NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

55 Kenmount Road
P.O. Box 8910
St. John's, NL A1B 3P6
Business: (709) 737-5600
Facsimile: (709) 737-2974
www.newfoundlandpower.com

DELIVERED BY HAND

June 28, 2012

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 2013 Capital Budget Application

A. 2013 Capital Budget Application

Enclosed are the original and 10 copies of Newfoundland Power Inc.'s (the "Company") 2013 Capital Budget Application and supporting materials (the "Filing").

The Filing outlines a proposed 2013 Capital Budget totaling $80,788,000 including $7,095,000 in capital expenditures approved by the Board in Order No. P.U. 26 (2011). There are also 2 new multi-year projects involving 2014 capital expenditures totaling $3,853,000. In addition, the Filing seeks approval of a 2011 rate base in the amount of $876,356,000.

B. Compliance Matters

B.1 Board Orders

In Order No. P.U. 26 (2011) (the "2012 Capital Order"), the Board required a progress report on 2012 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. *2012 Capital Expenditure Status Report*: this meets the requirements of the 2012 Capital Order;

2. *2013 Capital Plan*: this meets the requirements of the 2004 Capital Order; and

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

B.2 The Guidelines

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

Section 2 of the *2013 Capital Plan* provides a breakdown of the overall 2013 Capital Budget by definition, classification, and materiality segmentation as described in the Guidelines. Pages ii through viii of Schedule B to the formal application provide details of these categorizations by project.

C. Filing Details and Circulation

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

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

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

Telephone: (709) 737-5609 *Email: ghayes@newfoundlandpower.com* *Fax: (709) 737-2974*

Newfoundland Power Inc.
2013 Capital Budget Application
Filing Contents

Application

Application
Schedule A *2013 Capital Budget Summary*
Schedule B *2013 Capital Projects*
Schedule C *Multi-Year Projects*
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2012 Capital Expenditure Status Report

Supporting Materials

Generation
1.1 2013 Facility Rehabilitation
1.2 Heart's Content Hydro Plant Penstock Replacement
1.3 New Chelsea Hydro Plant Runner Replacement and Rewind
1.4 Pitmans Pond Hydro Plant Refurbishment

Substations
2.1 2013 Substation Refurbishment and Modernization

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Deferred Charges
8.1 Rate Base: Additions, Deductions & Allowances

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 2013 Capital Budget of $80,788,000;
(b) approving certain capital expenditures related to multi-year projects commencing in 2013; and
(c) fixing and determining a 2011 rate base of $876,356,000

2013 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 2013 Capital Budget of $80,788,000;
(b) approving certain capital expenditures related to multi-year projects commencing in 2013; and
(c) fixing and determining a 2011 rate base of $876,356,000

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 2013 Capital Budget in the amount of $80,788,000, 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 2013. 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 2013 Capital Budget are required.

4. Schedule C to this Application is a list of multi-year projects that are ongoing and multi-year projects that will commence as part of the 2013 Capital Budget but will not be completed in 2013. The 2013 Capital Budget includes capital expenditures of $7,095,000 that were approved by the Board in Order No. P.U. 26 (2011).

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 2011 of $876,356,000.

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 2013 of the improvements and additions to its property in the amount of $80,788,000 as set out in Schedules A and B to the Application;

   (b) pursuant to Section 41 of the Act, approving Newfoundland Power's purchase and construction of improvements and additions to its property in the amount of $3,853,000 in 2014, as set out in Schedule C to the Application; and

   (d) pursuant to Section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2011 in the amount of $876,356,000 as set out in Schedule D to the Application.

DATED at St. John's, Newfoundland and Labrador, this 28th day of June, 2012.

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

Telephone: (709) 737-5609
Telecopier: (709) 737-2974

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

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

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:
(a) approving a 2013 Capital Budget of $80,788,000;
(b) approving certain capital expenditures related to multi-year projects commencing in 2013; and
(d) fixing and determining a 2011 rate base of $876,356,000

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, 2012:

Barrister

Peter Alteen

2013 CAPITAL BUDGET SUMMARY

Asset Class	**Budget (000s)**
1. Generation - Hydro	$ 4,450
2. Generation - Thermal	284
3. Substations[1]	17,618
4. Transmission	5,371
5. Distribution	38,740
6. General Property	1,737
7. Transportation	2,950
8. Telecommunications	874
9. Information Systems	4,014
10. Unforeseen Allowance	750
11. General Expenses Capitalized	4,000
Total	**$ 80,788**

1 Includes $7,095,000 in expenditures approved in Order No. P.U. 26 (2011).

2013 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[2]
1. Generation – Hydro		
Facility Rehabilitation	$1,400	2
Hydro Plant Production Increase	1,128	4
New Chelsea Plant Refurbishment	847	7
Pitman's Pond Plant Refurbishment	875	9
Heart's Content Plant Refurbishment	200	11
Total Generation – Hydro	**$ 4,450**	
2. Generation – Thermal		
Facility Rehabilitation Thermal	$ 284	14
Total Generation – Thermal	**$ 284**	
3. Substations		
Substations Refurbishment and Modernization	$ 4,452	17
Replacements Due to In-Service Failures	2,685	19
Additions Due to Load Growth[3]	3,974	21
PCB Bushing Phase-out	3,386	23
Substation Addition – Portable Substation[4]	3,121	26
Total Substations	**$ 17,618**	
4. Transmission		
Transmission Line Rebuild	$ 5,371	29
Total Transmission	**$ 5,371**	

2 Project descriptions can be found in Schedule B at the page indicated.
3 Approved in Order No. P.U. 26 (2011).
4 Approved in Order No. P.U. 26 (2011).

2013 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[5]
5. Distribution		
Extensions	$ 11,376	33
Meters	2,849	35
Services	3,705	38
Street Lighting	2,267	41
Transformers	7,983	44
Reconstruction	3,499	46
Rebuild Distribution Lines	2,997	48
Relocate/Replace Distribution Lines for Third Parties	2,554	51
St. John's Trunk Feeders	117	53
Feeder Additions for Growth	1,204	55
Allowance for Funds Used During Construction	189	57
Total Distribution	**$ 38,740**	
6. General Property		
Tools and Equipment	$ 389	60
Additions to Real Property	238	63
Company Building Renovations	950	65
Stand-by and Emergency Power – Duffy Place	160	67
Total General Property	**$ 1,737**	
7. Transportation		
Purchase Vehicles and Aerial Devices	$ 2,950	70
Total Transportation	**$ 2,950**	

5 Project descriptions can be found in Schedule B at the page indicated.

2013 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[6]
8. Telecommunications		
Replace/Upgrade Communications Equipment	$ 124	74
Mobile Radio System Replacement	750	76
Total Telecommunications	**$ 874**	
9. Information Systems		
Application Enhancements	$ 1,380	79
System Upgrades	1,177	81
Personal Computer Infrastructure	380	83
Shared Server Infrastructure	877	85
Network Infrastructure	200	88
Total Information Systems	**$ 4,014**	
10. Unforeseen Allowance		
Allowance for Unforeseen Items	$ 750	91
Total Unforeseen Allowance	**$ 750**	
11. General Expenses Capitalized		
General Expenses Capitalized	$ 4,000	93
Total General Expenses Capitalized	**$ 4,000**	

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

2013 CAPITAL PROJECTS SUMMARY

2013 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 2013 Capital Project Summary provides a summary of the planned capital expenditures contained in Newfoundland Power's 2013 Capital Budget Application by definition (pages iii to iv), classification (pages v to vi), and segmentation by materiality (pages vii to viii) as required by the Guidelines. In addition, each of the project descriptions in Schedule B indicate the definitions, classifications and forecast costs as provided for in the Guidelines.

**Summary of
2013 Capital Projects by Definition
(000's)**

Clustered	**$3,347**	**Page**
Distribution	**117**	
St. John's Trunk Feeders	117	53
Generation-Hydro	**2,850**	
Hydro Plant Production Increase	1,128	4
New Chelsea Plant Refurbishment	847	7
Pitmans Pond Plant Refurbishment	875	9
Transmission	**380**	
Transmission Line Rebuild	380	29

Pooled	**$68,460**	**Page**
Distribution	**38,623**	
Allowance for Funds Used During Construction	189	57
Extensions	11,376	33
Feeder Additions for Growth	1,204	55
Meters	2,849	35
Rebuild Distribution Lines	2,997	48
Reconstruction	3,499	46
Relocate/Replace Distribution Lines for Third Parties	2,554	51
Services	3,705	38
Street Lighting	2,267	41
Transformers	7,983	44
General Property	**1,577**	
Additions to Real Property	238	63
Tools and Equipment	389	60
Company Building Renovations	950	65
Generation-Hydro	**1,400**	
Facility Rehabilitation	1,400	2
Generation-Thermal	**284**	
Facility Rehabilitation Thermal	284	14
Information Services	**4,014**	
Application Enhancements	1,380	79
Network Infrastructure	200	88
Personal Computer Infrastructure	380	83
Shared Server Infrastructure	877	86
System Upgrades	1,177	81
Substations	**14,497**	
Additions Due to Load Growth	3,974	21
PCB Bushings Phase-out	3,386	23
Replacements Due to In-Service Failures	2,685	19
Substations Refurbishment & Modernization	4,452	17

Telecommunications	**124**	
Replace/Upgrade Communications Equipment	124	74
Transmission	**4,991**	
Transmission Line Rebuild	4,991	29
Transportation	**2,950**	
Purchase Vehicles and Aerial Devices	2,950	70

Other	**$8,981**	**Page**
Allowance for Unforeseen	**750**	
Allowance for Unforeseen Items	750	91
General Expenses Capitalized	**4,000**	
General Expenses Capitalized	4,000	93
General Property	**160**	
Stand-by and Emergency Power Duffy Place	160	67
Generation-Hydro	**200**	
Heart’s Content Plant Refurbishment	200	11
Substations	**3,121**	
Substation Addition - Portable Substation	3,121	26
Telecommunications	**750**	
Mobile Radio System Replacement	750	76

Summary of
2013 Capital Projects by Classification
(000's)

Normal Capital	**$71,023**	**Page**
Allowance for Unforeseen	**750**	
Allowance for Unforeseen Items	750	91
Distribution	**38,740**	
Allowance for Funds Used During Construction	189	57
Extensions	11,376	33
Feeder Additions for Growth	1,204	55
Meters	2,849	35
Rebuild Distribution Lines	2,997	48
Reconstruction	3,499	46
Relocate/Replace Distribution Lines for 3rd Parties	2,554	51
Services	3,705	38
Street Lighting	2,267	41
St. John's Trunk Feeders	117	53
Transformers	7,983	44
General Expenses Capitalized	**4,000**	
General Expenses Capitalized	4,000	93
General Property	**1,737**	
Additions to Real Property	238	63
Tools and Equipment	389	60
Stand-by and Emergency Power Duffy Place	160	67
Company Building Renovations	950	65
Generation-Hydro	**3,322**	
Facility Rehabilitation	1,400	2
New Chelsea Plant Refurbishment	847	7
Pitmans Pond Plant Refurbishment	875	9
Heart's Content Plant Refurbishment	200	11
Generation-Thermal	**284**	
Facility Rehabilitation Thermal	284	14
Information Services	**2,634**	
Network Infrastructure	200	88
Personal Computer Infrastructure	380	83
Shared Server Infrastructure	877	86
System Upgrades	1,177	81
Substations	**11,111**	
Additions Due to Load Growth	3,974	21
Replacements Due to In-Service Failures	2,685	19
Substations Refurbishment & Modernization	4,452	17
Telecommunications	**124**	
Replace/Upgrade Communications Equipment	124	74

Transmission	**5,371**	
Transmission Line Rebuild	5,371	29
Transportation	**2,950**	
Purchase Vehicles and Aerial Devices	2,950	70

Justifiable	**$6,379**	**Page**
Generation-Hydro	**1,128**	
Hydro Plant Production Increase	1,128	4
Information Services	**1,380**	
Application Enhancements	1,380	79
Substations	**3,121**	
Substation Addition - Portable Substation	3,121	26
Telecommunications	**750**	
Mobile Radio System Replacement	750	76

Mandatory	**$3,386**	**Page**
Substations	**3,386**	
PCB Bushings Phase-out	3,386	23

Summary of
2013 Capital Projects by Materiality
(000's)

Large – Greater than $500	**$78,507**	**Page**
Allowance for Unforeseen	**750**	
Allowance for Unforeseen Items	750	91
Distribution	**38,434**	
Extensions	11,376	33
Feeder Additions for Growth	1,204	55
Meters	2,849	35
Rebuild Distribution Lines	2,997	48
Reconstruction	3,499	46
Relocate/Replace Distribution Lines for 3rd Parties	2,554	51
Services	3,705	38
Street Lighting	2,267	41
Transformers	7,983	44
General Expenses Capitalized	**4,000**	
General Expenses Capitalized	4,000	93
General Property	**950**	
Company Building Renovations	950	65
Generation-Hydro	**4,250**	
Facility Rehabilitation	1,400	2
Hydro Plant Production Increase	1,128	4
New Chelsea Plant Refurbishment	847	7
Pitmans Pond Plant Refurbishment	875	9
Information Services	**3,434**	
Application Enhancements	1,380	79
Shared Server Infrastructure	877	86
System Upgrades	1,177	81
Substations	**17,618**	
Additions Due to Load Growth	3,974	21
Replacements Due to In-Service Failures	2,685	19
Substations Refurbishment & Modernization	4,452	17
PCB Bushings Phase-out	3,386	23
Substation Addition Portable Substation	3,121	26
Telecommunications	**750**	
Mobile Radio System Replacement	750	76
Transmission	**5,371**	
Transmission Line Rebuild	5,371	29
Transportation	**2,950**	
Purchase Vehicles and Aerial Devices	2,950	70

Medium - Between $200 and $500	**$1,691**	**Page**
General Property	**627**	
Additions to Real Property	238	63
Tools and Equipment	389	60
Generation-Hydro	**200**	
Heart's Content Plant Refurbishment	200	11
Generation-Thermal	**284**	
Facility Rehabilitation Thermal	284	14
Information Services	**580**	
Network Infrastructure	200	88
Personal Computer Infrastructure	380	83

Small – Under $200	**$590**	**Page**
Distribution	**306**	
Allowance for Funds Used During Construction	189	57
St. John's Trunk Feeders	117	53
Telecommunications	**124**	
Replace/Upgrade Communications Equipment	124	74
General Property	**160**	
Stand-by and Emergency Power Duffy Place	160	67

GENERATION - HYDRO

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

Project Cost: **$1,400,000**

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 hydro dams and spillways;
- Refurbishment of 2 outlet structures; 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 2013 proposed expenditures are included in ***1.1*** *2013 Facility Rehabilitation*.

Justification

The Company's 23 hydroelectric plants range in age from 13 to 112 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 $118.80 per barrel, this translates into approximately $81 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 2013 and a projection of expenditures through 2017.

Table 1

Projected Expenditures (000s)

Cost Category	**2013**	**2014**	**2015 - 2017**	**Total**
Material	$1,129	-	-	-
Labour – Internal	47	-	-	-
Labour – Contract	-	-	-	-
Engineering	171	-	-	-
Other	53	-	-	-
Total	**$1,400**	**$1,410**	**$4,385**	**$7,195**

Costing Methodology

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

Table 2

Expenditure History (000s)

Year	**2008**	**2009**	**2010**	**2011**	**2012F**
Total	$3,551[1]	$2,519[2]	$1,301	$1,450	$1,362

[1] Includes protection and control system upgrades at Cape Broyle and runner replacement at Hearts Content.
[2] Includes protection and control system upgrades at Horse Chops plant.

The budget estimate for this project is comprised of 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 (Clustered)**

Project Cost: **$1,128,000**

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 2013, Newfoundland Power will undertake runner replacements at New Chelsea and Pitmans Pond hydroelectric generating plants. The New Chelsea/Pittman's development is composed of two plants, New Chelsea and Pitmans Pond.

The New Chelsea plant was placed into service in 1956 and has one generating unit with a capacity of 3.7 MW under a net head of 83.8 metres. The normal annual energy production at New Chelsea is approximately 16.3 GWh or 3.8% of the total hydroelectric production of Newfoundland Power. Details on the proposed expenditures are included in ***1.3*** *New Chelsea Hydro Plant Runner Replacement and Rewind*.

The Pitmans Pond plant was placed into service in 1959 and has one generating unit with a capacity of 625 kW under a net head of 21.3 metres. The normal annual energy production at Pitmans Pond is approximately 2.8 GWh or 0.7% of the total hydroelectric production of Newfoundland Power. Details on the proposed expenditures are included in ***1.4*** *Pitmans Pond Hydro Plant Refurbishment*.

Two items are included in this project:

1. *New Chelsea Runner Replacement ($653,000).* The runner at New Chelsea is 56 years old. Efficiency testing on this unit estimated the best efficiency to be just over 83% and efficiency at maximum load at 82%.[3] A new runner design is estimated to increase these efficiency values to approximately 89% and 85%, respectively. The increase in annual energy production resulting from the runner replacement is estimated to be 1.0 GWh, or about 6%. The estimated levelized cost of energy from New Chelsea plant over the next 50 years is 1.37¢ per kWh.

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1 A copy of this study was filed as Attachment A to Response to Request for Information PUB-NP-09 in the Company's 2010 Capital Budget Application.
2 At the end of 2012 4 of these potential projects will have been completed. Another 5 projects are included in the 2013 to 2017 Capital Plan. Included in the 31 potential projects are 9 projects involving the construction of small hydro plants.
3 Efficiency testing was completed on this unit by Hatch in 1997 as part of a Water Management Study.

2. *Pitmans Pond Runner Replacement ($475,000).* The runner at Pitmans Pond is 53 years old. Based upon an analysis of SCADA data on this unit the estimated best efficiency was just over 71% and efficiency at maximum load was over 66%.[4] A new runner design is estimated to increase these efficiency values to approximately 88% and 84%, respectively. The increase in annual energy production resulting from the runner replacement is estimated to be 0.7 GWh, or about 25%. The estimated levelized cost of energy from Pitmans Pond plant over the next 25 years is 6.90¢ per kWh.

The Hydro Plant Production Increase project is clustered with the New Chelsea Plant Refurbishment project and the Pitmans Pond Plant Refurbishment project. The projects are organized in this manner due to the fact the projects are justified differently. The plant refurbishment projects are justified on the basis of continuing to provide low cost energy production. The Hydro Plant Production Increase project is justified on the basis of displacing higher cost energy production with lower cost production.

