	786				
P&C and Governor Controls	840		200		
Switchgear	468				
AC & DC Systems	90				
Battery Bank/Charger	30	20	10		
Annual Totals ($2013)	**5,736**	**20**	**275**	**180**	**200**

Attachment B
Summary of Operating Costs

Heart's Content Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs
($2013)

Year	Amount
2008	$36,848
2009	$45,907
2010	$48,713
2011	$91,431
2012	$65,850
Average	**$57,750**

5 -Year Average Operating Cost	$57,750[1]
Reduced Future Penstock Maintenance	-$10,000
Total Forecast Annual Operating Cost	$47,750

[1] 2013 dollars.

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted Average Incremental Cost of Capital 7.50%
PW Year 2013

YEAR	Generation Hydro 64.4yrs 8% CCA	Generation Hydro 64.4yrs 50% CCA	Capital Revenue Requiremen	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
2014	2,240,800	3,495,000	566,877	47,750	0	-614,627	-571,268	-571,268	-5,362,750	-5,934,018	7.405	6.2656
2015	0	0	582,424	48,849	0	-631,273	-545,348	-1,116,615	-4,859,602	-5,976,218	7.606	6.2656
2016	0	0	544,784	49,872	0	-594,657	-477,475	-1,594,090	-4,422,172	-6,016,262	7.165	6.2656
2017	0	0	520,619	50,807	0	-571,426	-426,455	-2,020,545	-4,033,635	-6,054,180	6.885	6.2656
2018	0	0	503,339	51,743	0	-555,082	-385,033	-2,405,578	-3,684,494	-6,090,072	6.688	6.2656
2019	0	0	489,638	52,704	0	-542,342	-349,657	-2,755,234	-3,368,816	-6,124,051	6.534	6.2656
2020	0	0	477,852	53,647	0	-531,499	-318,493	-3,073,727	-3,082,471	-6,156,198	6.404	6.2656
2021	0	0	467,139	54,620	0	-521,759	-290,599	-3,364,327	-2,822,292	-6,186,619	6.286	6.2656
2022	0	0	457,069	55,614	0	-512,683	-265,400	-3,629,727	-2,585,682	-6,215,409	6.177	6.2656
2023	0	0	447,417	56,656	0	-504,074	-242,535	-3,872,262	-2,370,407	-6,242,669	6.073	6.2656
2024	0	0	438,065	57,762	0	-495,827	-221,737	-4,094,000	-2,174,501	-6,268,500	5.974	6.2656
2025	0	0	428,945	58,824	0	-487,769	-202,746	-4,296,745	-1,996,206	-6,292,951	5.877	6.2656
2026	0	0	420,018	59,965	0	-479,983	-185,435	-4,482,180	-1,833,937	-6,316,118	5.783	6.2656
2027	0	0	411,256	61,121	0	-472,377	-169,622	-4,651,802	-1,686,263	-6,338,065	5.691	6.2656
2028	0	0	402,642	62,271	0	-464,914	-155,165	-4,806,967	-1,551,881	-6,358,848	5.601	6.2656
2029	26,590	0	396,835	63,483	0	-460,318	-142,793	-4,949,760	-1,428,780	-6,378,541	5.546	6.2656
2030	0	0	388,657	64,692	0	-453,348	-130,710	-5,080,471	-1,316,722	-6,397,193	5.462	6.2656
2031	0	0	380,322	65,913	0	-446,235	-119,583	-5,200,054	-1,214,803	-6,414,856	5.376	6.2656
2032	0	0	372,094	67,161	0	-439,255	-109,408	-5,309,462	-1,122,123	-6,431,585	5.292	6.2656
2033	394,002	0	403,575	68,413	0	-471,988	-109,268	-5,418,730	-1,028,693	-6,447,423	5.687	6.2656
2034	0	0	398,229	69,688	0	-467,917	-100,684	-5,519,413	-943,004	-6,462,418	5.638	6.2656
2035	0	0	389,013	71,014	0	-460,027	-92,003	-5,611,416	-865,204	-6,476,620	5.542	6.2656
2036	0	0	379,935	72,350	0	-452,285	-84,073	-5,695,489	-794,579	-6,490,069	5.449	6.2656
2037	0	0	370,983	73,712	0	-444,695	-76,831	-5,772,320	-730,484	-6,502,804	5.358	6.2656
2038	283,099	0	390,609	75,099	0	-465,709	-74,785	-5,847,106	-667,758	-6,514,864	5.611	6.2656
2039	320,475	0	416,039	76,513	0	-492,552	-73,516	-5,920,622	-605,662	-6,526,284	5.934	6.2656
2040	0	0	408,700	77,953	0	-486,653	-67,512	-5,988,133	-548,965	-6,537,098	5.863	6.2656
2041	0	0	398,281	79,420	0	-477,702	-61,595	-6,049,728	-497,610	-6,547,338	5.755	6.2656
2042	0	0	388,038	80,915	0	-468,953	-56,201	-6,105,929	-451,107	-6,557,036	5.650	6.2656
2043	172,647	0	395,313	82,438	0	-477,751	-53,216	-6,159,145	-407,073	-6,566,218	5.756	6.2656
2044	0	0	386,560	83,990	0	-470,550	-48,717	-6,207,862	-367,052	-6,574,914	5.669	6.2656
2045	0	0	376,211	85,571	0	-461,782	-44,436	-6,252,298	-330,850	-6,583,148	5.564	6.2656
2046	0	0	366,015	87,182	0	-453,196	-40,533	-6,292,831	-298,114	-6,590,946	5.460	6.2656
2047	0	0	355,959	88,823	0	-444,781	-36,974	-6,329,806	-268,524	-6,598,329	5.359	6.2656
2048	0	0	346,032	90,494	0	-436,526	-33,728	-6,363,534	-241,787	-6,605,322	5.259	6.2656
2049	0	0	336,223	92,198	0	-428,421	-30,767	-6,394,301	-217,642	-6,611,943	5.162	6.2656
2050	0	0	326,524	93,933	0	-420,457	-28,065	-6,422,366	-195,847	-6,618,213	5.066	6.2656
2051	0	0	316,925	95,701	0	-412,626	-25,599	-6,447,965	-176,185	-6,624,150	4.971	6.2656
2052	0	0	307,419	97,503	0	-404,921	-23,349	-6,471,314	-158,458	-6,629,772	4.879	6.2656
2053	208,038	0	318,913	99,338	0	-418,251	-22,416	-6,493,730	-141,366	-6,635,096	5.039	6.2656
2054	0	0	310,994	101,208	0	-412,202	-20,533	-6,514,263	-125,874	-6,640,138	4.966	6.2656
2055	0	0	301,060	103,113	0	-404,173	-18,713	-6,532,976	-111,935	-6,644,912	4.870	6.2656
2056	0	0	291,225	105,053	0	-396,278	-17,053	-6,550,030	-99,403	-6,649,433	4.774	6.2656
2057	0	0	281,481	107,031	0	-388,512	-15,540	-6,565,569	-88,144	-6,653,714	4.681	6.2656
2058	0	0	271,821	109,045	0	-380,866	-14,159	-6,579,728	-78,039	-6,657,767	4.589	6.2656
2059	0	0	262,238	111,098	0	-373,335	-12,900	-6,592,628	-68,978	-6,661,606	4.498	6.2656
2060	0	0	252,725	113,189	0	-365,914	-11,752	-6,604,380	-60,861	-6,665,241	4.409	6.2656
2061	0	0	243,278	115,320	0	-358,598	-10,704	-6,615,084	-53,599	-6,668,684	4.320	6.2656
2062	0	0	233,891	117,490	0	-351,381	-9,749	-6,624,833	-47,110	-6,671,943	4.234	6.2656
2063	0	0	224,559	119,702	0	-344,261	-8,878	-6,633,711	-41,319	-6,675,030	4.148	6.2656
2064	0	0	215,278	121,955	0	-337,233	-8,083	-6,641,794	-36,160	-6,677,953	4.063	6.2656

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 2013 dollars escalated yearly using the GDP Deflator for Canada.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55.00%	6.606%	3.63%
Common Equity	45.00%	8.800%	3.96%
Total	**100.00%**		**7.59%**

CCA Rates:

Class	Rate	Details
1	4.00%	All generating, transmission, substation and distribution equipment not otherwise noted.
17	8.00%	Expenditures related to the betterment of electrical generating facilities.

Escalation Factors: Conference Board of Canada GDP deflator, November 16, 2012.

Appendix C
Heart's Content Hydro Plant
Switchgear Arc Flash Study

ELECTRICAL ENGINEERING

ARC FLASH HAZARD STUDY

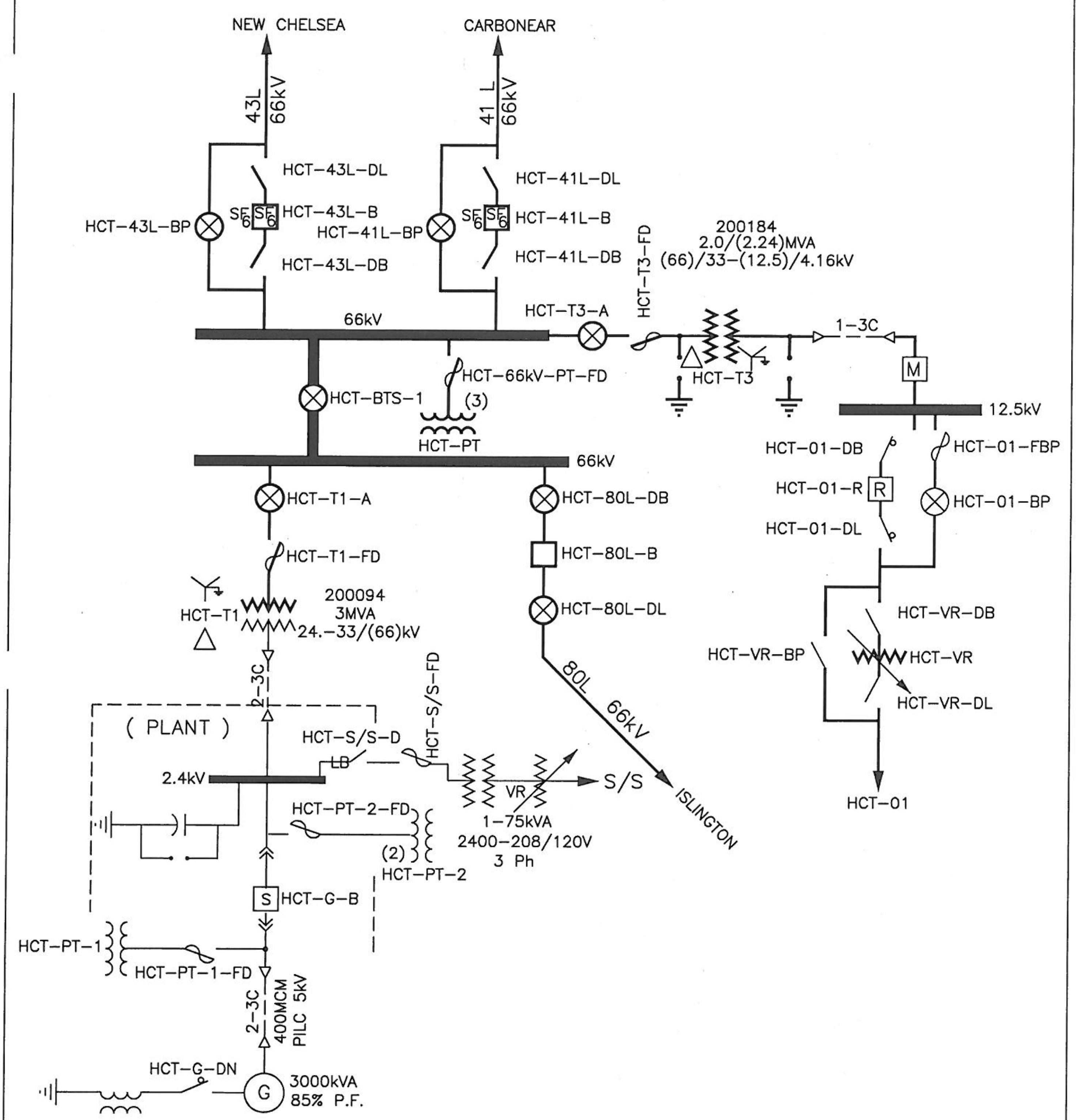
Company Area:	Avalon		
Switchgear Included:	HCT 2.4 kV		
Prepared by:	D Jones	**Date:**	3/7/2006

REASON FOR ARC FLASH HAZARD STUDY

Arc Flash Hazard calculations to be done for all Metal Clad Switrchgear.

POINTS TO NOTE

1. PPE level class 4 at 16 inches (working inside switchgear).
2. PPE level class 3 at 36 inches (racking out breaker).



REGISTERED PROFESSIONAL ENGINEER

G. Richard Spurrell

SIGNATURE

2006-01-30

DATE

PROVINCE OF NEWFOUNDLAND

SINGLE LINE DIAGRAM

NEWFOUNDLAND POWER

PROVINCE OF NEWFOUNDLAND PERMIT HOLDER

This Permit Allows

NEWFOUNDLAND POWER INC.

To practice Professional Engineering in Newfoundland and Labrador. Permit No. as issued by APEGN G0057 which is valid for the year 2006.

HEART'S CONTENT (HCT)

Date: 2006-01-30	Page 1 Of 1
App: / Drawn: FWA	SLD No. 2-913

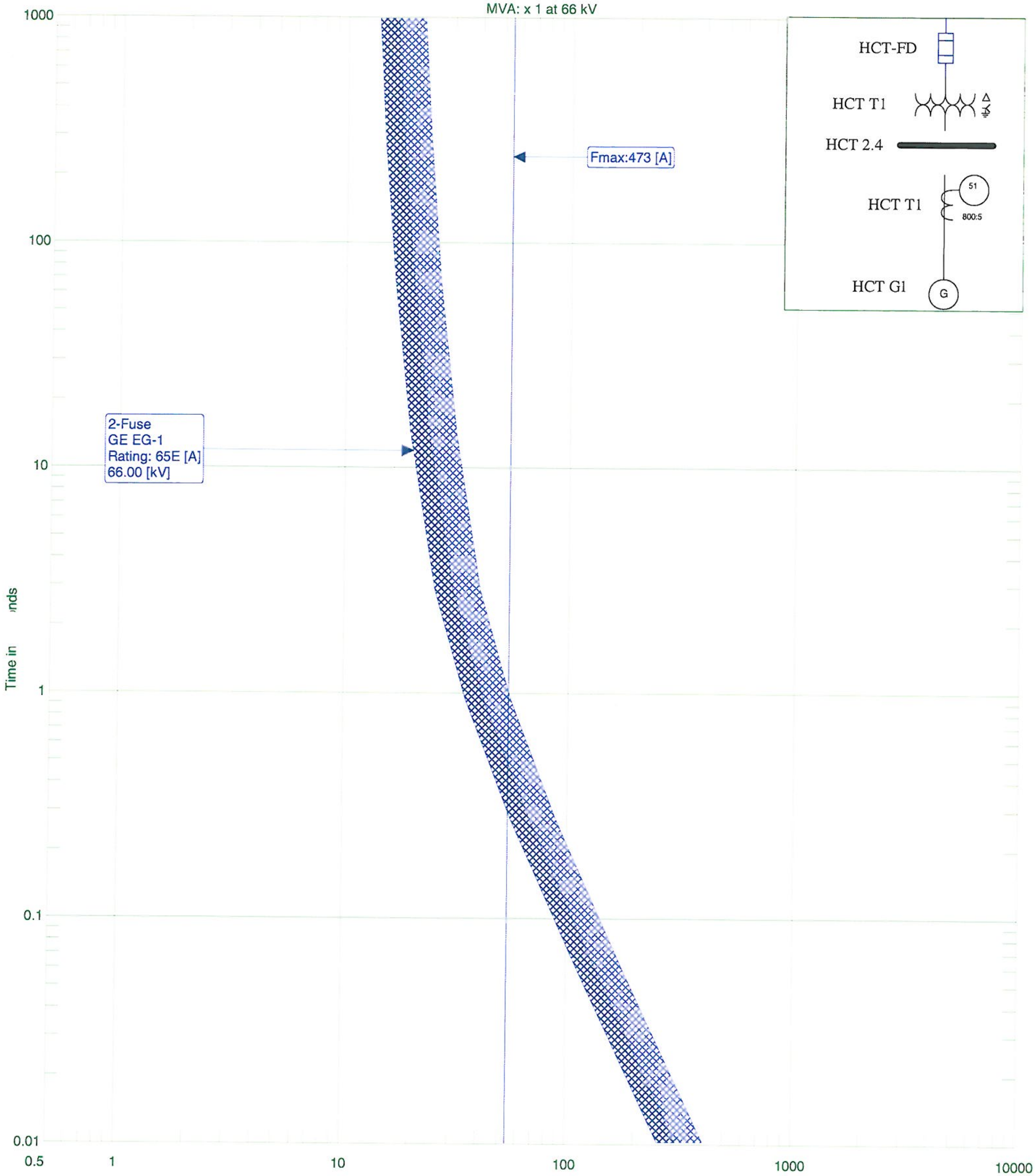
Maximum Generation Faullt HCT 2.4 kV.

ID	Type	Prefault kV	Angle	Fault type	Fault S [MVA]	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
Faulted Bus ->													
HCT 02		2.4	0	LLL	54	13013.7875	-84.2433	13013.7874	155.7567	13013.7874	35.7567	0	0
First Ring Contributions													
HCT G1	Generator	2.4	0	LLL	14	3281.2738	-90	3281.2738	150	3281.2738	30	0	0
HCT T1	Fixed-Tap Xmer	2.4	0	LLL	41	9754.0187	-82.3095	9754.0187	157.6905	9754.0187	37.6905	0	0

Current Multiplier for CYMTCC HCT FD

= 54 MVA / 41 MVA

Current Multiplier = 1.32



For LLL HCT 2.4 kV fault at Maximum Generation. HCT-FD maximum melting time 1.0158 seconds. with existing General Electric GE EG-1 65E fuse.

Dave Jones

March 07, 2006

Study: C:\Arc Flash\Plants\HCT\HCT T1 Fuse Max Gen LLL.tcc

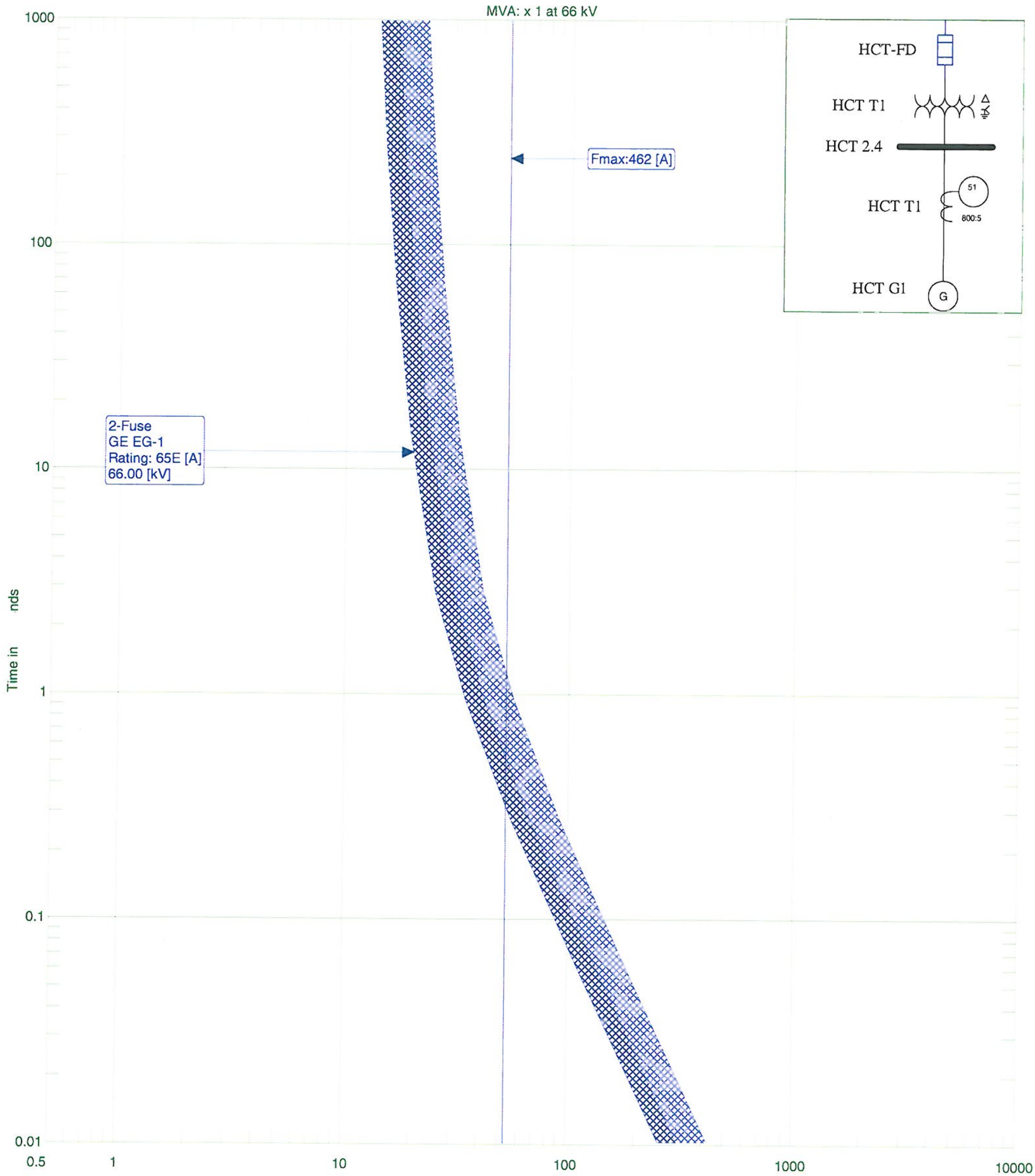
Minimum Generation Faullt HCT 2.4 kV. HCt plant on.

ID	Type	Prefault kV	Angle	Fault type	Fault S [MVA]	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
Faulted Bus ->													
HCT 02		2.4	0	LLL	53	12698.2652	-84.2038	12698.2652	155.7962	12698.2652	35.7962	0	0
First Ring Contributions													
HCT T1	Fixed-Tap Xmer	2.4	0	LLL	39	9438.9161	-82.1912	9438.9161	157.8088	9438.9161	37.8088	0	0
HCT G1	Generator	2.4	0	LLL	14	3281.2738	-90	3281.2738	150	3281.2738	30	0	0

Current Multiplier for CYMTCC HCT FD

= 53 MVA / 39 MVA

Current Multiplier = 1.36



For LLL HCT 2.4 kV fault at Minimum Generation. HCT-FD maximum melting time 1.2264 seconds. with existing General Electric GE EG-1 65E fuse.

Dave Jones

March 07, 2006

Study: C:\Arc Flash\Plants\HCT\HCT T1 Fuse Min Gen LLL.tcc

Arc Flash Hazard HCT 2.4 kV.
IEEE standard

Faulted Bus	Generation	Fault	Fault Current	CT	CT Plus Fuse	Working Distance	Flash Hazard Boundry	cal / cm2	PPE Level	L.A.B.	R.A.B.	P.A.B.
HCT 2.4	Max	LLL	13014	1.0158	1.0158	16"	466"	32.7	4	60"	26"	7"
HCT 2.4	Min	LLL	12698	1.2264	1.2264	16"	551"	38.4	4	60"	26"	7"

Faulted Bus	Generation	Fault	Fault Current	CT	CT Plus Breaker	Working Distance	Flash Hazard Boundry	cal / cm2	PPE Level	L.A.B.	R.A.B.	P.A.B.
HCT 2.4	Max	LLL	13014	1.0158	1.0158	36"	466"	14.8	3	60"	26"	7"
HCT 2.4	Min	LLL	12698	1.2264	1.2264	36"	551"	17.5	3	60"	26"	7"

***Arc Flash Calculated for Switchgear and fixed conductor.**
PSAF Software won't supply Arc Flash results for clearing times over one second.
Arc Flash calculations for clearing times over one second obtained from IEEE calculator on the internet.

L.A.B. Limited Approach Boundry
R.A.B. Restricted Approach Boundry
P.A.B. Prohibited Approach Boundry

IEEE 1584 Based Arc Flash Calculator

Equipment Class: Switchgear
Gap between Conductors: 104 mm.
Grounding Type: Grounded
Working Distance: 406.4 mm.

Available 3 Phase Bolted Current: 13.014 kA
System Voltage: 2400 Volt

☑ I agree to be bound with Terms & Conditions of this website.

Calculate Boundaries

Equipment Type:	Switchgear
Typical Gap bw. Electrodes:	104mm.
Grounding:	Grounded
Work Distance:	406.4 mm.
Arc Duration @ Predicted Arcing Current:	1.0158 sec.
Arc Duration @ 15% Reduced Arc Current :	1.0158 sec.
Available 3Ø Bolted Current:	13.014 kA
Predicted 3Ø Arcing Current:	12570 A
System Voltage L-L:	2400 Volt

Calculation Mode	Incident Energy Exposure (cal/cm ^{2})	Flash Protection Boundary (feet)	Level of PPE
@ 100% Arcing Current	32.66	38.85	4
@ 85% Arcing Current	27.40	32.43	4

IEEE 1584 Based Arc Flash Calculator

Equipment Class	Switchgear	
Gap between Conductors	104	mm.
Grounding Type	Grounded	
Working Distance	406.4	mm.
Available 3 Phase Bolted Current	12.698	kA
System Voltage	2400	Volt

☑ I agree to be bound with Terms & Conditions of this website.

Calculate Boundaries

Equipment Type:	Switchgear
Typical Gap bw. Electrodes:	104mm.
Grounding:	Grounded
Work Distance:	406.4 mm.
Arc Duration @ Predicted Arcing Current:	1.2264 sec.
Arc Duration @ 15% Reduced Arc Current :	1.2264 sec.
Available 3Ø Bolted Current:	12.698 kA
Predicted 3Ø Arcing Current:	12270 A
System Voltage L-L:	2400 Volt

Calculation Mode	Incident Energy Exposure (cal/cm ^{2})	Flash Protection Boundary (feet)	Level of PPE
@ 100% Arcing Current	38.41	45.90	4
@ 85% Arcing Current	32.22	38.32	4

IEEE 1584 Based Arc Flash Calculator

Equipment Class	Switchgear	
Gap between Conductors	104	mm.
Grounding Type	Grounded	
Working Distance	914.4	mm.
Available 3 Phase Bolted Current	13.014	kA
System Voltage	2400	Volt

☑ I agree to be bound with Terms & Conditions of this website.

Calculate Boundaries

Equipment Type:	Switchgear
Typical Gap bw. Electrodes:	104mm.
Grounding:	Grounded
Work Distance:	914.4 mm.
Arc Duration @ Predicted Arcing Current:	1.0158 sec.
Arc Duration @ 15% Reduced Arc Current :	1.0158 sec.
Available 3Ø Bolted Current:	13.014 kA
Predicted 3Ø Arcing Current:	12570 A
System Voltage L-L:	2400 Volt

Calculation Mode	Incident Energy Exposure (cal/cm²)	Flash Protection Boundary (feet)	Level of PPE
@ 100% Arcing Current	14.84	38.85	3
@ 85% Arcing Current	12.45	32.43	3

IEEE 1584 Based Arc Flash Calculator

Equipment Class: Switchgear

Gap between Conductors: 104 mm.

Grounding Type: Grounded

Working Distance: 914.4 mm.

Available 3 Phase Bolted Current: 12.698 kA

System Voltage: 2400 Volt

☑ I agree to be bound with Terms & Conditions of this website.

Calculate Boundaries

Equipment Type: Switchgear

Typical Gap bw. Electrodes: 104mm.

Grounding: Grounded

Work Distance: 914.4 mm.

Arc Duration @ Predicted Arcing Current: 1.2264 sec.

Arc Duration @ 15% Reduced Arc Current : 1.2264 sec.

Available 3Ø Bolted Current: 12.698 kA

Predicted 3Ø Arcing Current: 12270 A

System Voltage L-L: 2400 Volt

Calculation Mode	Incident Energy Exposure (cal/cm²)	Flash Protection Boundary (feet)	Level of PPE
@ 100% Arcing Current	17.45	45.90	3
@ 85% Arcing Current	14.64	38.32	3

Hydro Production Increase
La Manche Canal

June 2013

Prepared by:

David Ball, B.Eng.

Gary Humby, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
GARY K. HUMBY
SIGNATURE
June/21/2013
DATE
PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

Page

1.0 Introduction

La Manche Canal is located approximately 40 km south of St. John's within the Rocky Pond and Tors Cove hydroelectric development.[1] Tors Cove plant came into service in 1940, followed by the La Manche Canal and Rocky Pond Plant in 1943. The combined annual production of these plants is approximately 39 GWh or about 9% of Newfoundland Power's ("the Company") total hydroelectric production.

In 2000, Hatch, an external consultant, completed a Water Management Study to provide an estimate of the normal production of Newfoundland Power's hydroelectric system.[2] As a follow up to that study in 2001, Hatch also completed a review of the Company's larger hydroelectric developments to identify potential opportunities for increasing production.

In 2008, Newfoundland Power undertook a review of its existing hydroelectric facilities to determine potential opportunities for increasing production.[3] The technical evaluations completed in 2000 and 2001 still remain valid. However, the increased cost of fuel since 2001 has changed the economic feasibility of some projects previously identified.

As part of the 2008 review, options to increase production at the Rocky Pond and Tors Cove hydroelectric development were assessed. It was estimated that 2.88 GWh per year of energy could be recovered by raising the Cape Pond Dam and increasing the capacity of La Manche Canal. It was later determined that due to constraints associated with the Avalon Wilderness Reserve, raising the height of Cape Pond Dam would not be permitted.

In 2012 the Company completed preliminary engineering design work on increasing the capacity of La Manche Canal.[4] As a result of this engineering work completed in 2012 it has been determined that by increasing the capacity of the La Manche Canal, significant spill could be recovered and utilized at the Rocky Pond and Tors Cove generating stations. Production at these generating stations could increase by 5.54 GWh at a cost of 2.19 ¢ per kWh. Because of these improvements, the expected new combined annual energy output from the Rocky Pond and Tors Cove hydroelectric development will be 44.54 GWh.

---

[1] Water from the La Manche Canal passes through the Rocky Pond and Tors Cove generating facilities, therefore both plants utilize the same water.

[2] Hatch, formerly SGE Acres, is a leading provider of process and business consulting, engineering project and construction management to the energy, mining, metallurgical, manufacturing and infrastructure industries.

[3] A copy of this study was included with the response to Request for Information PUB-NP-009 in the Company's *2010 Capital Budget Application.*

[4] The engineering design work was included in the Company's *2012 Capital Budget Application* and approved in Order No. P.U. 26 (2011).

2.0 Background

Rocky Pond and Tors Cove generators have a nameplate capacity of 6.9 MW and 3.2 MW respectively. La Manche Canal is approximately 5,600 metres long and incorporates 7 spillways. The 7 spillways serve to regulate the flow in the La Manche Canal by spilling excess water during rainfall or snowmelt events. The spillways are typically located at the La Manche Canal's intersection with small streams. The total drainage area upstream of the La Manche Canal is approximately 135 km^2. Storage upstream of the canal is provided by structures at Cape Pond and Franks Pond. A schematic of the hydroelectric development is provided in Figure 1.

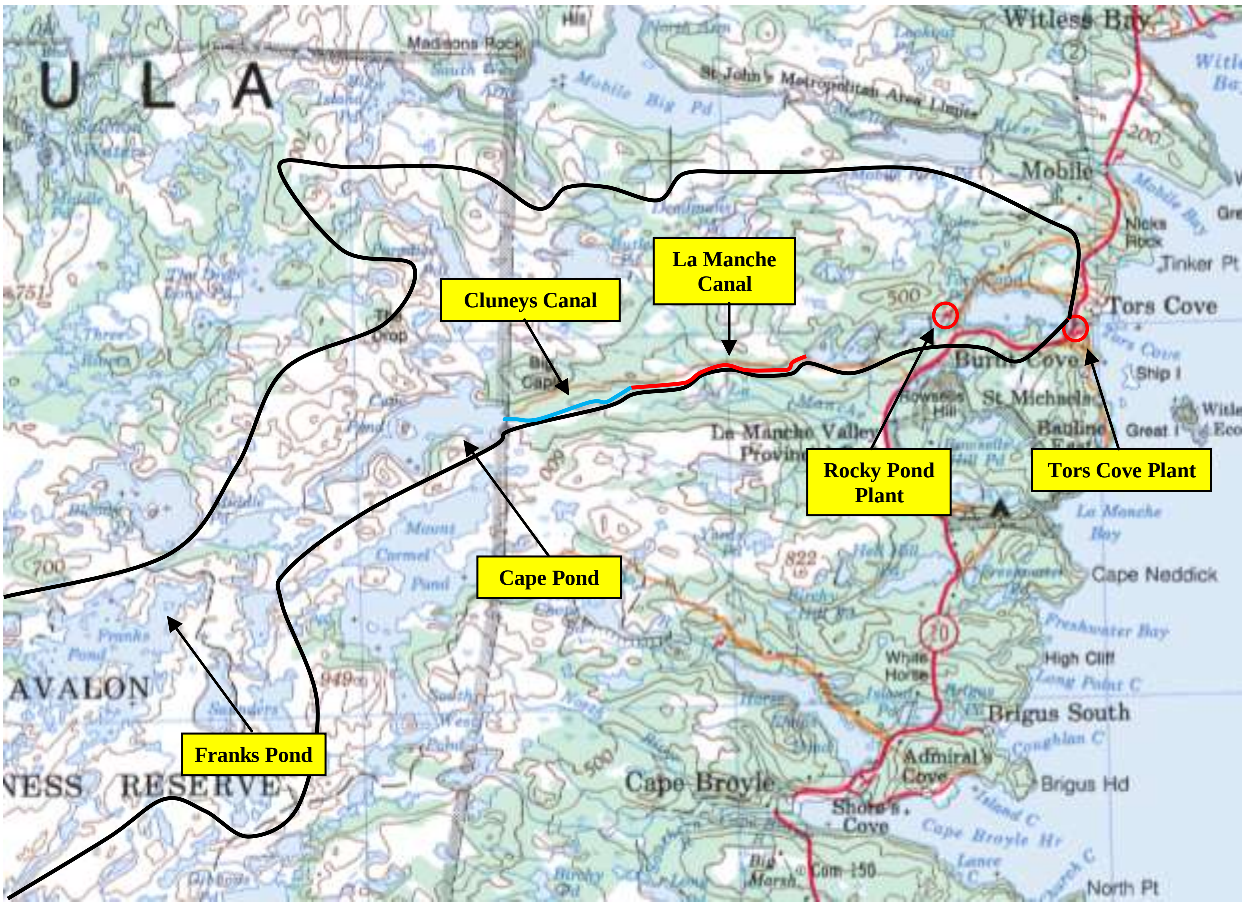


Figure 1 – Rocky Pond and Tors Cove Development

The drainage system associated with this hydroelectric development is very complex as a result of the large number of diversions and canals. Structures within this system include:

- A gated outlet, 5 freeboard dams and 2 overflow spillways at Franks Pond,
- A 1,500 metre canal from Franks Pond to Middle Pond with one overflow spillway,
- A dam, gated outlet and overflow spillway at Cape Pond,

- The 3,700 metre Cluneys Canal, with a diversion dam/spillway at the entrance, two overflow spillways and a control gate and weir near its end,
- The 5,600 metre La Manche Canal with 7 overflow spillways,
- A dam and spillway at Long Pond,
- Three freeboard dams, a diversion dam with penstock intake and overflow spillway at Rocky Pond, and
- One freeboard dam, a diversion dam with penstock intake and overflow spillway at Tors Cove Pond.

With the exception of the Cape Pond and Rocky Pond Spillways, all spillways release water out of the system.

La Manche Canal is approximately 10 metre wide and has a design capacity of 6 m^3/s. As-built details of the original construction are not available, however, it appears that the La Manche Canal was built as a cut and fill side hill dam.[5]

3.0 Options to Increase Energy Production

In 2001, Hatch completed a study to identify potential opportunities to increase production at the Company's larger hydroelectric developments. As part of this study options to increase energy production at the Rocky Pond and Tors Cove hydroelectric development were assessed. It was determined that by increasing the capacity of La Manche Canal and the raising the height of Cape Pond Dam, significant spill could be recovered and utilized at the generating stations. A follow up study was completed by Newfoundland Power in 2008 to update the cost estimates and economic feasibility. At that time, the increase in production was estimated to cost approximately 3.8 ¢/kWh.

Based on review of the relevant legislation it was determined that increasing the height of the Cape Pond Dam would not be permitted because Cape Pond is within the boundary of the Avalon Wilderness Reserve Area.[6] By not raising the height of the Cape Pond Dam the energy gain was decreased, but most of the increased energy production could be recovered by increasing the capacity of La Manche Canal.

In 2012, Newfoundland Power engaged Mitchelmore Engineering Company Ltd. ("MECO") to complete preliminary engineering on the La Manche Canal project, including a physical model as well as an evaluation of concepts to increase the canal capacity.[7] MECO estimated that at its existing capacity, the average annual spill from the La Manche Canal totalled 9.2 GWh per year of which up to 5.54 GWh per year could be recovered by increasing the canal capacity.

[5] A cut and fill side hill dam is constructed by placing fill from the canal excavation on the downstream side of the canal to form an embankment.

[6] Under the Wilderness and Ecological Reserves Act, 1997, no new structures are permitted in the Avalon Wilderness Reserve however; Newfoundland Power is permitted to maintain its existing structures in the area.

[7] Mitchelmore Engineering Company Ltd. is an engineering consultant that services the Water, Energy and Infrastructure sectors. It specializes in Civil and Geotechnical Engineering and Dam Safety Management.

MECO estimated the cost of increasing the La Manche Canal's capacity to 9 m^3/s using 4 different design concepts.[8] It was determined that raising the height of the La Manche Canal embankment by adding fill is the least cost design concept.

Bedrock is evident in places along the La Manche Canal's length. Bedrock conditions do not impact construction of the raising option; however they significantly impact construction of the deepening and widening options. Bedrock excavation is significantly more expensive than earth excavation and therefore significantly increased costs of the deepening and widening options.

In addition to being the least cost option, raising the La Manche Canal is the simplest option technically, has the lowest construction uncertainty and will result in a negligible amount of lost generation during construction. Both the deepening and widening options would require the dewatering of the La Manche Canal. It is unlikely that dewatering of the entire canal would be permitted under both provincial and federal law. To avoid dewatering, significant cost would be incurred to isolate work areas and provide fisheries flow downstream. Therefore, the La Manche Canal's capacity would be severely limited during the construction, resulting in lost generation. Raising the La Manche Canal was selected as the best option because it does not require significant environmental cost or lost generation due to dewatering.

4.0 Feasibility Analysis

Appendix B of this report provides a feasibility analysis for increasing the capacity of the La Manche Canal to increase production at the Rocky Pond/Tors Cove plants. The results of the feasibility analysis show that increasing the capacity to 9 m^3/s resulting in an additional 5.54 GWh of annual energy production is economical.

The estimated levelized cost of the incremental energy output from increasing the capacity of the La Manche Canal is 2.19 ¢/kWh. This energy is lower in cost than energy from Holyrood thermal generation.[9]

5.0 Canal Rehabilitation Work

As a result of increasing the La Manche Canal's water elevation, modifications would be required to the elevation of the 7 spillways. In addition to this work, rehabilitation of the La Manche Canal spillways as well as the Cluneys Diversion Dam/Spillway is required at this time. Concrete on 6 of the La Manche Canal spillways are in fair condition with isolated deterioration. The downstream erosion protection is typically in poor condition and in places has started to undermine the spillway. The Cluneys Diversion Dam/Spillway requires refurbishment as the riprap is poorly graded causing erosion in places.[10] This work will be completed at the same

[8] Design concepts were: deepen canal, widen canal, raise crest using either fill or a diaphragm wall. The cost of a diaphragm wall was approximately 40% more expensive than using fill and as a result this alternative was not considered viable.

[9] The avoided cost of fuel at the Holyrood Thermal Generating Station is estimated at 16.8¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.80 per barrel for 2013 as per Newfoundland and Labrador Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated April 12, 2013.

[10] Riprap is rock or other materials used to protect dams, spillways and shorelines from water or ice erosion.

time as the capacity increase project to take advantage of the access to the spillways that will be created as part of that project.

6.0 Concluding

Increasing the capacity of the La Manche Canal to 9 m^3/s will result in an additional 5.54 GWh of combined annual energy production at the Rocky Pond and Tors Cove plants. The feasibility analysis included in Appendix B verifies the economic viability of completing this project. Based upon the considerations outlined in this report and the attached assessment, the project is recommended to proceed in 2014.

Appendix A
Photos of the La Manche Canal

Figure 1 - La Manche Canal

Figure 2 - La Manche Canal, near the downstream end

Figure 3 - Minimum operating capacity of approximately 0.9m^3/s

Figure 4 - Typical La Manche Canal Spillway

Figure 5 - Typical erosion on a La Manche Canal Spillway

Figure 6 - Poorly Graded Riprap - Cluneys Diversion

Appendix B
Feasibility Analysis

Table of Contents

1.0 Introduction

This feasibility analysis was completed by Newfoundland Power to determine if increasing the capacity of the La Manche Canal to reduce spill and increase the energy production at Newfoundland Power's Rocky Pond and Tors Cove hydroelectric development is feasible.

The results of the Company's analysis are presented in this report.

2.0 Capital Costs, Energy Benefits and Financial Analysis

The capital cost to increase the La Manche Canal's capacity was estimated by Newfoundland Power and is largely based on the construction costs provided by Mitchelmore Engineering Company Ltd. ("MECO") in 2013. Additional costs including final engineering and project management are included based on previous projects of similar scope. The energy benefit was provided by MECO based on their research and experience in hydroelectric system modelling.

An overall financial analysis has been completed using the levelized cost of energy approach. The results of this analysis are included in Attachment A. The levelized cost of energy is representative of the revenue requirement to support the capital costs associated with increasing the capacity of the La Manche Canal.

The estimated capital costs, energy benefit and levelized cost of energy for increasing the capacity 9 m^3/s is summarized in Table 1.

Table 1
Capital Costs and Energy Benefits

Capital Cost	$1,665,000
Energy Benefit	5.54 GWh
Levelized Cost	2.19 ¢/kWh

3.0 Recommendation

The results of the financial analysis show that the levelized cost of energy at 2.19 ¢/kWh is lower than energy from sources such as a new hydroelectric development or additional thermal generation.[1]

Based on these results it is recommended that the capacity of the La Manche Canal be increased to 9 m^3/s. This will provide an additional 5.54 GWh of annual energy production. When completed, the refurbished La Manche Canal will provide a combined annual energy output from the Tors Cove and Rocky Pond plants of 44.54 GWh.

[1] The cost of fuel from the Holyrood thermal generating station is estimated at 16.8 cents per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $105.80 per barrel as of April 12, 2013.

Attachment A
Calculation of Levelized Cost of Energy

Weighted Average Incremental Cc			7.59%								
Escalation Rate			See following worksheet								
PW Year			2013								
	---		**Capital**					**Cumulative**	**Present**	**Total**		**Levelized**
			Revenue	**Operating**	**Operating**		**Present**	**Present**	**Worth of**	**Present**	**Rev Rqmt**	**Rev Rqmt**
	Generation	**Generation**	**Requireme**	**Costs**	**Benefits**	**Net benefit**	**Worth**	**Value**	**Sunk Costs**	**Worth**	**(¢/kWhr)**	**(¢/kWhr)**
	Hydro	Hydro					**Benefit +ve**	**Benefit +ve**		**Benefit +ve**		**50 years**
	64.4yrs	64.4yrs										
	8% CCA	50% CCA										
YEAR												
2014	0	1,665,000	162,731	0	0	-162,731	-151,251	-151,251	-1,403,227	-1,554,478	2.937	2.1861
2015	0	0	162,831	0	0	-162,831	-140,667	-291,918	-1,262,559	-1,554,478	2.939	2.1861
2016	0	0	148,301	0	0	-148,301	-119,077	-410,996	-1,143,482	-1,554,478	2.677	2.1861
2017	0	0	140,022	0	0	-140,022	-104,498	-515,494	-1,038,984	-1,554,478	2.527	2.1861
2018	0	0	134,869	0	0	-134,869	-93,552	-609,046	-945,432	-1,554,478	2.434	2.1861
2019	0	0	131,278	0	0	-131,278	-84,637	-693,683	-860,794	-1,554,478	2.370	2.1861
2020	0	0	128,469	0	0	-128,469	-76,983	-770,666	-783,811	-1,554,478	2.319	2.1861
2021	0	0	126,050	0	0	-126,050	-70,205	-840,871	-713,606	-1,554,478	2.275	2.1861
2022	0	0	123,827	0	0	-123,827	-64,102	-904,973	-649,505	-1,554,478	2.235	2.1861
2023	0	0	121,702	0	0	-121,702	-58,557	-963,530	-590,948	-1,554,478	2.197	2.1861
2024	0	0	119,625	0	0	-119,625	-53,497	-1,017,027	-537,451	-1,554,478	2.159	2.1861
2025	0	0	117,573	0	0	-117,573	-48,870	-1,065,897	-488,581	-1,554,478	2.122	2.1861
2026	0	0	115,532	0	0	-115,532	-44,634	-1,110,531	-443,946	-1,554,478	2.085	2.1861
2027	0	0	113,498	0	0	-113,498	-40,755	-1,151,287	-403,191	-1,554,478	2.049	2.1861
2028	0	0	111,468	0	0	-111,468	-37,202	-1,188,489	-365,989	-1,554,478	2.012	2.1861
2029	0	0	109,438	0	0	-109,438	-33,948	-1,222,437	-332,040	-1,554,478	1.975	2.1861
2030	0	0	107,409	0	0	-107,409	-30,968	-1,253,406	-301,072	-1,554,478	1.939	2.1861
2031	0	0	105,381	0	0	-105,381	-28,240	-1,281,646	-272,832	-1,554,478	1.902	2.1861
2032	0	0	103,353	0	0	-103,353	-25,743	-1,307,389	-247,089	-1,554,478	1.866	2.1861
2033	0	0	101,325	0	0	-101,325	-23,457	-1,330,846	-223,631	-1,554,478	1.829	2.1861
2034	0	0	99,297	0	0	-99,297	-21,366	-1,352,212	-202,265	-1,554,478	1.792	2.1861
2035	0	0	97,269	0	0	-97,269	-19,453	-1,371,666	-182,812	-1,554,478	1.756	2.1861
2036	0	0	95,241	0	0	-95,241	-17,704	-1,389,370	-165,108	-1,554,478	1.719	2.1861
2037	0	0	93,213	0	0	-93,213	-16,105	-1,405,474	-149,003	-1,554,478	1.683	2.1861
2038	0	0	91,186	0	0	-91,186	-14,643	-1,420,117	-134,360	-1,554,478	1.646	2.1861
2039	0	0	89,158	0	0	-89,158	-13,307	-1,433,425	-121,053	-1,554,478	1.609	2.1861
2040	0	0	87,130	0	0	-87,130	-12,087	-1,445,512	-108,966	-1,554,478	1.573	2.1861
2041	0	0	85,102	0	0	-85,102	-10,973	-1,456,485	-97,993	-1,554,478	1.536	2.1861
2042	0	0	83,074	0	0	-83,074	-9,956	-1,466,441	-88,037	-1,554,478	1.500	2.1861
2043	0	0	81,046	0	0	-81,046	-9,028	-1,475,468	-79,009	-1,554,478	1.463	2.1861
2044	0	0	79,018	0	0	-79,018	-8,181	-1,483,649	-70,828	-1,554,478	1.426	2.1861
2045	0	0	76,990	0	0	-76,990	-7,409	-1,491,058	-63,420	-1,554,478	1.390	2.1861
2046	0	0	74,962	0	0	-74,962	-6,705	-1,497,762	-56,715	-1,554,478	1.353	2.1861
2047	0	0	72,935	0	0	-72,935	-6,063	-1,503,825	-50,652	-1,554,478	1.317	2.1861
2048	0	0	70,907	0	0	-70,907	-5,479	-1,509,304	-45,174	-1,554,478	1.280	2.1861
2049	0	0	68,879	0	0	-68,879	-4,946	-1,514,250	-40,227	-1,554,478	1.243	2.1861
2050	0	0	66,851	0	0	-66,851	-4,462	-1,518,713	-35,765	-1,554,478	1.207	2.1861
2051	0	0	64,823	0	0	-64,823	-4,022	-1,522,734	-31,743	-1,554,478	1.170	2.1861
2052	0	0	62,795	0	0	-62,795	-3,621	-1,526,355	-28,122	-1,554,478	1.133	2.1861
2053	0	0	60,767	0	0	-60,767	-3,257	-1,529,612	-24,866	-1,554,478	1.097	2.1861
2054	0	0	58,739	0	0	-58,739	-2,926	-1,532,538	-21,940	-1,554,478	1.060	2.1861
2055	0	0	56,711	0	0	-56,711	-2,626	-1,535,164	-19,314	-1,554,478	1.024	2.1861
2056	0	0	54,684	0	0	-54,684	-2,353	-1,537,517	-16,961	-1,554,478	0.987	2.1861
2057	0	0	52,656	0	0	-52,656	-2,106	-1,539,623	-14,855	-1,554,478	0.950	2.1861
2058	0	0	50,628	0	0	-50,628	-1,882	-1,541,505	-12,972	-1,554,478	0.914	2.1861
2059	0	0	48,600	0	0	-48,600	-1,679	-1,543,185	-11,293	-1,554,478	0.877	2.1861
2060	0	0	46,572	0	0	-46,572	-1,496	-1,544,680	-9,797	-1,554,478	0.841	2.1861
2061	0	0	44,544	0	0	-44,544	-1,330	-1,546,010	-8,468	-1,554,478	0.804	2.1861
2062	0	0	42,516	0	0	-42,516	-1,180	-1,547,189	-7,288	-1,554,478	0.767	2.1861
2063	0	0	40,488	0	0	-40,488	-1,044	-1,548,234	-6,244	-1,554,478	0.731	2.1861
2064	0	0	38,460	0	0	-38,460	-922	-1,549,155	-5,322	-1,554,478	0.694	2.1861

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

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

Operating Costs: There is no change in operating costs assumed.

Average Incremental Cost of Capital:

	Capital Structure	Return	Weighted Cost
Debt	55.00%	6.606%	3.63%
Common Equity	45.00%	8.800%	3.96%
Total	**100.00%**		**7.59%**

CCA Rates:

Class	Rate	Details
1	4.00%	All generating, transmission, substation and distribution equipment not otherwise noted.
17	8.00%	Expenditures related to the betterment of electrical generating facilities.

Escalation Factors: Conference Board of Canada GDP deflator, November 16, 2012.

2014 Substation Refurbishment and Modernization

June 2013

Prepared by:

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NEWFOUNDLAND & LABRADOR

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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. For example, in 2014 the Company has included the Bay Roberts substation in the Substation Refurbishment and Modernization project. This work was scheduled for 2015 but has been advanced to 2014 principally to permit coordination with the installation of a second power transformer required in 2014. The efficiencies gained in this coordination contribute to the approximately 17% cost reduction associated with the rescheduling of this work.

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 five-year forecast for the Substation Refurbishment and Modernization Plan is shown in Appendix A.

2.0 Substation Refurbishment and Modernization 2014 Projects

The 2014 Substation Refurbishment and Modernization Project includes planned refurbishment and modernization of five substations. This substation work is estimated to cost a total of $5,868,000 which comprises approximately 97% of the total 2014 project cost. The remaining project cost of $155,000 is associated with Substation Monitoring and Operations upgrades to substation communication systems to accommodate increased data requirements.

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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.

Table 1 identifies the 2014 Substation Refurbishment and Modernization Project expenditures for 2014.

Table 1
2014 Substation Refurbishment and Modernization Projects
(000s)

Project	Budget
Springdale (SPR)	$963
Massey Drive (MAS)	$747
Holyrood (HOL)	$622
Bay Roberts (BRB)	$1,485
Carbonear (CAR)	$2,051
Substation Monitoring and Operations	$155
Total	**$6,023**

2.1 2014 Substation Projects ($5,868,000)

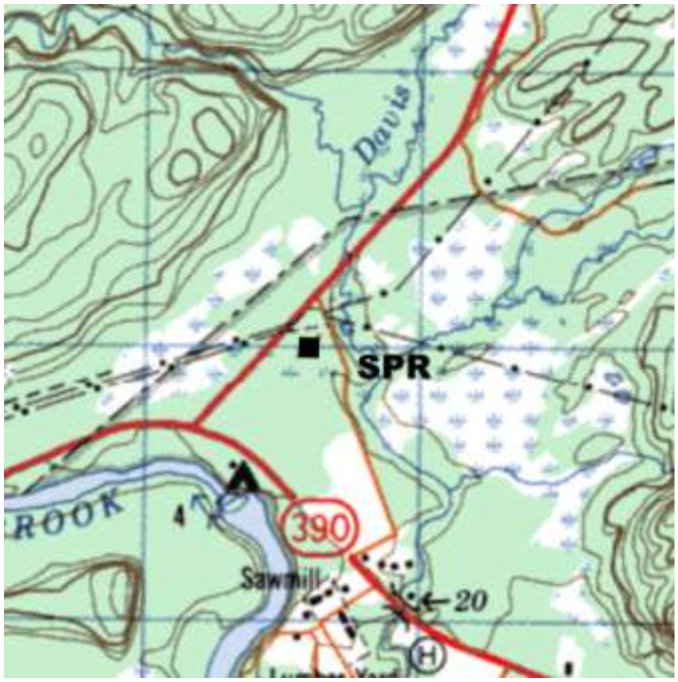
Springdale Substation ($963,000)

Springdale Substation (SPR) was built in 1965 as a distribution substation and is a shared substation with Newfoundland and Labrador Hydro (Hydro).[2] The substation contains one 138 kV to 25 kV distribution power transformer (SPR-T1) with a capacity of 16.7 MVA. The substation directly serves approximately 1,552 customers in the Springdale area through four 25 kV feeders.

In 2014 the Company will replace the bushings on transformer T1 as part of the PCB phase out program. The Company will also undertake other substation refurbishment and modernization work at Springdale substation to take advantage of the installation of the portable substation to minimize the number and duration of customer outages.[3]

[2] The substation is connected to Hydro's 138 kV transmission lines TL222 to South Brook substation and TL223 to Indian River substation. The 138 kV bus and breakers are owned and maintained by Hydro.

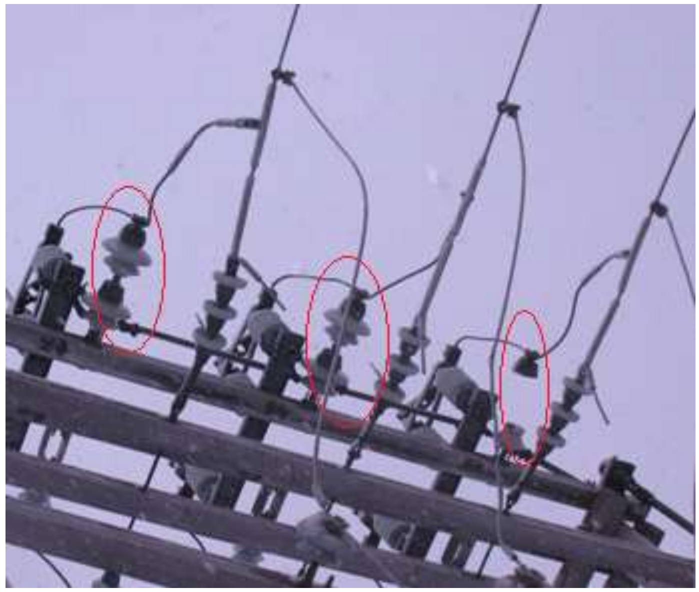
[3] Wherever possible the Company coordinates maintenance work on individual substations with capital substation refurbishment projects to minimize interruption to customers.



Springdale Substation Location

Maintenance records and on-site engineering assessments determine that the 25 kV structures and bus are in good condition, with the exception of deteriorated cap-and-pin insulators and some switch-supporting cross arms that are deteriorated due to decay. These insulators and cross arms will be replaced as a part of this project.

Low Voltage Bus Structure (Wood Poles and Cross Arms)



Low Voltage Structure Insulator Missing

A portable substation will be installed to bypass the substation to replace PCB bushings, refurbish the power transformer and upgrade the transformer's auxiliary protection. The existing auxiliary devices that are used for transformer protection and monitoring, which include a temperature gauge, oil level gauge, and gas detection relay, will be replaced. These devices are showing signs of deterioration, largely due to their exposure to the elements.[4] This can lead to false trips, and as such, these devices can no longer operate reliably. New transformer tap changer controls 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 System Control Centre.

The transformer 138 kV air break switch (SPR-T1-A), transformer low voltage disconnect switch, and four 25kV feeder bypass switches are 36 years old and will be replaced due to their mechanical condition and associated age. These switches are operated infrequently and due to deterioration of Teflon bushings, corrosion of the operating mechanisms, and misalignment of blades, they frequently seize during operation.[5] Over the course of the last number of years, failures in switches of this vintage have required the use of line personnel to close them by use of excessive force (i.e., a hot line hookstick).[6]

4 Transformer auxiliary protection devices are contained inside NEMA rated enclosures mounted to the side of the transformer. Over time, the presence of moisture and humidity corrodes these devices, causing them to fail, leading to false trips and unplanned outages. In 2013, at each of Berry Head and Doyles substations, a transformer gas detect relay of the same vintage failed, resulting in unplanned service interruptions.

5 The Company's strategy for switches is to operate and maintain switches whenever opportunities and substation work permit, and to replace switches when they are more than 30 years old.

6 The use of hot line hooksticks to forcibly close airbreak switches under load is not considered by the Company to be an operational best practice or an efficient use of line personnel.

The existing transformer protection relays are electromechanical types that are original to the 1965 substation construction.[7] The 48 year old transformer protection will be replaced with new microprocessor based digital relays. In addition, a complete communications package including a gateway will be installed, to facilitate remote monitoring and control of the various protection elements within the substation. The monitored protection elements will include the T1 transformer protection and 4 intelligent reclosers.

Transformer Protection Panel (Electromechanical Relays)

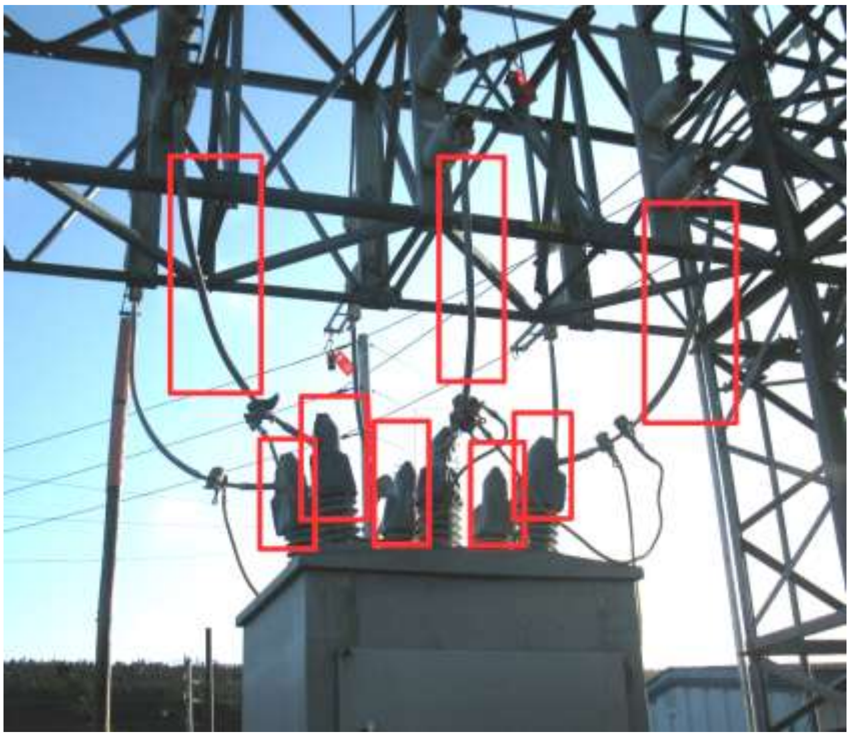
The 4 feeder reclosers for feeders SPR-01, SPR-02, SPR-03, and SPR-04 are all hydraulic-type reclosers ranging in age from 29 years to 37 years old. These reclosers are not equipped with protection and control capabilities that would facilitate automation, enhanced fault isolation, and remote settings changes to minimize unnecessary trips in the event of cold load pickup. The 4 reclosers will be replaced with new intelligent reclosers that have no maintenance requirements, are oil-free, and will be automated for monitoring and control from the System Control Center. The automation equipment, transformer protection and recloser controls will be installed in the existing control building. With feeder automation, the Springdale feeders will be added to the provincial under-frequency load shedding scheme.[8]

[7] Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust.

[8] 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 grounding study will be completed and the ground grid for the Newfoundland Power portion of the substation will be extended to improve safety for personnel inside the substation.[9] The grounding study and ground grid upgrade will be coordinated with Newfoundland and Labrador Hydro.

Standard varmint protection practices, in the form of insulated coverings, guards, and leads, will be installed on all low voltage switches and recloser bushings.[10]



Varmint Protection Example Including Insulated Busing Covers and Leads

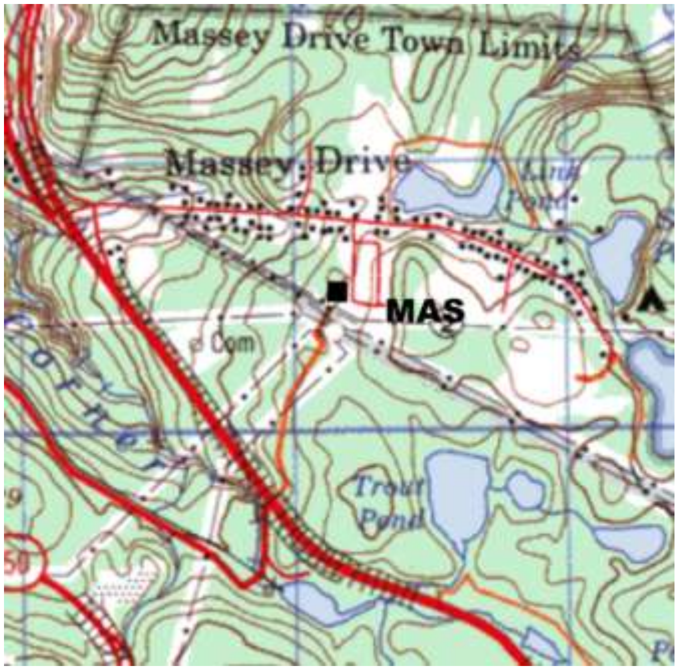
Massey Drive Substation ($747,000)

The Massey Drive substation was built in 1967 as a transmission substation, and is located on a shared site containing assets for Newfoundland Power, Newfoundland and Labrador Hydro, and Deer Lake Power. The Newfoundland Power transmission portion of the substation contains high voltage switches and 4 breakers associated with the 66kV transmission lines.[11] The substation indirectly serves approximately 21,500 customers in the greater Corner Brook area through this transmission network.

9 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.

10 These barriers have proven effective in preventing damage to equipment and customer outages caused by small animals and birds.

11 The four 66 kV transmission lines are 356L to Humber substation, 351L and 352L to Walbournes substation, and 357L to Bayview substation.



Massey Drive Substation Location

Maintenance records and on-site engineering assessments determine that the substation steel structures, foundations, bus work, and insulators are all in good condition. There are 2 side-break disconnect switches and 2 line to ground switches that have been in service since 1967 and will be replaced with new 66 kV switches due to their mechanical condition and associated age. Substation switches are operated infrequently, and as they age will seize when operated due to deterioration of bushings, corrosion in operating mechanisms and/or misalignment of blades.[12]

The relays for the transmission lines and bus protection are vintage electro-mechanical type and are original to the 1967 substation construction. Electro-mechanical 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 electro-mechanical relays are prone to failure 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.[13]

At present, there are 15 electromechanical relays installed in 2 individual protection panels inside the substation control building. These relays, used for the protection of 4 transmission lines, are

[12] The Company's strategy for switches is to operate and maintain switches whenever opportunities and substation work permit, and to replace switches when they are more than 30 years old.

[13] More than 20 failures of this type of relay have contributed to system events and unplanned outages since 2006. During Hurricane Leslie in September 2012, electro-mechanical relay failures resulted in the slow clearing of faults which contributed to prolonged system outages. The investigation identified the failure of electro-mechanical relays used to protect transmission lines 48L and 64L at Blaketown substation as having contributed to the system event. These relays are being replaced in 2013. Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust.

vintage electromechanical type with more than 35 years in service. Replacing the electro-mechanical relays with digital relays reduces the total protection relay device count from 15 to 4.