Justification

Increased energy production at Newfoundland Power's existing hydroelectric plants would displace energy produced at Hydro's Holyrood thermal generating plant.[5]

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2013 and a projection of expenditures through 2017.

Table 1
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$675	-	-	-
Labour – Internal	336	-	-	-
Labour – Contract		-	-	-
Engineering	37	-	-	-
Other	80	-	-	-
Total	**$1,128**	**$1,130**	**$2,220**	**$4,478**

4 The efficiency analysis was completed by Hatch in 1997 as part of a Water Management Study.
5 The cost of electricity from the Holyrood thermal generating station is estimated at 18.9¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $118.80 per barrel for 2012 as per Newfoundland Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated March 31, 2012.

Costing Methodology

The budget estimate for this project is comprised of 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: New Chelsea Plant Refurbishment (Clustered)

Project Cost: $847,000

Project Description

This 2013 generation hydro project involves replacing stator coils and re-insulating rotor poles of the generator at the New Chelsea Plant. The generator stator coils and rotor poles are original to the 1956 installation of the Canadian Westinghouse generator. The stator coils will be replaced and the rotor poles re-insulated during the same plant outage as the runner replacement to minimize plant downtime and maximize overall construction efficiency.[1]

The project is clustered with the Hydro Plant Production Increase project to replace the runner to increase annual production by 1.0 GWh.

Details on the proposed expenditures are included in ***1.3*** *New Chelsea Hydro Plant Runner Replacement and Rewind.*

Justification

The New Chelsea Plant was commissioned in 1956 and continues to provide normal annual production of approximately 16.3 GWh of energy, or about 3.8% of Newfoundland Power's total hydroelectric generation.

In 2004, the civil, mechanical and electrical systems were refurbished. At that time the refurbishment of the generator was not completed. Undertaking the project in a controlled manner during the summer of 2013 will ensure the plant is returned to service without the loss of production that would occur if the generator windings failed in service.

A present worth feasibility analysis of projected capital and operating expenditures for the New Chelsea Plant has determined the levelized cost of energy from the plant over the next 50 years to be 1.37¢ per kWh, which is significantly less than the cost of replacement energy at Holyrood.[2]

[1] The New Chelsea runner will be replaced as part of the *2013 Hydro Plant Production Increase* capital project.

[2] The cost of electricity from the Holyrood thermal generating station is estimated at 18.9¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $118.80 per barrel for 2012 as per Newfoundland Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated March 31, 2012.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2013 and a projection of expenditures through 2017.

Table 1

Projected Expenditures (000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$718	-	-	-
Labour – Internal	63	-	-	-
Labour – Contract	-	-	-	-
Engineering	45	-	-	-
Other	21	-	-	-
Total	**$847**	**-**	-	**$847**

Costing Methodology

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

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

Future Commitments

This is not a multi-year project.

Project Title: **Pitmans Pond Plant Refurbishment (Clustered)**

Project Cost: **$875,000**

Project Description

This generation hydro project involves a major refurbishment of electrical and mechanical systems at Pitmans Pond Plant. The components requiring replacement or refurbishment include the plant controls, gate positioner controls, electrical protection AC and DC electricity distribution panels, and switchgear.

The project is clustered with the Hydro Plant Production Increase project to replace the runner to increase annual production by 0.7 GWh.

Details on the proposed expenditures are included in ***1.4** Pitmans Pond Hydro Plant Refurbishment*.

Justification

The Pitmans Pond Plant was commissioned in 1959 with a capacity of 625 kW and continues to provide normal annual production of approximately 2.8 GWh of energy, or about 0.7% of Newfoundland Power's total hydroelectric generation.

Engineering assessments of the electrical systems at this facility have revealed a number of deficiencies. In particular, some key components have been identified as deteriorated and in need of replacement.

A present worth feasibility analysis of projected capital and operating expenditures for the Pitmans Pond Plant has determined the levelized cost of energy from the plant over the next 25 years to be 6.90¢ per kWh, which is significantly less than the cost of replacement energy at Holyrood.[1]

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[1] The cost of electricity from the Holyrood thermal generating station is estimated at 18.9¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $118.80 per barrel for 2012 as per Newfoundland Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated March 31, 2012.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2013 and a projection of expenditures through 2017.

Table 1

Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$625	-	-	-
Labour – Internal	100	-	-	-
Labour – Contract		-	-	-
Engineering	85	-	-	-
Other	65	-	-	-
Total	**$875**	**-**	-	**$875**

Costing Methodology

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

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

Future Commitments

This is not a multi-year project.

Project Title: **Heart's Content Plant Refurbishment (Other)**

Project Cost: **$200,000**

Project Description

This generation hydro project involves the replacement and refurbishment of the 579 metre long penstock at Heart's Content Plant. The 558 meter long woodstave penstock, substantially installed in 1946, requires replacement. The intake was also constructed in 1946, is deteriorated and will be replaced when the penstock is replaced.

The project is a multi-year project and will be executed over 2 years, with the engineering design and procurement work completed in 2013. The delivery of the replacement penstock, construction of the intake and the installation of the penstock will take place in 2014.

Details on the proposed expenditures are included in ***1.2*** *Heart's Content Hydro Plant Penstock Replacement*.

Justification

The Heart's Content Plant, located on the Avalon Peninsula near the community of Heart's Content, was commissioned in 1918 with a capacity of 2.7 MW. 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 the intake and penstock 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 5.93¢ per kWh, which is significantly less than the cost of replacement energy at Holyrood.[1]

[1] The cost of electricity from the Holyrood thermal generating station is estimated at 18.9¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $118.80 per barrel for 2012 as per Newfoundland Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated March 31, 2012.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2013 and 2014, along with a projection of expenditures through 2017.

Table 1
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$25	$3,269	-	-
Labour – Internal	25	25	-	-
Labour – Contract	-	-	-	-
Engineering	125	103	-	-
Other	25	98	-	-
Total	**$200**	**$3,495**	-	**$3,695**

Costing Methodology

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

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

Future Commitments

This is a multi-year project, commencing in 2013 and finishing in 2014. The complete multi-year project expenditure is included above in Table 1.
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GENERATION - THERMAL

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

Project Cost: **$284,000**

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 2013 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 $221,000 is estimated to be the cost of refurbishment or replacement of thermal plant structures in 2013.

Also in 2013 the Company will replace the roof on the diesel enclosure and the building that houses the controls and battery plant for the Port aux Basques diesel generator. Based upon an engineering estimate the cost to replace the 2 roofs in 2013 is $63,000.

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 43.0 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 2013 and a projection of expenditures through 2017.

Table 1 **Projected Expenditures** **(000s)**				
Cost Category	**2013**	**2014**	**2015 - 2017**	**Total**
Material	$190	-	-	-
Labour – Internal	40	-	-	-
Labour – Contract	-	-	-	-
Engineering	40	-	-	-
Other	14	-	-	-
Total	**$284**	**$355**	**$9,613**[1]	**$10,252**

Costing Methodology

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

Table 2 **Expenditure History** **(000s)**					
Year	**2008**	**2009**	**2010**	**2011**	**2012F**
Total	$301	$202	$196	$252	$156

The process of estimating the budget requirement for facilities rehabilitation of thermal generating facilities is 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.

[1] In 2015 and 2016 the Company plans to purchase a 5 MW mobile generator at an estimate cost of $9 million.

SUBSTATIONS

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

Project Cost: **$4,452,000**

Project Description

This Substations Refurbishment and Modernization 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 this plan. An update to the *Substation Strategic Plan* is included in ***2.1** 2013 Substation Refurbishment and Modernization*.

The Company has 130 substations varying in age from 10 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.

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.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2013 and a projection of expenditures through 2017.

Table 1

Projected Expenditures (000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$3,407	-	-	-
Labour – Internal	198	-	-	-
Labour – Contract	-	-	-	-
Engineering	709	-	-	-
Other	138	-	-	-
Total	**$4,452**	**$3,288**	**$19,901**	**$27,641**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	**2008**	**2009**	**2010**	**2011**	**2012F**
Total	$2,508	$4,153	$4,101	$2,208	$2,682

The budget for this project is comprised of 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: **$2,685,000**

Project Description

This substation 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 2013 and a projection of expenditures through 2017.

Table 1
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$1,789	-	-	-
Labour – Internal	582	-	-	-
Labour – Contract	-	-	-	-
Engineering	262	-	-	-
Other	52	-	-	-
Total	**$2,685**	**$2,758**	**$8,661**	**$14,104**

Costing Methodology

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

Table 2 **Expenditure History** **(000s)**					
Year	**2008**	**2009**	**2010**	**2011**	**2012F**
Total	$2,357	$2,329	$2,388	$2,689	$2,876

The Company has 130 substations. The major equipment items comprising a substation include power transformers, circuit breakers, reclosers, voltage regulators, potential transformers and battery banks. In total, Newfoundland Power has in service approximately 190 power transformers, 400 circuit breakers, 200 reclosers, 360 voltage regulators, 220 potential transformers, 115 battery banks and 2,500 high voltage switches.

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 (Pooled)**

Project Cost: **$3,974,000**

Project Description

This substations project includes the installation of a new 66/12.5 kV 25 MVA substation transformer at Glendale Substation in Mount Pearl to accommodate load growth in the St. John's South - Mount Pearl area. The St. John's South - Mount Pearl area includes customers served from Glendale, Goulds and Hardwoods substations. ($3,974,000)

This project is a multi-year project with expenditures for 2012 and 2013.[1] Details on 2013 proposed expenditures were included in the 2012 Capital Budget Application in report ***2.2** 2012 Additions Due to Load Growth*.

The individual requirements for additions to substations due to load growth that are 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 St. John's South - Mount Pearl area. 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 25 MVA power transformers at Glendale 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 2013 and a projection of expenditures through 2017.

[1] The Glendale substation transformer was approved as a multi-year project for 2012 and 2013 by Order No. P.U. 26 (2011).

Table 1 **Projected Expenditures** **(000s)**				
Cost Category	**2013**	**2014**	**2015 - 2017**	**Total**
Material	$3,447	-	-	-
Labour – Internal	40	-	-	-
Labour – Contract	-	-	-	-
Engineering	419	-	-	-
Other	68	-	-	-
Total	**$3,974**	**$6,083**	**$12,888**	**$22,945**

Costing Methodology

The budget estimate for this project is comprised of 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

The Glendale addition is a multi-year project approved by Order No. P.U. 26 (2011). Table 2 details the complete multi-year project expenditure approved by the Board.

Table 2 **Multi-Year Projected Expenditures** **(000s)**			
Cost Category	**2012F**	**2013B**	**Total**
Material	$957	$3,447	$4,404
Labour – Internal	40	40	80
Labour – Contract	-	-	-
Engineering	140	419	559
Other	19	68	87
Total	**$1,156**	**$3,974**	**$5,130**

The project is underway and proceeding on schedule with no anticipated changes to the project budget.

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

Project Cost: **$3,386,000**

Project Description

This substation 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 Canada Environment Protection Act were amended by the Government of Canada. The new *PCB Regulations* have effectively accelerated the previous schedule Canadian utilities were operating under for addressing the phase out of PCBs contained in substation equipment.

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

By the end of 2012 the bushings on 124 of 168 power transformers will have been tested. The bushings on the remaining 44 transformers will be tested in 2013.[1] By the end of 2012, bushings on 16 power transformers will have been replaced and in 2013, bushings will be replaced on 16 additional transformers. Table 1 summarizes the results of the testing completed and scheduled.

Table 1

Power Transformer Bushing Testing & Replacement Schedule

Year	**Tested / To Be Tested**	**Replaced / To Be Replaced**
2010 & Prior	23	2
2011	52	2
2012	49	12
2013F	44	16
2014F	0	10
Total	**168**	**42**

[1] The remediation strategy for power transformer bushings is to replace bushings that (1) test at 500 ppm or more or (2) that cannot be tested. 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 also be replaced, to minimize costs and customer outages.

By the end of 2012 bushings on 182 bulk oil circuit breakers will have been tested. The bushings on the 5 remaining breakers will be tested in 2013. Whenever the bushings on a bulk oil circuit breaker test at 500 ppm or more, the complete breaker will be replaced. By the end of 2012 13 breakers will have been replaced and in 2013 an additional 3 breakers will be replaced under this program.

Table 2

Bulk Oil Circuit Breaker Bushing Testing & Replacement Schedule

Year	Tested / To Be Tested	Replaced / To Be Replaced
2010 & Prior	26	2
2011	90	3
2012	66	8
2013F	5	3
2014F	0	0
Total	**187**	**16**

Actual failure rates for transformer and breaker bushings tested under the program have been slightly less than forecast. This has resulted in lower project expenditures than originally forecast.[2] Also contributing to lower expenditures is experience gained through project execution resulting in better estimates and lower contingencies.

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

In 2013, the Company estimates that there will be 4,536,000 customer-minute outages to complete testing and equipment replacements.

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*.

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2 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 2013 Capital Budget Application over the period from 2011 to 2014 are estimated at approximately $9.0 million

Projected Expenditures

Table 3 provides a breakdown of the proposed expenditures for 2013 and a projection of expenditures through 2017.

Table 3 **Projected Cost** **(000s)**				
Cost Category	**2013**	**2014**	**2015 - 2017**	**Total**
Material	$2,340	-	-	-
Labour – Internal	457	-	-	-
Labour – Contract	-	-	-	-
Engineering	522	-	-	-
Other	67	-	-	-
Total	**$3,386**	**$3,225**	**$4,492**	**$11,103**

Costing Methodology

The budget for this project is comprised of 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.

Expenditures for future years will be presented in future Capital Budget Applications. Expenditures 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. Government regulations require all equipment with PCB concentrations greater than 50 ppm and less than 500 ppm be removed from service by 2025.

Project Title: Substation Addition – Portable Substation (Other)

Project Cost: $3,121,000

Project Description

Newfoundland Power's fleet of portable substations includes 3 units ranging in age from 20 years to 46 years old. The 3 units have capacity of 10 MVA, 25 MVA and 50 MVA, respectively, at a variety of operating voltages. The Company uses portable substations to minimize customer power outages resulting from failure of substation power transformers and from execution of the Company's substation capital and maintenance programs.

Newfoundland Power's current fleet of portable substations is insufficient to meet the requirements of the capital and maintenance programs while maintaining availability of the units for back-up in the event of a power transformer failure. This results in an unacceptable level of risk of extended outages to customers due to the in-service failure of a power transformer.

This substations project is a multi-year project to purchase a new 50 MVA portable substation. The order for the new portable substation will be placed in 2012 with delivery scheduled for late 2013.[1] The project is proceeding on schedule with an anticipated reduction in project cost related to lower than estimated tender pricing.

Details on proposed expenditures were included in ***2.4*** *Portable Substation Study* included with the 2012 Capital Budget Application.

Justification

The project is justified on the basis of providing least cost reliable service. Four alternatives were considered to address concerns related to high utilization of the existing portable substation fleet for the Company's capital and maintenance programs and for emergency back-up. The least cost alternative consistent with reliable service is the purchase of a new 50 MVA portable substation.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2013 and a projection of expenditures through 2017.

[1] The multi-year project to purchase the portable substation was approved as a multi-year project for 2012 and 2013 by Order No. P.U. 26 (2011).

Table 1 **Projected Expenditures** **(000s)**				
Cost Category	**2013**	**2014**	**2015 - 2017**	**Total**
Material	$2,874	-	-	$2,874
Labour – Internal	110	-	-	110
Labour – Contract	-	-	-	-
Engineering	95	-	-	95
Other	42	-	-	42
Total	**$3,121**	**-**	**-**	**$3,121**

Costing Methodology

The budget estimate for this project is comprised of engineering estimates.

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

Future Commitments

This is a multi-year project approved by Order No. P.U. 26 (2011). Table 2 details the complete multi-year project expenditure approved by the Board.

Table 2 **Multi-Year Projected Expenditures** **(000s)**			
Cost Category	**2012F**	**2013B**	**Total**
Material	$844	$2,874	$3,718
Labour – Internal	-	110	110
Labour – Contract	-	-	-
Engineering	30	95	125
Other	5	42	47
Total	**$879**	**$3,121**	**$4,000**

The 2013 expenditures are forecast to be $500,000 below the budget estimate provided in the 2012 Capital Budget Application. This is the result of tender pricing for the portable substation coming in less than the original budget estimate.

TRANSMISSION

Project Title: **Transmission Line Rebuild (Clustered)**

Project Cost: **$5,371,000**

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 *Transmission Line Rebuild Strategy* filed with the 2006 Capital Budget Application.

   Proposed 2013 transmission line rebuilding work will take place on transmission lines 110L and 12L. Transmission line 110L operates between Clarenville Substation and Lockston Substation on the Bonavista Peninsula. Transmission line 12L operates between Kings Bridge Substation and Memorial University Substation in St. John's.

   Details on the 2013 rebuilds are included in ***3.1*** *Transmission Line Rebuild* ($3,119,000).

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 ($2,252,000).

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 thirty percent of the Company's 103 transmission lines are in excess of 40 years of age. Many of these lines are experiencing pole, crossarm, conductor, insulator and hardware deterioration. Replacement is required to maintain the strength and integrity of these lines.

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

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2013 and a projection of expenditures through 2017. Appendix A of ***3.1** Transmission Line Rebuild* details the transmission line rebuilds planned for each year.

Table 1
Projected Expenditures (000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$1,547	-	-	-
Labour – Internal	423	-	-	-
Labour – Contract	2,799	-	-	-
Engineering	204	-	-	-
Other	398	-	-	-
Total	**$5,371**	**$5,483**	**$17,809**	**$28,663**

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, distance covered and the construction standard used in the design.

Table 2
Expenditure History (000s)

Year	2008	2009	2010	2011	2012F
Total	$5,236	$4,520	$6,409[1]	$3,689[2]	$5,577

1 Includes actual expenditures of $3,161,000 approved under P.U. No. 17 (2010) for work associated with the March 2010 ice storm and $109,000 approved under P.U. 35 (2010) for work associated with Hurricane Igor.
2 Includes $300,000 carried over into 2012 for work associated with the rebuild of transmission line 16L.

The budget estimates for rebuilding and upgrade projects are based on engineering cost estimates. The budget estimates for replacements and relocation 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. In 2013 the Company will rebuild approximately 1.2 kilometres of aerial single pole transmission line. In 2014 the Company will rebuild approximately 1.0 kilometres of aerial single pole transmission line. Table 2 details the complete multi-year project expenditure included above in Table 1 for the transmission line 12L multi-year project.