The protection upgrade will also involve replacing both 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. 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.[14] The gateway will integrate the digital protection relays for the 4 transmission lines and the 66 kV bus structure into the SCADA system.

Transmission Line Electromechanical Relay Panels and RTU

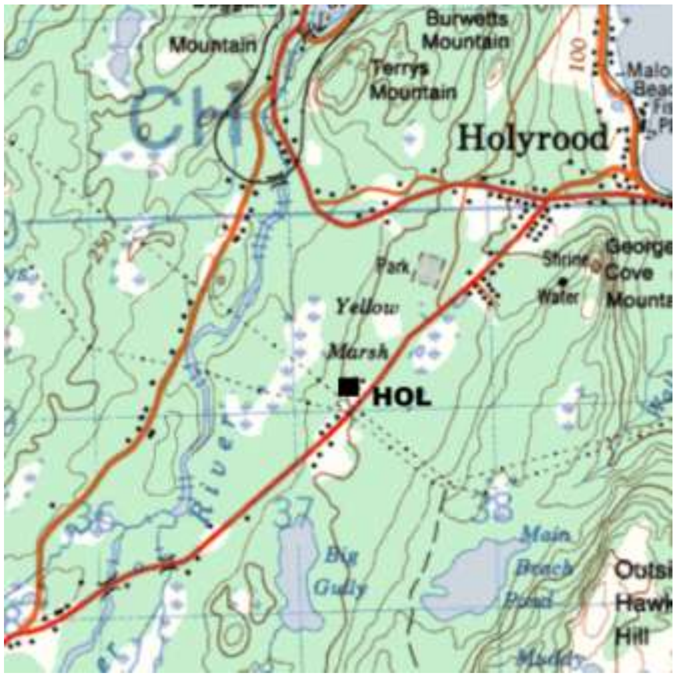
A grounding study will be completed and the ground grid for the Newfoundland Power portion of the substation will be upgraded as required to enhance safety for personnel inside the substation.[15] The grounding study and ground grid upgrade will be coordinated with Newfoundland and Labrador Hydro and Deer Lake Power Company.

[14] 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.

[15] 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.

Holyrood Substation ($622,000)

Holyrood substation was built in 1976 as both a transmission and distribution substation. The transmission portion of the substation contains two 138 kV transmission lines.[16] There is a single 20 MVA, 138kV to 12.5kV power transformer (HOL-T1) feeding the 12.5kV bus infrastructure. There are two feeders (HOL-01 and HOL-02), which serve approximately 2,700 customers in the community of Holyrood and surrounding area.[17]



Holyrood Substation Location

Maintenance records and on-site engineering assessments determine that the 138kV and 12.5 kV steel structures, foundations, buses, switches and insulators are all in good condition.

Feeder HOL-01 is a distribution feeder that splits outside the substation to serve 2 different areas. One section of feeder serving approximately 800 customers south of the substation travels 24.5 km along the Salmonier Line to its termination south of the TransCanada Highway. The second section of feeder serves approximately 1,300 customers north of the substation and travels 13.5 km along the Conception Bay Highway through the communities of Harbour Main, Chapel Cove and Avondale. HOL-01 feeder will be broken into 2 separate feeders with one feeder serving the customers on the Salmonier Line section and a second feeder serving the customers along the

[16] The 138 kV transmission lines are 39L to the Holyrood Thermal Generating Station and 39L to Colliers Substation.

[17] HOL-01 serves approximately 2,150 customers and HOL-02 serves approximately 550 customers.

Conception Bay Highway.[18] This work will involve adding a new recloser and associated switches in an existing bay in the 12.5 kV substation bus structure. No distribution work is required for this project as the feeder splits just outside the substation.

Low Voltage Distribution Bus Structure (Feeder Infrastructure)

The substation has 2 existing reclosers, a hydraulic recloser (HOL-01) and an intelligent Nulec recloser (HOL-02). The hydraulic recloser on HOL-01 is 30 years old and not capable of automation through the SCADA system.[19] The hydraulic recloser on HOL-01 will be replaced with a new intelligent recloser. The new feeder will also be equipped with an intelligent recloser thereby providing all 3 feeders with automation for monitoring and control from the System Control Center. This will provide a means of automated restoration of service which will improve service reliability for customers. With feeder automation, the Holyrood feeders will be added to the provincial under-frequency load shedding scheme.

Control of the existing motor operated switch will be integrated into the overall system protection and control scheme including remote monitoring and control from the System Control Center. In the event of a fault at the transformer, this new motor operator will provide enhanced protection for the transformer.

Transformer HOL-T1 has been in service for 37 years. The power transformer will be refurbished and upgrades made to both the transformer's primary and auxiliary protection.

18 Breaking feeder HOL-01 into 2 separate feeders will improve reliability for customers by (1) reducing the exposure of each customer group to outages on the section of feeder serving the other customer group and (2) reducing the time required to locate a faulted section of line during an outage.

19 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.

Upgrades to the primary protection involve a new digital protection relay to monitor the substation transformer. The existing auxiliary protection devices, including a temperature gauge and gas detection relay, will be replaced. After 37 years in service, 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.[20]

New transformer tap changer controls will be installed on HOL-T1 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 System Control Centre.

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 transformer and feeder protection and control upgrades.

Standard varmint protection practices, in the form of insulated coverings, guards, and leads, will be installed on all low voltage switches and recloser bushings.[21]

A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation.[22]

Bay Roberts ($1,485,000)

The refurbishment and modernization of Bay Roberts substation will be undertaken in 2014 in concert with the installation of an additional power transformer.[23]

Bay Roberts substation was built in 1967 as a distribution substation and expanded to include both transmission and distribution in 1978. The transmission portion of the substation contains two 138 kV transmission lines and two 66 kV transmission lines.[24] There are two 42 MVA, 138 kV to 66 kV power transformers (BRB-T2 and BRB-T3) feeding the 66 kV bus structure. There is a single 20 MVA, 138 kV to 12.5 kV power transformer (BRB-T1) feeding the 12.5 kV bus infrastructure.[25] There are five feeders (BRB-01 to BRB-05), which serve approximately 3,600 customers in the Town of Bay Roberts and surrounding area.

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[20] The Company's strategy for these protection devices is to replace them once they approach 25 to 30 years of service life. See page 4, footnote 4 for further details.

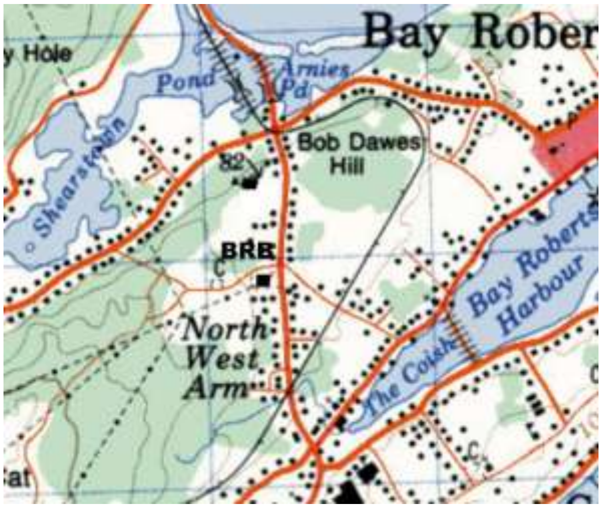
[21] These barriers have proven effective in preventing damage to equipment and customer outages caused by small animals and birds.

[22] 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.

[23] The Substations project *2014 Additions Due to Load Growth* includes a new 25 MVA substation transformer required for Bay Roberts substation.

[24] The two 138 kV transmission lines are 39L to Springfield substation and 48L to Blaketown substation. The two 66 kV transmission lines are 56L to Carbonear substation and 57L to Upper Island Cove substation.

[25] The Substations *2014 Additions Due to Load Growth* project includes an item to install a new 25 MVA 66/12.5 kV substation transformer to operate in parallel with BRB-T1.



Bay Roberts Substation Location

Maintenance records and on-site engineering assessments determine that the 138 kV, 66 kV and 12.5 kV steel structures, foundations, buses, and insulators are all in good condition.

At present, there are 42 electromechanical relays installed in 9 individual protection panels inside the substation control building. These relays, used for the protection of 4 transmission lines, 3 transformers and 2 bus structures are vintage electromechanical type, ranging in age from 35 to 45 years old. Electro-mechanical relays contain moving parts and are prone to failure as they age, wear, and accumulate dirt and dust. The age of these relays dictate they are to be replaced.

Electromechanical Relay Panels

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 42 to 8.[26] 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.

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.

A portable substation will be installed to bypass transformer BRB-T1 to refurbish the power transformer and replace the air break switch.

The 3 power transformers installed between 1976 and 1984 will be refurbished and upgrades made to the transformers' auxiliary protection. The existing auxiliary protection devices, including a temperature gauge and gas detection relay, will be replaced. Having been in service for 30 years or more, these devices are showing signs of deterioration. This can lead 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 3 power transformers.[27]

The transformer 138 kV air break switch (BRB-T1-A) is 35 years old and will be replaced due to its mechanical condition and associated age. The switch is operated infrequently and due to deterioration of bushings, corrosion in its operating mechanism and misalignment of blades it frequently seizes during operation.[28]

Standard varmint protection practices, in the form of insulated coverings, guards, and leads, will be installed on all low voltage switches and recloser bushings.[29]

A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation.[30]

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[26] Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust.

[27] The Company's strategy for these protection devices is to replace them once they approach 25 to 30 years of service life.

[28] 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.

[29] These barriers have proven effective in preventing damage to equipment and customer outages caused by small animals and birds.

[30] 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.

Carbonear Substation ($2,051,000)

Carbonear substation was built in 1974 as both a transmission and distribution substation. The transmission portion of the substation contains four 66 kV transmission lines.[31] There is a single 25 MVA, 66 kV to 12.5 kV power transformer (CAR-T1) which provides distribution voltage to the 12.5 kV bus infrastructure. There are four feeders (CAR-01, CAR-02, CAR-03, and CAR-04), which serve approximately 2,700 customers in the community of Carbonear and surrounding areas.

In 2014, the Company has transformer maintenance activities scheduled for transformer T1 at Carbonear substation. The Company will also undertake other substation refurbishment and modernization work at Carbonear substation to take advantage of the installation of the portable substation, which is being installed to minimize the number and duration of customer outages.[32]

Carbonear Substation Location

Maintenance records and on-site engineering assessments determine that the 66kV and 12.5 kV steel structures are in good condition. The foundation for transmission line breaker 56L-B is in poor condition, and will be replaced. In addition, column foundations for two 66kV steel structures are in poor condition and will be refurbished.

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31 The 4 transmission lines include 56L to Bay Roberts Substation, 68L to Harbour Grace Substation, 41L to Heart's Content Substation, and 40L to Victoria Substation.

32 Wherever possible the Company coordinates maintenance work on individual substations with capital substation refurbishment projects to minimize interruption to customers.

Deteriorated 15kV Pothead Structure Column Foundation

A large section of cable trench and 26 trench covers will be replaced with rust-resistant trench covers.[33] A large section of substation fencing is in need of replacement due to frost heaving. The root cause of the frost heaving issue is poor drainage in that area of the substation, and to correct this issue, a continuous ditch will be created around the perimeter of the substation.

Deteriorated Cable Trench Covers

33 In addition to being corroded the cable tray covers are bent as they were not designed to permit heavy vehicle traffic. As a result the existing cable trench presents a tripping hazard for employees working in the substation.

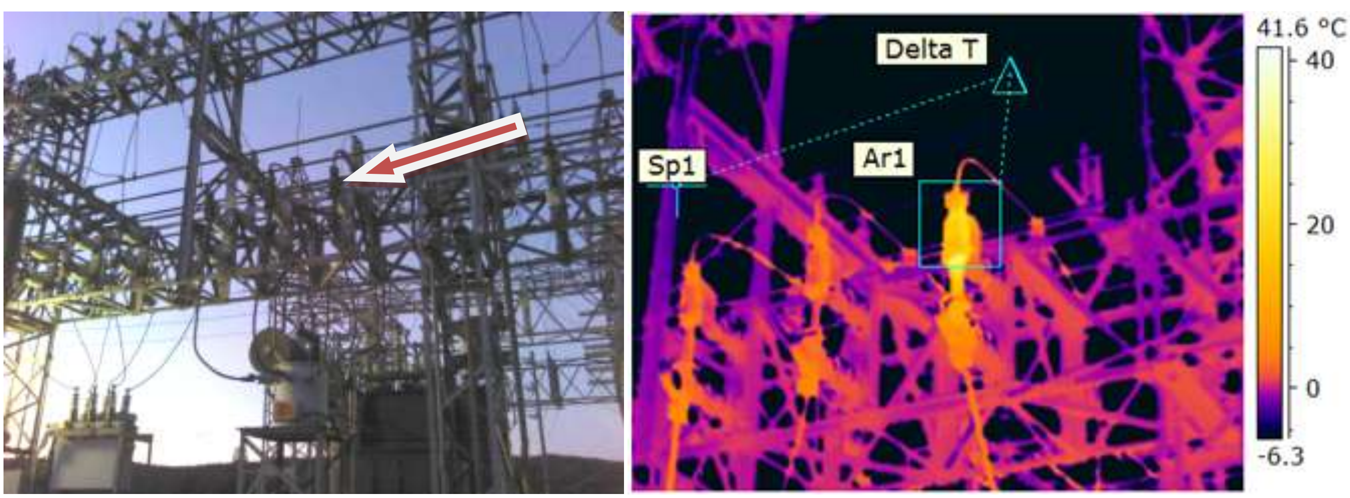
Upgrades to the substation control building are required, including work on the roof, siding and access door in order to maintain a weather-proof operating environment for the various protection devices operating inside the building. A contained battery room will be installed inside the building in order to bring the control building up to current design standards for employee safety.

A portable substation will be installed to bypass the substation and facilitate the refurbishment of power transformer CAR-T1 and associated protection and control devices. The existing 40 year old 66kV potential transformers will be replaced with dry-type units. In addition, the 15 kV oil-filled metering tank has been in service for 25 years and will be replaced with an oil free unit for transformer metering.

The existing switch (CAR-T1-A) used to isolate transformer T1 will be replaced with a new motorized air break switch to allow for the integration of switch operation into the overall protection and control scheme for the station.

The existing auxiliary protection devices, including a temperature gauge and gas detection relay, will be replaced. After more than 25 years in service, these devices are showing signs of deterioration. This can lead to false trips, and as such, these devices can 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 3 power transformers.[34]

In addition, all 1974 vintage high voltage and low voltage switches will be replaced due to their age and the presence of multiple hot spots in the current carrying path.[35]



CAR-T1-D Switch Replacement (Hot spots visible with infrared camera)

[34] The Company's strategy for these protection devices is to replace them once they approach 25 to 30 years of service life.

[35] The need to replace additional switches arose as a result of inspection and is a primary contributor to the increase in forecast cost of refurbishment and modernization of Carbonear substation from approximately $1.3 million in the 2013 Capital Budget Application to $2.1 million in this Application. See page 4 and footnotes 5 and 6 for more detail on the reliability of switches of this vintage.

The protection and controls for transmission lines 56L, 68L, 41L and 40L currently incorporate 40 year old electro mechanical protection relays and these will be replaced utilizing micro processor based digital relays.[36] The age and condition of these relays dictate they are to be replaced.

Three of the 4 distribution feeders are protected and controlled using hydraulic reclosers ranging in age from 31 to 44 years old.[37] The hydraulic reclosers are not capable of automation through the SCADA system.[38] New intelligent reclosers will be installed to replace the hydraulic reclosers providing automation for monitoring and control from the System Control Center. This will provide a means of automated restoration of service which will improve customer service as a result of this enhanced restoration capability. With feeder automation, the 4 Carbonear distribution feeders will be added to the provincial under-frequency load shedding scheme.

The feeder automation equipment, transformer protection and recloser controls will be installed in the existing control building. This will provide a means of automated restoration of power delivered to the station and in-turn, will improve customer service as a result of this enhanced power restoration capability.

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 controlling the transmission lines, distribution feeders and substation transformers into the SCADA system.

Standard varmint protection practices, in the form of insulated coverings, guards, and leads, will be installed on all low voltage switches and recloser bushings.[39]

A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation.[40]

2.2 Substation Monitoring and Operations ($155,000)

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.

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[36] Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust.

[37] The 3 hydraulic reclosers are associated with distribution feeders CAR-01, CAR-02 and CAR-03. Distribution feeder CAR-04 has an intelligent Nulec recloser.

[38] 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.

[39] These barriers have proven effective in preventing damage to equipment and customer outages caused by small animals and birds.

[40] 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.

In 2014, 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 2014, 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.

Appendix A

Substation Refurbishment and Modernization Plan
Five-Year Forecast 2014 to 2018

Substation Refurbishment and Modernization Plan Five-Year Forecast 2014 to 2018 (000s)									
2014		**2015**		**2016**		**2017**		**2018**	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
SPR	$ 963	STX	$ 552	SPO	$1,631	CAT	$2,474	HCP	$ 503
MAS	$ 747	RRD	$1,047	P135	$ 740	BVA	$ 946	NCH	$1,605
HOL	$ 622	BVS	$1,400	HUM	$2,506	GAN	$3,385	TCV	$ 619
CAR	$2,051	VIC	$1,685	SMU	$ 165	SMU	$ 170	BLA	$ 743
BRB	$1,485	SMU	$ 160					MOL	$1,914
SMU	$ 155							GBS	$1,472
								SMU	$ 176
	$6,023		**$4,844**		**$5,042**		**$6,975**		**$7,032**

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.

2014 Additions Due to Load Growth

June 2013

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June 19/2013
DATE
NEWFOUNDLAND & LABRADOR

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 power 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 2014 Capital Budget planning cycle have identified systems where 3 substation transformers will be overloaded in 2014 if no capital improvements are undertaken. To address these overloads, the addition of transformer capacity at Hardwoods, Bay Roberts and Marble Mountain substations are required. Two studies completed in 2010 and submitted to the Board in that year included, as part of the least cost alternative, adding substation transformer capacity to Hardwoods substation in 2014 to avoid a transformer overload.[2] The results of these studies are discussed in Section 2 of this report. Adding transformer capacity at the Bay Roberts and Marble Mountain substations were the results of studies of the Bay Roberts 12.5 kV system, and the Humber Valley 12.5 kV system respectively. These studies are discussed in Sections 3 and 4 of this report and the study results are attached as appendices.

This report provides the justifications for the 3 items to be included in the 2014 Capital Budget Application *2014 Additions Due to Load Growth* project.

2.0 Northeast St. John's and Conception Bay South Studies ($2,399,000)

Two previously completed engineering studies were submitted as attachments to the Newfoundland Power 2011 Capital Budget Application – *2011 Additions Due to Load Growth* report. Both of these studies identified, as part of the lowest cost alternative, the purchase and installation of a new 25 MVA transformer in Hardwoods ("HWD") substation in 2014 to deal with their respective area's forecasted overload conditions. Without the installation of a new 25 MVA transformer in 2014, the forecast overload is 10%.

Each of these studies examined 3 alternatives to determine the least cost approach to dealing with their respective area's forecasted overload condition. Each alternative was evaluated using a 20 year load forecast period. Based on net present value calculations the least cost alternative was selected.

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[1] A distribution power 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] The "Conception Bay South Study" and the "Northeast St. John's Study" were submitted with the Newfoundland Power 2011 Capital Budget Application, *Additions Due to Load Growth* report as Attachments A and B, respectively.

2.1 Least Cost Alternative Review

To ensure the conclusion of the 2010 studies was still applicable, the Company reviewed the cost of the Hardwoods transformer addition, changes in load growth, and potential for further load transfers.

Review of Hardwoods transformer cost estimate

Both of the previously completed studies indicated that the least cost alternative was to purchase and install a new 25 MVA transformer in HWD substation in 2014. The cost of the new transformer was estimated to be $2,500,000 in the 2010 studies. The current estimate for the installation of a new 25 MVA transformer is $2,402,000. These estimates are similar to each other and would not impact the previously determined least cost alternative.

When reviewing this project, consideration was also given to providing the 25 MVA capacity increase by replacing the existing 25 MVA transformer with a 50 MVA transformer.[3] This alternative for providing a 25 MVA increase in capacity at HWD would cost $2,399,000. While the cost of these two alternatives are practically the same, replacement of the existing 25 MVA unit with a 50 MVA unit has greater overall economic value.[4] The savings from using the 25 MVA unit to avoid the cost of a future purchase of transformation capacity makes the 50 MVA transformer the least cost option.[5] From this review the Company is now recommending the replacement of a 25 MVA unit with 50 MVA unit at HWD substation rather than the previously least cost alternative of installing an additional 25 MVA unit.[6]

Review of Load Forecast

Both of the studies completed in 2010 indicated that the peak demand forecast for the HWD 25kV substation transformer would be 25.5 MVA in 2014. This compares to a current forecast of 27.5 MVA. This increase is related to shifting of load growth from Chamberlains ("CHA") substation and Hardwoods substation.[7] As a result, additional capacity is still required.

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[3] The installation of 50MVA was not considered in the 2010 study because the requirement to reuse the 25MVA transformer was not clearly defined at the time. Also, in 2010 the Company had only one 50 MVA portable substation available to backup substation transformers. In 2013 the Company will have a second 50 MVA portable substation as approved in Order No. P.U. 26(2011). These two portable substations will provide backup to the proposed 50MVA power transformer installation at Hardwoods substation.

[4] The 25 MVA transformer to be removed from HWD can be used at another substation to increase transformation capacity. The five year plan currently includes a project to install this transformer at the St. John's Main ("SJM") substation in 2015.

[5] Another factor contributing to the lower cost of the 50 MVA transformer is that it will occupy the existing transformer bay in the substation bus structure. The addition of a second 25 MVA transformer to provide the increase in capacity would necessarily involve the construction of a second transformer bay in the substation bus structure.

[6] This change does not impact any of the other components of the least cost alternatives presented in the 2010 studies.

[7] The 2010 load studies showed a total forecast peak demand for CHA and HWD substations of 76.5 MVA in 2014. The most recently completed forecast indicates that the total load on CHA and HWD substations will be 75.2 MVA.

Review of Potential Load Transfers

The two studies focused on the systems supplying the communities of Conception Bay South, Paradise, St. Phillips – Portugal Cove, Torbay and north to Pouch Cove. They did not consider load transfer options presented by Kenmount Road ("KEN") substation. The KEN substation distribution system does offer some potential for transferring load being supplied from HWD to KEN substation.[8] However, the KEN transformers are also reaching their capacity limits and as a result there is no spare capacity at KEN substation to permit load transfers from HWD substation.[9]

Summary

A review of the 2010 studies shows that the addition of transformer capacity at HWD in 2014 is still needed and remains part of the least cost option for meeting load growth. However a review of project costs results in recommending the installation of a 50 MVA transformer to replace a 25 MVA unit at HWD as the least cost option for adding capacity to HWD.

3.0 Bay Roberts 12.5 kV System ($2,320,000)

An engineering study has been completed on the distribution system upgrades to meet the electrical demands in the Bay Roberts area. This 12.5 kV system includes customers serviced from Bay Roberts ("BRB") and Springfield ("SPF") substations. This study is presented in Appendix A to this report.

The study examined 3 alternatives to determine the least cost alternative for dealing with the forecasted overload conditions of the BRB 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 project involves installing a new 25 MVA substation transformer at BRB substation.

4.0 Humber Valley 12.5 kV System ($285,000)

An engineering study has been completed on the upgrades to the distribution system to meet the electrical demands of the Humber Valley area. This 12.5 kV system includes customers served from Marble Mountain ("MMT") and Pasadena ("PAS") substations. This study is presented in Appendix B to this report.

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8 The Company is currently completing a tie between the KEN 25 kV distribution system and the HWD 25 kV System in the area of Elizabeth Park on Topsail Road.

9 The total 2014 forecast peak load on KEN substation transformers is 50.4 MVA, exceeding their rating of 50 MVA. With the addition of new transformer capacity at HWD, load will be transferred from KEN onto HWD feeders to alleviate the potential overload at KEN. To permit this load transfer, the Company is proposing the construction of a new feeder, HWD-09, in 2014. See report ***4.2*** *Feeder Additions for Load Growth.*

The study examined 3 alternatives to determine the least cost approach to dealing with the forecasted overload conditions of the Humber Valley 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. Based on net present value calculations the least cost alternative was selected.

The least cost project involves installing an existing 6.7 MVA substation transformer at MMT substation to replace the existing 4 MVA MMT-T1 transformer.

5.0 Project Cost

Table 4 shows the total 2014 project capital costs for the least cost alternative.

Table 4
2014 Project Costs
($000)

Cost Category	Hardwoods Substation Transformer Replacement	Bay Roberts Substation Transformer Addition	Marble Mountain Substation Transformer Replacement
Material	2,111	2,166	207
Labour – Internal	35	35	43
Engineering	210	86	31
Other	43	33	4
Total	**2,399**	**2,320**	**285**[10]

[10] The cost of installing a 6.7 MVA transformer at Marble Mountain substation is low due to the project utilizing a transformer previously removed from Mobile substation.

6.0 Concluding

The Company continues to experience customer and load growth in the Paradise and Kenmount Road area, Bay Roberts area and the Humber Valley. 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 sections 2.0 and the attached studies be undertaken in 2014 to address the capacity issues in the Paradise and Kenmount Road area, Bay Roberts area and the Humber Valley. The recommended projects include:

- The replacement of the existing 25 MVA HWD-T3 transformer with a new 50 MVA transformer,
- The addition of a 25 MVA transformer in BRB substation, and
- The replacement of the existing 4 MVA MMT-T1 transformer with an existing 6.7 MVA transformer.

This project is estimated to cost $5,004,000 in 2014.

Attachment A
Bay Roberts 12.5 kV System 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 Bay Roberts ("BRB") substation 12.5 kV system.

In the winter of 2014, the substation transformer that supplies electricity to the BRB 12.5 kV system is expected to experience a total peak load of 22.1 MVA.[1] The current capacity of BRB-T1 is 20 MVA. As a result, the load forecast indicates that BRB-T1 will be overloaded in 2014. Load growth on this transformer is primarily the result of an increase in residential and commercial development throughout the town of Bay Roberts.

This report identifies the capital project(s) required to avoid the 2014 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 Bay Roberts Substation

BRB substation is located near the intersection of Cathill Road and Conception Bay Highway (route 70) in the town of Bay Roberts. There are 3 transformers located in the substation: BRB-T1, BRB-T2, and BRB-T3. BRB-T1 is a 20 MVA, 138/12.5 kV transformer that is used to convert 138 kV to a distribution level voltage of 12.5 kV to supply customers through 5 BRB distribution feeders. BRB-T2 and BRB-T3 are 41.6 MVA, 138/66 kV system transformers that supply the 66 kV transmission lines to Upper Island Cove and Carbonear substations[2].

There are five 12.5 kV feeders originating from BRB substation:

1) BRB-01 feeder serves approximately 551 customers. The main trunk portion of this feeder consists of approximately 3.2 km of 477 ASC primary conductor heading south along the Conception Bay Highway and 2.8 km of 477 ASC primary conductor that runs along Coleys Point North Road. It can be paralleled with SPF-01 along the Conception Bay Highway. It can be paralleled with BRB-02, BRB-03, and BRB-04 at various locations.

2) BRB-02 feeder serves approximately 100 customers. The main trunk portion of this feeder consists of approximately 2.5 km of 4/0 AASC primary conductor heading north along the Conception Bay Highway. It can be paralleled with ILC-02 along the Conception Bay Highway just south of New Harbour Road in the town of Spaniard's Bay[3]. It can be paralleled with BRB-01, BRB-03, and BRB-05 at various locations.

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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 A system transformer converts electricity from one transmission level voltage (typically between 230 kV and 66 kV) to another transmission level voltage.

3 There is limited opportunity to transfer load from BRB-02 to ILC-02. There is currently only a small amount of load supplied through BRB-02 (less than 0.8 MVA). Also, load on ILC-02 is near capacity. To transfer the remaining load will require the installation of a bank of voltage regulators. Due to the cost of a bank of regulators ($130,000) and the small load on BRB-02, this transfer is not considered a viable alternative to address the forecast overload of the Bay Roberts substation transformer.

3) BRB-03 feeder serves approximately 1,054 customers. The main trunk portion of this feeder consists of approximately 3.0 km of 2/0 copper primary conductor that runs northeast along Water Street towards French's Cove and 1.1 km of 4/0 AASC primary conductor that runs northeast along Track Road. It can be paralleled with both BRB-01 and BRB-02 near the Barracks Road and Conception Bay Highway intersection.

4) BRB-04 feeder serves approximately 1,164 customers. The main trunk portion of this feeder consists of approximately 1.6 km of 4/0 AASC primary conductor that heads south along the Conception Bay Highway and then extends another 7.2 km with 2/0 AASC conductor along Bareneed Road towards Port de Grave. It can be paralleled with BRB-01 near the Butler Drive and Conception Bay Highway intersection

5) BRB-05 feeder serves approximately 731 customers. The main trunk portion of this feeder consists of approximately 2.4 km of 4/0 AASC primary conductor that heads north along the Conception Bay Highway where it then extends into the communities of Shearstown and Butlerville. It can be paralleled with BRB-02 near the Shearstown Road and Conception Bay Highway intersection.

2.2 Springfield Substation

Springfield ("SPF") substation is located on Springfield Road within the town of South River. There is a single transformer located in the substation, SPF-T1. SPF-T1 is a 20 MVA, 138/12.5 kV distribution power transformer that is used to convert a transmission level voltage of 138 kV to a distribution level voltage of 12.5 kV to supply power to customers through a number of SPF feeder distribution lines.

There are three 12.5 kV feeders originating from SPF substation:

1) SPF-01 feeder serves approximately 1,067 customers within the communities of Clarke's Beach and North River. The main trunk portion of this feeder consist of approximately 6.5 km of 4/0 AASC primary conductor that runs through the town of Clarke's Beach along Main Street and the Conception Bay Highway (Route 70). It then extends north along the Conception Bay Highway towards the town of Bay Roberts where it can be paralleled with the BRB-01 feeder near the Department of Transportation and Works depot. It can also be paralleled with SPF-03 at two different locations.

2) SPF-02 feeder serves approximately 1,697 customers along Roaches Line as well as within the towns of Brigus, Cupids, and Makinsons. The main trunk portion of this feeder consists of approximately 7 km of 4/0 AASC primary conductor heading south on Springfield Road and then west along the Conception Bay Highway (Route 60) towards the outskirts of Brigus. It also extends southwest for 11 km through the community of Makinsons towards the TransCanada Highway as well as 9 km along Roaches Line.

3) SPF-03 feeder serves approximately 326 customers, the majority of which reside in the community of South River. The main trunk portion of this feeder consists of approximately 2.7 km of a combination of 4/0 and 2/0 AASC primary conductor. It exits the substation and proceeds northeast along Springfield Road where it then heads north along the Conception

Bay Highway (Route 70) towards the town of Clarke's Beach. It can be paralleled with SPF-01 at two different locations.

3.0 Load Forecast

In the winter of 2014 the peak load on BRB-T1 is forecasted to be 22.1 MVA. BRB-T1 is rated for 20 MVA and is overloaded at the forecasted peak load.

This study uses a 20 year load forecast for this substation transformer. The base case 20 year substation forecast for BRB-T1 is located in Appendix A. A high and low load growth forecast has 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.[4] 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 2014, reconductor 4.0 km of SPF-01 feeder's main trunk with 477 ASC conductor and install a new bank of 400 amp voltage regulators on SPF-01 to enable a 2.5 MVA load transfer from BRB-01 to SPF-01.
- In 2016, replace the existing 20 MVA, 138/12.5 kV BRB-T1 transformer with a new 25 MVA, 138/12.5 kV transformer. This would increase the total substation capacity from 20 MVA to 25 MVA.
- In 2029, add a new 25 MVA, 138/12.5 kV transformer (BRB-T4) to BRB substation. The additional transformer would be configured to operate in parallel with the 25 MVA, 138/12.5 kV BRB-T1 transformer. This transformer addition would increase the total substation 12.5 kV transformer capacity to 50 MVA.

The resultant peak load forecasts for BRB-T1, BRB-T4, and SPF-T1 under Alternative 1 are shown in Appendix B.

4.2 Alternative 2

- In 2014, add a new 25 MVA, 138/12.5 kV transformer (BRB-T4) to BRB substation. The additional transformer would be configured to operate in parallel with the 20 MVA,

[4] The following technical criteria were applied:
- The steady state distribution power 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.

138/12.5 kV BRB-T1 transformer. This transformer addition would increase the total substation 12.5 kV transformer capacity to 45 MVA.

The resultant peak load forecasts for BRB-T1 and BRB-T4 under Alternative 2 are shown in Appendix C.

4.3 Alternative 3

- In 2014, reconductor 4.0 km of SPF-01 feeder's main trunk with 477 ASC conductor and install a new bank of 400 amp voltage regulators on SPF-01 to enable a 2.5 MVA load transfer from BRB-01 to SPF-01.
- In 2016, addition of a new 25 MVA, 138/12.5 kV transformer (BRB-T4) to BRB substation. The additional transformer would be configured to operate in parallel with the 20 MVA, 138/12.5 kV BRB-T1 transformer. This transformer addition would increase the total substation 12.5 kV transformer capacity to 45 MVA.

The resultant peak load forecasts for BRB-T1, BRB-T4, and SPF-T1 under Alternative 3 are shown in Appendix D.

5.0 Evaluation of Alternatives

5.1 Cost of Alternatives

Table 1 shows the capital costs estimated for Alternative 1.

Table 1
Alternative 1 Capital Costs

Year	Item	Cost
2014	Reconductor 4.0 km SPF-01 feeder's main trunk with 477 ASC conductor.	$306,000
2014	Purchase and install a new bank of 400 amp voltage regulators on SPF-01.	$130,000
2016	Purchase and install a new 25 MVA transformer to replace the existing BRB-T1.	$1,900,000
2029	Purchase and install a new 25 MVA transformer (BRB-T4) in BRB substation.	$2,320,000
	Total	**$4,656,000**

Table 2 shows the capital costs estimated for Alternative 2.

Table 2
Alternative 2 Capital Costs

Year	Item	Cost
2014	Purchase and install a new 25 MVA transformer (BRB-T4) in BRB substation.	$2,320,000
	Total	**$2,320,000**

Table 3 shows the capital costs estimated for Alternative 3.

Table 3
Alternative 3 Capital Costs

Year	Item	Cost
2014	Reconductor 4.0 km SPF-01 feeder's main trunk with 477 ASC conductor.	$306,000
2014	Purchase and install a new bank of 400 amp voltage regulators on SPF-01.	$130,000
2016	Purchase and install a new 25 MVA transformer (BRB-T4) in BRB substation.	$2,320,000
	Total	**$2,756,000**

5.2 Economic Analysis

In order to compare the economic impact of the alternatives, an NPV calculation of customer revenue requirement was completed for each alternative. Capital costs from 2014 to 2031 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.[5]

[5] 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 base case load forecast.

Table 5
Net Present Value Analysis
($000)

Alternative	NPV
1	3,142
2	2,592
3	2,978

Alternative 2 has the lowest NPV of customer revenue requirement. As a result, Alternative 2 is recommended as the most appropriate expansion plan.

5.3 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]

Table 6 shows the NPV of customer revenue requirement for each alternative under the high and low load forecasts.

Table 6
Sensitivity Analysis
($000)

Alternative	High Load Forecast NPV	Low Load Forecast NPV
1	3,560	2,107
2	2,795	2,475
3	3,426	2,361

[6] The sensitivity analysis for each of the alternatives includes additional projects to add transformer capacity at the end of the 20 year forecast period.

Under all 3 scenarios, the base case, high and low growth forecast for Alternative 3 is not the least cost alternative. Under the base case and high load forecast scenarios, Alternative 2 is the least cost alternative with NPV difference of 18% and 21% respectively when compared to Alternative 1. Under the low load forecast scenario, Alternative 1 is the least cost alternative, with a NPV difference of 17% when compared to Alternative 2. Further analysis of the load growth sensitivity indicates Alternative 1 and Alternative 2 break even at around 70% of the base case load growth.

The sensitivity analysis confirms that Alternative 2 is the least cost alternative for both the base case and high load forecasts. The sensitivity analysis indicates that Alternative 2 is least cost for load growth above 70% of the base case load. As a result, on balance the recommendation to implement Alternative 2 is still appropriate given the results of the sensitivity analysis.

6.0 Project Cost

Table 7 shows the estimated project costs for the chosen alternative.

Table 7
Project Capital Costs

Year	Item	Cost
2014	Purchase and install a new 25 MVA transformer (BRB-T4) in BRB substation.	$2,320,000
	Total	**$2,320,000**

7.0 Conclusion and Recommendation

A 20 year load forecast has projected the electrical demands for the Bay Roberts 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 5.2 of this study indicates that Alternative 2 is the least cost alternative that meets all of the required technical criteria. The sensitivity analysis indicates that Alternative 2 is the least cost alternative under the high load growth forecast and that Alternative 2 is the least cost alternative for load growth above 70% of the base case growth. The sensitivity analysis was 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 2 expansion plan has been selected as the most appropriate project.

The least cost expansion plan includes the following item in the 2014 Capital Budget:

- The purchase and installation of a new 25 MVA transformer (BRB-T4) in BRB substation.

The 2014 project is estimated to cost $2,320,000.

Appendix A
2012 Substation Load Forecast – Base Case

20 Year Substation Load Forecast – Base Case

Device	**BRB-T1**	**SPF-T1**
Sec. Voltage (kV)	12.5	12.5
Rating (MVA)	20.0	20.0
2011 Peak (MVA)	19.8	12.1
Year	**Forecasted Undiversified Peak (MVA)**	
2012	21.4	12.8
2013	21.7	12.8
2014	22.1	12.7
2015	22.4	12.8
2016	22.7	13.0
2017	23.1	13.1
2018	23.4	13.3
2019	23.8	13.4
2020	24.1	13.5
2021	24.5	13.7
2022	24.8	13.8
2023	25.2	14.0
2024	25.6	14.1
2025	26.0	14.3
2026	26.4	14.4
2027	26.8	14.6
2028	27.2	14.8
2029	27.6	14.9
2030	28.0	15.1
2031	28.4	15.2

Appendix B
Alternative 1
20 Year Substation Load Forecasts

Alternative 1
20 Year Substation Load Forecast – Base Case

Device	**BRB-T1**	**BRB-T1 (New)**	**BRB-T4**	**SPF-T1**
Sec. Voltage (kV)	12.5	12.5	12.5	12.5
Rating (MVA)	20.0	25.0	25.0	20.0
2011 Peak (MVA)	19.8	N/A	N/A	12.1
Year	**Forecasted Undiversified Peak (MVA)**			
2012	21.4	0.0	0.0	12.8
2013	21.7	0.0	0.0	12.8
2014	19.6	0.0	0.0	15.2
2015	19.9	0.0	0.0	15.3
2016	0.0	20.2	0.0	15.5
2017	0.0	20.6	0.0	15.6
2018	0.0	20.9	0.0	15.8
2019	0.0	21.3	0.0	15.9
2020	0.0	21.6	0.0	16.0
2021	0.0	22.0	0.0	16.2
2022	0.0	22.3	0.0	16.3
2023	0.0	22.7	0.0	16.5
2024	0.0	23.1	0.0	16.6
2025	0.0	23.5	0.0	16.8
2026	0.0	23.9	0.0	16.9
2027	0.0	24.3	0.0	17.1
2028	0.0	24.7	0.0	17.3
2029	0.0	12.5	12.5	17.4
2030	0.0	12.7	12.7	17.6
2031	0.0	13.0	13.0	17.7

Alternative 1
20 Year Substation Load Forecast – High Growth

Device	BRB-T1	BRB-T1 (New)	BRB-T4	SPF-T1
Sec. Voltage (kV)	12.5	12.5	12.5	12.5
Rating (MVA)	20.0	25.0	25.0	20.0
2011 Peak (MVA)	19.8	N/A	N/A	12.1
Year	**Forecasted Undiversified Peak (MVA)**			
2012	21.4	0.0	0.0	12.8
2013	21.9	0.0	0.0	12.8
2014	19.9	0.0	0.0	15.2
2015	0.0	20.4	0.0	15.5
2016	0.0	20.9	0.0	15.7
2017	0.0	21.4	0.0	15.9
2018	0.0	22.0	0.0	16.1
2019	0.0	22.5	0.0	16.3
2020	0.0	23.1	0.0	16.5
2021	0.0	23.7	0.0	16.8
2022	0.0	24.2	0.0	17.0
2023	0.0	24.8	0.0	17.2
2024	0.0	12.7	12.7	17.5
2025	0.0	13.0	13.0	17.7
2026	0.0	13.4	13.4	18.0
2027	0.0	13.7	13.7	18.2
2028	0.0	14.0	14.0	18.5
2029	0.0	14.4	14.4	18.7
2030	0.0	14.7	14.7	19.0
2031	0.0	15.1	15.1	19.3

Alternative 1
20 Year Substation Load Forecast – Low Growth

Device	BRB-T1	BRB-T1 (New)	BRB-T4	SPF-T1
Sec. Voltage (kV)	12.5	12.5	12.5	12.5
Rating (MVA)	20.0	25.0	25.0	20.0
2011 Peak (MVA)	19.8	N/A	N/A	12.1
Year	**Forecasted Undiversified Peak (MVA)**			
2012	21.4	0.0	0.0	12.8
2013	21.6	0.0	0.0	12.8
2014	19.2	0.0	0.0	15.1
2015	19.4	0.0	0.0	15.2
2016	19.6	0.0	0.0	15.3
2017	19.7	0.0	0.0	15.3
2018	19.9	0.0	0.0	15.4
2019	0.0	20.1	0.0	15.5
2020	0.0	20.2	0.0	15.5
2021	0.0	20.4	0.0	15.6
2022	0.0	20.6	0.0	15.7
2023	0.0	20.7	0.0	15.8
2024	0.0	20.9	0.0	15.8
2025	0.0	21.1	0.0	15.9
2026	0.0	21.3	0.0	16.0
2027	0.0	21.4	0.0	16.0
2028	0.0	21.6	0.0	16.1
2029	0.0	21.8	0.0	16.2
2030	0.0	22.0	0.0	16.3
2031	0.0	22.2	0.0	16.3

Appendix C
Alternative 2
20 Year Substation Load Forecasts

Alternative 2
20 Year Substation Load Forecast – Base Case

Device	**BRB-T1**	**BRB-T4**
Sec. Voltage (kV)	12.5	12.5
Rating (MVA)	20.0	25.0
2011 Peak (MVA)	19.8	N/A
Year	**Forecasted Undiversified Peak (MVA)**	
2012	21.4	0.0
2013	21.7	0.0
2014	9.8	12.3
2015	10.0	12.4
2016	10.1	12.6
2017	10.3	12.8
2018	10.4	13.0
2019	10.6	13.2
2020	10.7	13.4
2021	10.9	13.6
2022	11.0	13.8
2023	11.2	14.0
2024	11.4	14.2
2025	11.5	14.4
2026	11.7	14.7
2027	11.9	14.9
2028	12.1	15.1
2029	12.3	15.3
2030	12.4	15.5
2031	12.6	15.8

Alternative 2
20 Year Substation Load Forecast – High Growth

Device	BRB-T1	BRB-T4
Sec. Voltage (kV)	12.5	12.5
Rating (MVA)	20.0	25.0
2011 Peak (MVA)	19.8	N/A
Year	**Forecasted Undiversified Peak (MVA)**	
2012	21.4	0.0
2013	21.9	0.0
2014	9.9	12.4
2015	10.2	12.7
2016	10.4	13.0
2017	10.6	13.3
2018	10.9	13.6
2019	11.1	13.9
2020	11.4	14.2
2021	11.6	14.5
2022	11.9	14.9
2023	12.2	15.2
2024	12.4	15.5
2025	12.7	15.9
2026	13.0	16.2
2027	13.3	16.6
2028	13.6	17.0
2029	13.9	17.4
2030	14.2	17.7
2031	14.5	18.1

Alternative 2
20 Year Substation Load Forecast – Low Growth

Device	BRB-T1	BRB-T4
Sec. Voltage (kV)	12.5	12.5
Rating (MVA)	20.0	25.0
2011 Peak (MVA)	19.8	N/A
Year	**Forecasted Undiversified Peak (MVA)**	
2012	21.4	0.0
2013	21.6	0.0
2014	9.7	12.1
2015	9.7	12.2
2016	9.8	12.3
2017	9.9	12.3
2018	10.0	12.4
2019	10.0	12.5
2020	10.1	12.6
2021	10.2	12.7
2022	10.3	12.8
2023	10.3	12.9
2024	10.4	13.0
2025	10.5	13.1
2026	10.6	13.2
2027	10.6	13.3
2028	10.7	13.4
2029	10.8	13.5
2030	10.9	13.6
2031	11.0	13.7

Appendix D
Alternative 3
20 Year Substation Load Forecasts

Alternative 3
20 Year Substation Load Forecast – Base Case

Device	**BRB-T1**	**BRB-T4**	**SPF-T1**
Sec. Voltage (kV)	12.5	12.5	12.5
Rating (MVA)	20.0	25.0	20.0
2011 Peak (MVA)	19.8	N/A	12.1
Year	**Forecasted Undiversified Peak (MVA)**		
2012	21.4	0.0	12.8
2013	21.7	0.0	12.8
2014	19.6	0.0	15.2
2015	19.9	0.0	15.3
2016	9.0	11.2	15.5
2017	9.1	11.4	15.6
2018	9.3	11.6	15.8
2019	9.5	11.8	15.9
2020	9.6	12.0	16.0
2021	9.8	12.2	16.2
2022	9.9	12.4	16.3
2023	10.1	12.6	16.5
2024	10.3	12.8	16.6
2025	10.4	13.0	16.8
2026	10.6	13.3	16.9
2027	10.8	13.5	17.1
2028	11.0	13.7	17.3
2029	11.1	13.9	17.4
2030	11.3	14.2	17.6
2031	11.5	14.4	17.7

Alternative 3
20 Year Substation Load Forecast – High Growth

Device	BRB-T1	BRB-T4	SPF-T1
Sec. Voltage (kV)	12.5	12.5	12.5
Rating (MVA)	20.0	25.0	20.0
2011 Peak (MVA)	19.8	N/A	12.1
Year	**Forecasted Undiversified Peak (MVA)**		
2012	21.4	0.0	12.8
2013	21.9	0.0	12.8
2014	19.9	0.0	15.2
2015	9.1	11.3	15.5
2016	9.3	11.6	15.7
2017	9.5	11.9	15.9
2018	9.8	12.2	16.1
2019	10.0	12.5	16.3
2020	10.3	12.8	16.5
2021	10.5	13.1	16.8
2022	10.8	13.5	17.0
2023	11.0	13.8	17.2
2024	11.3	14.1	17.5
2025	11.6	14.5	17.7
2026	11.9	14.9	18.0
2027	12.2	15.2	18.2
2028	12.5	15.6	18.5
2029	12.8	16.0	18.7
2030	13.1	16.4	19.0
2031	13.4	16.8	19.3

Alternative 3
20 Year Substation Load Forecast – Low Growth

Device	**BRB-T1**	**BRB-T4**	**SPF-T1**
Sec. Voltage (kV)	12.5	12.5	12.5
Rating (MVA)	20.0	25.0	20.0
2011 Peak (MVA)	19.8	N/A	12.1
Year	**Forecasted Undiversified Peak (MVA)**		
2012	21.4	0.0	12.8
2013	21.6	0.0	12.8
2014	19.2	0.0	15.1
2015	19.4	0.0	15.2
2016	19.6	0.0	15.3
2017	19.7	0.0	15.3
2018	19.9	0.0	15.4
2019	8.9	11.1	15.5
2020	9.0	11.2	15.5
2021	9.1	11.3	15.6
2022	9.1	11.4	15.7
2023	9.2	11.5	15.8
2024	9.3	11.6	15.8
2025	9.4	11.7	15.9
2026	9.5	11.8	16.0
2027	9.5	11.9	16.0
2028	9.6	12.0	16.1
2029	9.7	12.1	16.2
2030	9.8	12.2	16.3
2031	9.9	12.3	16.3

Attachment B
Humber Valley 12.5 kV System Study

Table of Contents

Page

1.0 Introduction

The purpose of this study is to determine the distribution system alternative that best meets the electrical demands of the Humber Valley 12.5 kV system.

In the winter of 2014, the substation transformers that supply electricity to the Humber Valley 12.5 kV distribution system (MMT-T1 and PAS-T1) are expected to experience a total peak load of 18.1 MVA. The current capacity of the system is 17.3 MVA.[1] As a result, the load forecast indicates that the Humber Valley 12.5 kV system will be overloaded in 2014. The growth on these transformers is primarily the result of an increase in residential and commercial development throughout the Humber Valley area.

This report identifies the capital project(s) required to avoid the 2014 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 Marble Mountain Substation

Marble Mountain ("MMT") substation is located near the community of Steady Brook, which is approximately 1 km east of the Marble Mountain resort along the TransCanada Highway. There is one transformer located in the substation: MMT-T1. MMT-T1 is a 4 MVA, 66/12.5 kV distribution power transformer that converts transmission level voltage of 66 kV to distribution level voltage of 12.5 kV to supply power to customers through the single MMT feeder distribution line, MMT-01.

There is only one 12.5 kV feeder originating from MMT substation:

- MMT-01 feeder serves approximately 475 customers. This feeder consists of approximately 9 km of 4/0 AASC conductor and services customers at the Marble Mountain Ski Resort as well as customers from the towns of Steady Brook, Humber Village and Little Rapids.

2.2 Pasadena Substation

Pasadena ("PAS") substation is located in the town of Pasadena, which is approximately 20 km east of the Marble Mountain resort along the TransCanada Highway. There is one transformer located in the substation, PAS-T1. PAS-T1 is a 13.3 MVA, 66/12.5 kV distribution power transformer that converts transmission level voltage of 66 kV to distribution level voltage of 12.5 kV to supply power to customers through the two PAS distribution feeder lines, PAS-01 and PAS-02.

1) PAS-01 feeder serves approximately 1,052 customers that mostly reside on Pasadena's west side. The main trunk portion of this feeder consists of approximately 8 km of 4/0 AASC

[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).

conductor heading west along the TransCanada Highway as well as two 4 km branches of 4/0 AASC conductor that serve the Humber Valley Resort area.

2) PAS-02 feeder serves approximately 1,080 customers that mostly reside on Pasadena's east side. The main trunk portion of this feeder consists of approximately 5.0 km of #2 ACSR and 4/0 AASC conductor. There is a single phase tap which services the rural districts of Eastern Brook, Pynn's Brook and Little Harbour.

3.0 Load Forecast

The following is the forecasted peak substation load that is expected for MMT-T1 and PAS-T1 in the winter of 2014.

- MMT-T1 is rated for 4 MVA. The peak load on MMT-T1 is forecasted to be 4.2 MVA.
- PAS-T1 is rated for 13.3 MVA. The peak load on PAS-T1 is forecasted to be 13.9 MVA.

This study uses a 20 year load forecast for these distribution power transformers. The base case 20 year substation forecast for MMT-T1 and PAS-T1 is located in Appendix A. A high and low load growth forecast has 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 2014, extend 0.6 km of MMT-01 feeder's main trunk with 4/0 AASC conductor and install a new bank of 300 amp voltage regulators on MMT-01 to enable a 1.5 MVA load transfer from PAS-01 to MMT-01.[3]

- In 2014, replace the existing 4 MVA, 66/12.5 kV MMT-T1 transformer with an existing 5/6.7 MVA, 66/12.5 kV transformer. This would increase the total substation capacity from 4 MVA to 6.7 MVA.

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[2] The following technical criteria were applied:
- The steady state distribution power 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 extension of MMT-01 is required to split the Humber Valley Resort load and enable the 1.5 MVA load transfer from PAS-01 to MMT-01.

- In 2021, replace the existing 10/13.3 MVA, 66/12.5 kV PAS-T1 transformer with a new 15/20/25 MVA, 66/12.5 kV transformer. This would increase the total substation capacity from 13.3 MVA to 25 MVA.

The resultant peak load forecasts for MMT-T1 and PAS-T1 under Alternative 1 are shown in Appendix B.

4.2 Alternative 2

- In 2014, replace the existing 10/13.3 MVA, 66/12.5 kV PAS-T1 transformer with a new 15/20/25 MVA, 66/12.5 kV transformer. This would increase the total substation capacity from 13.3 MVA to 25 MVA.
- In 2014, complete a 1 MVA load transfer from MMT-01 (MMT-T1) to PAS-01 (PAS-T1).

The resultant peak load forecasts for MMT-T1 and PAS-T1 under Alternative 2 are shown in Appendix C.

4.3 Alternative 3

- In 2014, build a new substation in Little Rapids (“LRP”), which includes the purchase of a new 10/13.3 MVA, 66/12.5 kV LRP-T1 transformer, to supply the Humber Village, Humber Valley Resort, and Little Rapids community loads.
- In 2014, complete a 1 MVA load transfer from MMT-01 (MMT-T1) to LRP-01 (LRP-T1).
- In 2014, complete a 5 MVA load transfer from PAS-01 (PAS-T1) to LRP-01 (LRP-T1).

The resultant peak load forecasts for MMT-T1, PAS-T1, and LRP-T1 under Alternative 3 are shown in Appendix D.

5.0 Evaluation of Alternatives

5.1 Cost of Alternatives

Table 1 shows the capital costs estimated for Alternative 1.

Table 1
Alternative 1 Capital Costs

Year	Item	Cost
2014	Extend MMT-01 feeder's main trunk 0.6 km with 4/0 AASC.	$75,000
2014	Purchase and Install a new bank of 300 amp voltage regulators on MMT-01.	$75,000
2014	Replace the existing 4 MVA MMT-T1 transformer with the existing (former MOB-T1) 6.7 MVA transformer.	$285,000
2021	Replace the existing 13.3 MVA PAS-T1 transformer with a new 25 MVA transformer.	$2,412,000
	Total	**$2,847,000**

Table 2 shows the capital costs estimated for Alternative 2.

Table 2
Alternative 2 Capital Costs

Year	Item	Cost
2014	Replace the existing 13.3 MVA PAS-T1 transformer with a new 25 MVA transformer.	$2,412,000
	Total	**$2,412,000**

Table 3 shows the capital costs estimated for Alternative 3.

Table 3
Alternative 3 Capital Costs

Year	Item	Cost
2014	Substation portion of the new Little Rapids substation.	$3,040,000
2014	Distribution portion of the new Little Rapids substation.	$110,000
2014	Transmission portion of the new Little Rapids substation.	$350,000
	Total	**$3,500,000**

5.2 Economic Analysis

In order to compare the economic impact of the alternatives, an NPV calculation of customer revenue requirement was completed for each alternative. Capital costs from 2011 to 2031 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]

Table 5 shows the NPV of customer revenue requirement for each alternative under the base case load forecast.

Table 5
Net Present Value Analysis
($000)

Alternative	NPV
1	2,076
2	2,480
3	3,763

Alternative 1 has the lowest NPV of customer revenue requirement. As a result, Alternative 1 is recommended as the most appropriate project expansion plan.

[4] This analysis captures the customer revenue requirement for the life of a new transformer asset.

5.3 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.[5]

Table 6 shows the NPV of customer revenue requirement for each alternative under the high and low load forecasts.

Table 6
Sensitivity Analysis
($000)

Alternative	High Load Forecast NPV	Low Load Forecast NPV
1	2,633	1,131
2	2,587	2,400
3	3,855	3,739

Under the high load forecast scenario, Alternative 2 is the least cost alternative. However, it should be noted that the cost for Alternative 1 is only 1.78% higher than Alternative 2.

Under the low load forecast scenario, Alternative 1 is the least cost alternative.

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.

[5] The sensitivity analysis for each of the alternatives includes additional projects to add transformer capacity at the end of the 20 year forecast period.

6.0 Project Cost

Table 7 shows the estimated project costs for the chosen alternative.

Table 7
Project Capital Costs

Year	Item	Cost
2014	Extend MMT-01 feeder's main trunk 0.6 km with 4/0 AASC.	$75,000
2014	Purchase and Install a new bank of 300 A voltage regulators on MMT-01.	$75,000
2014	Replace the existing 4 MVA MMT-T1 transformer with the spare (old MOB-T1) 6.7 MVA transformer.	$285,000
2021	Replace the existing 13.3 MVA PAS-T1 transformer with a new 25 MVA transformer.	$2,412,000
	Total	**$2,847,000**

7.0 Conclusion and Recommendation

A 20 year load forecast has projected the electrical demands for the Humber Valley 12.5 kV system. This system includes customers serviced from MMT and PAS substations. The development and analysis of system alternatives has established a preferred expansion plan to meet the forecasted needs.

The economic analysis performed in section 5.2 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 2 is the least cost alternative under the high load growth forecast and that Alternative 1 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 2014 project that is part of the least cost expansion plan includes the following items:

- The installation of the 5/6.7 MVA, 66/12.5 kV system spare transformer in MMT.
- The extension of MMT-01 feeder's main trunk 0.6 km with 4/0 AASC conductor.
- The purchase and installation of a new bank of 300 amp voltage regulators on MMT-T1.

The total project cost for this 2014 project is estimated to cost $435,000, which includes $285,000 in Substations and $150,000 in Distribution.

Appendix A
2012 Substation Load Forecast – Base Case

20 Year Substation Load Forecast – Base Case

Device	**MMT-T1**	**PAS-T1**
Sec. Voltage (kV)	12.5	12.5
Rating (MVA)	4.0	13.3
2011 Peak (MVA)	3.9	12.6
Year	**Forecasted Undiversified Peak (MVA)**	
2012	4.0	12.9
2013	4.1	13.1
2014	4.2	13.9
2015	4.2	14.0
2016	4.3	14.2
2017	4.3	14.4
2018	4.4	14.5
2019	4.4	14.7
2020	4.5	14.8
2021	4.5	15.0
2022	4.5	15.1
2023	4.6	15.3
2024	4.6	15.5
2025	4.7	15.6
2026	4.7	15.8
2027	4.8	15.9
2028	4.8	16.1
2029	4.8	16.3
2030	4.9	16.5
2031	4.9	16.6

Appendix B
Alternative 1
20 Year Substation Load Forecasts

Alternative 1
20 Year Substation Load Forecast – Base Case

Device	MMT-T1	MMT-T1 (New)	PAS-T1	PAS-T1 (New)
Sec. Voltage (kV)	12.5	12.5	12.5	12.5
Rating (MVA)	4.0	6.7	13.3	25.0
2011 Peak (MVA)	3.9	N/A	12.6	N/A
Year	**Forecasted Undiversified Peak (MVA)**			
2012	4.0	0.0	12.9	0.0
2013	4.1	0.0	13.1	0.0
2014	0.0	5.7	12.4	0.0
2015	0.0	5.7	12.5	0.0
2016	0.0	5.8	12.7	0.0
2017	0.0	5.8	12.9	0.0
2018	0.0	5.9	13.0	0.0
2019	0.0	5.9	13.2	0.0
2020	0.0	6.0	13.3	0.0
2021	0.0	6.0	0.0	13.5
2022	0.0	6.0	0.0	13.6
2023	0.0	6.1	0.0	13.8
2024	0.0	6.1	0.0	14.0
2025	0.0	6.2	0.0	14.1
2026	0.0	6.2	0.0	14.3
2027	0.0	6.3	0.0	14.4
2028	0.0	6.3	0.0	14.6
2029	0.0	6.3	0.0	14.8
2030	0.0	6.4	0.0	15.0
2031	0.0	6.4	0.0	15.1

Alternative 1
20 Year Substation Load Forecast – High Growth

Device	MMT-T1	MMT-T1 (New)	PAS-T1	PAS-T1 (New)
Sec. Voltage (kV)	12.5	12.5	12.5	12.5
Rating (MVA)	4.0	6.7	13.3	25.0
2011 Peak (MVA)	3.9	N/A	12.6	N/A
Year	**Forecasted Undiversified Peak (MVA)**			
2012	4.0	0.0	12.9	0.0
2013	4.1	0.0	13.2	0.0
2014	0.0	5.8	12.8	0.0
2015	0.0	5.8	13.1	0.0
2016	0.0	5.9	0.0	13.4
2017	0.0	6.0	0.0	13.6
2018	0.0	6.0	0.0	13.9
2019	0.0	6.1	0.0	14.1
2020	0.0	6.2	0.0	14.3
2021	0.0	6.2	0.0	14.6
2022	0.0	6.3	0.0	14.9
2023	0.0	6.4	0.0	15.1
2024	0.0	6.4	0.0	15.4
2025	0.0	6.5	0.0	15.6
2026	0.0	6.6	0.0	15.9
2027	0.0	6.6	0.0	16.2
2028	0.0	6.7	0.0	18.0
2029	0.0	5.3	0.0	18.3
2030	0.0	5.4	0.0	18.5
2031	0.0	5.4	0.0	18.8

Alternative 1
20 Year Substation Load Forecast – Low Growth

Device	MMT-T1	MMT-T1 (New)	PAS-T1	PAS-T1 (New)
Sec. Voltage (kV)	12.5	12.5	12.5	12.5
Rating (MVA)	4.0	6.7	13.3	13.3
2011 Peak (MVA)	3.9	N/A	12.6	N/A
Year	**Forecasted Undiversified Peak (MVA)**			
2012	4.0	0.0	12.9	0.0
2013	4.1	0.0	13.0	0.0
2014	0.0	5.6	11.9	0.0
2015	0.0	5.6	12.0	0.0
2016	0.0	5.7	12.1	0.0
2017	0.0	5.7	12.1	0.0
2018	0.0	5.7	12.2	0.0
2019	0.0	5.7	12.3	0.0
2020	0.0	5.7	12.3	0.0
2021	0.0	5.8	12.4	0.0
2022	0.0	5.8	12.5	0.0
2023	0.0	5.8	12.6	0.0
2024	0.0	5.8	12.6	0.0
2025	0.0	5.8	12.7	0.0
2026	0.0	5.9	12.8	0.0
2027	0.0	5.9	12.9	0.0
2028	0.0	5.9	12.9	0.0
2029	0.0	5.9	13.0	0.0
2030	0.0	5.9	13.1	0.0
2031	0.0	6.0	13.2	0.0

Appendix C
Alternative 2
20 Year Substation Load Forecasts

Alternative 2
20 Year Substation Load Forecast – Base Case

Device	MMT-T1	PAS-T1	PAS-T1 (New)
Sec. Voltage (kV)	12.5	12.5	12.5
Rating (MVA)	4.0	13.3	25.0
2011 Peak (MVA)	3.9	12.6	N/A
Year	**Forecasted Undiversified Peak (MVA)**		
2012	4.0	12.9	0.0
2013	4.1	13.1	0.0
2014	3.2	0.0	14.9
2015	3.2	0.0	15.0
2016	3.3	0.0	15.2
2017	3.3	0.0	15.4
2018	3.4	0.0	15.5
2019	3.4	0.0	15.7
2020	3.5	0.0	15.8
2021	3.5	0.0	16.0
2022	3.5	0.0	16.1
2023	3.6	0.0	16.3
2024	3.6	0.0	16.5
2025	3.7	0.0	16.6
2026	3.7	0.0	16.8
2027	3.8	0.0	16.9
2028	3.8	0.0	17.1
2029	3.8	0.0	17.3
2030	3.9	0.0	17.5
2031	3.9	0.0	17.6

Alternative 2
20 Year Substation Load Forecast – High Growth

Device	**MMT-T1**	**MMT-T1 (New)**	**PAS-T1**	**PAS-T1 (New)**
Sec. Voltage (kV)	12.5	12.5	12.5	12.5
Rating (MVA)	4.0	6.7	13.3	25.0
2011 Peak (MVA)	3.9	N/A	12.6	N/A
Year	**Forecasted Undiversified Peak (MVA)**			
2012	4.0	0.0	12.9	0.0
2013	4.1	0.0	13.2	0.0
2014	3.3	0.0	0.0	15.3
2015	3.3	0.0	0.0	15.6
2016	3.4	0.0	0.0	15.9
2017	3.5	0.0	0.0	16.1
2018	3.5	0.0	0.0	16.4
2019	3.6	0.0	0.0	16.6
2020	3.7	0.0	0.0	16.8
2021	3.7	0.0	0.0	17.1
2022	3.8	0.0	0.0	17.4
2023	3.9	0.0	0.0	17.6
2024	3.9	0.0	0.0	17.9
2025	4.0	0.0	0.0	18.1
2026	0.0	4.1	0.0	18.4
2027	0.0	4.1	0.0	18.7
2028	0.0	4.2	0.0	19.0
2029	0.0	4.3	0.0	19.3
2030	0.0	4.4	0.0	19.5
2031	0.0	4.4	0.0	19.8

Alternative 2
20 Year Substation Load Forecast – Low Growth

Device	**MMT-T1**	**MMT-T1 (New)**	**PAS-T1**	**PAS-T1 (New)**
Sec. Voltage (kV)	12.5	12.5	12.5	12.5
Rating (MVA)	4.0	6.7	13.3	25.0
2011 Peak (MVA)	3.9	N/A	12.6	N/A
Year	**Forecasted Undiversified Peak (MVA)**			
2012	4.0	0.0	12.9	0.0
2013	4.1	0.0	13.0	0.0
2014	3.1	0.0	0.0	14.4
2015	3.1	0.0	0.0	14.5
2016	3.2	0.0	0.0	14.6
2017	3.2	0.0	0.0	14.6
2018	3.2	0.0	0.0	14.7
2019	3.2	0.0	0.0	14.8
2020	3.2	0.0	0.0	14.8
2021	3.3	0.0	0.0	14.9
2022	3.3	0.0	0.0	15.0
2023	3.3	0.0	0.0	15.1
2024	3.3	0.0	0.0	15.1
2025	3.3	0.0	0.0	15.2
2026	3.4	0.0	0.0	15.3
2027	3.4	0.0	0.0	15.4
2028	3.4	0.0	0.0	15.4
2029	3.4	0.0	0.0	15.5
2030	3.4	0.0	0.0	15.6
2031	3.5	0.0	0.0	15.7

Appendix D
Alternative 3
20 Year Substation Load Forecasts

Alternative 3
20 Year Substation Load Forecast – Base Case

Device	MMT-T1	PAS-T1	LRP-T1
Sec. Voltage (kV)	12.5	12.5	12.5
Rating (MVA)	4.0	13.3	13.3
2011 Peak (MVA)	3.9	12.6	N/A
Year	**Forecasted Undiversified Peak (MVA)**		
2012	4.0	12.9	0.0
2013	4.1	13.1	0.0
2014	3.2	8.9	6.0
2015	3.2	9.0	6.0
2016	3.3	9.1	6.1
2017	3.3	9.2	6.2
2018	3.3	9.3	6.3
2019	3.4	9.4	6.3
2020	3.4	9.5	6.4
2021	3.4	9.6	6.5
2022	3.5	9.7	6.5
2023	3.5	9.8	6.6
2024	3.5	9.9	6.7
2025	3.6	10.0	6.7
2026	3.6	10.1	6.8
2027	3.6	10.2	6.9
2028	3.7	10.3	6.9
2029	3.7	10.4	7.0
2030	3.7	10.5	7.1
2031	3.8	10.7	7.2

Alternative 3
20 Year Substation Load Forecast – High Growth

Device	MMT-T1	MMT-T1 (New)	PAS-T1	LRP-T1
Sec. Voltage (kV)	12.5	12.5	12.5	12.5
Rating (MVA)	4.0	6.7	13.3	13.3
2011 Peak (MVA)	3.9	N/A	12.6	N/A
Year	**Forecasted Undiversified Peak (MVA)**			
2012	4.0	0.0	12.9	0.0
2013	4.1	0.0	13.2	0.0
2014	3.3	0.0	9.3	6.0
2015	3.3	0.0	9.3	6.3
2016	3.4	0.0	9.5	6.4
2017	3.4	0.0	9.7	6.5
2018	3.5	0.0	9.8	6.6
2019	3.5	0.0	10.0	6.7
2020	3.6	0.0	10.1	6.8
2021	3.6	0.0	10.3	6.9
2022	3.7	0.0	10.5	7.0
2023	3.7	0.0	10.6	7.1
2024	3.8	0.0	10.8	7.2
2025	3.8	0.0	11.0	7.4
2026	3.9	0.0	11.1	7.5
2027	3.9	0.0	11.3	7.6
2028	4.0	0.0	11.5	7.7
2029	4.0	0.0	11.7	7.8
2030	0.0	4.1	11.9	7.9
2031	0.0	4.1	12.1	8.1

Alternative 3
20 Year Substation Load Forecast – Low Growth

Device	**MMT-T1**	**PAS-T1**	**LRP-T1**
Sec. Voltage (kV)	12.5	12.5	12.5
Rating (MVA)	4.0	13.3	13.3
2011 Peak (MVA)	3.9	12.6	N/A
Year	**Forecasted Undiversified Peak (MVA)**		
2012	4.0	12.9	0.0
2013	4.1	13.0	0.0
2014	3.1	8.4	6.0
2015	3.1	8.4	6.0
2016	3.1	8.5	6.1
2017	3.2	8.5	6.1
2018	3.2	8.6	6.1
2019	3.2	8.6	6.2
2020	3.2	8.7	6.2
2021	3.2	8.7	6.2
2022	3.2	8.8	6.3
2023	3.3	8.8	6.3
2024	3.3	8.9	6.3
2025	3.3	8.9	6.4
2026	3.3	9.0	6.4
2027	3.3	9.0	6.4
2028	3.3	9.1	6.5
2029	3.3	9.1	6.5
2030	3.4	9.1	6.5
2031	3.4	9.2	6.6

2014 Transmission Line Rebuild

June 2013

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1.0 Transmission Line Rebuild Strategy

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 way.