Table 2
Multi-Year Projected Expenditures
(000s)

Cost Category	2013	2014	Total
Material	$101	$104	$205
Labour – Internal	114	118	232
Labour – Contract	80	83	163
Engineering	51	18	69
Other	34	35	69
Total	**$380**	**$358**	**$738**

DISTRIBUTION

Project Title: **Extensions (Pooled)**

Project Cost: **$11,376,000**

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 2013 and a projection of expenditures through 2017.

Table 1
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$3,551	-	-	-
Labour – Internal	3,346	-	-	-
Labour – Contract	2,678	-	-	-
Engineering	1,435	-	-	-
Other	366	-	-	-
Total	**$11,376**	**$11,495**	**$36,607**	**$59,478**

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 2013.

Table 2

Expenditure History and Unit Cost Projection

Year	2008	2009	2010	2011	2012F	2013B
Total (000s)	\$ 10,592	\$ 12,892	\$ 14,616	\$ 11,420	\$ 11,361	\$ 11,376
Adjusted Cost (000s)[1]	\$ 10,600	\$ 12,285	\$ 13,686	\$ 11,796	-	-
New Customers	4,625	5,051	5,300	4,909	4,904	4,657
Unit Cost (\$/customer)[2]	\$ 2,292	\$ 2,432	\$ 2,582	\$ 2,403	\$ 2,317	\$ 2,443

1 An adjustment has been made to the expenditure history recognizing the impact of the sale of 40% of joint use support structures to Bell Aliant.
2 2012 Dollars.

The project cost for the connection of new customers is calculated on the basis of historical data.[1] Historical annual expenditures over the most recent five-year period, including the current year, are expressed in current-year dollars ("Adjusted Cost") using the Statistics Canada Distribution Systems Price Index. 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 Cost"). The average of these unit costs, with unusually high and low data excluded, is adjusted by the GDP Deflator for Canada before being multiplied by the forecast number of new customers for the budget year to determine the budget estimate. The forecast number of new customers is derived from economic projections provided by independent agencies.

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

Future Commitments

This is not a multi-year project.

Project Title: **Meters (Pooled)**

Project Cost: **$2,849,000**

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 2013.

Table 1
2013 Proposed Meter Acquisition

Program	Number of Meters
Energy Only Domestic Meters	25,768
Other Energy Only and Demand Meters	3,300

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 Company last filed a *Metering Strategy* with its 2006 Capital Budget Application. A key recommendation of that study was the installation of automated meter reading ("AMR") technology where it is determined that the higher cost is justified by the savings provided. Included with the 2013 Capital Budget Application is an updated strategy included as ***4.3*** *2013 Metering Strategy*. The main focus of the 2013 Metering Strategy is as follows:

- 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 all meter replacements and new installations, and
- Maintain focus on route optimization in order to achieve productivity improvements through AMR and reduce costs.

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 2013 and a projection of expenditures through 2017.

Table 2
Projected Expenditures (000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$2,507	-	-	-
Labour – Internal	285	-	-	-
Labour – Contract	57	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$2,849**	**$2,742**	**$7,437**	**$13,028**

Costing Methodology

Table 3 shows the annual expenditures for the most recent five-year period, as well as a projection for 2013.

Table 3
Expenditure History and Unit Cost Projection

Year	2008	2009	2010	2011	2012F	Avg	2013B
Meter Requirements							
New Connections	4,625	5,051	5,300	4,909	4,904		4,657
GROs/CSOs	13,691	14,188	10,284	13,671	19,570		20,255
Other	2,156	1,097	7,494	8,366	4,156		4,156
Total	20,472	20,336	23,078	26,946	28,630		29,068
Meter Costs							
Actual (000s)	$ 1,474	$ 1,962	$ 1,872	$ 1,763	$ 2,025		$ 2,849
Adjusted[1] (000s)	$ 1,634	$ 2,083	$ 1,980	$ 1,815	$ 2,025		
Unit Cost[1]	$ 80	$ 102	$ 86	$ 94[2]	$ 102[2]	$ 94	$ 98

1 2012 dollars.
2 Adjusted to exclude meters from 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”) using the Statistics Canada Distribution Systems Price Index. The adjusted costs are divided by the total meter requirements in each year to derive the annual meter cost in current-year dollars (“Unit Cost”). The average of these costs, with unusually high and low data excluded, is adjusted 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 the transition strategy outlined in ***4.3*** *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: **$3,705,000**

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 utility'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 service wires 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 2013 and a projection of expenditures through 2017.

Table 1
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$1,115	-	-	-
Labour – Internal	2,055	-	-	-
Labour – Contract	181	-	-	-
Engineering	310	-	-	-
Other	44	-	-	-
Total	**$3,705**	**$3,762**	**$11,971**	**$19,438**

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 2013.

Table 2

Expenditure History and Unit Cost Projection
New Services

Year	2008	2009	2010	2011	2012F	2013B
Total (000s)	$ 2,111	$ 2,828	$ 3,255	$ 3,887	$ 3,094	$ 3,036
Adjusted Cost (000s)[1]	$ 2,370	$ 3,068	$ 3,460	$ 3,410[2]	-	-
New Customers	4,625	5,051	5,300	4,909	4,904	4,657
Unit Cost ($/customer)[1]	$ 512	$ 607	$ 653	$ 695	$ 631	$ 652

1 2012 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 Cost") using the Statistics Canada Distribution Systems Price index. 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 Cost"). The average of these unit costs, with unusually high and low data excluded, is adjusted 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 2013.

Table 3

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

Year	2008	2009	2010	2011	2012F	2013B
Total	$427	$410	$1,083	$795	$425	$669
Adjusted Cost[1]	$479	$445	$875[2]	$821	$425	

1 2012 dollars.
2 Excludes cost 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: **$2,267,000**

Project Description

This Distribution project involves the installation of new 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 2013 and a projection of expenditures through 2017.

Table 1
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$1,228	-	-	-
Labour – Internal	808	-	-	-
Labour – Contract	174	-	-	-
Engineering	34	-	-	-
Other	23	-	-	-
Total	**$2,267**	**$2,299**	**$7,273**	**$11,839**

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 2013.

Table 2

Expenditure History and Unit Cost Projection
New Street Lights

Year	2008	2009	2010	2011	2012F	2013B
Total (000s)	$ 1,315	$ 1,805	$ 1,781	$ 1,461	$ 1,534	$ 1,482
Adjusted Cost (000s)[1]	$ 1,468	$1,940	$ 1,889	$1,507		
New Customers	4,625	5,051	5,300	4,909	4,904	4,657
Unit Cost ($/cust.)[1]	$ 317	$ 384	$ 356	$ 307	$ 313	$ 318

1 2012 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 Cost”) using the Statistics Canada Distribution Systems Price Index . 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 Cost”). The average of these unit costs, with unusually high and low data excluded, is adjusted 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 unit cost for 2013.

Table 3

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

Year	2008	2009	2010	2011	2012F	2013B
Total	$ 692	$ 683	$ 797	$ 750	$ 687	$ 785
Exclusions	-	-	-	-		
Adjusted Cost[1]	$ 772	$ 734	$ 846	$ 774	$ 687	

1 2012 dollars

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

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

Future Commitments

This is not a multi-year project.

Project Title: **Transformers (Pooled)**

Project Cost: **$7,983,000**

Project Description

This Distribution project includes the cost of purchasing transformers for 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 2013 and a projection of expenditures through 2017.

Table 1
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$7,983	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$7,983**	**$8,151**	**$25,410**	**$41,544**

Costing Methodology

Table 2 shows the annual expenditures for the most recent five-year period, as well as an estimate for 2013.

Table 2

Expenditure History and Budget Estimate
(000s)

Year	**2008**	**2009**	**2010**	**2011**	**2012F**	**2013B**
Total	$8,545	$6,909	$6,588	$7,196	$7,944	$7,983
Adjusted Cost[1]	$9,446	$7,301	$6,962	$7,405	$7,944	

[1] 2012 Dollars.

The process of estimating the budget requirement for transformers is based on a historical average. Historical annual expenditures related to distribution transformers over the most recent five-year period, including the current year, are expressed in current-year dollars ("Adjusted Cost") using the Statistics Canada Distribution Systems Price Index. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and adjusting 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: **$3,499,000**

Project Description

This Distribution project involves the replacement of deteriorated or damaged distribution structures and electrical equipment. This project is comprised of 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 2013 and a projection of expenditures through 2017.

Table 1
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$828	-	-	-
Labour – Internal	1,408	-	-	-
Labour – Contract	790	-	-	-
Engineering	354	-	-	-
Other	119	-	-	-
Total	**$3,499**	**$3,616**	**$11,431**	**$18,546**

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 2013.

Table 2

Expenditure History and Budget Estimate (000s)

Year	2008	2009	2010	2011	2012F	2013B
Total	$3,193	$4,123	$5,202[2]	$3,967	$2,861	$3,499
Adjusted Cost[1]	$3,162	$4,001	2,805[3]	$4,098	$2,861	

1 2012 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.[1] 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 Cost”) using the Statistics Canada Distribution Systems Price Index. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and adjusting 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.

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

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

Project Cost: **$2,997,000**

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 2013 includes the following 43 of the Company's 303 feeders. A listing of the feeders upon which work is proposed for 2013 follows:

BLA-01	KBR-10	BFS-01	HWD-01	PUL-02	GBY-01
BRB-01	KEN-04	BVS-02	HWD-03	QTZ-01	GFS-02
BRB-02	LLK-01	BVS-04	HWD-04	RRD-05	GFS-06
BRB-03	MOL-03	COB-01	ILC-01	SLA-07	PAS-01
BRB-05	NHR-02	DLK-03	ILC-02	SLA-08	STG-01
CAB-01	PHR-01	DOY-01	KBR-05	SLA-10	TWG-03
GDL-04	PJN-01	GAL-03	KBR-09	SUN-01	WES-03
WAV-03					

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 9,000 kilometres of distribution lines in service and has an obligation to maintain this plant in good condition to safeguard the public and its employees and to maintain reliable electrical service. The replacement of deteriorated distribution structures and equipment is an important element of this obligation.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2013 and a projection of expenditures through 2017.

Table 1
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$1,259	-	-	-
Labour – Internal	1,378	-	-	-
Labour – Contract	180	-	-	-
Engineering	30	-	-	-
Other	150	-	-	-
Total	**$2,997**	**$3,087**	**$9,720**	**$15,804**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2008	2009	2010	2011	2012F
Actual	$3,566	$1,608	$1,268	$2,413	$3,403
Adjusted[1]	$ 3,538	$ 2,322	$ 2,789	$ 2,490	$ 3,403

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

[1] An adjustment has been made to the expenditure history recognizing the impact of the sale of 40% of joint use support structures to Bell Aliant. 2009 and 2010 expenditures have been adjusted to reflect higher customer-driven, third party and storm related work in those years, converted to 2012 Dollars.

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.

Included with the 2013 Capital Budget Application is the report ***4.4*** *Rebuild Distribution Lines Update* which describes the Company's preventative maintenance program, distribution inspection standard, and targeted replacement programs.

Inspections for the lines upon which work is to take place in 2013 are ongoing throughout 2012. Complete inspection data will not be available until late 2012; therefore the 2013 budget estimate is based on average historical expenditures over the past 5 years.

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

Future Commitments

This is not a multi-year project.

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

Project Cost: **$2,554,000**

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.

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 2013 and a projection of expenditures through 2017.

Table 1
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$895	-	-	-
Labour – Internal	816	-	-	-
Labour – Contract	537	-	-	-
Engineering	261	-	-	-
Other	45	-	-	-
Total	**$2,554**	**$1,632**	**$5,140**	**$9,326**

Expenditures in recent years have been higher than normal as the result 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	**2008**	**2009**	**2010**	**2011**	**2012F**
Total	$1,585	$2,077	$2,363	$2,863	$2,205
Adjusted Cost[1]	$1,772	$2,238	$2,508	$2,955	$2,205

1 2012 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 Cost") using the Statistics Canada Distribution Systems Price Index. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and adjusting it using the GDP Deflator for Canada.

Estimated contributions from customers and requesting parties associated with this project have been included in the contribution in aid of construction amount 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: **St. John’s Trunk Feeders (Clustered)**

Project Cost: **$117,000**

Project Description

This Distribution project consists of the relocation of 5 St. John’s feeders from structures shared with transmission line 12L. 12L is a 66 kV transmission line running between King’s Bridge Substation on King’s Bridge Road and Memorial University Substation. For 2013 the St. John’s Trunk Feeders project is clustered with the Transmission Line rebuild project.

Constructed in 1950 transmission line12L runs alongside Empire Avenue, Rennies Mill Road, Long Pond Road and Strawberry Marsh Lane. The transmission line is 3.14 kilometres in length including 2.17 kilometres of single pole construction and 0.97 kilometres of underground cable. The transmission line consists of 59 structures, *all* of which have distribution sharing the same poles.[1]

The rebuild of the aerial section of transmission line 12L is planned for completion in 2013 and 2014. The 2013 St. John’s Trunk Feeders project involves the distribution line rebuilds completed at the same time as the structures are replaced on transmission line 12L.

Justification

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

Inspections 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. A number of the wooden poles are original vintage (over 60 years old) and have surpassed their normal life expectancy. As well, much of the structure guying on 12L is insufficient by today’s standards and has resulted in a number of leaning or bent poles.

Recent inspections have determined 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. The rebuilding of the distribution feeder is a result of the need to rebuild the transmission line with which it shares poles.

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1 A description of the project to refurbish transmission line 12L can be found in report ***3.1** 2013 Transmission Line Rebuild.*

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2013 and a projection of expenditures through 2017.

Table 1
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$34	-	-	-
Labour – Internal	45	-	-	-
Engineering	9	-	-	-
Other	29	-	-	-
Total	**$117**	**$1,545**	**$8,288**	**$9,950**

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 (Pooled)**

Project Cost: **$1,204,000**

Project Description

This Distribution project consists of the following 4 items to address overload conditions and provide additional capacity to address growth in the number of customers and volume of energy deliveries on the Northeast Avalon Peninsula.

1. The construction of two (2) new feeders originating at Glendale substation. ($451,000)

2. The increase in capacity of existing feeders for future growth in the St. John's downtown. ($252,000)

3. Relocate 1.1 km of feeder SJM-07 to the new duct bank between Hutching Street and Beck's Cove. ($428,000)

4. The installation of three (3) voltage regulators and associated wood pole structure to address a significant voltage drop at the end of feeder KEL-02 in the vicinity of Incinerator Road. The voltage drop is due to the length of the distribution line and increasing customer growth in the area. ($73,000)

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 2013 and a projection of expenditures through 2017.

Table 1

Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$651	-	-	-
Labour – Internal	180	-	-	-
Labour – Contract	142	-	-	-
Engineering	74	-	-	-
Other	157	-	-	-
Total	**$1,204**	**$511**	**$977**	**$2,692**

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: **$189,000**

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 the AFUDC is the mainstream practice of 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 2013 and a projection of expenditures through 2017.

Table 1

Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	-	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering		-	-	-
Other	$189	-	-	-
Total	**$189**	**$193**	**$603**	**$985**

Costing Methodology

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

Table 2
Expenditure History and Budget Estimate
(000s)

Year	2008	2009	2010	2011	2012F
Total	$176	$172	$172	$181	$182

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: **$389,000**

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 ($100,000)*: 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 ($180,000)*: 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 ($84,000)*: 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.[1]

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[1] 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 2013 and a projection of expenditures through 2017.

Table 1

Projected Expenditures (000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$389	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$389**	**$397**	**$1,236**	**$2,022**

Costing Methodology

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

Table 2

Expenditure History (000s)

Year	2008	2009	2010	2011	2012F
Total	$673	$384	$383	$428	$457

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. Historical expenditures in recent years have included items such as thermo scan cameras and arc flash equipment.

The budget for this project is calculated on the basis of historical data for the operations tools and equipment, engineering tools and equipment and office furniture. The budget for the substation grounding sticks is based upon 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: **$238,000**

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 2013 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 $238,000 is required for 2013. 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 2013 and a projection of expenditures through 2017.

Table 1
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$198	-	-	-
Labour – Internal	15	-	-	-
Labour – Contract	-	-	-	-
Engineering	15	-	-	-
Other	10	-	-	-
Total	**$238**	**$243**	**$750**	**$1,231**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	**2008**	**2009**	**2010**	**2011**	**2012F**
Total	\$244	\$244	\$219	\$311[1]	\$234

[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: **Company Building Renovations (Pooled)**

Project Cost: **$950,000**

Project Description

This General Property project includes the renovation of Company owned office buildings and service centres across its service territory. The renovations are required to replace deteriorated building components necessary to ensure the continued safe operation of Company facilities, properties and workplaces. In some instances renovations will be required to accommodate changes in workforce which are reflective of changes in the business.

The items within this project include:

1. *Carbonear Office Building Refurbishment ($375,000)*: This item involves addressing leaks in the building envelope by replacing the siding and roofing, replacement of flooring, drainage improvements and repairs to sections of the parking lot.

2. *Kenmount Road Office Renovations ($475,000)*: This item includes the replacement of flooring and wall coverings on the 2nd and basement floors as well as refurbishment of washrooms at the Company's 55 Kenmount Road office building.

3. *Corporate Security Upgrades ($100,000)*: This item includes upgrades to the Company's security infrastructure, including improvements in surveillance, fencing and lighting of Company facilities.

Details on the proposed expenditures are included in ***5.1** Company Building Renovations*.

Justification

The project is justified on the age and the deterioration of the existing Company buildings. Justification for individual projects is based upon inspections completed by professional engineers or independent experts.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2013 and a projection of expenditures through 2017.

Table 1
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$845	-	-	-
Labour – Internal	30	-	-	-
Labour – Contract	-	-	-	-
Engineering	55	-	-	-
Other	20	-	-	-
Total	**$950**	**$1,400**	**$1,971**	**$4,321**

Costing Methodology

The budget estimate for this project is comprised of engineering estimates.

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

Future Commitments

This is not a multi-year project.

Project Title: **Standby and Emergency Power – Duffy Place (Other)**

Project Cost: **$160,000**

Project Description

This General Property project consists of the replacement of the 12 year Uninterruptible Power Supply ("UPS") located at the Company's Duffy Place regional operations centre. The existing UPS was installed in 2000 to provide conditioned and emergency power for the Company's computer systems including those used in the Customer Contact Centre.

The reliability of the UPS is expected to diminish with time. The capacity of the replacement UPS will be increased to allow for computers in the engineering, operations and central stores areas to be supplied from protected power.

Details on the proposed expenditures are included in ***5.2*** *Duffy Place UPS Replacement*.

Justification

The Company's computer systems and associated communications equipment are integral to the provision of least cost reliable customer service. The reliability of the Company's Information System servers and critical communications equipment is dependent on a reliable UPS.

The existing Duffy Place UPS protects the Customer Contact Centre and the computer room servers and communications equipment. The computers used by engineering, operations and central stores staff are not currently protected. The Customer Contact Centre, regional operations and central stores are critical to the overall operations of Newfoundland Power, especially at times of storms and relate power outages. A reliable UPS at Duffy Place is essential to the provision of customer service.

This project, for which there is no feasible alternative, is required to ensure the continued provision of reliable standby and emergency power for the Duffy Place facility.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2013 and a projection of expenditures through 2017.

Table 1
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$140	-	-	-
Labour – Internal	5	-	-	-
Labour – Contract	-	-	-	-
Engineering	10	-	-	-
Other	5	-	-	-
Total	**$160**	**$275**	**$450**	**$885**

Costing Methodology

The budget estimate for this project is comprised of engineering estimates.

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

Future Commitments

This is not a multi-year project.

TRANSPORTATION

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

Project Cost: **$2,950,000**

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 2013.

Table 1
2013 Proposed Vehicle Replacements

Category	No. of Units
Heavy fleet vehicles	9
Passenger vehicles[1]	26
Off-road vehicles2	6
Total	**41**

[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 2008 to 2012 the Company replaced 25 heavy fleet vehicles, an average of 5 heavy fleet vehicles per year. In 2013 there are 9 heavy fleet vehicles that meet the age, mileage and condition parameters and require replacement.

Similarly, over the period 2008 to 2012 the Company replaced 143 passenger vehicles, an average of approximately 29 passenger vehicles per year. In 2013 the Company has identified 26 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 2013 and a projection of expenditures through 2017.

Table 2
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$2,950	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$2,950**	**$2,690**	**$8,180**	**$13,820**

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

Table 3
Expenditure History
(000s)

Year	2008	2009	2010	2011	2012F
Total	$2,384	$2,087	$2,287	$2,272	$2,306

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: **$124,000**

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 2013 and a projection of expenditures through 2017.

Table 1

Projected Expenditures (000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$112	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	10	-	-	-
Other	2	-	-	-
Total	**$124**	**$69**	**$211**	**$404**

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	**2008**	**2009**	**2010**	**2011**	**2012F**
Total	$96	$105	$149	$88	$150
Adjusted Cost[1]	$107	$113	$158	$91	$150

[1] 2012 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 Cost") are modified by the Statistics Canada Distribution Systems Price Index for the budget year to determine the budget estimate. 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 plan projects are excluded from the calculation of the historical average.

Also included in the 2013 Capital Budget Application is a project to replace the Mobile Radio System. In recognition of the lower failure rates anticipated with the new mobile equipment, the forecast expenditures for the years 2014 to 2017 have been reduced.

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: **Mobile Radio System Replacement (Other)**

Project Cost: **$750,000**

Project Description

This Telecommunications project involves the replacement of the VHF mobile radio system owned and maintained by Newfoundland Power.[1] The Company's VHF mobile radio system is approaching the end of its life as some components are reaching 28 years of age. A review of replacement alternatives has been completed and the least cost solution is to transfer the Company's VHF operational voice requirements to a system shared with Newfoundland Hydro and other users on a rental basis. The chosen alternative will require capital expenditures for the purchase of mobile radio units, portable radio units, base stations and consoles to allow access to the shared system.

In 2004 a report prepared by a consultant determined that the existing VHF mobile radio system could continue to provide reliable service to the Company at least until 2011.[2] At that time it was recognized that any future replacement of the VHF mobile radio system must consider moving to a shared system with Newfoundland Hydro. The 2013 project has chosen the shared system with Newfoundland Hydro as the least cost alternative.

Justification

Reliable communications equipment is essential to the provision of safe, reliable electrical service. Replacement of the Newfoundland Power owned mobile radio system with rented facilities shared with Newfoundland Hydro and other users is justified by the positive Net Present Value analysis provided in ***6.1** Mobile Radio System Replacement.*

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[1] The existing VHF mobile radio system is a combination of owned and leased radio sites and towers, along with radio and telecommunications equipment owned by Newfoundland Power, networked together to provide an island wide operational voice communications system.

[2] The consultant's report was submitted in response to Request for Information PUB-22-NP of Newfoundland Hydro's 2005 Capital Budget Application.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2013 and a projection of expenditures through 2017.

Table 1
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$692	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	40	-	-	-
Other	18	-	-	-
Total	**$750**	**-**	**-**	**$750**

Costing Methodology

The budget estimate for this project is comprised of engineering estimates.

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

Future Commitments

This is not a multi-year project.

INFORMATION SYSTEMS

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

Project Cost: **$1,380,000**

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 2013 include Distribution System Design Improvements, Customer Call-back Technology, Customer Group Billing Enhancements and Customer Service Internet and Energy Conservation Website enhancements.

The application enhancements proposed for 2013 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 ***7.1*** *2013 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 ***7.1*** *2013 Application Enhancements*.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2013 and a projection of expenditures through 2017.

Table 1

Projected Expenditures (000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$325	-	-	-
Labour – Internal	800	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	255	-	-	-
Total	**$1,380**	**$1,200**	**$3,100**	**$5,680**

Costing Methodology

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

Table 2

Expenditure History (000s)

Year	2008	2009	2010	2011	2012F
Total	$1,485	$1,444	$945	$1,003	$1,013

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: **$1,177,000**

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 2013, the project includes upgrades to the Company's financial management system (Great Plains), the asset management system (Avantis), the Safety Management System and database management software, SQL Server.

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 ***7.2** 2013 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 2013 and a projection of expenditures through 2017.

Table 1
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$299	-	-	-
Labour – Internal	713	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	165	-	-	-
Total	**$1,177**	**$1,419**	**$6,425**	**$9,021**

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	2008	2009	2010	2011	2012F
Total	$668	$630	$1,000	$853	$1,276

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 the Microsoft Enterprise Agreement for 2013 and 2014.

This is not otherwise a multi-year project.

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

Project Cost: **$380,000**

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 2013 a total of 96 PCs will be purchased, consisting of 52 desktop computers and 44 laptop 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 2011 and 2012, as well as the proposed additions and retirements for 2013.

Table 1
PC Additions and Retirements
2011 – 2013

	2011			**2012F**			**2013B**		
	Add	**Retire**	**Total**	**Add**	**Retire**	**Total**	**Add**	**Retire**	**Total**
Desktop	53	53	458	50	50	458	52	52	458
Laptop	65	31	295	40	40	295	44	44	295
Total	**118**	**84**	**753**	**90**	**90**	**753**	**96**	**96**	**753**

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 2013 and a projection of expenditures through 2017.

Table 2

Projected Expenditures (000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$252	-	-	-
Labour – Internal	93	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	35	-	-	-
Total	**$380**	**$375**	**$1,125**	**$1,880**

Costing Methodology

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

Table 3

Expenditure History (000s)

Year	2008	2009	2010	2011	2012F
Total	$415	$459	$449	$423	$390

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, laptop, 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: **$877,000**

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 2013, 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 2013 include:

1. The replacement of technology infrastructure to operate Great Plains;
2. Additional data storage capacity used to manage corporate and customer information;
3. Infrastructure upgrades required for the Citrix Application Server, Safety Management System and SCADA field communication devices;
4. The replacement of internet protection security technology; and
5. The replacement of the Intrusion Prevention System.

The shared server infrastructure requirements for 2013 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 ***7.3*** *2013 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 2013 and a projection of expenditures through 2017.

Table 1

Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$494	-	-	-
Labour – Internal	323	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	60	-	-	-
Total	**$877**	**$900**	**$2,700**	**$4,477**

Costing Methodology

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

Table 2

Expenditure History
(000s)

Year	2008	2009	2010	2011	2012F
Total	$903	$632	$577	$941	$607

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: **$200,000**

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, VHF radio communications, corporate and customer service data. The Company has increased its use of wireless communications technologies in recent years.

For 2013, 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 2013 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 the equipment that facilitates communication between all of the Company's shared servers and related applications. This equipment is 8 years old and has reached the end of its useful life.

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 2013 and a projection of expenditures through 2017.

Table 1
Projected Expenditures
(000s)

Cost Category	2013	2014	2015 - 2017	Total
Material	$110	-	-	-
Labour – Internal	70	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	20	-	-	-
Total	**$200**	**$100**	**$300**	**$600**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2008	2009	2010	2011	2012F
Total	$162	$115	$148	$158	$394

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 significant expenditures erode the balance in the Allowance for Unforeseen Items project, the Company will file an application for supplemental 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.
2013 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	P.U. 26 (2011)	Budget	$1,156	$3,974		$5,130
				Forecast	$1,156	$3,974		$5,130
Substations	Substation Additions Portable Substation[2]	2012	P.U. 26 (2011)	Budget	$879	$3,621		$4,500
				Forecast	$879	$3,121		$4,000
Generation	Heart's Content Plant Refurbishment[3]	2013		Budget		$200	$3,495	$3,695
Transmission	Transmission Line Rebuild[4]	2013		Budget		$380	$358	$738

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)

	2011	2010
Net Plant Investment		
Plant Investment[1]	1,371,678	1,393,801
Accumulated Amortization	(575,926)	(585,245)
Contributions in Aid of Construction	(29,013)	(30,266)
	766,739	778,290
Additions to Rate Base		
Deferred Pension Costs	97,628	102,549
Credit Facility Costs[2]	270	258
Cost Recovery Deferral – Seasonal/TOD Rates	228	-
Cost Recovery Deferral – Hearing Costs	253	507
Cost Recovery Deferral – Regulatory Amortizations	1,642	-
Cost Recovery Deferral – Conservation	454	682
Customer Finance Programs	1,527	1,647
	102,002	105,643
Deductions from Rate Base		
Weather Normalization Reserve	5,020	1,954
Adjustment – 2010 Hearing Costs	6	-
Other Post Employment Benefits	7,199	-
Customer Security Deposits	695	705
Accrued Pension Obligation	3,778	3,548
Future Income Taxes	862	3,617
Demand Management Incentive Account	1,252	676
	18,812	10,500
Year End Rate Base	849,929	873,433
Average Rate Base Before Allowances	861,681	861,442
Rate Base Allowances		
Materials and Supplies Allowance	5,012	4,476
Cash Working Capital Allowance	9,663	9,292
Average Rate Base at Year End	876,356	875,210

[1] 2011 plant investment has been reduced by $83,517 to reflect the reclassification of costs related to General Properties.
[2] For 2011, Credit Facility Costs are reported separately from Deferred Pension Costs. This is consistent with Return 8 of the 2011 Annual Report to the Board.

2013 Capital Plan

June 2012

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Appendix A: 2013-2017 Capital Plan

1.0 Introduction

Newfoundland Power's 2013 Capital Plan provides an overview of the Company's 2013 Capital Budget together with an outlook for capital expenditure through 2017.

Newfoundland Power's 2013 Capital Budget totals $80,788,000.

The Company's 2013 capital budget is part of a series of stable and predictable annual capital budgets which the Board has recognized assist in fostering stable and predictable rates for consumers into the future.[1]

Newfoundland Power's annual capital expenditure for the next 5 years will average approximately $86 million. This level of annual expenditure is broadly consistent on an inflation adjusted basis with that in the period 2008 through 2012.[2]

The Company's annual capital budgets continue to focus on plant replacement and meeting customer and sales growth, which combine 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.

Newfoundland Power is examining longer term aspects of current capital budget composition. For example, the Company is currently assessing its distribution pole replacement practices. Newfoundland Power has approximately 183,000 distribution poles in service, of which an average of approximately 700 poles are replaced each year.[3] Approximately 60% of Company distribution poles have been in service for over 25 years, while 5% or 8,000 poles have been in service for over 60 years. The relatively low level of pole replacement presents a potential risk to long-term capital expenditure stability. The assessment will consider whether replacement of the oldest and most deteriorated poles through a multi-year program is necessary to ensure continued stability and predictability in capital expenditures over the long-term.

2.0 2013 Capital Budget

Newfoundland Power's 2013 capital budget is $80,788,000.

This section of the 2013 Capital Plan provides an overview of the 2013 capital budget by origin (root cause) and asset class. In addition, this section summarizes 2013 capital projects by the various categories set out in the Board's October 2007 Capital Budget Application Guidelines.

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

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

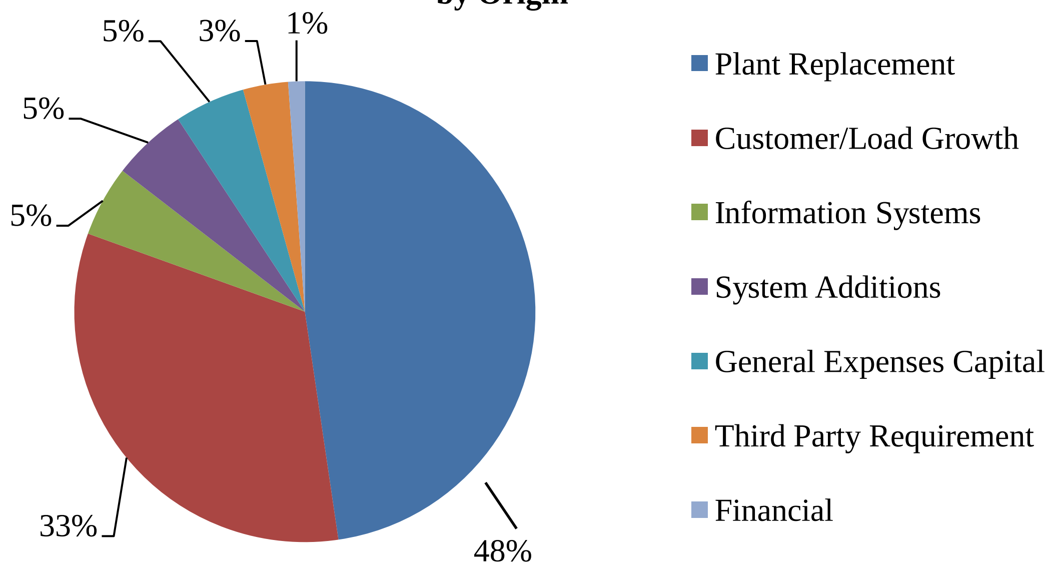
3 Replacing 700 of 160,000 poles on an annual basis implies that at least some distribution poles will remain in service for in excess of 200 years (160,000 poles / 700 poles per year = 229 years). Current depreciation rates indicate that the *average* service life of a distribution pole is approximately 45 years.

2.1 2013 Capital Budget Overview

Newfoundland Power's 2013 capital budget contains 37 projects totalling $80.8 million. From 2008 to 2012, the Company's annual capital program averaged $73.0 million in a range of $63.2 million to $81.3 million.

Chart 1 shows the 2013 capital budget by origin, or root cause.

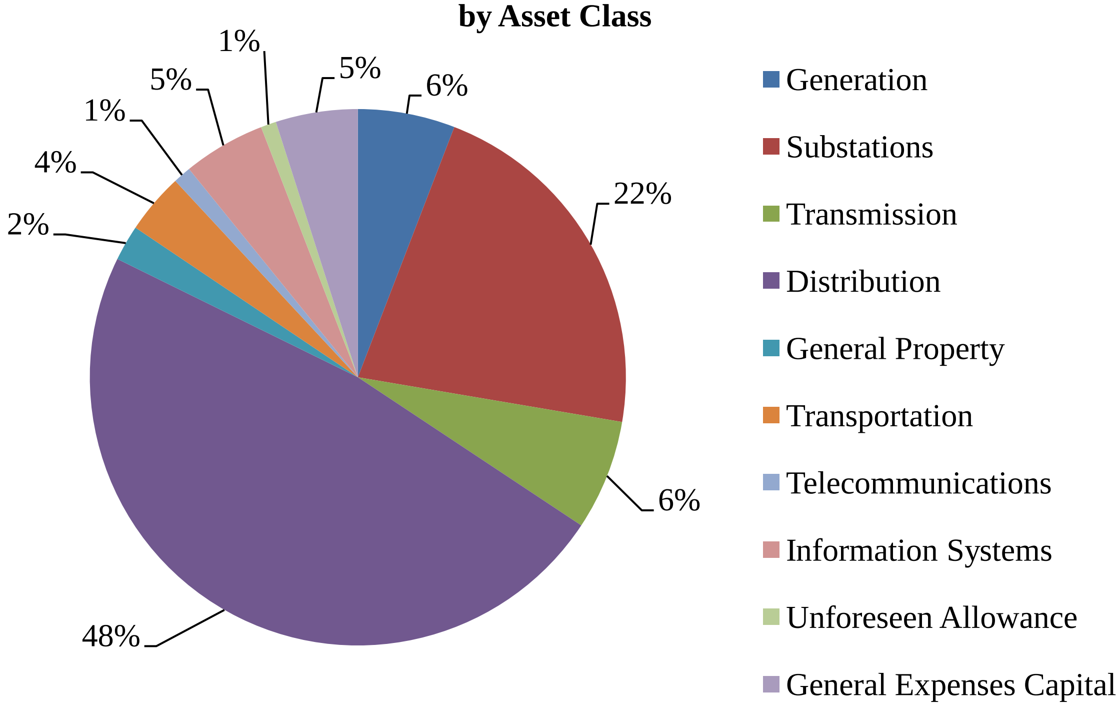
Chart 1
2013 Capital Expenditures by Origin



Approximately 48% of proposed 2013 capital expenditure is related to the replacement of plant. A further 33% of proposed 2013 capital expenditure is required to meet the Company's obligation to provide service to new customers and meet the requirement for increased system capacity. The 5% of proposed 2013 capital expenditure associated with System Additions includes an additional portable substation and 2 projects to increase energy production. The remaining 14% of forecast capital expenditures for 2013 relate to information systems, capitalized general expenses, third party requirements and financial carrying costs (allowance for funds used during construction). The allocation of 2013 capital expenditures is broadly consistent with capital budgets for the past five years.

Chart 2 shows the 2013 capital budget by asset class.