In 2006, Newfoundland Power ("the Company") submitted its *Transmission Line Rebuild Strategy* outlining a 10-year plan to rebuild aging transmission lines. This plan prioritized 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 2014 Transmission Line Rebuild Projects

In 2014, the Company proposes to rebuild sections of 5 transmission lines with an average age of 59 years, totalling 16 km. 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 2014 are included in Table 1.

Table 1
2014 Transmission Line Rebuilds

Transmission Line	Distance to be Rebuilt	Year Constructed
12L	1.00 km	1950
13L	1.84 km	1962
18L	4.62 km	1951
35L	3.39 km	1959
68L	5.15 km	1958

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.

2.1 Transmission Line 12L ($370,000)

Transmission line 12L is a 66 kV line running between Memorial University Substation ("MUN") and King's Bridge Road Substation ("KBR"). The line consists of a 2.2 km aerial section and a 1.0 km underground cable section located through the university campus area.[1] 12L in conjunction with transmission line 14L, 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 and consists of 59 single pole structures all of which have under built distribution circuitry. The route taken by the transmission line, as shown by Figure 1 of Appendix B, is through heavy residential areas of the City of St. John's. 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 12L over 2 years.

With the infrastructure additions in this area, load growth at MUN substation will continue to increase.[2] With this increase in load, the existing 1/0 copper conductor on 12L will not be able to carry peak load without 14L also in service. To address these loading concerns the 1/0 copper conductor on 12L will be replaced with 477 ASC.

Inspections have identified deterioration due to decay, splits and checks in the poles and crossarms.[3] 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. The copper conductor is deteriorated and at the end of its service life. 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.

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.

In Order No. P.U. 31 (2012) the Board approved a multiyear project to rebuild transmission line 12L. In 2013 work is ongoing to rebuild 1.2 km of 12L at an estimated cost of $380,000.

In 2014, the remaining 1.0 km of 12L will be rebuilt at an estimated cost of $370,000.

---

1 The 2013 and 2014 projects only involve the rebuild of the 2.2 kilometre aerial section of transmission line.

2 Recent infrastructure additions have taken place at the Health Science Centre and the Janeway Children's Health and Rehabilitation Centre. Planned infrastructure additions include 2 new residence buildings.

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 13L ($816,000)

Transmission line 13L is a 66 kV single pole line running between St. John's Main Substation ("SJM") and Stamps Lane Substation ("SLA"). It consists of 0.42 km of underground cable from SJM Substation to a termination steel tower on Southside Road, and a 2.64 km aerial section to SLA Substation.

The aerial section was originally constructed in 1962 and consists of 81 single pole structures, most of which have distribution circuits under built. Over the years a number of sections have been replaced and relocated for road widening and other third party development, leaving a total of 1.84 km or 56 structures of original construction.

Due to the age and condition of the line, it is susceptible to damage when it becomes exposed to severe wind, ice or snow loading. 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 most recent inspections have also identified deficiencies with guys and anchors, hardware, and insulators on the line.

The transmission line route as shown in Figure 2 of Appendix B is through heavy residential and high traffic areas of the City of St. John's.[4] Considerable damage to the poles caused by contact with snowploughs and other vehicles is evident. 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 continue its safe, reliable operation.

Based on the overall deteriorated condition of the line, it is recommended the line be rebuilt in 2014 at an estimated cost of $816,000.

2.3 Transmission Line 18L ($700,000)

Transmission line 18L is a 66 kV line running between Goulds Substation ("GOU") and Glendale Substation ("GDL") in Mount Pearl. The line was originally constructed in 1951 and ran from GOU Substation to Stamp's Lane Substation ("SLA"). Upon construction of GDL Substation in 1977 transmission line 18L was rerouted to power the new substation.

The line is 5.82 km in length and is comprised of 84 single pole structures. Approximately 1.19 km or 22 structures was erected along Old Placentia Road as part of the 1977 reroute, leaving 4.62 km or 64 structures of original construction from Brookfield Road to GOU Substation. 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. This section of line is built with 266.8 ACSR conductor which has

[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 sidewalk to mitigate future damage.

deteriorated to the point of failure at some locations in recent years.[5] This conductor size is not adequate to support the future load growth in the Mount Pearl area served by GDL substation.

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. Inspections have identified deterioration of the old conductor and hardware, as well as decay, splits and checks in the wooden components.

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. Upgrading the conductor size to 715.5 ASC is also required to service the increased load forecast in the area.

Based on the overall deteriorated condition of the line, it is recommended the line be rebuilt at an estimated cost of $700,000 in 2014.

2.4 Transmission Line 35L ($514,000)

Transmission line 35L is a 66 kV line running between Kenmount Substation ("KEN") and Oxen Pond Substation ("OXP") in St. John's. The line was originally constructed in 1959, while sections near the substations were rebuilt during a subsequent system reconfiguration. Approximately 3.39 km of original vintage line consisting of 39 single-pole wood structures remain in service.

Due to its location transmission line 35L has been subjected to extreme weather loading resulting in significant damage.[6] Due to age and condition of the remaining original structures the line remains susceptible to damage in the event of further exposure to ice, wind and snow loads.

Recent inspections have identified substantial deterioration of the poles and crossarms. Many of the wooden components show decay, splits and checks.

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. Upgrading the conductor size on the section being replaced to match the conductor size on the remainder of the line will increase the overall transfer capacity of the line.

Based on the age, deteriorated condition and weather loadings on this section of line it is recommended that the section be rebuilt in 2014 using 715.5 ASC conductor at an estimated cost of $514,000.

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[5] Failures were caused by damaged conductor surfaces as a result of corrosion and contact between phases during high winds.

[6] Most recently in 2012 three poles in this section failed due to heavy wind loading during Tropical Storm Leslie.

2.5 Transmission Line 68L ($770,000)

Transmission line 68L is a 66 kV line running between Carbonear Substation (“CAR”) and Harbour Grace Substation (“HGR”). The line was originally constructed in 1958, with the exception of a 2.01 km section extending into CAR substation which was constructed in 1974. Approximately 5.15 km of original vintage line consisting of 50 two-pole and three-pole H-Frame structures with non-standard 4/0 ACSR conductor, remain in service.

Inspections have identified significant deterioration of the line due to decay, splits and checks in the poles and crossarms, cracks in insulators and other hardware deficiencies. Many of these components are in advanced stages of deterioration and require replacement.

In 1958 transmission line 68L was built using the construction standards of the time, which did not include crossbraces on the H-Frame structures. Some of the structure types used on the line has since been identified as failure points when subjected to extreme weather loads and have thus been removed from the Company’s construction standards.

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 2014 at an estimated cost of $770,000.

3.0 Concluding

In 2014, the Company will rebuild the remaining section of 12L, along with sections of 13L, 18L, 35L and 68L. Each of these transmission lines has structures experiencing deterioration of the poles, crossarms, hardware, and conductor. Recent inspections and engineering assessment has 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 2014 – 2018 ($000s)						
Line	**Year**	**2014**	**2015**	**2016**	**2017**	**2018**
012L KBR-MUN	1950	370				
013L SJM-SLA	1962	816				
018L GOU-GDL	1951	700				
035L KEN-OXP	1959	514				
068L HGR-CAR	1958	770				
015L SLA-MOL	1958		166			
014L SLA-MUN	1950		263			
069L KEN-SLA	1951		1,036			
030L RRD-KBR	1959		567	546		
400L BBK-WHE	1967		1,731	1,807		
032L OXP-RRD	1963			320		
057L BRB-HGR	1958			1,492	1,535	
302L SPO-LAU	1959				1,432	3,524
041L CAR-HCT	1958				1,366	1,067
101L GFS-RBK	1957				1,701	2,179
	Total	**3,170**	**3,763**	**4,165**	**6,034**	**6,770**

Transmission Line Rebuilds 2019 – 2025 ($000s)								
Line	**Year**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
102L GAN-RBK	1958	4,213	4,251	4,507				
363L BVJ-SCR	1963	2,923	3,088	3,265	4,090			
403L TAP-ROB	1960				956			
124L CLV-GAM	1964				3,685	4,316	2,229	5,388
146L GAN-GAM	1964					2,682	3,590	4,216
100L SUN-CLV	1964					2,438	3,099	
035L KEN-OXP	1965							584
049L HWD-CHA	1966			608				
	Total	**7,136**	**7,339**	**8,380**	**8,731**	**9,436**	**8,918**	**10,188**

Appendix B
Maps of Transmission Lines
12L, 13L, 18L, 35L and 68L

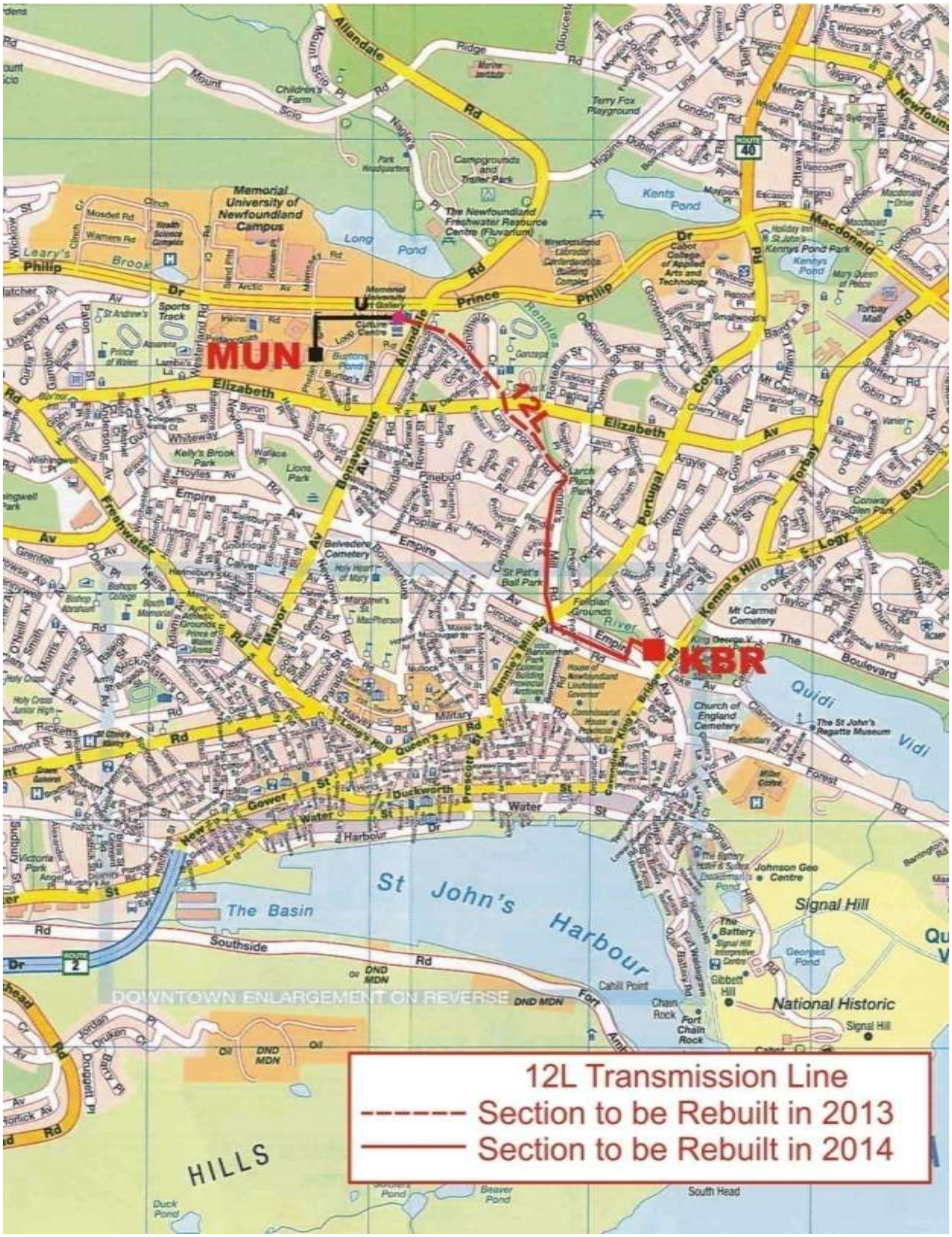

Figure 1 – Map of 12L Route

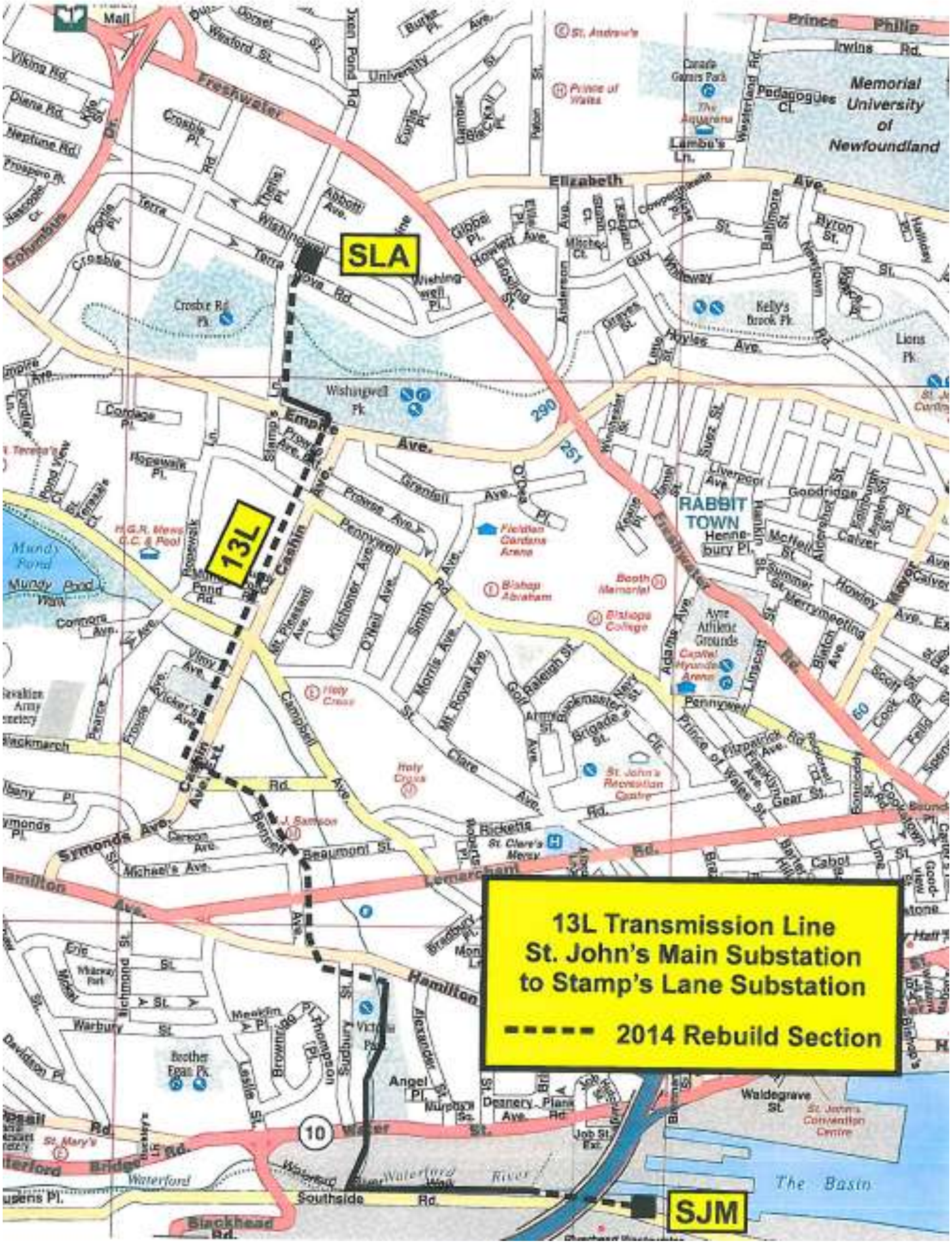

Figure 2 – Map of 13L Route

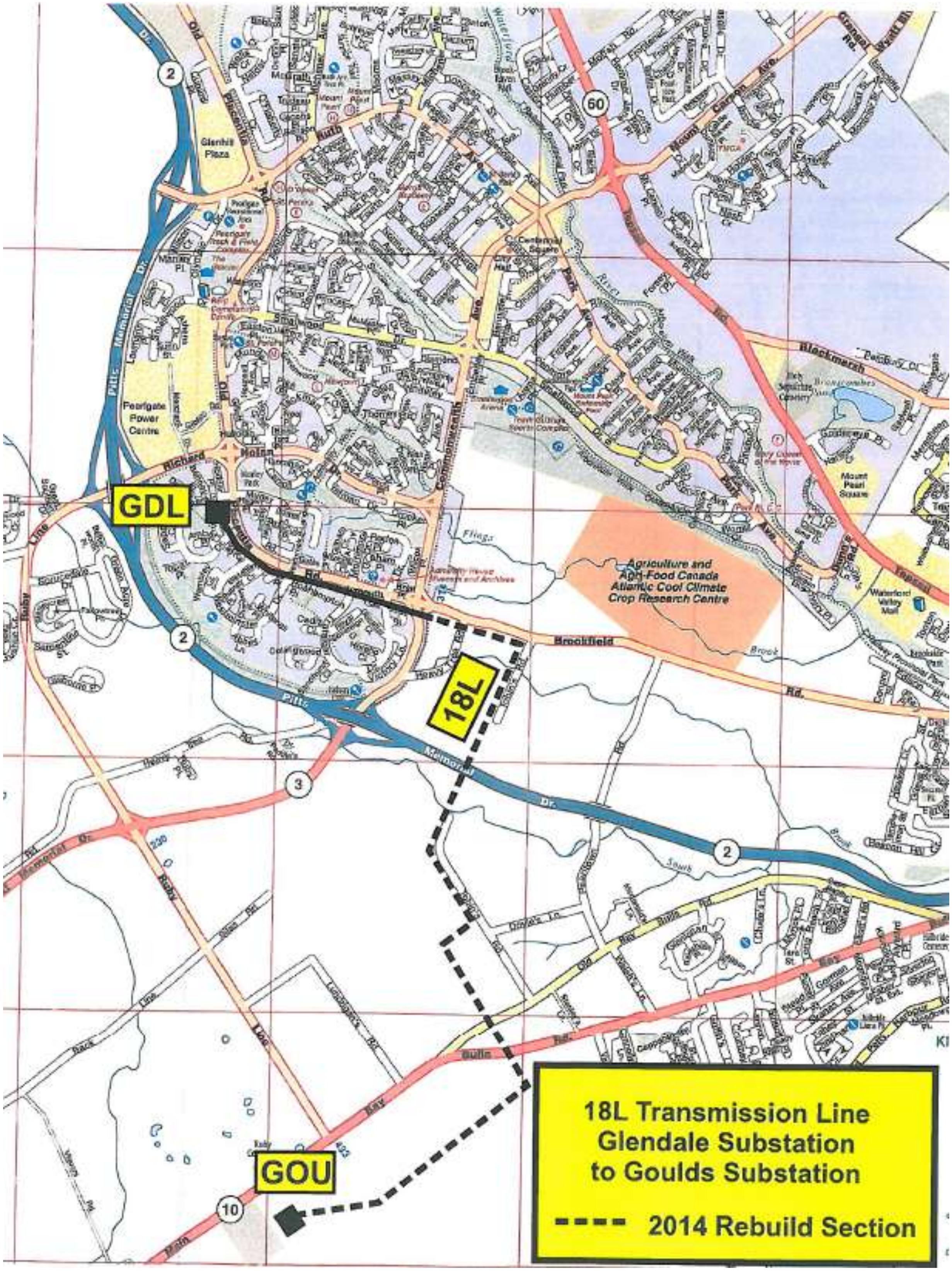

Figure 3 – Map of 18L Route

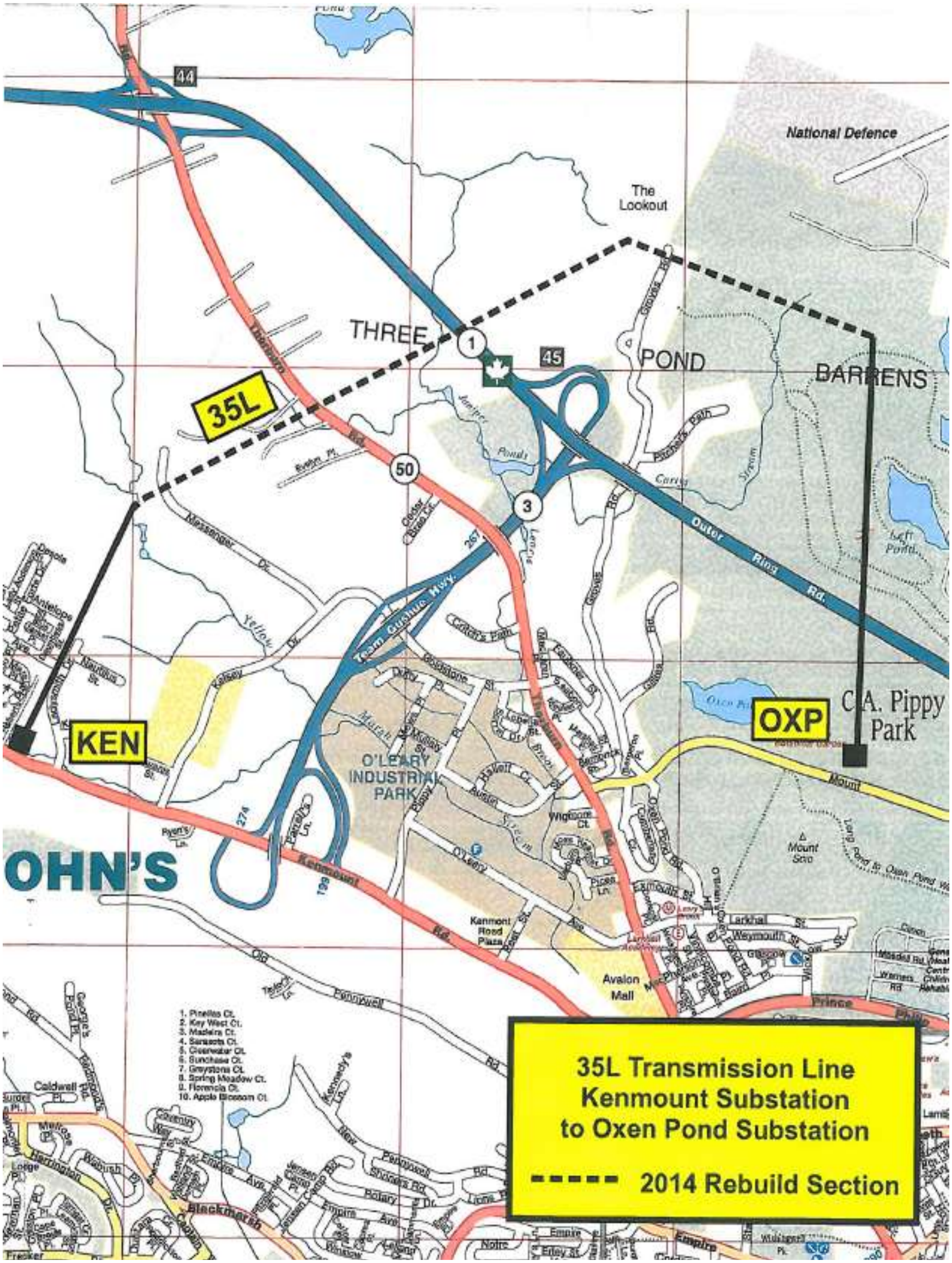

Figure 4 – Map of 35L Route

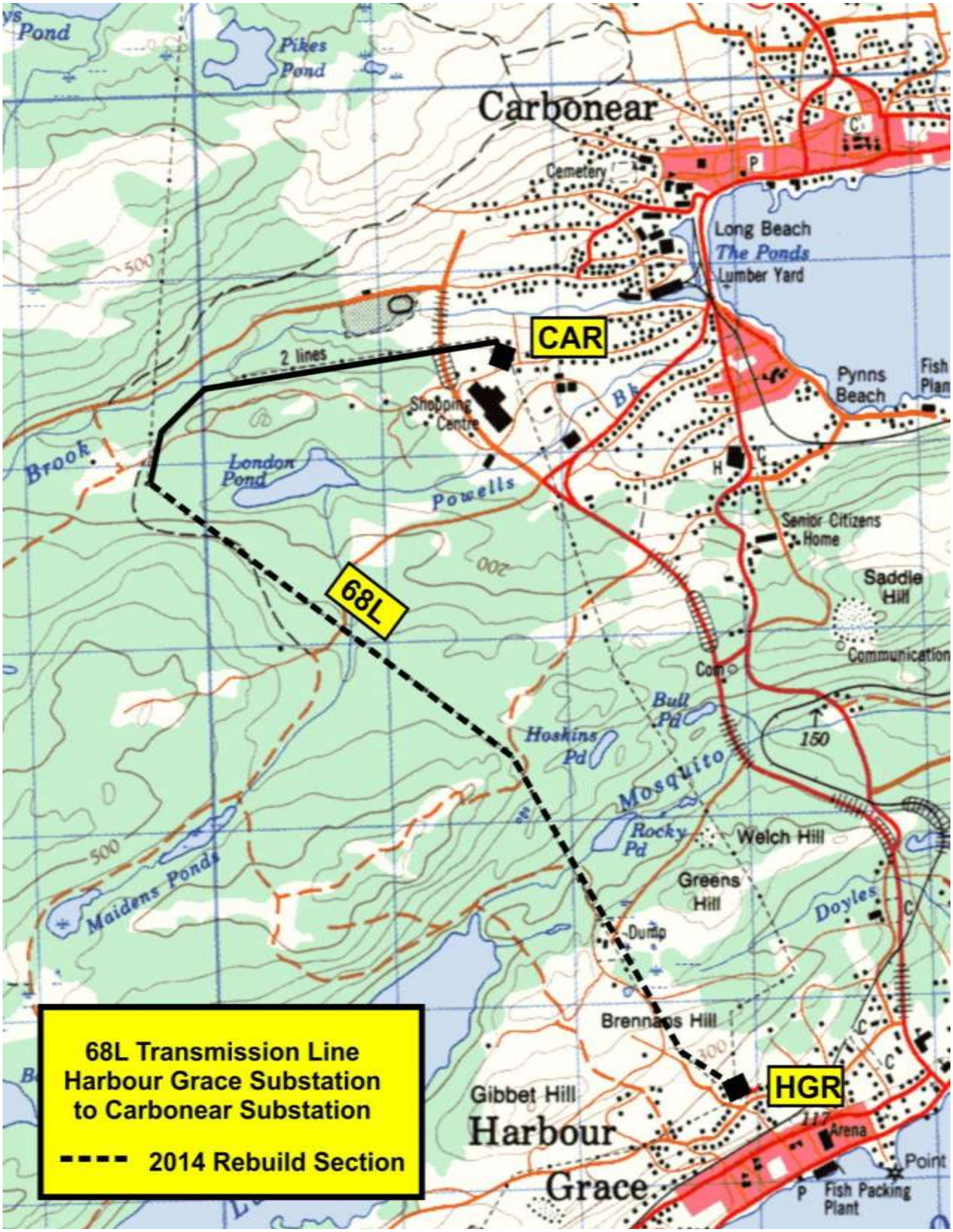

Figure 5 – Map of 68L Route

Appendix C
Photographs of Transmission Lines
12L, 13L, 18L, 35L and 68L

<u>Transmission Line 12L</u>

Figure 1 – 12L - Pole showing checking around bolts

Figure 2 – 12L - Pole showing shell separation and damage

Figure 3 – 12L - Pole bent due to significant loading caused by high voltage aerial cables

Figure 4 – 12L - Deteriorated Crossarms

Transmission Line 13L

Figure 5 – 13L - Conductor removed from 13L - damage due to phase contact

Figure 6 – 13L - Pole showing vehicular or snow plough damage

Figure 7 – 13L - Deteriorated pole showing shell separation

Figure 8 – 13L - Heavily loaded pole leaning

Transmission Line 18L

Figure 9 – 18L - Deteriorated Pole Crib

Figure 10 – 18L - Split crossarm and nonstandard guy wire

Figure 11 – 18L - Pole with severe checks

Figure 12 – 18L - Conductor damage removed in 2012

Transmission Line 35L

Figure 13 – 35L - Split crossarm

Figure 14 – 35L - Severely deteriorated pole

Figure 15 – 35L - Broken pole - Tropical Storm Leslie

Figure 16 – 35L - Horizontal crack in pole

Transmission Line 68L

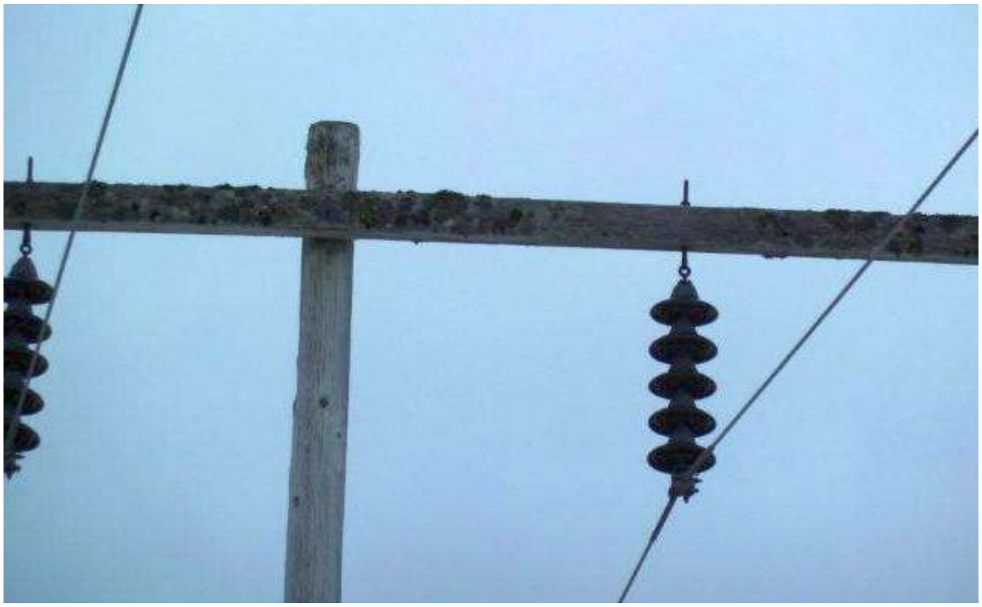

Figure 17 – 68L - Mossy/rotten crossarm

Figure 18 – 68L - Deep check in pole

Figure 19 – 68L - Pole showing shell separation

Figure 20 – 68L - Deteriorated pole and crossarm

Distribution Reliability Initiative

June 2013

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1.0 Distribution Reliability Initiative

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. Through this process, the Company identifies the worst performing feeders in the power system based upon reliability measures. Engineering assessments are completed for each of the worst performing feeders and, where appropriate, the Company makes capital investment to improve the reliability of these feeders.