Chart 2
2013 Capital Expenditures
by Asset Class



As in past years, Distribution capital expenditure accounts for the greatest percentage of overall expenditure at $38.7 million, or 48% of the 2013 capital budget. Substations capital expenditure accounts for $17.6 million, or 22% of the 2013 capital budget. Generation capital expenditure accounts for $4.7 million, or 6% of the 2013 capital budget. Transmission capital expenditure accounts for $5.4 million, or 6% of the 2013 capital budget. Together, expenditure for these four asset classes comprises 82% of the Company's 2013 capital budget.

Distribution capital expenditure is primarily driven by customer requests for new connections to the electrical system. Expenditures in 2013 are expected to be similar to recent years. Distribution capital projects that address reliability have been reduced in recent years, with no expenditures in 2013 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 2013, the Company plans to install a new power transformer at Glendale substation in Mount Pearl. Also in 2013, the Company will complete the purchase and commissioning of a portable substation as part of a multi-year project approved in 2012.[4]

[4] The Glendale substation transformer and the portable substation were approved as a multi-year projects for 2012 and 2013 by Order No. P.U. 26 (2011).

Changes in the regulation of polychlorinated biphenyls ("PCB") 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 PCB to December 31, 2014. The change in regulations has resulted in a forecast capital expenditure of $2.4 million through 2012 and an additional $11.1 million in expenditures in the forecast period.[5]

Transmission lines proposed for rebuild in 2013 include 110L (built in 1958) serving the Bonavista Peninsula and 12L (built in 1950) located within the City of St. John's.

In 2013, the Company plans to upgrade the governor, switchgear, protection and control systems at the Pitmans Pond hydroelectric plant. The Company will complete projects to increase hydro plant production at New Chelsea and Pitmans Pond in 2013.

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 definition and categorization of capital expenditures for which a public utility requires prior approval of the Board. Newfoundland Power's 2013 Capital Budget Application complies with the CBA Guidelines.

The 2013 Capital Budget Application includes 37 projects, as detailed in *Schedule A*. Included in *Schedule B* is a summary of these projects organized by definition, classification, and segmentation by materiality.

The following section provides a summary of each of these views of the 2012 Capital Budget, along with costs by costing method (Table 3).

2013 Capital Projects by Definition

Table 1 summarizes Newfoundland Power's proposed 2013 capital projects by definition as set out in the CBA Guidelines.

Table 1
2013 Capital Projects
By Definition

Definition	**Number of Projects**	**Budget (000s)**
Pooled	26	$68,460
Clustered	5	3,347
Other	6	8,981
Total	**37**	**$80,788**

[5] 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.

There are a total of 31 *pooled* or *clustered* projects accounting for 89% of total expenditures.

2013 Capital Projects by Classification

Table 2 summarizes Newfoundland Power's proposed 2013 capital projects by classification as set out in the CBA Guidelines.

Table 2
2013 Capital Projects
By Classification

Classification	**Number of Projects**	**Budget (000s)**
Mandatory	1	$3,386
Normal	32	71,023
Justifiable	4	6,379
Total	**37**	**$80,788**

There are 32 *normal* projects accounting for 88% of total expenditures.

2013 Capital Projects Costing

Table 3 summarizes Newfoundland Power's proposed 2013 capital projects by costing method (i.e., identified need vs. historical pattern) as set out in the CBA Guidelines.

Table 3
2013 Capital Projects
By Costing Method

Method	**Number of Projects**	**Budget (000s)**
Identified Need	21	$34,899
Historical Pattern	16	45,889
Total	**37**	**$80,788**

Projects with costing method based on *identified need* account for 43% of total expenditures, while those based on *historical pattern* account for 57% of total expenditures.

2013 Capital Projects Materiality

Table 4 segments Newfoundland Power's proposed 2013 capital projects by materiality as set out in the CBA Guidelines.

Table 4
2013 Capital Projects
Segmentation by Materiality

Segment	Number of Projects	Budget (000s)
Under $200,000	4	$590
$200,000 - $500,000	6	1,691
Over $500,000	27	78,507
Total	**37**	**$80,788**

There are 27 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 2013 through 2017 includes forecast average annual capital expenditure of $86.4 million. Over the five year period 2008 through 2012, the average annual capital expenditure is expected to be $73.0 million.

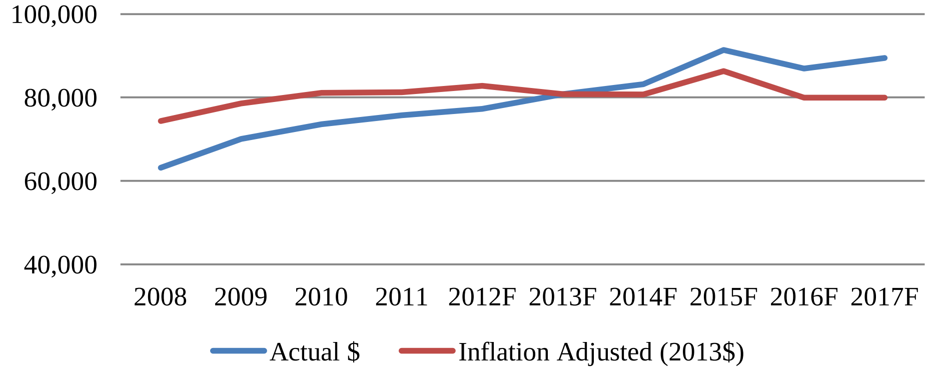
The increase in forecast annual capital expenditure reflects inflation and requirements for specific projects, related to replacement of deteriorated facilities, meeting customer and load growth, maintaining compliance with federal regulations and additional portable substations and generation. Annual expenditure through the forecast period is consistent on an inflation adjusted basis with that in the period 2008 through 2012.

3.1 Capital Expenditures: 2008 - 2017

The Company plans to invest $432 million in plant and equipment during the 2013 through 2017 period. On an annual basis, capital expenditures are expected to average approximately $86.4 million and range from a low of $80.8 million in 2013 to a high of $91.4 million in 2015.

Chart 3 shows actual capital expenditures for the period 2008 through 2011 and forecast capital expenditures for the period 2012 through 2017. For comparison purposes, the annual capital expenditures are also expressed in 2013 dollars to remove the effects of inflation.

Chart 3
Capital Expenditures
2008 to 2017F
($000s)



Overall planned capital expenditures for the 5-year period from 2013 through 2017 are expected to be greater than those in the 5-year period from 2008 through 2012. As shown in Chart 3 this is principally the result of inflation.[6] Forecast requirements for the 5-year period from 2013 through 2017 include additional power transformers due to load growth, the phase out of PCB equipment, changes in meter regulations, the Rattling Brook fish pass, the replacement of Pierre's Brook penstock, a portable substation and mobile generation. These additional costs are being offset by reduced expenditure on plant replacement and 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 51% of total expenditure for the 10-year period from 2008 through 2017.

Capital expenditures to meet increased customer connections and electricity sales over the same 10-year period account for approximately 32% of total expenditures.

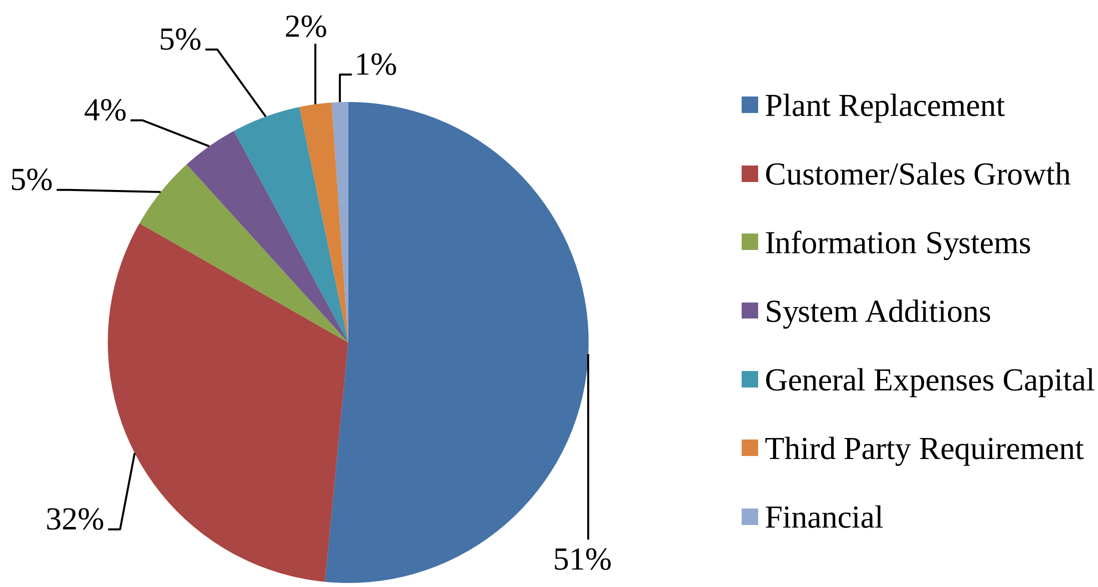
[6] With the exception of 2015, the inflation adjusted curve is relatively flat. The increase in forecast capital expenditure in 2015 is attributable to the $9 million project to replace the Pierre's Brook penstock.

3.2 2013 – 2017 Capital Expenditures

3.2.1 Overview

Chart 4 shows aggregate forecast capital expenditures by origin for the period 2013 through 2017.

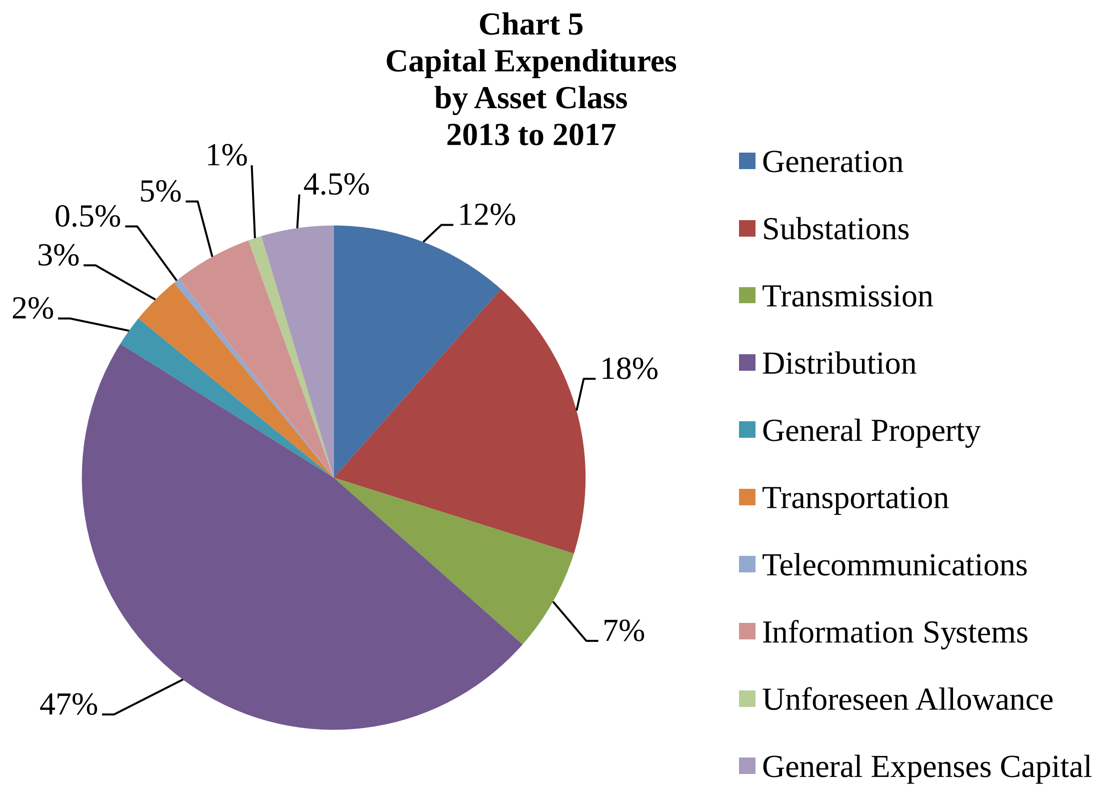
Chart 4
Capital Expenditures
by Origin
2013 to 2017



Plant replacement accounts for 51% of all planned expenditures over the 5-year period from 2013 through 2017. Capital expenditure related to customer and sales growth accounts for 32% of planned expenditures for this period. This is less than the average of 34% in the previous 5-year period from 2008 through 2012.

The remaining 17% of total capital expenditures for the 2013 through 2017 period relate to a variety of origins including information systems, system additions, third party requirements and financial costs.

Chart 5 shows aggregate forecast capital expenditures for the period 2013 through 2017 by asset class.



The Distribution asset class accounts for 47% 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 16% of total capital expenditures for the 2013 through 2017 period.

Overall, planned expenditures for the period 2013 through 2017 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 substations and generation over the forecast period.

A summary of planned capital expenditures by asset class and by project for 2013 to 2017 is provided in Appendix A.

3.2.2 Generation

Generation capital expenditures will average approximately $10.0 million per year from 2013 through 2017, which is greater than the annual average of $7.4 million from 2008 through 2012.

Generation capital expenditures on the Company's 23 hydroelectric plants, 3 gas turbines and 3 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, the Company plans to replace the runners at the Pitmans Pond and New Chelsea hydroelectric plants to increase hydro production by 1.7 GWh at an estimated cost of $1.1 million as described in the reports ***1.3*** *New Chelsea Hydro Plant Runner Replacement and Rewind* and ***1.4*** *Pitmans Pond Hydro Plant Refurbishment.*

- In 2013, the Company plans to rewind the generator of the 54 year old New Chelsea hydroelectric plant at an estimated cost of $0.8 million as described in the report ***1.3*** *New Chelsea Hydro Plant Runner Replacement and Rewind*.

- In 2013, the Company plans to upgrade the 55 year old gate positioner, switchgear, protection and control systems at the Pitmans Pond hydroelectric plant at an estimated cost of $0.9 million as described in the report ***1.4*** *Pitmans Pond Hydro Plant Refurbishment*.

- In 2013 and 2014, the Company plans to replace the Heart's Content hydroelectric plant penstock at an estimated cost of $3.7 million as described in the report ***1.2*** *Heart's Content Hydro Plant Penstock Replacement*. The existing penstock was installed in 1945. Also in 2014 the Company plans to refurbish the governor, protection and control systems at the Heart's Content hydroelectric plant.

- In 2014 and 2015, the Company plans to replace the Pierre's Brook hydroelectric plant penstock at an estimated cost of $9.0 million. The existing penstock was installed in 1965.

- In 2015, the Company plans to refurbish the 61 year old Mobile hydroelectric plant at an estimated cost of $2.6 million.[7]

[7] Mobile hydroelectric plant is subject to an ongoing case in the Supreme Court of Newfoundland.

- In 2015 and 2016, 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.[8]

- In 2016 and 2017, the Company plans to replace the Topsail hydroelectric plant penstock at an estimated cost of $5.4 million.

The Company will bring forward, as part of its annual Capital Budget Application 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 $5.7 million annually from 2013 through 2017 compared with $4.8 million annually from 2008 through 2012.

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*.

3.2.4 Substations

Substations capital expenditures are expected to average $15.8 million annually from 2013 through 2017, a material increase from the average of $9.9 million annually from 2008 through 2012. The increase in expenditure is largely attributable to the requirement for additional system capacity to serve increased customer load, compliance with revised PCB regulations, and the purchase of a portable substation.

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

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; 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*** *2013 Substation Refurbishment and Modernization*.

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 2013 to 2017 forecast period there is a requirement to purchase 6 new substation transformers to accommodate load growth.[9] In 2013, a new power transformer will be required at Glendale substation due to the customer and load growth experienced in Mount Pearl and St. John's south over the past decade.[10] Commencing in 2014 and continuing through 2017, 5 new substation transformers will be required for the Northeast Avalon Peninsula and Clarenville areas.[11]

Regulatory changes by the Government of Canada with respect to the phase out of bushings and instrument transformers containing polychlorinated biphenyls ("PCB") have increased capital expenditures by approximately $11.1 million over the next 5 years.[12] Detailed reports on the impact of the change in PCB regulations were included in the 2011 and 2012 Capital Budget Applications.

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9 By comparison, in the period 2006 through 2010, Newfoundland Power has installed 1 additional power transformer and relocated 1 power transformer to serve increased customer load. The purchase of transformers to serve customer load growth is in addition to the requirement to replace aged or deteriorated equipment.

10 Planning study for the St. John's south Mount Pearl area was included in the 2012 Capital Budget Application report ***2.2*** *2012 Additions Due To Load Growth*.

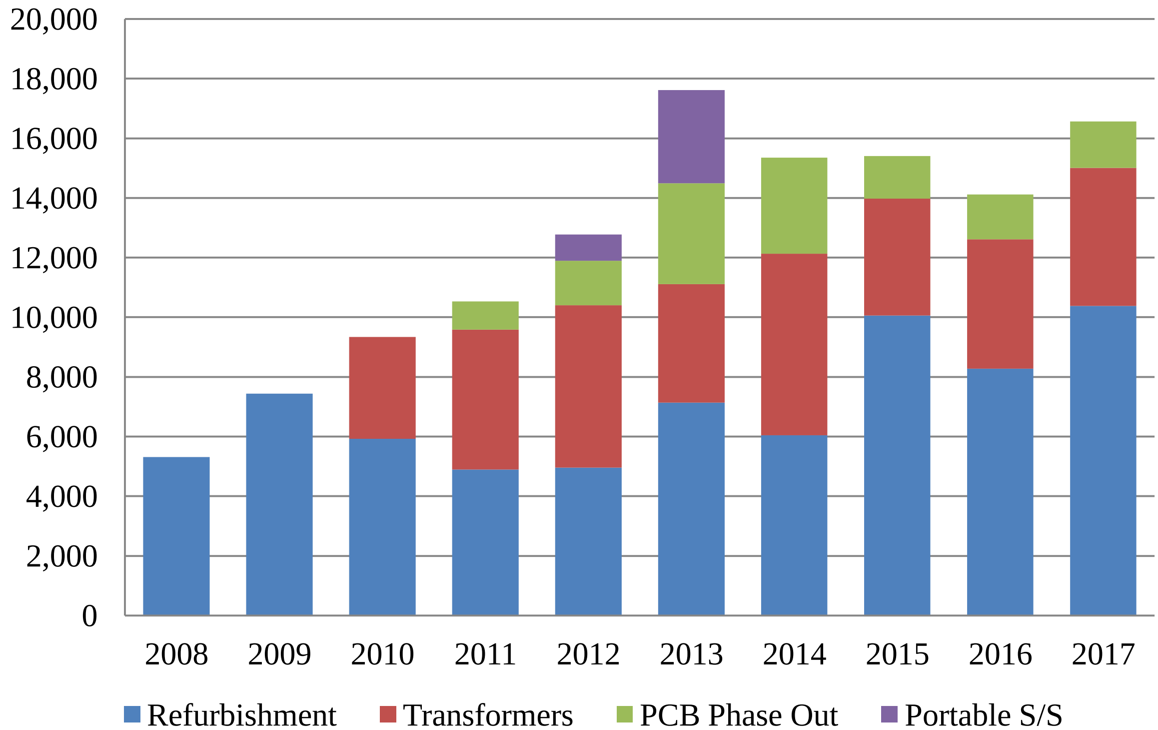
11 The Company's annual Capital Budget Applications will include engineering studies detailing the requirements for additional power transformers in the years in which they are required.