Appendix A contains the five-year average distribution reliability data, excluding significant events, for the 15 worst performing feeders based on data for 2008 - 2012.

Appendix B contains a summary of the assessment carried out on each of the feeders listed in Appendix A.

2.0 Distribution Reliability Initiative Projects: 2012

There were no Distribution Reliability Initiative projects during 2012.

3.0 Distribution Reliability Initiative Projects: 2013

There are no Distribution Reliability Initiative projects planned for 2013.

4.0 Distribution Reliability Initiative Projects: 2014

The examination of the worst performing feeders, as listed in Appendix A and B, has determined no work is required under the Distribution Reliability Initiative at this time.

Appendix A
Distribution Reliability Data

Unscheduled Distribution Related Outages Five-Year Average 2008-2012 Sorted By Customer Minutes of Interruption				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
RRD - 09	4,381	455,051	2.89	5.00
KEN - 04	7,576	449,412	3.12	3.08
DOY - 01	4,587	413,181	2.79	4.19
DLK - 03	2,711	409,774	2.20	5.54
SUM - 01	5,355	400,223	2.96	3.69
GBY - 03	3,377	385,734	4.38	8.34
BOT - 01	2,717	382,393	1.64	3.84
GFS - 06	4,229	367,905	2.45	3.55
CAB - 01	4,526	357,907	3.65	4.81
GLV - 02	2,653	357,367	2.03	4.55
DUN - 01	3,198	351,009	3.33	6.09
GFS - 02	5,946	347,969	3.88	3.78
SLA - 09	3,700	345,623	2.60	4.05
CHA - 02	4,681	335,110	2.27	2.71
SCR - 01	2,057	321,429	2.16	5.59
Company Average	**948**	**73,961**	**1.21**	**1.58**

Unscheduled Distribution Related Outages Five-Year Average 2008-2012 Sorted By Distribution SAIFI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
GBY - 03	3,377	385,734	4.38	8.34
GBY - 02	3,658	237,712	4.04	4.38
GFS - 02	5,946	347,969	3.88	3.78
CAB - 01	4,526	357,907	3.65	4.81
DUN - 01	3,198	351,009	3.33	6.09
MOL - 04	3,952	297,867	3.26	4.10
KEN - 04	7,576	449,412	3.12	3.08
FER - 01	1,908	182,490	3.02	4.82
BCV - 02	4,618	316,615	2.99	3.41
SUM - 01	5,355	400,223	2.96	3.69
RRD - 09	4,381	455,051	2.89	5.00
DOY - 01	4,587	413,181	2.79	4.19
HWD - 06	2,280	122,884	2.79	2.50
SCT - 02	683	81,545	2.70	5.37
MMT - 01	1,239	97,300	2.65	3.47
Company Average	**948**	**73,961**	**1.21**	**1.58**

Unscheduled Distribution Related Outages Five-Year Average 2008-2012 Sorted By Distribution SAIDI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
GBY - 03	3,377	385,734	4.38	8.34
SUM - 02	1,407	225,689	2.31	6.18
BUC - 02	228	58,445	1.44	6.17
DUN - 01	3,198	351,009	3.33	6.09
SCR - 01	2,057	321,429	2.16	5.59
DLK - 03	2,711	409,774	2.20	5.54
SCT - 02	683	81,548	2.70	5.37
ABC - 01	1,676	233,820	2.15	5.00
RRD – 09	4,381	455,051	2.89	5.00
MKS - 01	741	140,803	1.58	4.99
FER - 01	1,908	182,490	3.02	4.82
CAB - 01	4,526	357,907	3.65	4.81
GLV - 02	2,653	357,367	2.03	4.55
GBY-02	3,658	237,712	4.04	4.38
NCH-02	960	142,190	1.46	4.25
Company Average	**948**	**73,961**	**1.21**	**1.58**

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.
BCV-02	BCV-02 has had good reliability over the years. Problems with a submarine cable resulted in poor overall reliability in 2012. No further work is required at this time.
BOT-01	A substantial amount of work was completed on this feeder since 2006. Reliability has improved considerably. Reliability numbers in 2010 were poor due to damages caused by a vehicle accident. No further work is required at this time.
BUC-02	Reliability problems in 2008 were due to three insulator failures in 2008. Insulators were replaced in 2009. There were two incidents of broken conductor in 2011. No work is required at this time.
CAB-01	Poor statistics in 2008 were due to a broken cutout and a broken insulator. Reliability was poor in 2012 principally due to two separate tree related incidents. No work is required at this time.
CHA-02	Reliability statistics were driven by a single event, a broken insulator in June 2009. No work is required at this time.
DLK-03	Reliability statistics were driven by a broken conductor in November 2009 and a single weather related event in 2011. 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 a single weather related issue in each of 2009, 2010 and 2012. Work is planned under the Feeder Additions for Load Growth project to address the single-phase taps issue.
DUN-01	Reliability statistics were poor in both 2007 and 2009. The statistics were driven by a broken recloser bushing in 2007 and a broken pole in 2009. Reliability improved greatly in 2010 and 2011. Poor reliability in 2012 was due to vegetation issues. No work is proposed for 2014.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
FER-01	Reliability statistics were driven by a single tree related event in 2009. No work is required at this time.
GBY-02	GBY-02 has had good reliability over the years. A single wind related event resulted in poor overall reliability in 2012. This was an isolated event and no further work is required at this time.
GBY–03	Reliability statistics were driven by isolated weather related events in each of 2009, 2010 and 2011. This feeder had significant upgrades as part of the 2011 CBA Rebuild Distribution Lines project. No additional work is required at this time.
GFS-02	Reliability statistics were driven by a single tree related event in October 2009. No work is required at this time.
GFS-06	Reliability problems relate to tree issues in 2009 and 2011. No work is required at this time.
GLV-02	A substantial amount of work was completed on this feeder since 2006. Reliability has improved considerably. High customer minutes in 2010 were due to problems accessing a line through Terra Nova Park associated with a tree related event. A single sleet related issue impacted reliability in 2012. No further work is required at this time.
HWD-06	HWD-06 has had good reliability over the years. A faulty breaker resulted in poor overall reliability in 2012. This was an isolated event and no work is required at this time.
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. These were isolated events and no further work is required at this time.
MIL-02	The MIL-02 feeder had displayed consistently poor reliability prior to significant work being carried out in 2006. In 2008 there was a tree related outage and in 2012 a vehicle accident both of which contributed to poor reliability statistics. No work is required at this time.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
MKS-01	Reliability statistics were driven by a single event, a broken cutout in March 2008. No work is required at this time.
MMT-01	Poor overall reliability is due to tree related events in 2009 and 2010 and a squirrel causing a fuse to operate in 2012. 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. No work is required at this time.
NCH-02	Reliability statistics were driven by a single tree related event in September 2010. No work is required at this time.
RRD-09	Reliability problems were due to two events involving broken conductor in 2008 and 2011. No work is required at this time.
SCR-01	Reliability statistics were driven by a single wind related event in November 2011. No work is required at this time.
SCT-02	Reliability problems in 2008 were due to a storm in March. No work is required at this time.
SLA-09	Poor overall reliability is due to an underground cable fault in 2011. No work is required at this time.
SUM-01	SUM-01 has had good reliability over the years. Two events, one involving salt spray the other a broken conductor resulted in poor overall reliability in 2012. These were isolated events and no further work is required at this time.
SUM-02	Reliability statistics were driven by two tree related events in May and December 2011 and a weather event in 2012 No work is required at this time.

Feeder Additions for Load Growth

June 2013

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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.

This report indentifies 4 projects to be included as part of the 2014 Capital Budget. These projects address overload conditions and provide additional capacity to address growth in customers and sales. The 1st project involves the upgrading of an overloaded section of distribution feeder CLV-03 from Clarenville substation to Shoal Harbour Drive in the Town of Clarenville. The 2nd project involves converting a heavily loaded single phase section of distribution feeder DOY-01 in the Codroy Valley to 3-phase. The 3rd project involves constructing a new distribution feeder from Hardwoods substation to serve customer and load growth in the Town of Paradise. The 4th project involves the extension of MMT-01 feeder to transfer load from Pasadena substation to a larger transformer being installed at Marble Mountain substation.

The overload conditions described in this report can each be attributed to commercial and residential customer growth in the Company's service territory.

2.0 Background

2.1 General

When an overload condition has been identified with a distribution feeder 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.

In some cases, when a substation is overloaded and additional capacity is being installed, additional distribution feeders are required to make the additional capacity available to customers. Otherwise, serving the additional load growth through the existing distribution feeder network will result in overloaded conductors.

An overloaded section of conductor on a distribution line is at risk of failure. Failures are caused by overheating of the conductor as the current 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

[1] Feeder balancing involves transferring load from one phase to another on a three phase distribution feeder in order to balance the amount of load on each phase. Load transfers involve transferring load from one feeder to another.

conditions that are identified using the computer modelling application are followed up with field visits to ensure the accuracy of information.[2]

2.2 Alternatives for Overloaded Conductor

There are several alternatives for dealing with a conductor overload condition. Each alternative may not be applicable to every overload condition. They are dependent on factors such as; available tie points to surrounding feeders, the amount of conductor overload, physical limitations of line construction, or the effect on offloading strategies for surrounding feeders.

Alternative #1 – Feeder Balancing
In some cases, conductor may be overloaded on only one phase of a three phase line. In this situation, it may be possible to remove the overload condition by balancing the downstream loads through load transfers from the highly loaded phase to one of the more lightly loaded phases. In some situations overload conditions on individual phases can be alleviated by extending the 3-phase trunk of the feeder. This is only applicable in situations where all three 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. Also, the effect of the offloading strategy for other surrounding feeders must also be considered.

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] 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.

3.0 CLV-03 Feeder Upgrade ($268,000)

A 3.5 km section of this feeder is overloaded. The overloaded section is from Clarenville substation to Shoal Harbour Drive in the Town of Clarenville.[3] The conductor in this section is #4/0 AASC and is rated for 356 amps per phase. The balanced 2014 forecasted peak loads on each of the phases on this section are 444 amps per phase.

This overload condition can be attributed to the commercial growth on this feeder in the Shoal Harbour Drive area. Continued growth is expected as development in this area continues to proceed.

Feeder balancing is not an option for this overload condition, due to the fact that the combined forecasted peak currents exceed the total capacity of the three phase conductors. There is a tie point to Clarenville substation through CLV-02 feeder. However, due to the routing of each feeder and the available capacity of CLV-02, the tie point does not allow for the offloading of a sufficient portion of CLV-03 feeder to resolve the overload condition. The tie point only allows for backup of CLV-02 feeder in the event of an unplanned outage or planned maintenance. Therefore, it is recommended that this section be upgraded to 477 ASC conductor, rated at 590 amps per phase.

4.0 DOY-01 Feeder Upgrade ($327,000)

Doyle's substation ("DOY") is located 41 km east of Port aux Basques in the Codroy Valley. DOY-01 feeder consists mostly of single phase customers supplied via many long single phase taps off from the main 3-phase trunk feeder.[4] Load on these taps has grown from customer conversions to electric heat and new line extensions to large cottage areas.

The capacity of a single phase tap is limited by the performance of feeder protection back on the 3-phase trunk feeder.[5] A heavily loaded single phase tap can result in unbalanced loads on the 3 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.[7] Eliminating the unbalanced condition caused by growth on the single phase feeder taps will result in a more reliable distribution system.

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[3] The single line diagram for feeder CLV-03 is included in Appendix B.

[4] The total length of DOY-01 feeder is approximately 140 km. This length consists of 11 km of 3-phase distribution line, 14 km of 2-phase distribution line and 115 km of single-phase distribution line. The single line diagram for feeder DOY-01 is included in Appendix C.

[5] Newfoundland Power's planning criteria for maximum current on a single-phase distribution line is 85 amps.

[6] To detect faults, such as when a conductor breaks and falls to the ground, protection schemes are based on detecting the short circuit current on the phase that has the fault and/or by detecting the differences between the current levels (unbalanced current) on each of the three phases and the neutral conductor on a distribution feeder. To ensure that a line-to-ground fault is detected on a distribution feeder the protection settings are established based on a minimal amount of short circuit and/or unbalanced current.

[7] Newfoundland Power's planning criteria for maximum neutral current on an unbalanced 3-phase distribution feeder is 50 amps.

An analysis of the DOY-01 distribution feeder was completed using a distribution feeder computer modelling application. Actual load measurements were taken to verify the results of the computer simulation. The DOY-01 distribution feeder exceeds the Company's planning criteria for both maximum current on a single-phase distribution line and for maximum neutral current on an unbalanced 3-phase distribution line.

This project involves upgrading approximately 6.3 km of single phase distribution line to three phases along the TransCanada Highway from Doyle's substation to Saint Andrews via Cooper's Brook.

5.0 HWD-09 New Feeder Construction ($357,000)

The main trunk section of distribution feeder HWD-08 leaving Hardwoods substation ("HWD") is forecasted to overload in 2014. The conductor on the main trunk section of HWD-08 is 477 ASC and is rated for 590 amps per phase. The balanced 2014 forecasted peak loads on each of the phases on this section are 595 amps per phase.

This forecasted overload condition can be attributed to load transfers between substations which were necessary to avoid substation transformer overloads on the Chamberlains, Hardwoods and Kenmount substations 25 kV distribution systems.[8]

Feeder balancing is not an option for this overload condition, due to the fact that the forecasted combined peak currents exceed the total capacity of the three phase conductors. Also, due to the routing and available capacity of adjacent feeders and substation transformers, there are no existing tie points that would allow load to be transferred. Therefore, the least cost option for this overload condition is to construct a new distribution feeder from HWD substation to Kenmount Road.[9] This will require the construction of a new distribution line ($357,000) and a new feeder termination at Hardwoods substation ($246,000).

The HWD-09 item of the *Feeder Additions for Load Growth* project is clustered with the *Hardwoods Substation Feeder Termination* substation project and the installation of a 50 MVA transformer at Hardwoods substation item of the *2014 Additions Due To Load Growth* substation project.

6.0 MMT-01 Feeder Extension ($150,000)

The Humber Valley area includes customers served from Marble Mountain ("MMT") and Pasadena ("PAS") substations. An engineering study has been completed on the system upgrades required to meet the electrical demands in this area.[10]

---

8 The substation transformers at Hardwoods, Chamberlains and Kenmount Road substations are approaching their capacity limits. In 2014, the aggregate peak load on the substation transformers is forecast to be 125.6 MVA while the aggregate capacity is 125 MVA. With the proposed addition of 25 MVA at Hardwoods Substation, there will be approximately 9 MVA of load transferred onto HWD-08 to reduce the load on transformers at Kenmount Road substation.

9 The new feeder will be designated HWD-09.

10 The study is included as Attachment B to the report ***2.2*** *2014 Additions Due to Load Growth*, filed with this 2014 Capital Budget Application.

The study examined alternatives to determine the least cost approach to dealing with the forecast overload conditions in this area. Each alternative was evaluated using a 20 year load forecast. Based on net present value calculations, the least cost alternative was selected. The project involves a 600 metre extension of MMT-01 feeder with 4/0 AASC conductor and the installation of a set of voltage regulators to enable a load transfer from PAS-01 to MMT-01 in 2014. The extension of this feeder provides the least cost alternative to dealing with the existing and forecasted transformer overloads at MMT and PAS substations.

The MMT-01 item of the *Feeder Additions for Load Growth* project is clustered with the Marble Mountain transformer replacement item of the Substations *2014 Additions Due To Load Growth* project.

7.0 Project Cost

Table 1 shows the estimated project costs for 2014.

Table 1
Project Costs

Description	Cost Estimate
CLV-03 Feeder Upgrade	$268,000
DOY-01 Feeder Upgrade	$327,000
HWD-09 Feeder Addition	$357,000
MMT-01 Feeder Extension	$150,000
Total	**$1,102,000**

8.0 Concluding

The *Feeder Additions for Load Growth* project for 2014 includes distribution system upgrades to:

- Upgrade 3.5 km section of CLV-03 feeder,
- Upgrade 6.3 km section of existing single phase on DOY-01 feeder to three phase,
- Construct new distribution feeder HWD-09 at Hardwoods substation, and
- Construct 600 metre extension of MMT-01 feeder towards Pasadena substation.

The estimated cost to complete this work in 2014 is $1,102,000.

Appendix A
Distribution Planning Guidelines
Conductor Ampacity Ratings

Aerial Conductor Capacity Ratings						
Size and Type	Continuous Winter Rating[11]	Continuous Summer Rating[12]	Planning Ratings CLPU Factor[13] = 2.0 Sectionalizing Factor[14] = 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

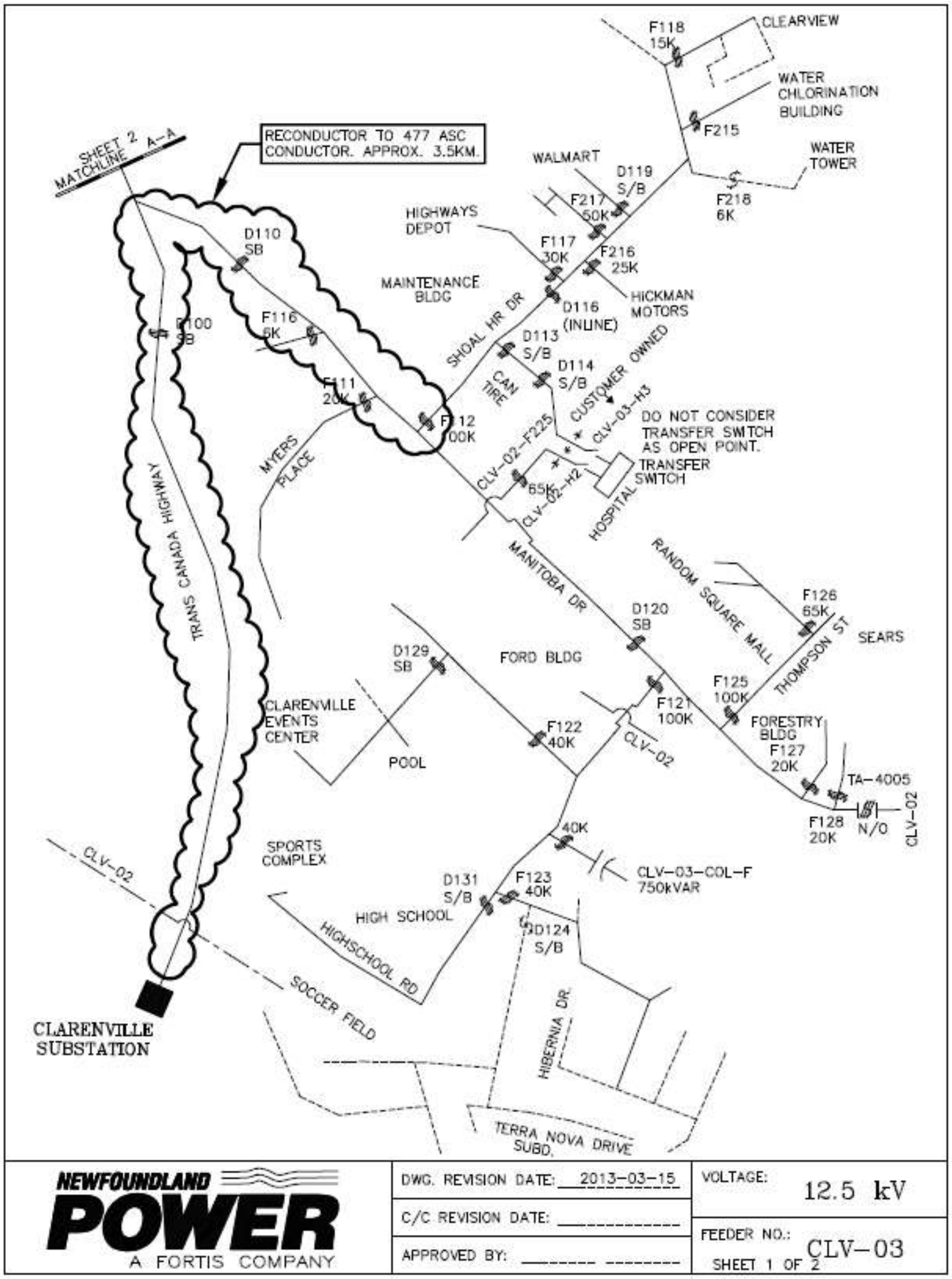
[11] The winter rating is based on ambient conditions of 0ºC and 2ft/s wind speed.

[12] The summer rating is based on ambient conditions of 25ºC and 2ft/s wind speed.

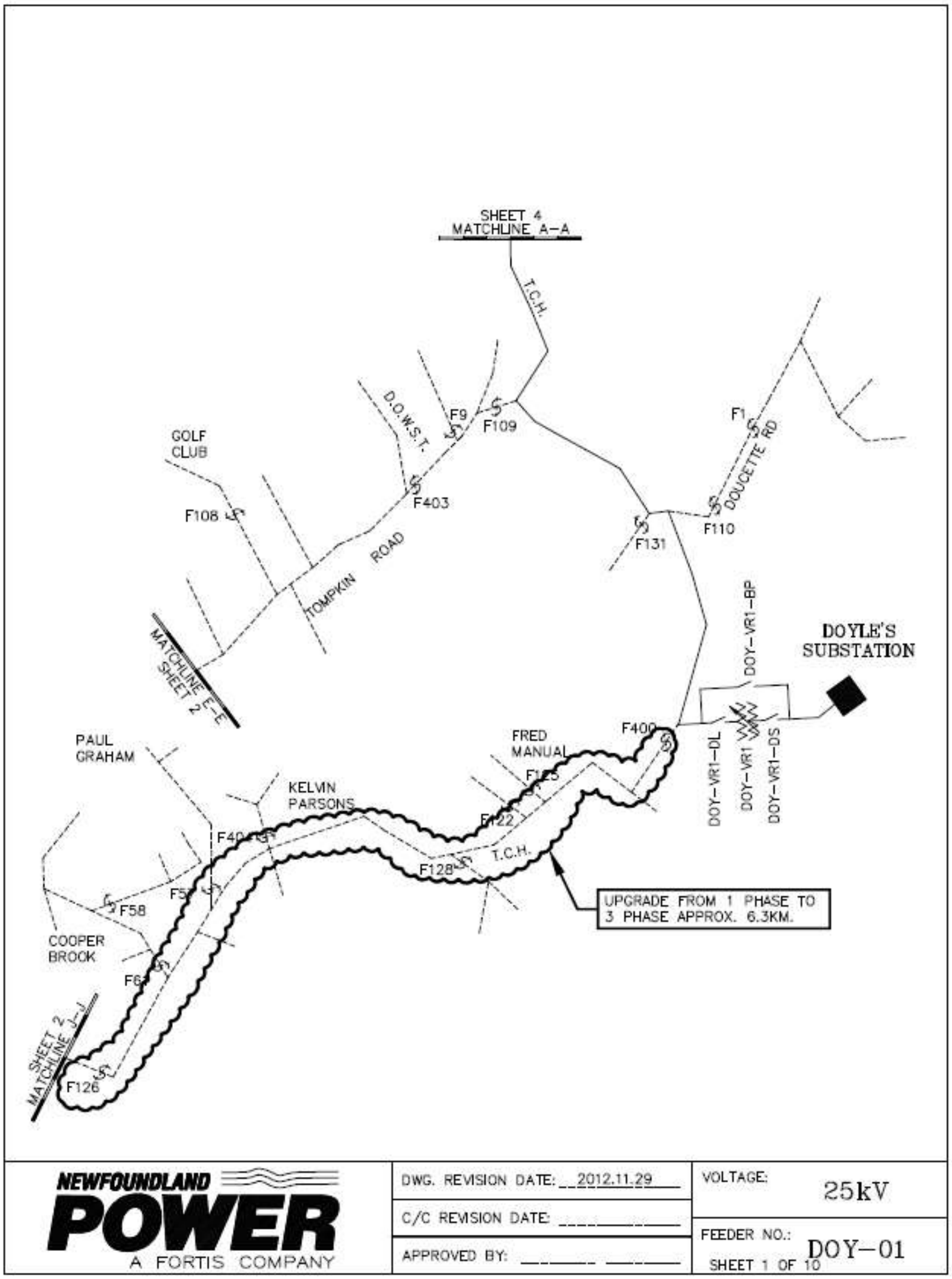
[13] Cold Load Pick Up: Occurs when power is restored after an extended outage. On feeders with electric heat, the load on the feeder can be 2.0 times as high as the normal winter peak load. This is the result of all electric heat coming on at once when power is restored. The duration of CLPU is typically between 20 minutes and 1 hour.

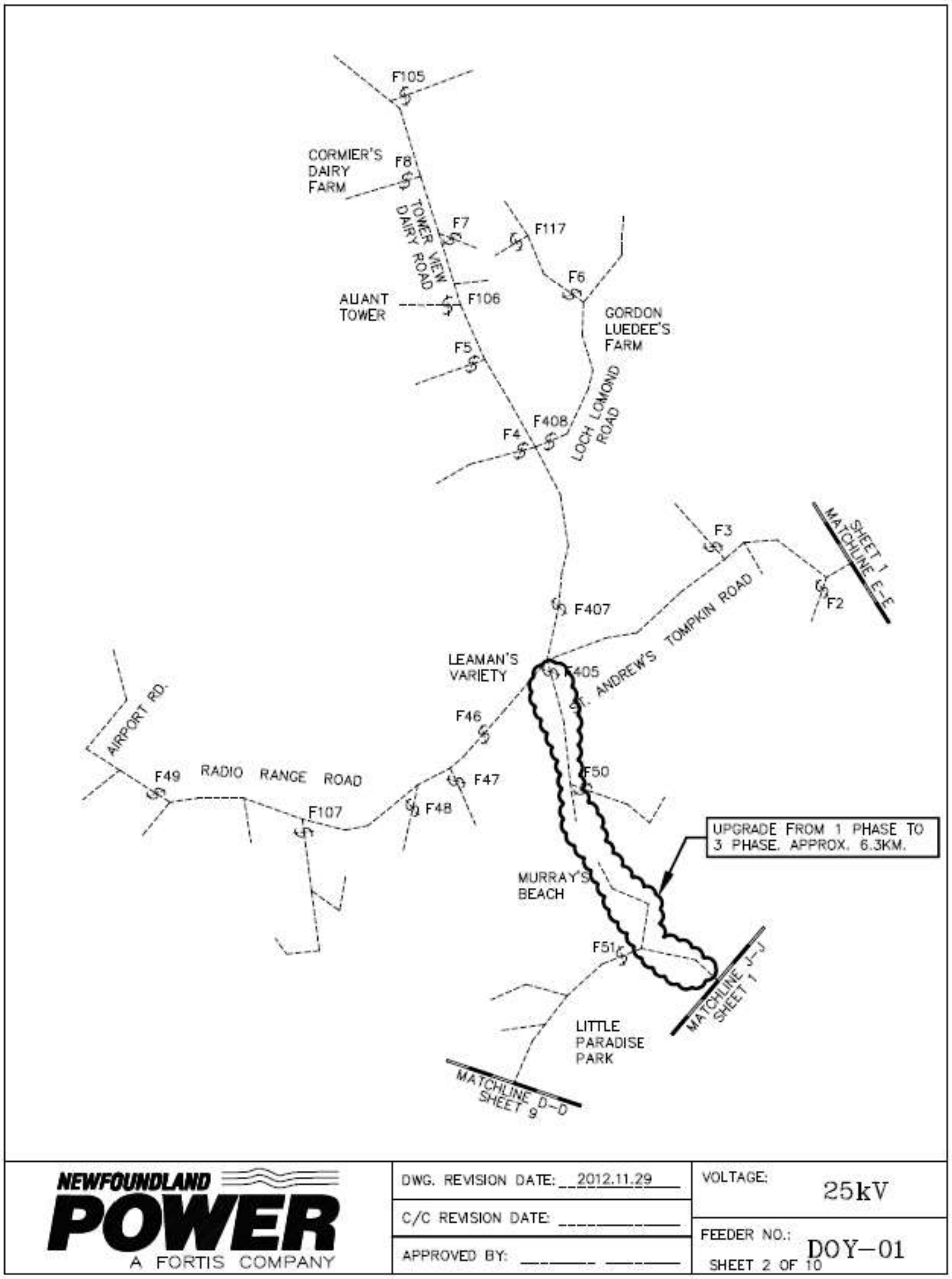
[14] Sectionalizing factor: Two-stage sectionalizing is used during CLPU conditions to increase the Planning Rating of aerial conductors. Restoring power to one section of the feeder at a time reduces the overall effect of CLPU. The sectionalizing factor is the fraction of the load that is restored in 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
CLV-03 Feeder Single Line Diagram


RECONDUCTOR TO 477 ASC CONDUCTOR. APPROX. 3.5KM.
SHEET 2 MATCHLINE A-A
CLARENVILLE SUBSTATION
TRANS CANADA HIGHWAY
CLV-02
D100 SB
D110 SB
F116 6K
F111 20K
F112 100K
MYERS PLACE
SHOAL HR DR
HIGHWAYS DEPOT
MAINTENANCE BLDG
WALMART
F117 30K
F217 50K
D119 S/B
F216 25K
D116 (INLINE)
HICKMAN MOTORS
D113 S/B
D114 S/B
CAN TIRE
CUSTOMER OWNED
CLV-03-H3
CLV-02-F225
CLV-02-H2
65K
DO NOT CONSIDER TRANSFER SWITCH AS OPEN POINT.
TRANSFER SWITCH
HOSPITAL
F118 15K
CLEARVIEW
WATER CHLORINATION BUILDING
F215
WATER TOWER
F218 6K
MANITOBA DR
RANDOM SQUARE MALL
D120 SB
F126 65K
THOMPSON ST
SEARS
F125 100K
F121 100K
FORESTRY BLDG
F127 20K
TA-4005
F128 20K
N/O
FORD BLDG
D129 SB
CLARENVILLE EVENTS CENTER
POOL
F122 40K
40K
CLV-03-COL-F 750kVAR
SPORTS COMPLEX
D131 S/B
F123 40K
D124 S/B
HIGH SCHOOL
HIGHSCHOOL RD
SOCCER FIELD
HIBERNIA DR.
TERRA NOVA DRIVE SUBD.
NEWFOUNDLAND POWER
A FORTIS COMPANY
DWG. REVISION DATE: 2013-03-15
C/C REVISION DATE:
APPROVED BY:
VOLTAGE: 12.5 kV
FEEDER NO.: CLV-03
SHEET 1 OF 2

Appendix C
DOY-01 Feeder Single Line Diagram


SHEET 4
MATCHLINE A–A
T.C.H.
D.O.W.S.T.
F9
F109
GOLF
CLUB
F403
F108
TOMPKIN ROAD
F1
DOUCETTE RD
F110
F131
MATCHLINE E–E
SHEET 2
DOY–VR1–BP
DOYLE'S
SUBSTATION
DOY–VR1–DL
DOY–VR1
DOY–VR1–DS
F400
FRED
MANUAL
PAUL
GRAHAM
KELVIN
PARSONS
F122
F128
T.C.H.
F58
COOPER
BROOK
UPGRADE FROM 1 PHASE TO
3 PHASE APPROX. 6.3KM.
SHEET 2
MATCHLINE J–J
F126
NEWFOUNDLAND
POWER
A FORTIS COMPANY
DWG. REVISION DATE: 2012.11.29
C/C REVISION DATE:
APPROVED BY:
VOLTAGE:
25kV
FEEDER NO.:
SHEET 1 OF 10
DOY–01


F105
CORMIER'S DAIRY FARM
F8
TOWER VIEW DAIRY ROAD
F7
F117
F6
ALIANT TOWER
F106
GORDON LUEDEE'S FARM
F5
LOCH LOMOND ROAD
F408
F4
F3
SHEET 1 MATCHLINE E-E
F2
F407
ST. ANDREW'S TOMPKIN ROAD
LEAMAN'S VARIETY
F405
AIRPORT RD.
F46
F49
RADIO RANGE ROAD
F47
F50
F107
F48
UPGRADE FROM 1 PHASE TO 3 PHASE. APPROX. 6.3KM.
MURRAY'S BEACH
F51
MATCHLINE J-J SHEET 1
LITTLE PARADISE PARK
MATCHLINE D-D SHEET 9
NEWFOUNDLAND POWER
A FORTIS COMPANY
DWG. REVISION DATE: 2012.11.29
C/C REVISION DATE:
APPROVED BY:
VOLTAGE: 25kV
FEEDER NO.: DOY-01
SHEET 2 OF 10

Vault Refurbishment and Modernization

June 2013

Prepared by:

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NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

This report outlines a plan for the refurbishment and modernization of Newfoundland Power's ("the Company") 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.