12 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.

The purchase of an additional portable substation was approved in 2012, increasing the Company's fleet from 3 units to 4 units.[13] Work on this project has commenced in 2012. The additional portable substation will increase availability in the event of an in-service transformer failure and will provide greater flexibility in scheduling planned substation projects.[14] This additional portable substation is estimated to cost approximately $4 million over 2 years. Refurbishment of portable substation P4 is also scheduled in 2013.

Chart 6 shows the impact of the required new transformers including a new portable substation and the PCB phase out program on the substations capital plan for the 2013 to 2017 period, as compared to substation capital expenditures from 2008 to 2012.

Chart 6
Substation Capital Plan[15]
2008 to 2017
($000)



13 The additional portable substation was approved as a multi-year project in Order No. P.U. 26 (2011).

14 The Company has 192 substation power transformers in service, over 75% of which are over 30 years old. As these transformers age, it can be expected that in-service failure will be experienced. Predicting these failures is not possible, and advance purchase of replacement transformers is impractical. Therefore it is critical that a sufficient number of portable substations are available to provide temporary service while replacement transformers are manufactured and installed.

15 2008 excludes expenditures for interconnection of wind turbines ($1.4 million) and conversion of 403L to 66Kv to reduce losses ($0.3 million).

As shown in Chart 6, the Company reduced substation refurbishment expenditures in 2010 through 2014 in order to moderate the overall increase in the substation capital budget. A degree of flexibility is necessarily required for ongoing planning of capital expenditures if a reasonable degree of stability in the Company's annual capital budgets is to be achieved.[16]

3.2.5 Distribution

Distribution capital expenditures from 2013 through 2017 are expected to increase to an average of approximately $40.9 million annually, compared to an average of $38.2 million annually from 2008 through 2012.

The Company operates approximately 9,000 km of distribution lines serving approximately 248,000 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 gradually increase over the planning period. This is primarily due to inflationary increases. 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

	2013	**2014**	**2015**	**2016**	**2017**
New Customer Connections	4,657	4,554	4,586	4,659	4,524
Average Cost/Connection	$4,583	$4,750	$4,851	$4,950	$5,082
Capital Expenditure (000s)	$21,341	$21,630	$22,247	$23,060	$22,993

Over the period 2013 to 2017, the expenditure associated with new customer connections is forecast to be within the range of $21 million to $23 million, or approximately 25% of the annual capital expenditures.

[16] In Order No. P.U. 36 (2002-2003), page 25, the Board stated that it believes more stable and predictable year over year capital budgets for Newfoundland Power is a desirable objective.

Distribution capital expenditures are required to relocate or replace distribution lines to meet third party requests from governments, telecommunications companies and individual customers. In 2013 the expenditures associated with third party requests is estimated at $2.6 million. Otherwise over the remainder of the five year period, these expenditures are forecast to remain stable and approximate the historical average of approximately $1.7 million.

Capital expenditures associated with the replacement of meters are typically based upon the historical average expenditures. This forecast has increased over the planning period as the result of changes to 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*.

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, will remain relatively stable over the next five years.

In the 2004 Capital Budget Application, the Company filed several reports pertaining to its preventive capital maintenance program for Distribution assets. An update to these reports is included in the report ***4.4*** *Rebuild Distribution Lines Update*. The expenditures associated with the preventive capital maintenance program are budgeted in the *Rebuild Distribution Lines* project. The Company plans to perform preventive capital maintenance on approximately 43 distribution feeders per year over the planning period.

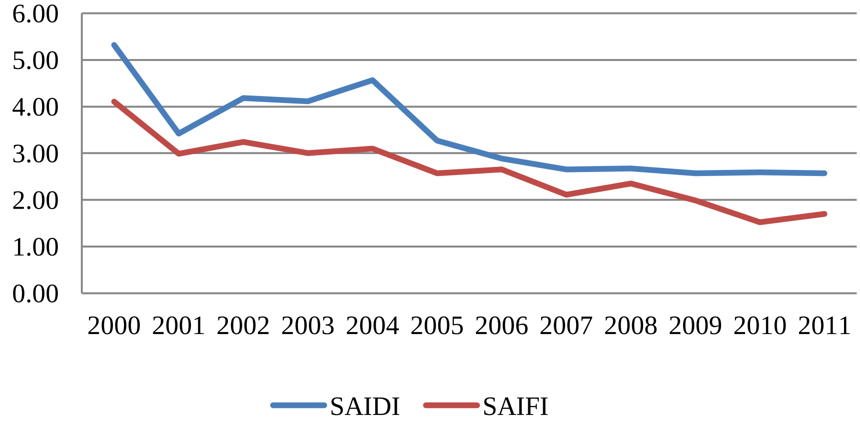
The Distribution *Reconstruction* project involves the replacement of deteriorated or damaged distribution structures and electrical equipment. The project is comprised of small unplanned projects and is estimated using the historical average of the most recent five-year period.

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 2013 through 2017 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 2013 based upon the information provided in the report ***4.1*** *Distribution Reliability Initiative*.

Chart 7 shows SAIDI, or system average interruption duration index, and SAIFI, or system average interruption frequency index, for the years 2000 through 2011. Chart 7 has been adjusted to remove the effects of severe weather events.[17]

Chart 7
SAIDI and SAIFI
2000 - 2011



Newfoundland Power considers current levels of service reliability to be satisfactory. This reflects the current condition of Newfoundland Power's distribution system assets. As a result, capital expenditures in the *Distribution Reliability Initiative* project have been reduced compared to previous years.[18]

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 $1.7 million annually from 2013 through 2017 which is an increase from the average of $1.4 million annually from 2008 through 2012.

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[17] Adjustments exclude the 2007 and 2010 Bonavista ice storms, Hurricane Igor in 2010 and the December 2011 high wind event. 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 and 2011 SAIDI and SAIFI would be 4.03 and 1.95, respectively.

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

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 2013 through 2017 are expected to increase to an average of approximately $2.8 million annually, compared to an average of $2.3 million annually from 2008 through 2012. The Company operates 68 heavy fleet vehicles which have an anticipated service life of 10 years. On average it would be expected that approximately 7 heavy fleet vehicles would be replaced annually. For the 5 year period from 2008 to 2012, based on the replacement parameters of age, mileage and overall condition, the Company replaced 25 heavy fleet vehicles, an average of 5 heavy fleet vehicles per year. The increase in transportation capital expenditures from 2013 through 2017 is reflective of the number of heavy fleet 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.

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. Details can be found in the report ***6.1*** *Mobile Radio System Replacement*.

Telecommunications capital expenditures are expected increase to an average of approximately $350,000 annually from 2013 through 2017 compared to the annual average of $259,000 from 2008 through 2012. The difference is attributable to the cost associated with moving to the new VHF mobile radio system in 2013.

3.2.9 Information Systems

The Information Systems asset class capital expenditure includes:

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

Information Systems capital expenditures from 2013 through 2017 are expected to increase to an average of approximately $4.3 million annually, compared to an average of $3.6 million annually from 2008 through 2012. The increase is largely driven by system upgrades required by the SCADA system and the Customer Service System.

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 events affecting the electrical system in advance of seeking approval of the Board. The Unforeseen Allowance constitutes $0.8 million in each year's capital budget from 2013 through 2017.

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 2013 through 2017.

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 2013 through 2017.

Newfoundland Power has an obligation to serve customers in its service territory. Should customer and energy 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 sales 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.[19]

Change in government regulations regarding PCB equipment and meter compliance sampling will impact future capital budgets. The current 5 year forecast includes significant cost to accelerate the removal of PCB equipment from service. Test results obtained in the early years of the project will be used to reforecast cost in the later years. Also, the industry continues to consult with Environment Canada to extend the time line associated with the removal of PCBs in substations. Therefore the estimated expenditures for the removal of PCB equipment are subject to information and events that are not certain at this time.

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

The current 5 year forecast for meter replacements is based upon a transition plan as outlined in the report ***4.3*** *2013 Meter Strategy*. 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. Samples of the submarine cable are currently being examined to determine if the planned replacement of some or all of the 4 in-service cables needs to be included in the 5-year plan.

The Company has taken steps to reduce the uncertainty regarding replacement of its Customer Service System ("CSS"), which has been in service since 1991. These steps included upgrades of hardware and software components and removal of technology components that posed the highest risk. Technology vendors are currently expected to sustain CSS related product support. The Company has continued to make modest enhancements to CSS where investments could be justified. The servers and operating system supporting CSS have a planned upgrade in the 2016 2017 timeframe. However, significant business changes such as rate design change would have an impact on CSS. The scale and complexity of these factors or changing technology and vendor support could require the Company to consider a full replacement of CSS. Replacement of the CSS would likely cost approximately $15 to $20 million.[20]

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. The occurrence and costs of severe storms are not predictable.

[20] The CSS originally cost approximately $10 million.

Appendix A
2013 – 2017 Capital Plan

Newfoundland Power Inc.
2013-2017 Capital Plan
(000s)

Asset Class	2013	2014	2015	2016	2017
Generation	$4,734	$9,030	$16,564	$10,254	$9,339
Substations	17,618	15,354	15,409	14,113	16,570
Transmission	5,371	5,483	5,546	5,954	6,309
Distribution	38,740	39,533	40,748	43,251	42,431
General Property	1,737	2,315	1,156	1,353	1,898
Transportation	2,950	2,690	2,740	2,655	2,785
Telecommunications	874	69	245	266	297
Information Systems	4,014	3,994	4,200	4,350	5,100
Unforeseen Allowance	750	750	750	750	750
General Expenses Capitalized	4,000	4,000	4,000	4,000	4,000
Total	**$80,788**	**$83,218**	**$91,358**	**$86,946**	**$89,479**

Newfoundland Power Inc.
2013-2017 Capital Plan
(000s)

GENERATION

Project	2013	2014	2015	2016	2017
Facility Rehabilitation – Hydro	$1,400	$1,410	$1,425	$1,470	$1,490
Facility Rehabilitation - Thermal	$284	$355	$206	$208	$199
Hydro Plant Production Increase	$1,128	$1,130	$0	$1,400	$820
Hearts Content Plant Refurbishment	$200	$5,935	$0	$0	$0
New Chelsea Rewind	$847	$0	$0	$0	$0
Pitmans Pond Plant Refurbishment	$875	$0	$0	$0	$0
Pierre's Brook Penstock	$0	$200	$8,790	$0	$0
Mobile Plant Refurbishment	$0	$0	$2,635	$0	$0
Purchase Portable Generation	$0	$0	$3,500	$5,500	$0
Tors Cove Plant Upgrade	$0	$0	$8	$581	$1,130
Topsail Plant Refurbishment	$0	$0	$0	$425	$5,000
Morris Plant Refurbishment	$0	$0	$0	$550	$0
Seal Cove Plant Refurbishment	$0	$0	$0	$120	$0
Rose Blanche Plant Refurbishment	$0	$0	$0	$0	$700
Total - Generation	**$4,734**	**$9,030**	**$16,564**	**$10,254**	**$9,339**

Newfoundland Power Inc.
2013-2017 Capital Plan
(000s)

SUBSTATIONS

Project	2013	2014	2015	2016	2017
Substations Refurbishment & Modernization	$4,452	$3,288	$7,086	$5,389	$7,426
Replacements Due to In-Service Failure	$2,685	$2,758	$2,823	$2,887	$2,951
Additions Due to Load Growth	$3,974	$6,083	$3,918	$4,341	$4,629
PCB Bushing Phase Out	$3,386	$3,225	$1,432	$1,496	$1,564
Purchase portable Substation P5	$3,121	$0	$0	$0	$0
Mobile Plant Refurbishment	$0	$0	$150	$0	$0
Total – Substations	**$17,618**	**$15,354**	**$15,409**	**$14,113**	**$16,570**

Newfoundland Power Inc.
2013-2017 Capital Plan
(000s)

TRANSMISSION

Project	2013	2014	2015	2016	2017
Rebuild Transmission Lines	$3,121	$3,183	$3,946	$4,354	$4,709
Transmission Line Reconstruction	$2,250	$2,300	$1,600	$1,600	$1,600
Total – Transmission	**$5,371**	**$5,483**	**$5,546**	**$5,954**	**$6,309**

Newfoundland Power Inc.
2013-2017 Capital Plan
(000s)

DISTRIBUTION

Project	2013	2014	2015	2016	2017
Extensions	$11,376	$11,495	$11,882	$12,387	$12,338
Meters	$2,849	$2,742	$2,585	$2,656	$2,196
Services	$3,705	$3,762	$3,884	$4,040	$4,047
Street Lighting	$2,267	$2,299	$2,367	$2,448	$2,458
Transformers	$7,983	$8,151	$8,313	$8,472	$8,625
Reconstruction	$3,499	$3,616	$3,712	$3,810	$3,909
Rebuild Distribution Lines	$2,997	$3,087	$3,163	$3,240	$3,317
Relocations For Third Parties	$2,554	$1,632	$1,672	$1,713	$1,755
Distribution Reliability Initiative	$0	$500	$512	$524	$537
Feeder Additions for Load Growth	$1,204	$511	$0	$333	$644
Trunk Feeders	$117	$1,545	$2,461	$3,427	$2,400
Allowance for Funds Used During Construction	$189	$193	$197	$201	$205
Total – Distribution	**$38,740**	**$39,533**	**$40,748**	**$43,251**	**$42,431**

Newfoundland Power Inc.
2013-2017 Capital Plan
(000s)

GENERAL PROPERTY

Project	2013	2014	2015	2016	2017
Tools and Equipment	$389	$397	$404	$412	$420
Additions to Real Property	$238	$243	$247	$250	$253
Renovations Company Buildings	$950	$1,400	$230	$516	$1,225
Standby Generators	$160	$275	$275	$175	$0
Total – General Property	**$1,737**	**$2,315**	**$1,156**	**$1,353**	**$1,898**

Newfoundland Power Inc.
2013-2017 Capital Plan
(000s)

TRANSPORTATION

Project	2013	2014	2015	2016	2017
Purchase Vehicles and Aerial Devices	$2,950	$2,690	$2,740	$2,655	$2,785
Total – Transportation	**$2,950**	**$2,690**	**$2,740**	**$2,655**	**$2,785**

Newfoundland Power Inc.
2013-2017 Capital Plan
(000s)

TELECOMMUNICATIONS

Project	2013	2014	2015	2016	2017
Replace/Upgrade Communications Equipment	$124	$69	$72	$66	$73
Fibre Optic Cable	0	0	173	200	224
Mobile Radio System Replacement	750	0	0	0	0
Total – Telecommunications	**$874**	**$69**	**$245**	**$266**	**$297**

Newfoundland Power Inc.
2013-2017 Capital Plan
(000s)

INFORMATION SYSTEMS

Project	2013	2014	2015	2016	2017
Application Enhancements	$1,380	$1,200	$1,200	$950	$950
System Upgrades	$1,177	$1,419	$1,625	$2,025	$2,775
Personal Computer Infrastructure	$380	$375	$375	$375	$375
Shared Server Infrastructure	$877	$900	$900	$900	$900
Network Infrastructure	$200	$100	$100	$100	$100
Total – Information Systems	**$4,014**	**$3,994**	**$4,200**	**$4,350**	**$5,100**

Newfoundland Power Inc.
2013-2017 Capital Plan
(000s)

UNFORESEEN ALLOWANCE

Project	2013	2014	2015	2016	2017
Allowance for Unforeseen	$750	$750	$750	$750	$750
Total – Unforeseen Allowance	**$750**	**$750**	**$750**	**$750**	**$750**

Newfoundland Power Inc.
2013-2017 Capital Plan
(000s)

GENERAL EXPENSES CAPITALIZED

Project	**2013**	**2014**	**2015**	**2016**	**2017**
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**

2012 Capital Expenditure Status Report

June 2012

NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

2012 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. 26 (2011).

Page 1 of the 2012 Capital Expenditure Status Report outlines the forecast variances from budget of the capital expenditures approved by the Board in Order Nos. P.U. 26 (2011), P.U. 7 (2012) and P.U. 8 (2012). The detailed tables on pages 2 to 13 provide additional detail on capital expenditures in 2012, and also include information on those capital projects approved for 2011 that were not completed prior to 2012.

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 2012 Capital Expenditure Status Report.

Newfoundland Power Inc.

2012 Capital Budget Variances
(000s)

	Approved by Order Nos. P.U. 26 (2011) P.U. 7 (2012) P.U. 8 (2012)	Forecast	Variance
Generation – Hydro	$9,933	$7,933	($ 2,000)
Generation - Thermal	156	156	-
Substations	12,776	13,576	800
Transmission	5,577	5,577	-
Distribution	38,047[1]	39,497	1,450
General Property	1,651	1,651	-
Transportation	2,306	2,306	-
Telecommunications	454	175	(279)
Information Systems	3,680	3,680	-
Unforeseen Items	750	750	-
General Expenses Capitalized	3500	4,000	500
Total	$78,830	$79,301	471
Projects carried forward from 2011		$1,335	

Notes:

[1] Includes $1,027,000 in estimated cost associated with the the upgrade of MIL-02 feeder from 2 phases to 3 phases approved in Order No. P.U. 7 (2012) and $510,000 in estimated cost associated with the Bell Island submarine cable approved in Order No. P.U. 8 (2012).