A preliminary assessment of these vaults was recently undertaken. The assessment has identified the need to refurbish and modernize these vaults to meet 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 vaults need to be updated to current standards to address substandard electrical clearances to exposed high voltage conductors, arc flash hazards, the possibility of oil leaks from transformers and metering tanks, the operation of fused cutouts which expel metal fragments and gas when the fuse operates and issues with accessibility, illumination and ventilation.

The Company has selected 3 of the 19 vaults to be upgraded in 2014. The Company plans to engage an engineering consulting firm with necessary expertise in the applicable codes and standards to complete the detailed design. The information and experience gained in 2014 will support developing plans to complete the remaining 16 vaults. Appendix A includes a detailed description of the work to be undertaken in 2014 on 3 vaults.

2.0 Background

Newfoundland Power has equipment in vaults located throughout its operating territory. The vast majority of these vaults are located in the St. John's downtown area and 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 a building and contain high voltage electrical equipment that convert 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.

---

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".

Table 1 provides a list of the existing vaults in the St. John's downtown area and the location of each.

Table 1
Location of St. John's Vaults

Vault Name	Building Name	Building Address
KBR-V1	Parks Canada – Signal Hill	Signal Hill Rd.
KBR-V2	Sir Humphrey Gilbert Building	80 Water St.
KBR-V3	Battery Hotel (Old)	100 Signal Hill Rd.
KBR-V4	Battery Hotel (New)	100 Signal Hill Rd.
SJM-V1	Fortis Building	139 Water St.
SJM-V2	TD Building	140 Water St.
SJM-V3	Neal Building	50 Harbour Dr.
SJM-V4	Terra Nova Tel Building	152 Water St.
SJM-V5	The London Building	177 Water St.
SJM-V6	Atlantic Place Parking Garage	215 Water St.
SJM-V7	Atlantic Place	215 Water St.
SJM-V8	Imperial Optical	220 Duckworth St.
SJM-V9	Newfoundland and Labrador Credit Union	240 Water St.
SJM-V10	Templeton's Building	343 Water St.
SJM-V11	City Hall Annex	10 New Gower St.
SJM-V12	Eclipse Building	354 Water St.
SJM-V13	Cabot Place East	120 New Gower St.
SJM-V14	Cabot Place West	120 New Gower St.
SJM-V15	Delta St. John's Hotel	120 New Gower St.

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.

CSA Z462 contains a detailed section on arc flash protection which Newfoundland Power utilizes to establish operating procedures for working in electrical vaults. It includes information on arc flash analysis, arc flash protection boundaries and the personal protective equipment that must be worn to protect against arc flash.

Due to the arc flash protection boundaries and limits of approach to exposed energized conductors established in Newfoundland Power's existing operating procedures, many of the vaults must be de-energized before personnel enter and perform any work. The configuration of the underground distribution system in downtown St. John's makes it impossible to de-energize all equipment inside a vault without an outage to one or more customers, many of which are large commercial businesses. It is therefore the Company's plan to improve these vaults to comply with current safety and electrical standards thereby allowing work to be completed safely without any extended customer outages.

3.0 Vault Refurbishment and Modernization

The vault refurbishment and modernization plan was developed following an assessment of the assets in each of the St. John's vaults occupied by Company. The assessment considered a number of factors including physical condition of equipment, potential impact of failures on service to customers, vault design and compliance with current codes, standards and operational procedures.

The following is a high level overview, with reference to specific components, of the refurbishment and modernization work identified from the assessment of the vaults.

3.1 Distribution Transformers

The majority of the distribution transformers located in the vaults are oil filled pole mounted type resting on the vault floor with exposed high voltage electrical connections. The preferred option will be to remove the transformers from the vault and replace them outside the building with either pole mounted or pad mounted transformers. In locations where it is not possible to remove the transformer from the vault it will be replaced with either a dry type transformer located inside metal clad switchgear or a vault type transformer with no exposed electrical terminations.

Removing or replacing pole mounted transformers from electrical vaults will eliminate the safety hazard associated with exposed high voltage conductors, and eliminate the environmental hazard associated with substandard spill containment for oil filled distribution transformers.[2]

3.2 Protection Devices and Switches

The primary function of transformer fusing is to protect distribution transformers. At each vault location there are fuses installed to provide overload and short circuit protection to the distribution transformer. In the majority of these locations these fuses are installed in open air fused cutouts which are intended for outdoor pole mounted use only and have exposed high voltage electrical parts.[3] There are also cutouts in some of the vaults that have solid blade disconnects installed to provide equipment isolation during switching operations.

In locations were these open air cutouts cannot be removed from the vault they will be replaced with enclosed switchgear designed for indoor vault applications.

---

2 Currently if a transformer or metering tank were to fail the oil would leak into the surrounding foundation and would be problematic to capture.

3 When a fuse operates it expels metal fragments and gas. Also the noise level during operation is magnified in the enclosed space.

3.3 Metering Tanks

Metering tanks are comprised of voltage and current transformers and are used to transform primary voltages and currents to lower levels for metering customers' energy usage. In the majority of the vault installations the metering tanks are intended for outdoor pole mounted use only and have exposed high voltage electrical parts. The preferred option will be to remove the metering tanks from the vaults and replace them with low voltage metering arrangements. In locations where this is not possible the metering tanks will be replaced with dry type voltage and current metering transformers located inside metal clad switchgear.

3.4 Metal Clad Switchgear

Approximately 40% of the existing vaults include metal clad switchgear. This is the preferred equipment to provide fuse protection and switching capability within the vaults since all high voltage electrical components are concealed. An assessment will be made of the metal clad switchgear at each vault location and refurbishment work completed as required on a case by case basis.

3.5 Buildings and Property

Since the majority of these vaults were built when the St. John's downtown electrical underground distribution was established in the late 1960's many of them do not comply with today's building codes and standards. Wherever possible the high voltage electrical equipment contained in the vaults will be removed and relocated outside, however there are locations were this is not possible due to lack of available space to install the equipment outside in the Water Street and Duckworth Street areas.

In locations where the electrical equipment cannot be removed the vault will be refurbished to current applicable standards. Items that will be addressed during the refurbishment of these vaults include worker safety, fire protection, accessibility, ventilation and illumination.

4.0 Capital Plan

The 5-year vault refurbishment and modernization 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 refurbishment and modernization of these 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. 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.

Table 2 details the expenditures included in the 5-year capital plan.

Table 2
Vault Refurbishment and Modernization
5-Year Capital Plan

2014	2015	2016	2017	2018
$397,000	$375,000	$350,000	$325,000	$300,000

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.

5.0 2014 Project Description

For 2014, the Company has identified 3 locations where refurbishment and modernization of existing vaults will take place. At the Parks Canada location on Signal Hill there is adequate space outdoors in the vicinity of the vault to eliminate the vault entirely. Pad mount transformers and outdoor distribution hardware will be installed to replace the Company's equipment in the vault. The Templeton's Building and the Eclipse Building on Water Street do not have adequate space outdoors in the vicinity therefore the vaults will have to be refurbished. Appendix A contains a detailed description of the refurbishment and modernization required at each of these 3 locations.

6.0 2014 Project Cost

Table 3 is a summary of the 2014 expenditures associated with the Vault Refurbishment and Modernization project.

Table 3
2014 Project Expenditures

Cost Category	Expenditure
Material	$159,000
Labour - Internal	40,000
Labour - Contract	99,000
Engineering	79,000
Other	20,000
Total	**$397,000**

Appendix A

2014 Vault Refurbishment and Modernization Projects

2014 Projects

For 2014 the Company has identified 3 locations where refurbishment and modernization of existing vaults will take place. At the Parks Canada location on Signal Hill there is adequate space outdoors in the vicinity of the vault to eliminate the vault entirely. The Templeton's Building and the Eclipse Building on Water Street do not have adequate space outdoors in the vicinity therefore the vaults will have to be refurbished. This appendix provides details regarding the existing vaults and the refurbishment and modernization necessary at these locations.

1. Parks Canada Signal Hill – Signal Hill Road ($117,000)

The Parks Canada - Signal Hill vault is located east of the Johnson Geo Centre on Signal Hill Road. Unlike the other vaults, the Parks Canada Signal Hill vault is not in a basement but is located inside a dedicated electrical building which shares both Newfoundland Power and customer owned electrical equipment.

Figure 1: Parks Canada – Signal Hill Vault Location

The following is a list of electrical equipment within the vault:

- High voltage power cable,
- Bare aerial conductor,
- Porcelain pole mount cutouts,
- 7.2 kV to 120/240 V pole mount distribution transformer,
- 12.5 kV Metering tank,
- 12.5 kV to 4.16 kV dry type distribution transformer, and
- Insulated secondary conductor.

The 12.5 kV power cable supplies the vault from an underground dip pole approximately 200 meters east of the vault and enters through an underground conduit. The power cable feeds into the metering tank via a porcelain cutout and then into the 12.5 kV to 4.16 kV dry type transformer. A 4.16 kV power cable then leaves the transformer through a raceway and enters the customer owned electrical room adjacent to the vault. Also within the vault is a 7.2 kV power cable that connects to a single pole mount transformer via a porcelain cutout. A 120/240 volt secondary cable is connected to the secondary conductors of the transformer and travels through a conduit to feed a customer owned distribution panel located within the adjacent maintenance building.

Figure 2: Parks Canada Signal Hill Vault – Metering Tank and Transformer

An inspection of the vault has identified the following:

- Lack of proper spill containment for the pole mount transformer and metering tank,
- Exposed high voltage electrical equipment that could result in arc flash and electrical contact,
- Lack of proper ventilation, and
- Rusting of the vault door and door box which has caused the door to crack in places.

The vault is small in size and there is exposed high voltage conductor approximately 48 inches from the door. Therefore personnel must wear arc flash personal protective equipment to open the door of the vault. It is also difficult to maintain the minimum approach distance of 30 inches from the exposed high voltage equipment and therefore equipment must be de-energized prior to entering.

Since there is adequate space outdoors in the vicinity it is feasible to eliminate the vault by installing the electrical equipment outside. The work to be completed is as follows:

- Install 12.5 kV to 4.16 kV padmount transformer complete with dry type metering equipment,
- Install 12.5 kV power cable from existing underground dip pole to new 12.5 kV to 4.16 kV padmount transformer,
- Install 4.16 kV cable underground to customer owned electrical vault,
- Install 7.2 kV to 120/240 volt padmount transformer, and
- Install 120/240 volt cable to customer owned AC panel.

2. Templeton's Building – 343 Water Street ($150,000)

The Templeton's vault is located in the basement of the building at 343 Water Street. All of the equipment within the vault is owned by Newfoundland Power.

Figure 3: Templeton's – 343 Water Street Vault Location

The following is a list of electrical equipment within the vault:

- High voltage power cable,
- Bare aerial conductor,
- Porcelain pole mount cutouts,
- Three 7.2 kV to 347/600 volt pole mount distribution transformers, and
- Insulated secondary conductor.

The power cable enters the vault from the existing Water Street underground distribution system. It terminates at a cable pothead and then feeds via bare aerial conductor into 3 porcelain cutouts and then onto three 7.2kV-347/600 volt pole mount distribution transformers. The 347/600 volt secondary cable exits the room through a conduit system and to the customer's electrical service.

Figure 4: Templeton's – 343 Water Street Vault

A detailed 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 proper ventilation.

Due to the exposed high voltage conductor located in the vault, personnel must wear arc flash personal protective equipment and maintain the minimum approach distance of 30 inches from the exposed high voltage equipment while inside the vault.

Due to the restrictions on available physical space downtown and the nature of the existing underground distribution in the area, it is not possible to remove the equipment from the vault and relocate it outside. Instead the equipment will be replaced to meet current codes and standards applicable to high voltage electrical vaults. The work to be completed is as follows:

- Install proper ventilation, as per the National Building Code of Canada,
- Remove high voltage bus suspended from the ceiling,
- Remove existing porcelain cutouts, and

- Replace the pole mount transformers with a 12.5 kV to 347/600 volt dry type transformer enclosed in metal clad switchgear.

3. Eclipse Building – 354 Water Street ($130,000)

The Eclipse Head Office vault is located in the basement of the building at 354 Water Street. All of the equipment within the vault is owned by Newfoundland Power.

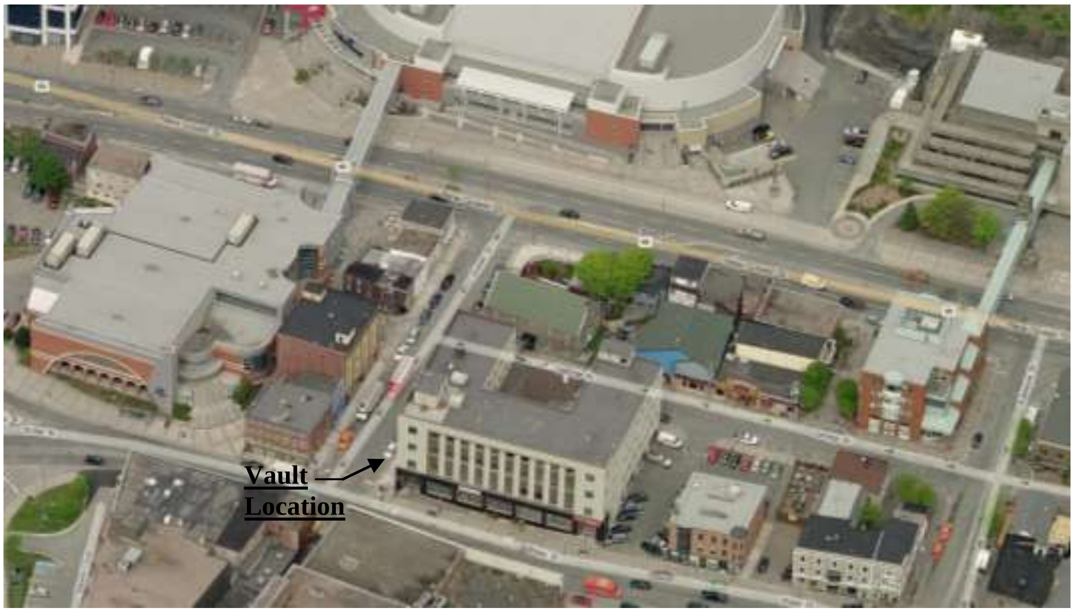


Figure 5: Eclipse – 343 Water Street Vault Location

The following is a list of electrical equipment within the vault:

- High voltage power cable,
- Bare aerial conductor,
- 12.5 kV circuit breaker,
- 12.5 kV metering tank,
- Three 7.2 kV to 347/600 volt pole mount distribution transformers, and
- Insulated secondary conductor.

The power cable enters the vault from the existing Water Street underground distribution system. It terminates at a cable pothead and then feeds into a 12.5 kV circuit breaker. Bare aerial conductor connects the breaker to the metering tank and then on to three 7.2 kV to 347/600 volt pole mount transformers. Insulated secondary conductor then travels through a cable tray and exits the vault to the customer electrical service location.

Figure 6: Eclipse – 343 Water Street Vault

Figure 7: Eclipse – 343 Water Street Vault

A detailed review of the vault has identified the following:

- Lack of proper spill containment on the pole mount transformer and metering tank,
- Exposed high voltage electrical equipment that could result in arc flash and electrical contact, and
- Lack of proper ventilation.

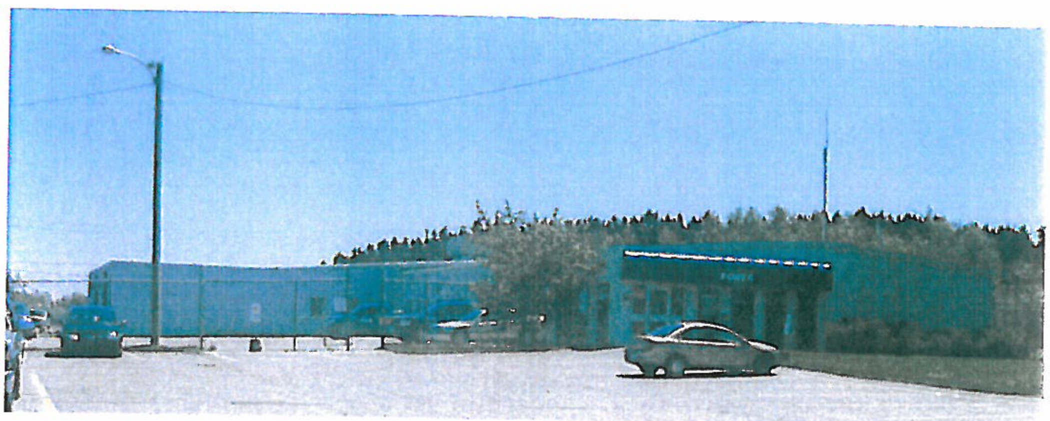
Due to the exposed high voltage conductor located in the vault personnel must wear personal protective equipment and maintain the minimum approach distance of 30 inches from the exposed high voltage equipment while inside the vault.

Due to the restrictions on available physical space downtown and the nature of the existing underground distribution in the area, it is not possible to remove the equipment from the vault and relocate it outside. Instead the equipment will be replaced to meet current codes and standards applicable to high voltage electrical vaults. The work to be completed is as follows:

- Install proper ventilation, as per the National Building Code of Canada,
- Replace existing metering tank with dry type unit enclosed in metal clad switchgear, and
- Replace the pole mount transformers with a 12.5 kV to 347/600 volt dry type transformer enclosed in metal clad switchgear.

Standby and Emergency Power
Gander Office

June 2013



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GARY K. HUMBY
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June/21/2013
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PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
A FORTIS COMPANY

Standby and Emergency Power
Gander Office

June 2013

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1.0 Introduction

During an emergency when power is interrupted for an extended period of time, Newfoundland Power ("the Company") must be prepared to respond effectively to restore power to its customers. This requires local buildings such as the Gander Service Centre to be fully functional.

During major storm and power outage situations power restoration teams require technology and communications infrastructure plus access to the Company's corporate computer network and SCADA system.[1] Computer systems such as outage management, asset management, and the various engineering applications are critical to employees involved with the assessment of system damage and the management of the service restoration effort. Customer service employees require access to the corporate computer network to facilitate effective response to customer outage reports and inquiries.

The small uninterruptible power supply ("UPS") systems that are currently located at many of the Company's buildings are only sufficient to sustain SCADA communications for a short duration (several hours) and cannot support any of the other critical computer systems. These limited UPS systems would not support normal operating conditions in those buildings during an outage event.

2.0 Background

The 2006 Newfoundland Power Capital Budget Application included the report ***5.1** Standby Generation at Newfoundland Power Facilities.* The report noted that although Newfoundland Power had continuity plans for power outages it also lacked standby generation for the Company's regional buildings in the event of major outages. The report recommended replacing standby generators at buildings that had inadequately sized units and to install appropriately sized equipment at buildings without standby generation.

The 2006 Capital Budget Application included projects to replace the Duffy Place standby generator with one sized to meet the increased building load and to relocate the former Duffy Place standby generator to Clarenville.[2] Standby generators were also included in the scope of work for the consolidation of the Company's office buildings and service centres in both Grand Falls and Corner Brook in 2006.[3] The 2008 Capital Budget Application included a project to install a new standby generator at the Burin building.[4]

---

1 Six substations (Gander, Cobb's Pond, Gambo, Wesleyville, Hare Bay and Trinity) rely on a communications link from the Gander Office. SCADA communications are not available to these substations if the equipment at the Gander Office is without power for an extended period.

2 See Order No. P.U. 30 (2005).

3 See Order Nos. P.U. 13 (2006) and P.U. 34 (2006).

4 See Order No. P.U. 27 (2007).

Table 1 shows the standby generation capability per building in 2004 compared to standby generation capability per building in 2013.

Table 1
Standby Building Generation in 2004 Compared to 2013

Office & Service Buildings	2004 Peak Demand (kW)	2004 Standby Generation (kW)	2013 Standby Generation (kW)	Additional Standby Generation Required (Y/N)
Duffy Place	734	145	1000	N
Carbonear	**169**	**80**	**80**	**Y**
Burin	45	Nil	60	N
Clarenville	134	Nil	150	N
Gander	**136**	**Nil**	**Nil**	**Y**
Grand Falls	145	Nil	150	N
Corner Brook	126	Nil	150	N
Stephenville	**81**	**Nil**	**Nil**	**Y**

3.0 Capital Plan

The 2014 Capital Plan includes projects for the installation of standby generators at the 3 Company offices identified in Table 1 as requiring standby generation. Table 2 includes the capital plan for standby generator installations.

Table 2
Capital Plan

Office	2014	2015	2016
Gander	$275,000	-	-
Carbonear	-	$275,000	-
Stephenville	-	-	$175,000

4.0 2014 Project Description

The Gander office building has a 347/600 volt service with a maximum demand of approximately 130 KVA. It is standard practice to size standby generation at approximately 25% higher than the building peak load. This will ensure smooth continual operation when it is required in outage situations and allow flexibility for marginal demand increases in the future. By using the criteria above, the building will require an estimated 165 kW of standby power. Standard sizes for standby diesel generators in this range are either 150 kW or 175 kW. A generator size of 175 kW will provide adequate capacity for the Gander Office and permit an allowance for future load growth.

The standby generator will be connected to the building through a 400 amp closed transition automatic transfer switch which will ensure the generator automatically starts upon loss of power to the building. This will also ensure a smooth transfer of load from normal AC power supply to the generator.

5.0 Project Cost

Table 3 provides a breakdown of the 2014 estimated cost for installing a standby generator at the Gander office.

Table 3
Project Cost

Description	Cost
Materials	$250,000
Labour - Internal	$10,000
Labour - Contract	-
Engineering	$10,000
Other	$5,000
Total	**$275,000**

2014 Application Enhancements

June 2013

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

Newfoundland Power ("the Company") operates and supports over 50 computer applications. These include third party software products, such as the Microsoft Dynamics Great Plains ("Dynamics GP") financial system and the Telvent OASyS Supervisory Control and Data Acquisition ("SCADA") 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 four 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 2014.

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 ("HR") 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 2014, enhancements to the Company's HR application and financial planning and forecasting application are proposed.

Table 1 summarizes the estimated cost associated with this item.

Table 1
Business Support Systems Enhancements
Project Expenditures
($000s)

Cost Category	2014 Estimate
Material	95
Labour – Internal	192
Labour – Contract	-
Engineering	-
Other	70
Total	**357**

2.1 Human Resources Application Enhancements ($174,000)

Description

The purpose of this item is to implement a number of enhancements to the Company's HR application. These include (i) the conversion of paper based files, related to employees and retirees, to electronic files, (ii) improvements to the disability management process and (iii) enhancements to the Company's reporting capabilities with respect to employee data.

Operating Experience

The Company anticipates approximately 150 employees will retire in the next 5 years. This is approximately 2 times the rate of retirements of the past 5 years. Largely as a result of increasing retirements, the Company has experienced a 220% increase in recruitments over the past 5 years. This level of hiring is expected to continue based on the anticipated retirements. Dealing with this level of employee transition requires complete and effective employee information in order to make timely decisions.

The Company manages information related to approximately 660 part-time and full-time employees and approximately 700 retirees using an HR application known as Empower as well as a variety of in-house developed spreadsheets, workflows and reports. Empower stores a significant amount of information on employees including compensation, benefits, pension and performance.[1] However, employee and retiree records are also stored in paper files and disparate electronic file shares.[2] Creating a complete employee or retiree profile requires significant manual effort, making it time consuming and prone to errors and omissions. With the increase in the number of retirements, new hires and internal position changes, the effort required to compile employee profiles has increased significantly. As well, the large volume of paper records is at risk of loss should they come in contact with fire or water.

Managing information regarding employees who are absent from work or returning to work from an injury or disability is a manual process. Paper records, supported by email and spreadsheets, are used to ensure an effective level of rigor and consistency is applied to the process. The manual nature of managing the safe and early return to work process is prone to error and omissions.

Significantly increased employee turnover and changes to the Company's employee demographics have exacerbated shortcomings in the current system's information reporting capabilities. These shortcomings have, for example, presented difficulties when determining employee service periods, calculating off-season vacation credits, reporting on education, training, professional designations and certifications. The existing systems also present limitations in making appropriate employee information accessible to supervisors, senior management and HR professionals within the Company. These reporting and data accessibility issues have also hampered the Company's workforce planning and analysis.

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[1] Empower was initially implemented in 2002 and its functionality, including reporting, has remained largely unchanged since that time.

[2] Information kept in paper files and electronic file shares includes initial employment records, education and training records, attendance and health insurance information, employee performance data, as well as disciplinary data, where applicable.

Justification

This item is justified based on improved operational effectiveness and risk management during the Company's ongoing workforce transition. Existing systems do not allow the Company to effectively keep pace with the number of new hires, retirements and internal organizational changes. These enhancements will reduce the Company's dependence on paper files and complex and disparate electronic files, and improve the reliability, security and quality of human resources information. As well, improving data accessibility and reporting capabilities in key areas will lessen the Company's dependence on a few experienced individuals who are now required to produce complete and correct reports and analyses. Efficiency improvements are also expected through automation of manual data gathering and reporting processes, such as those related to disability management.

2.2 Financial Planning and Forecasting ($183,000)

Description

The purpose of this item is to replace Newfoundland Power's existing 20-year old spreadsheet-based system for financial forecasting. This system supports forecasting of the Company's financial performance and analysis of possible future scenarios or policy proposals. This application enhancement also includes system integration to ensure data integrity and completeness between planning and other financial management systems, such as Great Plains. The new system will enable improved financial and regulatory planning, reduce the manual effort required, and allow broader access to planning information by Company employees.

Operating Experience

As of December 2012, Newfoundland Power's average rate base was approximately $883 million with annual electricity sales of approximately 5,652 GWh, revenue of approximately $580 million and earnings of approximately $36.6 million. Financial planning must consider operational and financial resources, as well as factors such as economic conditions, accounting practices and regulatory requirements. Forecasting the Company's financial performance is a complicated, highly specialized process which is currently performed by a very small group of employees using a series of complex Excel spreadsheets.

The current spreadsheet-based model of the Company's financial planning dynamics was developed in the early 1990s. It requires significant revision every 3 to 5 years to reflect the impact of factors such as Board orders and accounting practices. The central Excel spreadsheet includes approximately 50 worksheets, and its primary outputs are detailed financial statements. Additional Excel spreadsheets are used for calculation of inputs such as capital investment, rate base, finance costs and taxes. Manual intervention is required to transfer input data from Great Plains and CSS, as well as from separate Excel-based forecasts of Company sales and revenue. Publishing forecast results and comparison of forecast scenarios also requires manual intervention.

Financial forecasts are required for management decision-making regarding matters such as operational budgets, capital investment and debt issuance. Forecasts of financial performance are critical to regulatory planning and applications to the Board.[3] This system also supports the information requirements of the Company's external auditor, the Board's appointed auditor, Grant Thornton, banking institutions and credit rating agencies.

Justification

Replacement of the existing spreadsheet-based system for financial forecasting will make complete and consistent planning information more accessible to Company employees, supporting knowledge transfer during the ongoing workforce transition. The new application will improve the Company's capability to compile and compare forecast scenarios, and publish forecast outputs for use by management and external stakeholders. The system will enhance reliability, security and quality of financial planning data, and reducing risk of issues related to version control. The manual effort required to audit forecast inputs and calculations and to prepare reports is also expected to be reduced.

The financial forecasting function is critical to the Company's financial and regulatory management. This criticality constrains the timing of the transition to a new system to a year when no major planning events, such as a general rate application, are anticipated. The Company has identified 2014 as an appropriate time for this transition.

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 2014, enhancements are proposed to the Company's application for the scheduling and dispatching of crews to complete work on the electricity distribution system.

[3] See, for example, response to Request for Information CA-NP-398 in the Company's 2013-14 General Rate Application. Similar financial forecast information has also been required for various applications regarding cost recovery deferral, accounting policy change, and joint use support structure arrangements.

Table 2 summarizes the estimated cost associated with this item.

Table 2
Operations and Engineering Enhancements
Project Expenditures
($000s)

Cost Category	2014 Estimate
Material	75
Labour – Internal	130
Labour – Contract	-
Engineering	-
Other	58
Total	**263**

3.1 Crew Management Improvements ($263,000)

Description

The purpose of this project is to improve (i) the scheduling and execution of jobs that span multiple days and require multiple crews as well as (ii) the process of scheduling crews required to perform emergency work after normal business hours.

Operating Experience

The Company implemented work scheduling and tracking improvements in 2010 to improve operational efficiency and customer service related to jobs such as new service connections, outage tickets, asset maintenance requests and other customer service requests.[4] Since that time the Company has planned, scheduled, dispatched and completed over 18,000 jobs of short duration using the scheduling application known as Click Scheduler.

Benefits realized include improved scheduling and dispatching of service crews, reducing the requirement for supervisors to manually create daily schedules for significant volumes of requests, ability to assign crews new work in real time based on location and availability, ability to more effectively respond to emergency situations by selecting a crew based upon their proximity to location of trouble and improved customer response for certain types of work such as cover-ups and reconnects.

In 2014, the Company will expand the scope of work managed through Click Scheduler to include field work that is longer in duration and requires additional resources in order to complete.

The upgrade to Click Scheduler will include more complex jobs with multiple crews and longer timeframes. For example jobs that (i) extend past a normal 8 hour day, (ii) jobs that require multiple

[4] Work scheduling and tracking has been implemented in the St. John's Region. Other regions of the Company have implementation planned to come on line before the end of 2013.

days to complete, (iii) jobs that require multiple crews and associated equipment to complete, (iv) jobs that include work such as new line construction, line extensions or relocations, and (v) jobs involving upgrades or rebuild of existing lines. At this time these types of jobs are manually scheduled as part of the weekly job planning and schedule optimization process. This situation requires the scheduler to insert crews over multiple days, block multiple crews from the scheduling process and manipulate the schedule generated by the Click software.