2012 Capital Expenditure Status Report
(000s)

	Capital Budget			Actual Expenditures			Forecast			
	2011	2012	Total	2011	2012	Total To Date	Remainder 2012	Total 2012	Overall Total	Variance
	A	B	C	D	E	F	G	H	I	J
2012 Projects	$ -	$ 78,830	$ 78,830	$ -	$ 19,699	$ 19,699	$ 59,602	$ 79,301	$ 79,301	$ 471
2011 Projects	8,912	-	$ 8,912	5,939	130	6,069	1,205	1,335	7,404	(1,508)
Grand Total	**$ 8,912**	**$ 78,830**	**$ 87,742**	**$ 5,939**	**$ 19,829**	**$ 25,768**	**$ 60,807**	**$ 80,636**	**$ 86,705**	**$ (1,037)**

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

2012 Capital Expenditure Status Report
(000s)

Category: Generation - Hydro

	Capital Budget			Actual Expenditures			Forecast				
Project	**2011**	**2012**	**Total**	**2011**	**2012**	**Total To Date**	**Remainder 2012**	**Total 2012**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	I	J	
2012 Projects											
Hydro Plants - Facility Rehabilitation		$ 1,362	$ 1,362		$ 209	$ 209	$ 1,153	$ 1,362	$ 1,362	$ -	
Rattling Brook Fisheries Compensation		5,000	5,000		263	263	2,737	$ 3,000	3,000	(2,000)	1
Hydro Plant Production Increase		120	120		7	7	113	$ 120	120	-	
Lockston Plant Refurbishment		3,451	3,451		314	314	3,137	$ 3,451	3,451	-	
Total - 2012 Generation Hydro	**$ -**	**$ 9,933**	**$ 9,933**	**$ -**	**$ 793**	**$ 793**	**$ 7,140**	**$ 7,933**	**$ 7,933**	**$ (2,000)**	
2011 Projects											
Facility Rehabilitation	$ 1,610	$ -	$ 1,610	$ 1,285	$ -	$ 1,285	165	$ 165	$ 1,450	$ (160)	
Horse Chops Rewind and Rotor Re-insulation	1,276	-	1,276	795	-	$ 795	185	185	980	(296)	2
Total - 2011 Generation Hydro	**$ 2,886**	**$ 9,933**	**$ 12,819**	**$ 2,080**	**$ 793**	**$ 2,873**	**$ 7,490**	**$ 8,283**	**$ 10,363**	**$ (2,456)**	

* See Appendix A for notes containing variance explanations.

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

2012 Capital Expenditure Status Report
(000s)

Category: Generation - Thermal

Project	Capital Budget 2012 (A)	Capital Budget Total (B)	Actual Expenditures 2012 (C)	Actual Expenditures Total To Date (D)	Forecast Remainder 2012 (E)	Forecast Total 2012 (F)	Forecast Overall Total (G)	Variance (H)	Notes*
2012 Projects									
Thermal Plants - Facility Rehabilitation	$ 156	$ 156	$ 77	$ 77	$ 79	$ 156	$ 156	$ -	
Total - Generation Thermal	**$ 156**	**$ 156**	**$ 77**	**$ 77**	**$ 79**	**$ 156**	**$ 156**	**$ -**	

* See Appendix A for notes containing variance explanations.

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

2012 Capital Expenditure Status Report
(000s)

Category: Substations

Project	Capital Budget 2012 A	Capital Budget Total B	Actual Expenditures 2012 C	Actual Expenditures Total To Date D	Forecast Remainder 2012 E	Forecast Total 2012 F	Forecast Overall Total G	Variance H	Notes*
2012 Projects									
Substation Refurbishment and Modernization	$ 2,482	$ 2,482	$ 706	$ 706	$ 1,976	$ 2,682	$ 2,682	$ 200	
Replacements Due to In-Service Failures	2,276	2,276	977	977	1,899	2,876	2,876	600	3
Additions Due to Load Growth	5,439	5,439	780	780	4,659	5,439	5,439	-	
PCB Bushing Phase-out	1,500	1,500	200	200	1,300	1,500	1,500	-	
Substation Addition - Portable Substation	879	879	16	16	863	879	879	-	
Lockston Substation Upgrade	200	200	30	30	170	200	200	-	
Total - Substations	**12,776**	**12,776**	**2,709**	**2,709**	**10,867**	**13,576**	**13,576**	**800**	

* See Appendix A for notes containing variance explanations.

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

2012 Capital Expenditure Status Report
(000s)

Category: Transmission

	Capital Budget			Actual Expenditures			Forecast				
Project	**2011**	**2012**	**Total**	**2011**	**2012**	**Total To Date**	**Remainder 2012**	**Total 2012**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	I	J	
2012 Projects											
Rebuild Transmission Lines	$ -	$ 5,577	$ 5,577	$ -	$ 467	$ 467	$ 5,110	$ 5,577	$ 5,577	$ -	
Total 2012 Transmission	**$ -**	**$ 5,577**	**$ 5,577**	**$ -**	**$ 467**	**$ 467**	**$ 5,110**	**$ 5,577**	**$ 5,577**	**$ -**	
2011 Projects											
Rebuild Transmission Lines	$ 4,745	$ -	$ 4,745	$ 3,389	$ -	$ 3,389	300	$ 300	$ 3,689	$ (1,056)	4
Total - 2011 Transmission	**$ 4,745**	**$ 5,577**	**$ 10,322**	**$ 3,389**	**$ 467**	**$ 3,856**	**$ 5,410**	**$ 5,877**	**$ 9,266**	**$ (1,056)**	

* See Appendix A for notes containing variance explanations.

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

2012 Capital Expenditure Status Report
(000s)

Category: Distribution

Project	Capital Budget			Actual Expenditures			Forecast				
	2011	2012	Total	2011	2012	Total To Date	Remainder 2012	Total 2012	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2012 Projects											
Extensions	$ -	$ 10,326	$ 10,326	$ -	$ 3,283	$ 3,283	$ 8,078	$ 11,361	$ 11,361	$ 1,035	5
Meters	-	1,884	1,884	-	1,127	1,127	898	2,025	2,025	141	
Services	-	3,351	3,351	-	1,424	1,424	2,095	3,519	3,519	168	
Street Lighting	-	2,115	2,115	-	794	794	1,427	2,221	2,221	106	
Transformers	-	7,944	7,944	-	2,583	2,583	5,361	7,944	7,944	-	
Reconstruction	-	2,861	2,861	-	1,085	1,085	1,776	2,861	2,861	-	
Rebuild Distribution Lines	-	3,403	3,403	-	620	620	2,783	3,403	3,403	-	
Relocate/Replace Distribution Lines For Third Parties	-	2,205	2,205	-	552	552	1,653	2,205	2,205	-	
Trunk Feeders	-	848	848	-	7	7	841	848	848	-	
Feeder Additions for Growth	-	1,391	1,391	-	75	75	1,316	1,391	1,391	-	
Allowance for Funds Used During Construction	-	182	182	-	62	62	120	182	182	-	
Bell Island Submarine Cable Repair	-	510	510	-	276	276	234	510	510	-	
Milton Substation Property Additions	-	1,027	1,027	-	-	-	1,027	$ 1,027	$ 1,027	-	
Total - 2012 Distribution	**$ -**	**$ 38,047**	**$ 38,047**	**$ -**	**$ 11,888**	**$ 11,888**	**$ 27,609**	**$ 39,497**	**$ 39,497**	**$ 1,450**	
2011 Projects											
Feeder Additions for Growth	$ 1,281	$ -	$ 1,281	$ 470	$ 130	$ 600	555	$ 685	$ 1,155	$ (126)	
Total 2011 Distribution	**$ 1,281**	**$ 38,047**	**$ 39,328**	**$ 470**	**$ 12,018**	**$ 12,488**	**$ 28,164**	**$ 40,182**	**$ 40,652**	**$ 1,324**	

* See Appendix A for notes containing variance explanations.

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

2012 Capital Expenditure Status Report
(000s)

Category: General Property

Project	Capital Budget 2012	Capital Budget Total	Actual Expenditures 2012	Actual Expenditures Total To Date	Forecast Remainder 2012	Forecast Total 2012	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2012 Projects									
Tools and Equipment	$ 457	$ 457	$ 125	125	$ 332	$ 457	$ 457	$ -	
Additions to Real Property	234	234	217	217	17	$ 234	234	-	
Company Building Renovations	685	685	82	82	603	$ 685	685	-	
Standby Generator System Control Center	275	275	-	-	275	$ 275	275	-	
Total - 2012 General Property	**$ 1,651**	**$ 1,651**	**$ 424**	**$ 424**	**$ 1,227**	**$ 1,651**	**$ 1,651**	**$ -**	

* See Appendix A for notes containing variance explanations.

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

2012 Capital Expenditure Status Report
(000s)

Category: Transportation

Project	Capital Budget 2012 (A)	Capital Budget Total (B)	Actual Expenditures 2012 (C)	Actual Expenditures Total To Date (D)	Forecast Remainder 2012 (E)	Forecast Total 2012 (F)	Forecast Overall Total (G)	Variance (H)	Notes*
2012 Projects									
Purchase Vehicles and Aerial Devices	$ 2,306	$ 2,306	$ 697	$ 697	$ 1,609	$ 2,306	$ 2,306	$ -	
Total - Transportation	**$ 2,306**	**$ 2,306**	**$ 697**	**$ 697**	**$ 1,609**	**$ 2,306**	**$ 2,306**	**$ -**	

* See Appendix A for notes containing variance explanations.

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

2012 Capital Expenditure Status Report
(000s)

Category: Telecommunications

Project	Capital Budget		Actual Expenditures		Forecast				
	2012	Total	2012	Total To Date	Remainder 2012	Total 2012	Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2012 Projects									
Replace/Upgrade Communications Equipment	$ 150	$ 150	$ 47	$ 47	$ 103	$ 150	$ 150	$ -	
Fibre Optic Circuit Replacement	304	304	10	10	15	25	25	(279)	6
Total - Telecommunications	**$ 454**	**$ 454**	**$ 57**	**$ 57**	**$ 118**	**$ 175**	**$ 175**	**$ (279)**	

* See Appendix A for notes containing variance explanations.

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

2012 Capital Expenditure Status Report
(000s)

Category: Information Systems

Project	Capital Budget 2012	Capital Budget Total	Actual Expenditures 2012	Actual Expenditures Total To Date	Forecast Remainder 2012	Forecast Total 2012	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2012 Projects									
Application Enhancements	$ 1,013	$ 1,013	$ 275	$ 275	$ 738	$ 1,013	$ 1,013	$ -	
System Upgrades	1,276	1,276	313	313	963	1,276	1,276	-	
Personal Computer Infrastructure	390	390	85	85	305	390	390	-	
Shared Server Infrastructure	607	607	287	287	320	607	607	-	
Network Infrastructure	394	394	38	38	356	394	394	-	
Total - Information Systems	**$ 3,680**	**$ 3,680**	**$ 998**	**$ 998**	**$ 2,682**	**$ 3,680**	**$ 3,680**	**$ -**	

* See Appendix A for notes containing variance explanations.

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

2012 Capital Expenditure Status Report
(000s)

Category: Unforeseen Items

	Capital Budget		Actual Expenditures		Forecast				
Project	**2012**	**Total**	**2012**	**Total To Date**	**Remainder 2012**	**Total 2012**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2012 Projects									
Allowance for Unforeseen Items	$ 750	$ 750	$ 148	$ 148	$ 602	$ 750	$ 750	$ -	
Total - Unforeseen Items	**$ 750**	**$ 750**	**$ 148**	**$ 148**	**$ 602**	**$ 750**	**$ 750**	**$ -**	

* See Appendix A for notes containing variance explanations.

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

2012 Capital Expenditure Status Report
(000s)

Category: General Expenses Capitalized

	Capital Budget		Actual Expenditures		Forecast				
Project	**2012**	**Total**	**2012**	**Total To Date**	**Remainder 2012**	**Total 2012**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2012 Projects									
Allowance for General Expenses Capitalized	$ 3,500	$ 3,500	$ 1,441	$ 1,441	$ 2,559	$ 4,000	$ 4,000	$ 500	7
Total - General Expenses Capitalized	**$ 3,500**	**$ 3,500**	**$ 1,441**	**$ 1,441**	**$ 2,559**	**$ 4,000**	**$ 4,000**	**$ 500**	

* See Appendix A for notes containing variance explanations.

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Column A	Approved Capital Budget for 2012
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2012
Column D	Total of Column C
Column E	Forecast for Remainder of 2012
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 Fisheries Compensation:*
   Budget: $5,000,000 Forecast: $3,000,000 Variance: ($2,000,000)

   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 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 the technical work completed to date it has been determined that the original $5.0 million expenditure take place over a 5-year period from 2012 to 2016.[1] Extending the implementation period is necessary to adapt in-stream structures to make them more suitable to migrating salmon.[2] The revised implementation plan has been submitted to DFO for review and approval, with confirmation received from DFO.

2. *Horse Chops Rewind and Rotor Re-Insulation (2011 Project):*
   Budget: $1,276,000 Forecast: $980,000 Variance: ($296,000)

   Competitive bids from rewind suppliers resulted in a lower contract price than was anticipated in the original project estimate.

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[1] The recommendation involved distributing the initial $5 million project budget over 5 years, with an initial expenditure of $3 million in 2012 and the remaining $2 million over the 2013 to 2016 period.

[2] The revised implementation plan meets the original DFO order allowing downstream migration of salmon kelts and smolts by May 1, 2013 and the upstream migration of grilse and adult salmon by June 2014.

Substations

3. Replacements Due to In-Service Failures
Budget: $2,276,000 Forecast: $2,876,000 Variance: $600,000

The budget for Replacements Due to In-Service Failures is based on an assessment of historical expenditures. In addition to responding to multiple individual in-service failures, which typically involve expenditures below $50,000, thermo scanning carried out in December 2011 identified the need to replace a number of substation switches. It is estimated that an additional $400,000 is required to complete the replacements. An additional $200,000 is required to replace two failed UPS battery banks.

Transmission

4. *Rebuild Transmission Lines (2011 Project):*
Budget: $4,745,000 Forecast: $3,689,000 Variance: ($1,056,000)

The work planned for 21L in 2011 was deferred to 2012 and has been approved as part of the 2012 Capital Budget. This resulted in a reduction in planned 2011 expenditure of approximately $822,000. In addition, competitive bidding resulted in a contract price for the work on 25L that was $250,000 below the budget estimate.

Distribution

5. *Extensions:*
Budget: $10,326,000 Forecast: $11,361 000 Variance: $1,035,000

Expenditure associated with building line extensions to accommodate new customer connections is expected to be 10% above forecast. The budgeted expenditure for customer growth was based on 4,670 new customer connections. The current projection for new customer connections is 4,904, an increase of 5%. The unit cost is projected to increase by 5% principally due to a slight change in the mix of single phase versus three phase construction. Year to date the amount of 3 phase construction required has increased slightly.

Telecommunications

6. *Fibre Optic Circuit Replacement:*
   Budget: $304,000 Forecast: $25,000 Variance: ($279,000)

   Newfoundland Power believes that competition and capacity in the local telecommunications market is affecting the pricing of fibre capacity. As a result, Newfoundland Power is currently re-evaluating its Fibre Optic Replacement requirements.

General Expenses Capitalized

7. General Expenses Capitalized:
Budget: $3,500,000 Forecast: $4,000,000 Variance: $500,000

The variance is primarily related to an increase in the allocated portion of pension expense. Pension expenses increased in recent years as a result of the amortization of 2008 losses associated with the pension plan assets along with a lower discount rate being used to determine the Company's accrued obligation under its defined benefit pension plan.

2013 Facility Rehabilitation

June 2012

Prepared by:

David Ball, B.Eng.

Gary K. Humby, P.Eng.

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1.0 Introduction

The 2013 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 2013 Facility Rehabilitation project totalling $1,400,000 is comprised of Hydro Dam Rehabilitation and Generation Equipment Replacements Due to In-Service Failures.

2.0 Hydro Dam Rehabilitation

Cost: $825,000

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. 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 2013 includes:

1. *Lookout Brook Forbay Dam/Spillway. ($225,000)*
   This project involves the rehabilitation of deteriorated concrete on the sluice and upstream face of the structure. Dam safety inspections have noted that the concrete on the wing/breast walls of the sluice is in the late stages of deterioration with cracking/fracturing and the development of efflorescence paste in most joints. The concrete at the toe of the spillway has eroded along the bedrock interface. It is recommended that all the deteriorated concrete surfaces be refinished to ensure design performance of the structure is maintained. The railings on this spillway do

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

not meet current National Building Code of Canada requirements and the spillway abutment was constructed without railing. These deficiencies have been noted through inspections and will be corrected as part of this project.

Figure 1 – Concrete Erosion at Spillway Toe

Figure 2 – Deteriorated Concrete on Sluice

Figure 3 – Missing and Substandard Railing

Figure 4 – Deteriorated Concrete on Upstream Face

2. *Three Island Pond Spillway ($305,000)*
   This project involves replacement of the existing timber crib spillway and outlet. Inspections have determined the foundation near the existing gate has settled and the gate is misaligned as a result. Timbers along the structure are deteriorated from exposure to ice and water. Due to the deterioration and settlement of the foundation the structure will be completely replaced.

Figure 5 – Results of Settling Foundation

Figure 6 – Misalignment Due to Settling

Figure 7 – Deteriorated Wood and Misaligned Gate

Figure 8 – Deteriorated Wood Structure

3. *Cochrane Pond Outlet ($70,000)*
   This project involves the replacement of the existing timber crib outlet and spillway. This structure previously housed an operational gate that has since been decommissioned as it was no longer required. This outlet remains important to the regulation of flow from Cochrane Pond. The structure in its current deteriorated condition is prone to vandalism including timber removal and camp fires. The outlet will be replaced with a modified steel or concrete design to reduce vandalism and public safety risks.

Figure 9 – Evidence of Fires and Crossing Using Structure Timbers

Figure 10 – Removed Timbers

Figure 11 – Timber Deterioration

4. *Soldiers Pond Outlet ($225,000)*
   This project involves replacing the existing timber outlet structure and gabion wing walls. The lower sections of the gabion wing walls have corroded and are losing ballast. The risk of collapse of the gabian rock ballast has increased as the corrosion becomes more prevalent on the gabian baskets. The existing structure is used as a pedestrian bridge by the public. The wing walls currently do not have safety railings as they cannot be accommodated with the existing design. A more robust wingwall design that incorporates appropriate safety measures is required.