The scheduling of crews after hours to respond to emergency work is currently managed using emails and spreadsheets. Crew assignments must take into account the type of truck required, crew skills, and pairing of lead hands and power line technicians and the appropriate use of apprentices in order to safely and effectively respond to emergency work outside of normal business hours.

Justification

This item is justified based on improved operational effectiveness and customer service. Implementing the Click functionality that supports multiday and multi-crew jobs and automating the crew call-out process will reduce the effort operations staff spends on these tasks. In addition, it will allow optimization of these crews and improved utilization of available crew time that is currently blocked from the optimizer.

This project has a net present value of approximately $13,621 over an expected application life-cycle of 7 years, and will improve customer service.[5]

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 2014, enhancements are proposed to the process of completing month end reporting of energy sales and customer results.

[5] The net present value calculation for this project can be found on page A-1 of Appendix A.

Table 3 summarizes the estimated cost associated with this item.

Table 3
Customer Service Systems Enhancements
Project Expenditures
($000s)

Cost Category	2014 Estimate
Material	-
Labour – Internal	178
Labour – Contract	-
Engineering	-
Other	30
Total	**208**

4.1 Month End Automation ($208,000)

Description

The purpose of this item is to reduce the calendar time and manual effort associated with reporting month end and quarter end Company energy sales and customer results. It will involve the automation of a number of data inputs, calculations and queries required from sources inside and outside the Company.

Operating Experience

The current processes in place to create these month end and quarter end reports were designed and developed over 10 years ago, with very few modifications since that time.[6] Energy consumption from a number of metering points located across the Company's service territory is collected as a manual input. Similarly, weather data from various sites across the province is recorded from external websites and manually entered into spreadsheets for the month end processes. Information from other sources in the Company is exchanged, often by email or internal mail and captured as part of the month end process as well. Through this highly manual process involving many employees, information is collected, reformatted, summarized, and verified to produce month end results.

Justification

This item is justified through improved operating efficiency. With the automation of several key processes, the manual effort to produce month end and quarter end reports will be reduced. In addition, automation will mitigate the potential of errors often introduced when data is manually compiled from multiple sources. If errors are made by employees involved in the process, it can often result in overtime due to tight Company reporting deadlines.

[6] The month end and quarter end reports are necessary for both financial and regulatory reporting.

This project has a net present value of approximately $25,929 over an expected application life-cycle of 7 years.[7]

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 site and the takeCHARGE! website. takeCHARGE! supports the joint Newfoundland and Labrador Hydro and Newfoundland Power customer energy conservation initiative.

For 2014, enhancements are proposed for both the customer service website and the takeCHARGE! energy conservation website.

Table 4 summarizes the estimated cost associated with this item.

Table 4
Internet Enhancements
Project Expenditures
($000s)

Cost Category	**2014 Estimate**
Material	-
Labour – Internal	224
Labour – Contract	-
Engineering	-
Other	70
Total	**294**

5.1 Customer Service Internet Enhancements ($242,000)

Description

For 2014, this item includes (i) enhancements to the self-service functionality used by customers to display past electronic correspondence including eBills and eLetters, (ii) expansion of the landlord property management functionality, (iii) additional customer self-service functions for service requests and (iv) improvements to the website security to ensure customer data is effectively protected from cyber-crime. These 4 improvements to the customer self-service functionality expand overall customer choice and flexibility when contacting or receiving information from the Company. Included with these improvements is enhanced capability for accessing the Company's websites through smart phones and wireless devices.

The use of electronic communications between customers and the Company continues to increase. In 2012, the Company's website recorded over 635,000 site visits, up 17.5% over 2011.

7 The net present value calculation for this project can be found on page A-2 of Appendix A.

Approximately 30% of our customer accounts are being managed on the website. Customers continue to leverage mobile devices to connect with the Company. In 2012, approximately 93,000 customer visits were made to the website via mobile devices, up 185% over 2011.

Operating Experience

In 2003, the Company implemented eBills and in 2009 eLetters, as forms of electronic correspondence to be sent to customers via email. In its current form customers can only view their current eBill through the website interface and are unable to see their eLetters.[8]

Landlords represent a large customer group for Newfoundland Power. Over 20,000 individual landlords and property management companies have agreements for approximately 52,000 properties or 21% of all serviced premises. The current landlord self-service functionality on the website will be expanded to allow the modification of an agreement.[9]

In 2012, there were approximately 4,200 customer requests for service for area light installations, tree trimming and service cover ups. These service requests are currently handled by Contact Centre agents through the telephone system as customers are unable to request this type of service through the Company website.

Internet security is an issue that the Company must manage on a continual basis. The risk and frequency of potential internet threats such as identity theft and internet fraud continue to challenge organizations. The Company will continue to invest in appropriate methods to ensure the security and privacy of customer information.

Justification

This item is justified primarily on improved customer service, improving the customers' online experience, improving employee productivity and protection of customer information.

Self-service functionality, via smart phone, increases customer choice in conducting business with the Company. This enhancement will allow customers to interact with the Company independent of location, time of day or type of device used.

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[8] The Company currently has over 50,000 customer accounts receiving their correspondence electronically through eBills and eLetters.

[9] The landlord agreement provides Newfoundland Power direction on how the landlord would like the Company to handle the account when a tenant moves out of their rental property. For example, the agreement could direct the Company to automatically move the account back in the Landlord's name, or it could direct the Company to disconnect the electricity service when the tenant leaves.

5.2 Energy Conservation Website Enhancements ($52,000)

Description

The purpose of this item is to enhance the Internet based functionality which supports the Company's energy conservation initiatives.

For 2014, enhancements will address new functionality through the Company's website for commercial customer energy conservation programs as outlined in the 5-Year Energy Conservation Plan.[10] In addition, enhancements to Internet-based functionality will include promotion of a variety of smaller technologies, such as compact fluorescent lighting products ("CFLs") and light emitting diode ("LED") lighting products, 'smart' power bars and *ENERGY STAR* televisions. These programs will appeal to a broad customer group as these technologies will not involve a major home renovation.

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.

In 2012, the Company provided rebates to over 4,800 residential customers and recorded approximately 49,000 visits to the takeCHARGE! website. Energy efficiency education and awareness continues to include the use of social media, including use of Facebook and YouTube as new avenues of customer communication.[11] .

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. By increasing the functionality surrounding rebates and incentive programs customers are more likely to participate in the Company's customer energy conservation initiatives.

6.0 Various Minor Enhancements ($250,000)

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.

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[10] The 5-Year Energy Conservation Plan was filed September 14, 2012 with the Company's 2013 General rate Application in Volume B, Tab 1.

[11] The takeCHARGE! Facebook page had 7,600 followers at the end of 2012, up from 6,000 in 2011.

Operating Experience

Examples of previous work completed under this budget item include modifications to customer and financial applications required for the provincial government energy tax rebate, elimination of the penny from circulation, development of mobile applications for vehicle safety inspections and record of duty status (driving logs as required by Department of Works Service and Transportation), third party billing workflows for tracking work done on behalf of other companies, and improvements to the electronic data transfer process with Newfoundland & Labrador Housing Corporation.

Justification

Work completed as part of Various Minor Enhancements is justified on the basis of improved customer service, operating efficiencies, or compliance with regulatory and legislative requirements.

Appendix A
Net Present Value Analysis

Crew Management Improvements

		Capital Impacts						Operating Cost Impacts						
		Capital Additions		CCA Tax Deductions				Cost Increases		Cost Benefits				
	YEAR	New Software	New Hardware	Software	Hardware	Residual CCA	Total	Labour	Non-Lab	Labour	Non-Lab	Net Operating Savings	Income Tax	After-Tax Cash Flow
		A	B		C			D		E		F	G	H
0	2014	($248,000)	($15,000)	$124,000	$4,125		$128,125	$0	$0	$22,620	$0	$22,620	$30,596	($209,784)
1	2015	$0	$0	$124,000	$5,981		$129,981	$0	$0	$47,050	$0	$47,050	$24,050	$71,100
2	2016	$0	$0	$0	$2,692		$2,692	$0	($5,222)	$48,932	$0	$43,709	($11,895)	$31,814
3	2017	$0	$0	$0	$1,211		$1,211	$0	($5,320)	$50,889	$0	$45,569	($12,864)	$32,705
4	2018	$0	$0	$0	$545		$545	$0	($5,418)	$52,924	$0	$47,506	($13,619)	$33,887
5	2019	$0	$0	$0	$245		$245	$0	($5,519)	$55,041	$0	$49,523	($14,290)	$35,232
6	2020	$0	$0	$0	$110		$110	$0	($5,618)	$57,243	$0	$51,626	($14,939)	$36,686
7	2021	$0	$0	$0	$50	$41	$91	$0	($5,719)	$59,533	$0	$53,813	($15,580)	$38,234
7 Yr	Present Value (See Note I)	@	6.54%											$13,621

NOTES:

A is the sum of the software additions by year.

B is the sum of the computer network hardware additions by year.

C is the Capital Cost Allowance ("CCA") tax deduction. The CCA rate for software is 100% and the CCA rate for computer hardware is 55%. The CCA deduction in the first year is based on 50% of the Capital Cost.

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 using Newfoundland Power's Labour Escalation Rates. The non-labour costs are escalated using the GDP Deflator Index.

F is the sum of the labour and non-labour amounts 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. The present value calculation uses a discount rate equal to the Company's weighted after-tax incremental cost of capital.

Month End Automation

		Capital Impacts						Operating Cost Impacts						
		Capital Additions		CCA Tax Deductions				Cost Increases		Cost Benefits				
	YEAR	New Software A	New Hardware B	Software C	Hardware C	Residual CCA C	Total C	Labour D	Non-Lab D	Labour E	Non-Lab E	Net Operating Savings F	Income Tax G	After-Tax Cash Flow H
0	2014	($207,600)	$0	$103,800	$0		$103,800	$0	$0	$0	$0	$0	$30,102	($177,498)
1	2015	$0	$0	$103,800	$0		$103,800	$0	($2,455)	$42,640	$0	$40,185	$18,448	$58,633
2	2016	$0	$0	$0	$0		$0	$0	($2,507)	$44,346	$0	$41,839	($12,133)	$29,706
3	2017	$0	$0	$0	$0		$0	$0	($2,554)	$46,119	$0	$43,566	($12,634)	$30,932
4	2018	$0	$0	$0	$0		$0	$0	($2,601)	$47,964	$0	$45,363	($13,155)	$32,208
5	2019	$0	$0	$0	$0		$0	$0	($2,649)	$49,883	$0	$47,234	($13,698)	$33,536
6	2020	$0	$0	$0	$0		$0	$0	($2,696)	$51,878	$0	$49,182	($14,263)	$34,919
7	2021	$0	$0	$0	$0	$0	$0	$0	($2,745)	$53,953	$0	$51,208	($14,850)	$36,358
7 Yr	Present Value (See Note I)	@		6.54%										$25,929

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. The CCA rate for software is 100% and the CCA rate for computer hardware is 55%. The CCA deduction in the first year is based on 50% of the Capital Cost.
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 using Newfoundland Power's Labour Escalation Rates. The non-labour costs are escalated using the GDP Deflator Index.
F is the sum of the labour and non-labour amounts 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. The present value calculation uses a discount rate equal to the Company's weighted after-tax incremental cost of capital.

2014 System Upgrades

June 2013

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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 ($889,000)

Business Applications Upgrades involve third party software that supports the Company's business applications. For 2014, upgrades are proposed for the Company's engineering software, the Contact Centre's email management and desktop software, technical work request software and SharePoint environment.

Table 1 summarizes the cost associated with these items.

Table 1
Business Applications Upgrades
Project Expenditures
($000s)

Cost Category	2014 Estimate
Material	195
Labour – Internal	509
Labour – Contract	-
Engineering	-
Other	185
	889

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 2014, upgrades include:

2.1 Engineering Software ($139,000)

The Company uses a software application known as CYME to perform distribution planning, engineering design and load flow analysis. In the past this functionality was largely used by a limited group of engineers and technologists primarily located at Head Office. Over the last 2 years there has been an increased focus on distribution planning due to continued customer load growth. This requirement has meant that the number of users requiring concurrent access to CYME has increased to include engineers and technologists located at regional offices across the province. Also, there is increased need to ensure the information managed by the CYME software is effectively secured and backed up due to the broader and more dispersed group of users. This current situation has resulted in employees not being able to access and utilize the required software when needed.

In 2013 the Company is implementing improvements to the management of distribution system information.[1] These improvements will involve the implementation of a centralized system for distribution information. The 2014 upgrade to CYME will include a gateway functionality which will allow the application to share information with other applications through this centralized system.

This project includes the acquisition, installation and configuration of additional CYME licenses and the CYME gateway functionality to allow for multiple users to work simultaneously.

2.2 Email Management Upgrade ($176,000)

This item involves an upgrade to the Contact Centre's email management system known as Attensity to the latest version supported by the vendor.

Attensity provides Contact Centre representatives with automated workflow and response capabilities to manage incoming and outgoing customer email. Attensity was initially installed in 2009. This system manages approximately 47,000 incoming and 900,000 outgoing emails annually. In recent years, email volume inbound to the Contact Center has increased by almost 100%.[2]

Attensity is integrated with the Company's Customer Service System, customer website and internal email server, Microsoft Exchange. The Attensity database stores all customer electronic correspondence, allowing for rapid access to past communications with the customer. This continuity with past correspondence is important for Contact Centre representatives to respond meaningfully to questions from customers on the status of their account.

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1 The improvement to the management of distribution system information was included in the 2013 Capital Budget Application as part of the *2013 Applications Enhancements* project.

2 In 2007 the Company received approximately 24,000 emails from customers. In 2012 the number of email contacts increased to approximately 47,000, a 97% increase.

Ongoing changes to other 3rd party software components, such as the Microsoft XP Operating System, Java Client and Microsoft Net Framework, require an upgrade to a current release of the Attensity email management software in order to ensure effective operation. In addition, upgrade to the current release will provide the Contact Centre with access to enhanced reporting, avoiding the need to manually create reports in response to customer inquiries. The upgraded version of Attensity will also provide improvements to Contact Centre performance reporting.

2.3 Contact Center Software Upgrade ($250,000)

This item involves an upgrade to the Aspect Contact Centre software that operates on Customer Contact Centre representatives' desktop computers. The Aspect software applications are used by Contact Centre representatives when answering customer calls. The Aspect software also enables Contact Center supervisory staff to manage work load based on call volume and off-phone activities and also help to provide coaching and training support.

The upgrade involves upgrading operating systems and related software while also ensuring the new version of the software continues to support Company operations. There are a number of integrated components associated with this upgrade. They include:

- Upgrade an obsolete operating system on Contact Center PCs. Windows XP will be upgraded to Windows 7.[3]
- As a result of the Windows XP to Windows 7 upgrade, there are related software components deployed in the Contact Centre that will also require upgrades. These include Aspect eWorkforce Management and Internet Explorer.[4]
- Other components are no longer supported by the software vendor and must be upgraded to a supported software version. These include: Aspect Unified Connect and Aspect Quality Management.[5]
- Testing to ensure existing integrations function correctly with the upgraded software.

2.4 Technical Work Request Upgrade ($160,000)

The Company's Technical Work Request ("TWR") application was developed in-house in 2007. Over the past 6 years TWR has managed approximately 68,000 work orders, including requests for new services, new street light installations, requests for customer property restoration as well as distribution reconstruction and extension projects. TWR is an integral part of Company operations and is currently used by technologists, field supervisors,

3 Microsoft XP Professional is a desktop operating system that has been in use by the Company since 2002. Microsoft will discontinue support (including security updates) as of April 2014.

4 Aspect eWorkforce Management is used to provide forecasting, scheduling, tracking, adherence monitoring, and seat planning capabilities in the Contact Center. Microsoft Internet Explorer is used in the Contact Center to act as a secure, unified access point to enterprise information, applications and training material.

5 Aspect Unified Connect is used to support inbound automatic call distribution, to deliver customers to the appropriate Contact Center agent the first time, providing key identifying information on the customer as the call is delivered to the representative. Aspect Quality Management is used to provide voice and screen recording that help improve employee performance.

contractors, Customer Contact Centre agents, and office support staff to manage the various steps and approvals associated with performing customer driven work.

With third party contractors completing work such as tree trimming, pole installations and removals there is a requirement to provide secured access to TWR functions to these contractors from outside Newfoundland Power's secure infrastructure. To facilitate providing secure and consistent access, a browser based portal will be provided to allow contractors to view and update TWR. Application security will be upgraded to ensure the various contractors have the appropriate access to view and update work orders which have been assigned to them.[6]

This upgrade will reduce the number of applications and interfaces used to manage TWR work orders. It will improve the availability of information required by the various user groups who work with TWR. In addition, using the secure browser based approach, a reduction in software licensing and support and maintenance will be achieved.[7]

The proposed solution would not be device specific, providing employees and contractors the ability to utilize TWR independent of device, location or type of network connectivity. The upgrade would also improve overall data integrity by reducing data entry errors and improve application performance.

2.5 SharePoint Upgrade ($164,000)

The Company has been using Microsoft SharePoint since 2003. SharePoint provides employees, business partners and customers the ability to collaborate and share information via the Internet. The Company currently has 12 SharePoint extranet sites used to support a number of functions including: third party invoice tracking, safety and environment compliance and training for contractors.

As well, there are several employee-centric SharePoint applications used to manage regulatory documentation, corporate financial controls and compliance, vehicle management as well as engineering and operations project and document management. These applications operate on 4 different versions of SharePoint, 2 of which are no longer supported by the vendor, Microsoft.

The proposed upgrade will reduce the number of platforms used to operate the various applications, thereby reducing support, maintenance and administration effort from internal technical staff and ensure ongoing support and maintenance from the vendor.

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6 Without the proposed browser based approach, Newfoundland Power would have to create a new external website for each new contractor, requiring additional ongoing technical support and maintenance.

7 The reduction in software licensing will result in an estimated decrease of approximately $10,000 in operating savings.

The upgrade will also result in the retirement of several in-house developed and third party solutions currently used for search functionality, workflow management and multi-media file management.[8]

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.

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 ($170,000)

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 desktops. Under this agreement, the Company distributes its purchasing costs for these licenses over three years, as outlined in Schedule C of the 2012 Capital Budget Application.

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.[9] 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.

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8 This functionality was unavailable in the earlier version of SharePoint but will come standard with the most current version.

9 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.

Justification

The Microsoft Enterprise Agreement is the least cost option to ensuring access to current Microsoft software products.

2014 Shared Server Infrastructure

June 2013

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.

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	2014 Estimate
Material	425
Labour – Internal	273
Labour – Contract	-
Engineering	-
Other	135
Total	**833**

For 2014, this project includes:

1. The upgrading and replacement of the shared server infrastructure that hosts the Company's Contact Center technology, SharePoint environment, Technical Work Request ("TWR") environment, as well as replacement of the Company's shared multifunction printer devices that have reached the end of their useful lives. The estimated cost for this shared server infrastructure is $331,000.

2. The upgrading of the Company's wireless network security monitoring software. The Company relies on its wireless network for securing and updating mobile applications used

by field staff. These mobile applications include the Company's work order management application (*Click Mobile)*, safety inspections, operating procedures and electrical system connectivity information.

In addition, employees use the Company's wireless network to access the corporate computer network from within Company premises. The number and type of mobile devices that use wireless capabilities continues to grow. In order to securely network and monitor these devices, upgrades are required to the Company's wireless security monitoring tools. The estimated project cost for this security infrastructure upgrade is $226,000.

3. Remote connectivity enhancements to allow employees to work securely while away from Company owned facilities. Newfoundland Power's use of mobile devices, including smart phones, continues to grow. These, in addition to the Company's fleet of laptop computers, require upgrades to security software to enable employees to connect remotely over the Internet from any location and gain access to necessary applications and resources. The estimated project cost for this security infrastructure upgrade is $173,000.

4. Mobile Data Encryption Infrastructure to allow safe storage of data on portable media. Technology such as USB memory sticks, portable hard drives and smart phones, all have the capability to store large amounts of data. To ensure data stored on these devices remains secure, an encryption solution is required. The estimated project cost for this security infrastructure is $103,000.

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.[1] 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.

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

[1] Gartner Inc. is the leading provider of research and analysis on the global Information Technology industry.

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.

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 high 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.

Rate Base:
Additions, Deductions & Allowances

June 2013

Table of Contents

1.0 Introduction

1.1 General

In the 2014 Capital Budget Application (the "Application"), Newfoundland Power seeks final approval of its 2012 average rate base. This is consistent with current regulatory practice before the Board.

Newfoundland Power's 2012 average rate base of $883,045,000 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 2013 and 2104 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 2011 and 2012 and the forecast additions for 2013 and 2014.

Table 1
Additions to Rate Base
2011-2014F
($000s)

	2011	2012	2013F	2014F
Deferred Pension Costs	97,628	100,113	100,968	102,796
Credit Facility Issue Costs	270	239	-	-
Cost Recovery Deferral – Seasonal/TOD Rates	228	93	143	80
Cost Recovery Deferral – Hearing Costs	253	-	833	416
Cost Recovery Deferral – Regulatory Amortizations	1,642	3,320	2,213	1,106
Cost Recovery Deferral – 2012 Cost of Capital	-	1,766	1,178	589
Cost Recovery Deferral – 2013 Revenue Shortfall	-	-	2,252	1,126
Cost Recovery Deferral – Conservation	454	227	2,176	4,990
Customer Finance Programs	1,527	1,446	1,450	1,450
Total Additions	102,002	107,204	111,213	112,553

Additions to rate base were approximately $107.2 million in 2012. This is approximately $5.2 million more than 2011. The higher additions to rate base through 2012 reflect (i) an increase in deferred pension costs; (ii) the deferred recovery of costs related to the conclusion in 2010 of a number of specific regulatory amortizations[1]; and, (iii) the deferred recovery of costs related to the 2012 Cost of Capital.[2]

[1] In Order No. P.U. 30 (2010), the Board approved the deferred recovery of a number of specific costs related to the conclusion in 2010 of a number of amortizations associated with the 2010 general rate application. In Order No. P.U. 22 (2011), the Board approved the continuation of this cost recovery deferral for 2012.

[2] In Order No. P.U. 17 (2012), the Board approved that Newfoundland Power establish a 2012 Cost of Capital Cost Recovery Deferral Account to allow for the deferred recovery of the full amount of the difference in revenue between an 8.38% return on common equity and an 8.80% return on common equity for 2012, calculated on the basis of Newfoundland Power's 2010 test year costs.

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 2011 through 2014.

Table 2
Deferred Pension Costs
2011-2014F
($000s)

	2011	**2012**	**2013F**	**2014F**
Deferred Pension Costs	97,628	100,113	100,968	102,796

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).[3]

Table 3 shows details of changes in Newfoundland Power's deferred pension costs from 2011 through 2014.

Table 3
Deferred Pension Costs
2011-2014F
($000s)

	2011	**2012**	**2013F**	**2014F**
Deferred Pension Costs, January 1st	102,549	97,628	100,113	100,968
Pension Plan Funding[4]	5,137	13,638	13,599	13,716
Pension Plan Expense	(10,058)	(11,153)	(12,744)	(11,888)
Deferred Pension Costs, December 31st	97,628	100,113	100,968	102,796

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.

[3] Deferred pension costs were approved for inclusion in average rate base in Order No. P.U. 19 (2003).
[4] Pension funding for 2012 includes special funding payments of $10.7 million based on the latest actuarial information. Special funding payments of $10.7 million are expected in 2013 and 2014.

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 cost.

Table 4 shows details of Newfoundland Power's amortization of deferred credit facility issue costs from 2011 through 2012.

Table 4
Deferred Credit Facility Issue Costs[5]
2011-2012
($000s)

	2011	**2012**
Balance, January 1st	258	270
Cost	130	115
Amortization	(118)	(146)
Balance, December 31st	270	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.

[5] For the 2013 and 2014 test years, the unamortized credit facility costs are included as a component of the Company's weighted average costs of capital and are therefore reflected in the rate of return on rate base for those years. Consequently, there is no adjustment to rate base for 2013 and 2014.

Table 5 shows details of the Optional Seasonal Rate Revenue and Cost Recovery account for 2011 through 2014.

Table 5
Seasonal/TOD Rates
2011-2014F
($000s)

	2011	2012	2013F	2014F
Balance, January 1st	-	228	93	143
Additions	228	93	143	80
Reductions	-	(228)	(93)	(143)
Balance, December 31st	228	93	143	80

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 $1,250,000 in external costs related to the Company's 2013 General Rate Application. 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 2011 through 2014.

Table 6
Deferred Hearing Costs
2011-2014F
($000s)

	2011	2012	2013F	2014F
Balance, January 1st	507	253	-	833
Cost	-	-	1,250	-
Amortization	(254)	(253)	(417)	(417)
Balance, December 31st	253	-	833	416
2010 Hearing Cost Adjustments[6]	(6)	(3)	-	-

[6] In Order No. P.U. 26 (2011), the Board ordered Newfoundland Power to adjust the recovery of its 2010 Hearing Costs to reflect total costs of $750,000. Presented as a deduction from rate base.

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 2011 through 2014 related to the expiry of regulatory amortizations in 2010.

Table 7
Cost Recovery Deferral - Regulatory Amortizations
2011-2014F
($000s)

	2011	**2012**	**2013F**	**2014F**
Balance, January 1st	-	1,642	3,320	2,213
Cost	1,642	1,678	-	-
Amortization	-	-	(1,107)	(1,107)
Balance, December 31st	1,642	3,320	2,213	1,106

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 in 2013 and 2014.

Table 8
Cost Recovery Deferral - 2012 Cost of Capital
2011-2014F
($000s)

	2011	2012	2013F	2014F
Balance, January 1st	-	-	1,766	1,178
Cost	-	1,766	-	-
Amortization	-	-	(588)	(589)
Balance, December 31st	-	1,766	1,178	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.[7]

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 in 2013 and 2014.

Table 9
Cost Recovery Deferral – 2013 Revenue Shortfall
2011-2014F
($000s)

	2011	2012	2013F	2014F
Balance, January 1st	-	-	-	2,252
Cost	-	-	2,815	-
Amortization	-	-	(563)	(1,126)
Balance, December 31st	-	-	2,252	1,126

[7] 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 2011 through 2014.

Table 10
Cost Recovery Deferral - Conservation
2011-2014F
($000s)

	2011	**2012**	**2013F**	**2014F**
Balance, January 1st	682	454	227	2,176
Cost	-	-	2,176	3,125
Amortization	(228)	(227)	(227)	(311)
Balance, December 31st	454	227	2,176	4,990

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 2011 through 2014.

Table 11
Customer Finance Programs
2011-2014F
($000s)

	2011	2012	2013F	2014F
Balance, January 1st	1,647	1,527	1,446	1,450
Change	(120)	(81)	4	-
Balance, December 31st	1,527	1,446	1,450	1,450

3.0 Deductions from Rate Base

3.1 Summary

Table 12 summarizes Newfoundland Power's deductions from rate base for 2011 and 2012 and the Company's forecasts for 2013 and 2014.

Table 12
Deductions from Rate Base
2011-2014F
($000s)

	2011	2012	2013F	2014F
Weather Normalization Reserve	5,020	4,804	3,347	1,674
Adjustment – 2010 Hearing Costs	6	-	-	-
Other Post Employment Benefits ("OPEBs")	7,199	14,617	23,043	31,145
Customer Security Deposits	695	851	800	800
Accrued Pension Obligation	3,778	4,020	4,296	4,657
Accumulated Deferred Income Taxes	862	2,504	1,749	1,283
Demand Management Incentive Account	1,252	558	(368)	(368)
Total Deductions	18,812	27,354	32,867	39,191

Deductions from rate base were approximately $27.4 million in 2012. Newfoundland Power's deductions from rate base in 2012 have increased approximately $8.6 million from 2011. The reduction in rate base primarily reflects the amortization of the OPEB regulatory asset[8] and amortization of the employee future benefits regulatory asset[9] related to OPEBs and an increase in accumulated deferred income taxes.

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 2011 through 2014.

Table 13
Weather Normalization Reserve
2011-2014F
($000s)

	2011	**2012**	**2013F**	**2014F**
Balance, January 1st	(1,955)	(5,020)	(4,804)	(3,347)
Operation of the reserve	(1,699)	1,580	(216)	-
Amortization	(1,366)	(1,364)	1,673	1,673
Balance, December 31st	(5,020)	(4,804)	(3,347)	(1,674)

In Order No. P.U. 19 (2012) the Board approved the December 31, 2012 balance of $4,803,404 in the Weather Normalization Reserve.

[8] 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.

[9] 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. 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.

In Order No. PU. 11 (2012), the Board approved the opening balances for regulatory assets and liabilities associated with employee future benefits to be recognized for regulatory purposes under U.S. GAAP as of January 1, 2012.

Table 14 shows details of the changes related to the net OPEBs liability from 2011 through 2014.

Table 14
Other Post Employment Benefits
2011-2014F
($000)

	2011[10]	2012	2013F	2014F
Regulatory Asset	49,056	83,064	77,036	71,209
OPEB Liability	56,255	97,681	100,079	102,354
Net OPEBs Liability	7,199	14,617	23,043	31,145

[10] The 2011 amounts were prepared in accordance with Canadian GAAP. For comparison with 2012 and beyond, the 2011 restated amounts in accordance with U.S. GAAP for the regulatory asset is $70,172,000 and for the OPEB liability is $77,371,000. The change to U.S. GAAP was approved in Order No. P.U. 27 (2011).

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 2011 through 2014.

Table 15
Customer Security Deposits
2011-2014F
($000)

	2011	2012	2013F	2014F
Balance, January 1st	705	695	851	800
Change	(10)	156	(51)	-
Balance, December 31st	695	851	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 2011 through 2014.

Table 16
Accrued Pension Obligation
2011-2014F
($000)

	2011	2012	2013F	2014F
Balance, January 1st	3,548	3,778	4,020	4,296
Change	230	242	276	361
Balance, December 31st	3,778	4,020	4,296	4,657

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,[11] pension costs[12] and other employee future benefit costs.[13]

Table 17 shows details of changes in the accumulated deferred income taxes from 2011 through 2014.

Table 17
Accumulated Deferred Income Taxes
2011-2014F
($000)

	2011	**2012F**	**2013F**	**2014F**
Balance, January 1st	3,617	862	2,504	1,749
Change	(2,755)	1,642	(755)	(466)
Balance, December 31st	862	2,504	1,749	1,283

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 2011 through 2014.

Table 18
DMI Account
2011-2014F
($000)

	2011	**2012**	**2013F**	**2014F**
Balance, January 1st	676	1,252	558	(368)
Change	576	(694)	(926)	-
Balance, December 31st	1,252	558	(368)	(368)

In Order No. P.U. 8 (2013), the Board approved the transfer to the RSA at March 31, 2013, of $0.8 million equal to the balance in the DMI account for 2012 and related income tax effects.

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11 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.

12 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.

13 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).

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 2011 through 2014.

Table 19
Rate Base Allowances
Cash Working Capital Allowance
2011-2014F
($000)

	2011[14]	**2012**[14]	**2013F**[15]	**2014F**[15]
Gross Operating Costs	432,485	447,918	466,875	474,548
Income Taxes	19,631	7,755	131	14,424
Municipal Taxes Paid	13,348	14,507	11,928	15,613
Non-Regulated Expenses	(1,604)	1,090	(1,253)	(1,291)
Total Operating Expenses	463,860	471,270	477,681	503,294
Cash Working Capital Factor	2.0%	2.0%	1.73%	1.69%
	9,277	9,425	8,264	8,506
HST Adjustment	386	386	(1,986)	(2,180)
Cash Working Capital Allowance	9,663	9,811	6,278	6,326

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.[16]

[14] The cash working capital allowance for 2011 and 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).

[15] The cash working capital allowance for 2013 and 2014 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).

[16] 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 2011 through 2014.

Table 20
Rate Base Allowances
Materials and Supplies Allowance
2011-2014F
($000)

	2011	**2012**	**2013F**	**2014F**
Average Materials and Supplies	6,281	6,682	6,199	5,971
Expansion Factor[17]	20.2%	20.2%	22.53%	22.53%
Expansion	1,269	1,350	1,396	1,345
Materials and Supplies Allowance	5,012	5,332	4,803	4,626

[17] The expansion factor is based on a review of actual inventories used for expansion projects. The calculation of the 2010 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 and 2014 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).