Figure 12 – Gate Structure

Figure 13 – Corroded Gabions - Upstream

Figure 14 – Corroded Gabions - Downstream

Figure 15 – Corroded Gabions - Downstream

3.0 Generation Equipment Replacements Due to In-Service Failures

Cost: $575,000

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	**2008**	**2009**	**2010**	**2011**	**2012F**
Total	$679	$475	$569[2]	$464	$578

Based upon this recent historical information and engineering judgement, $575,000 is estimated to be required in 2013 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.

[2] 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 2013 budget of $1,400,000 for Facility Rehabilitation is recommended as follows:

- $825,000 for Hydro Dam Rehabilitation;
- $575,000 for Generation Equipment Replacements Due to In-Service Failures.

Heart's Content Hydro Plant Penstock Replacement

June 2012

Prepared by:

David Ball, B.Eng.

Gary K. Humby, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
GARY K. HUMBY
SIGNATURE
June/12/2012
DATE
PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
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Appendix A: Pictures of Heart's Content Penstock
Appendix B: Feasibility Analysis

1.0 Introduction

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 1918 and contains one generating unit with a nameplate capacity of 2.7 MW and a rated net head of 46.9 m. The normal annual production at Heart's Content is approximately 8.3 GWH or 1.9 % of the total hydroelectric production of Newfoundland Power. The development has provided 94 years of reliable energy production.

The woodstave penstock and intake have reached the end of their useful lives and require replacement.[1] The woodstave penstock is 66 years old and is in poor condition.[2] The existing intake is also 66 years old. The concrete foundation and wooden building are in poor condition with a constant flow of water leaking through the concrete. The intake is also susceptible to frazil ice formation which results in plant outages in the winter.[3]

Engineering and procurement for the penstock will need to be completed in 2013, to allow for replacement in 2014.

2.0 Background

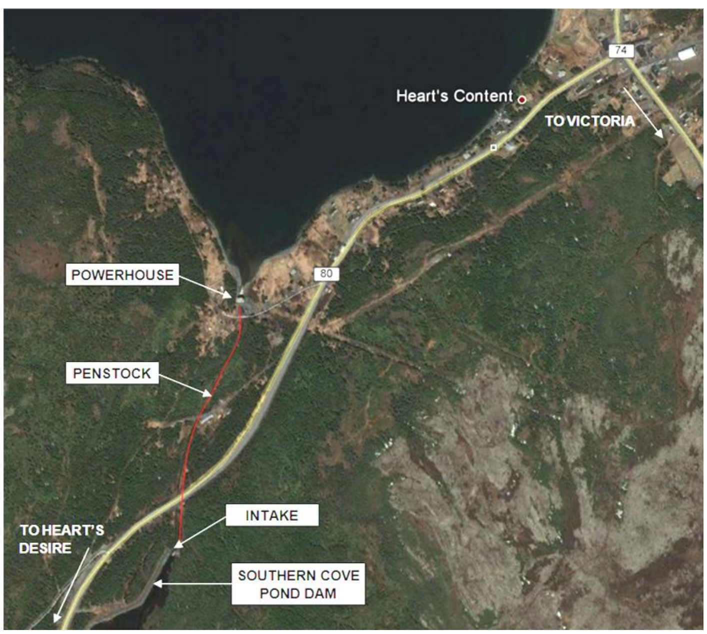

Figure 1 – Map of Heart's Content Development

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

The penstock is comprised of a woodstave section constructed in 1946 and a steel section built in 1959.[4] The woodstave portion of the penstock is

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1 See Appendix A for pictures of the penstock and intake structure.
2 Evidence suggests that some of the staves date back to the original 1918 construction.
3 Frazil ice is a collection of loose ice crystals that resembles slush and forms in super cooled, turbulent water. The ice crystals are prone to adhering and building up on surfaces such as trash racks.
4 The woodstave section is 558 metres long and 1,829 mm in diameter, whereas the steel section is 21 metres long and 1,829 mm in diameter.

supported on timber cradles. The timber staves and cradles were treated with creosote.[5] Concrete anchor blocks are provided on the steel penstock section near the steel/woodstave connection and at the powerhouse entrance.

The normal static head at the powerhouse is 490 kPa. The penstock pressure upon 100% load rejection, measured in 2009, was 538 kPa.

The intake constructed in 1946, is of reinforced concrete construction with concrete wingwalls. It includes 2 timber gates with screw stem lift, upstream stop logs, steel trashracks, control equipment and a wooden gatehouse. The wingwalls are situated on either side of the intake and extend to natural ground toward the east, and the forebay dam toward the west. They have a combined length of 19 metres with above ground elevation of 1.2 metres.

3.0 Penstock Condition

The woodstave penstock is 66 years old and is in poor condition with deterioration along its entire length. The bedding is saturated due to significant leakage from the penstock and intake. Saturation of the penstock bedding has resulted in rotting and settling of the support cradles. Although many of these cradles were repaired in the past with metal plates, the wood has now deteriorated beyond repair. As a result, many of the support cradles are now cracked and no longer able to support the penstock as designed. This has caused localized sagging and misalignment of the penstock.

Figure 2 - Cracked Cradle

Steel bands, shoes and nuts are heavily corroded near areas of heavy leakage and at the road crossing adjacent to the powerhouse. Most of the bands cannot be tightened or adjusted to facilitate maintenance.

The woodstaves are rotted and splitting over the length of the penstock. The butt joints between the staves are a concern as there are many locations that exhibit severe splitting. In addition, woodstaves are crushed below the bands in several places.

Leaks have been contained by various methods over the years, with repairs evident along the length of the penstock. Large leaks and end split outs are most often contained by placing large plates and rubber gaskets under the bands. Leaks along the springline are normally fixed with tapered wedges. The extent of deterioration of the wood is making repairs difficult to complete. The current amount of leakage in the penstock causes significant ice build up in winter months.

5 The cradles are constructed out of 150 mm by 200 mm timber. The staves are contained with 19 mm steel bands that vary in spacing from 200 mm at the intake end to 50 mm at the powerhouse end.

Figure 3 - Leak Repairs and Split Timbers

Recent experience indicates that the Plant's penstock is increasingly unable to withstand de-watering without significant leakage upon re-watering.[6] As a result, every effort is made to avoid de-watering the penstock. Consequently, leaks that cannot be plugged without de-watering may remain unrepaired, as long as the escaping water does not imperil safety or the plant infrastructure itself.[7] The inability to routinely de-water the penstock for maintenance reasons constitutes a serious operating limitation on the plant.

The woodstave penstock has reached the end of its useful life and requires replacement. In addition to replacing the penstock the project will involve other civil works. The penstock right of way has creosote contamination that will require clean up and disposal. The existing penstock does not have an access road adjacent to it.[8] To facilitate the removal and installation of the new penstock, an access road will be constructed. Also the 53 year old steel section of penstock is exhibiting coating system failure along its length and requires sandblasting and painting to extend the life of the asset.[9]

4.0 Intake Condition

The intake is 66 years old and is deteriorated. The design of the intake is such that during the winter it is prone to frazil and pan ice blockage and higher than normal head loss.

The concrete structure is cracked and there is crumbling and spalling in places. As a result there are several leaks in the structure near the penstock outlet, particularly along the bedrock to concrete interface at the base as shown in Figure 4. These leaks are contributing to the penstock bedding saturation as mentioned previously.

Figure 4 - Deteriorated Intake Concrete

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6 The deteriorated condition of the woodstaves, heavily corroded bands and deteriorated supports increase the potential need to de-water the penstock to address major leaks.

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

8 The road to the intake does not follow the penstock route.

9 Appendix A Figure 14 shows corrosion on the surface of the steel section of penstock.

The gates are functional, but are increasingly difficult to operate. When the head gate is required to dewater the intake or penstock, there is significant leakage.

Figure 5 - Leak Monitoring Weir

The wing wall, to the west of the intake, ties the intake structure into the Southern Cove Pond dam. There is a significant leak under the west wing wall. An attempt to investigate and fix the leak was made in 2005. It was determined that the source was inadequate fill beneath the wing wall. Permanent repairs were not made in 2005, however, a weir was installed to monitor the leakage as shown in Figure 5. Modifications to the wing wall will be required as part of intake rehabilitation work, therefore it is practical to address the leak in the 2013 refurbishment.

The gatehouse building envelope is in poor condition with deteriorated siding, soffit, fascia and roofing. The doors require replacement to ensure the security of the building.[10]

In winter months, frazil ice often forms in the fast moving water above the intake where a normal ice sheet cannot form. When this ice comes in contact with the trash racks, it can build up and block water entering the penstock. In addition, during periods when the plant is shut down, a normal ice sheet will form. Upon restart of the plant, the forebay ice breaks up into pans which also may block water flow to the penstock. This intake is particularly sensitive to ice problems and even with preventative operating measures, ice accounts for 73% of forced plant outages during winter months. When trash racks become blocked, operations staff are dispatched to clear the blockage and restart the plant. If ice forms while the plant is shut down, upon restart the plant has to run at reduced load to slowly clear the ice and prevent ice pans from becoming pinned on the trash racks.

In 2009, Hatch completed index testing of the Heart's Content turbine. Based on their observations, head loss through the intake and penstock could be reduced if the intake were modified.[11] Newfoundland Power's subsequent inspections revealed that head loss at the intake totalled approximately 1 metre during normal operations. This is contributed to flow constrictions at the intake entrance, trash rack, head gate and penstock entrance. This head loss results in very turbulent flow through the structure and a generation loss of approximately 0.06 MW. A simpler and more streamlined structure would increase production by approximately 0.2 GWH annually, worth approximately $38,000 per year at current fuel prices.[12]

[10] The gatehouse building restricts access by the public to the trash racks and the turbulent water flow into the penstock. The building also houses the water level monitoring equipment and the trash rack heaters.

[11] Modifications under consideration involve changes to the forebay channel approaching the intake. Increasing the depth of the channel, and other modifications to improve flow characteristics, will reduce the formation of surface ice.

[12] The $38,000 value is based upon $118.80 per barrel of fuel burned at Holyrood, according to the March 31, 2012 fuel forecast provided by Newfoundland Hydro and a conversion rate of 630 kWH per barrel.

The intake has reached the end of its useful life and requires replacement. The replacement structure will be designed to improve ice performance as well as achieve a significant reduction in intake head loss. This is expected to increase annual generation by 2% or 0.2 GWh. Repair of the leak under the west wing wall should be undertaken at this time.

5.0 Project Execution

The refurbishment of the Heart's Content Intake and Penstock is necessary in 2014. Both have reached the end of their useful life and require replacement. It is estimated that the plant will be out of service for 20 weeks from June to October 2014. It is anticipated that the penstock replacement will take 18 weeks and the intake replacement 8 weeks. They will be completed simultaneously. When the new penstock is re-watered, commissioning will commence and the plant will be back in service within 2 weeks of re-watering.

In order for the project to be completed on schedule, the penstock will be designed and ordered in 2013.[13] The detailed engineering for the project will be completed in the 3rd quarter of 2013 with the supply contracts for all items tendered and awarded in the 4th quarter. It is necessary to complete engineering of the intake replacement along with the penstock, as the correction of the ice and head loss related deficiencies may impact the intake location and therefore penstock alignment.

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

Table 1
High-Level Project Schedule

Date	Description
Q2 2013	Complete survey and geotechnical review of existing penstock route, intake and forebay channel immediately upstream of intake.
Q3/Q4 2013	Complete detailed engineering design
Q4 2013	Tender and award penstock installation contract
Q2 2014	Construct access road along penstock
Q3 2014	Complete penstock and intake installation
Q4 2014	Test and commission systems

During the 20 week plant downtime it is estimated, based on normal inflows, that spill at Heart's Content plant will be minimal at only 1.7 GWh.

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

6.0 Additional Work

In addition to the Penstock and Intake Replacement, the following work at Heart's Content is planned for 2014:

- Governor Upgrades
- Protection and Control Upgrades
- Generator Rewind

This work will be put forward as a separate project with justification included as part of Newfoundland Power's 2014 Capital Budget Application. An estimated cost of $2.440 million for these items has been included in the feasibility analysis.

7.0 Project Cost

The total project cost is estimated at $3.695 million which includes $200,000 in 2013 for engineering assessment, design and tendering, followed by $3.495 million in 2014 for penstock and intake replacement. This does not include the cost associated with the additional work outlined in Section 6.0.

Table 2 provides the project cost breakdown by year.

Table 2
Cost Estimate for Heart's Content Penstock and Intake
(000s)

Description	2013	2014
Material	$25	$3,269
Labour - Internal	25	25
Labour - Contract	-	-
Engineering	125	103
Other	25	98
Total	**$200**	**$3,495**

8.0 Feasibility Analysis

Appendix B provides a feasibility analysis for the continued operation of the Heart's Content hydroelectric development assuming that the planned capital refurbishment is undertaken. The results of the feasibility analysis show that the continued operation of the facility is economical over the long term. Investing in the life extension of the Heart's Content hydroelectric development ensures the continued availability of 8.3 GWH of energy annually to the Island Interconnected System.

The estimated levelized cost of energy from the Plant over the next 50 years is 5.93¢ 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.[14]

9.0 Concluding

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

[14] The cost of electricity from the Holyrood thermal generating plant is estimated at 18.9 ¢ per kWh. This is based upon a 630 kWh per barrel conversion efficiency and oil price forecast from Hydro of $118.80 per barrel for 2012 as per Newfoundland Hydro letter regarding Rate Stabilization plan – Fuel Price Projection dated March 31, 2012.

Appendix A
Pictures of Hearts Content Penstock

Figure 1: Typical Penstock Support Cradle Deterioration.

Figure 2: Penstock Settlement

Figure 3: Heavily Corroded Steel Bands

Figure 4: Major Leak (Partially repaired)

Figure 5: Blown Out Stave

Figure 6: Repaired and Deteriorated Staves

Figure 7: Leaking Joins along Length

Figure 8: Repairs along Spring Line

Figure 9: Water along Penstock Bed

Figure 10: Old Bridge over Penstock Right of Way

Figure 11: Ice Build-up on Penstock

Figure 12: Ice Build-up on Penstock

Figure 13: Steel Section (Note: Deteriorated Coating)

Figure 14: Woodstave/Steel Interface (Note: Deteriorated Coating)

Figure 15: Intake Concrete Deterioration

Figure 16: Intake Concrete Deterioration


Figure 17: Deteriorated Building Envelope

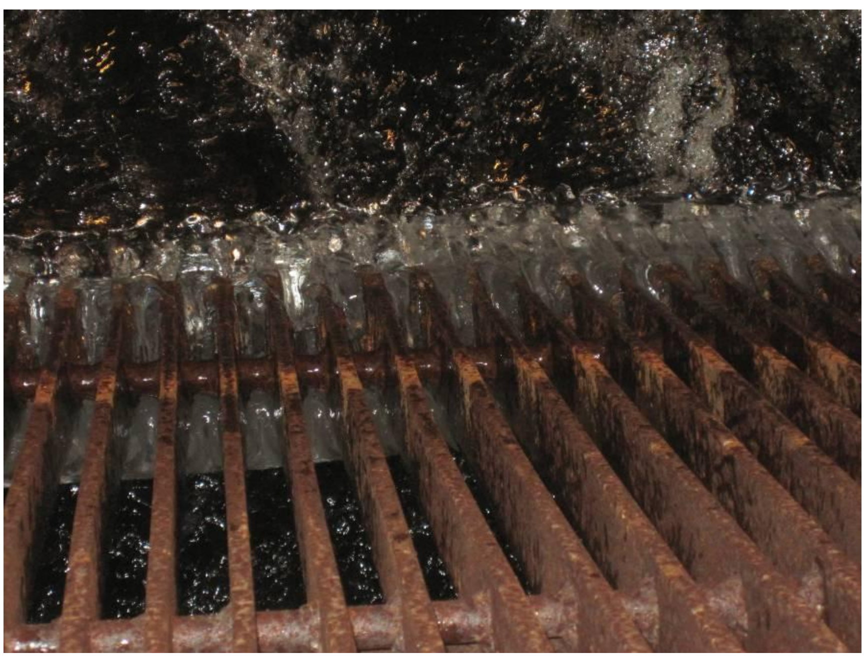
Figure 18: Ice Build-up on Trash Racks

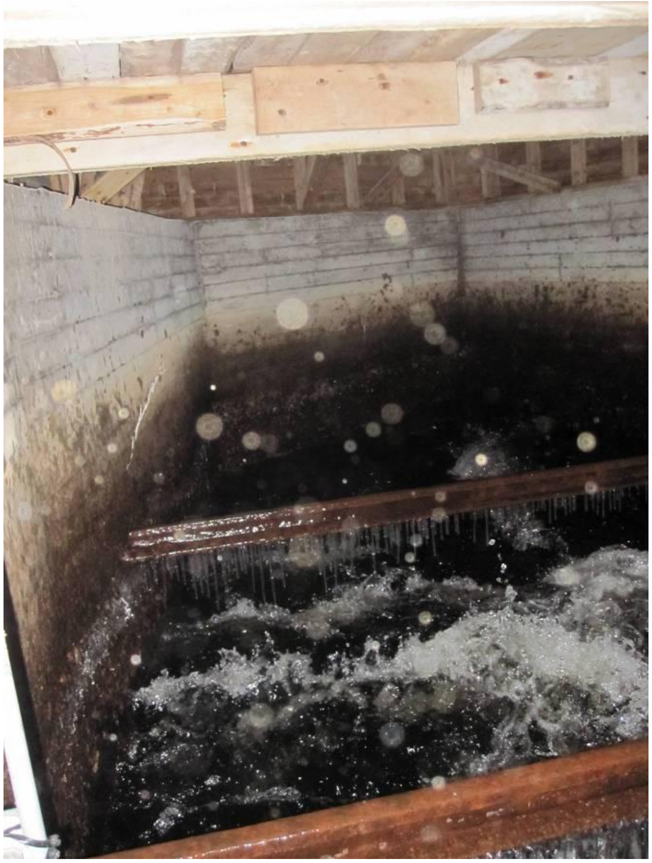

Figure 19: Turbulence in Intake

Figure 20: Leak under West Abutment

Appendix B
Feasibility Analysis

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2.0 Capital Costs B-1

3.0 Operating Costs B-1

4.0 Lost Production B-2

5.0 Financial Analysis B-2

6.0 Recommendation B-2

Attachment A: Summary of Capital Costs
Attachment B: Summary of Operating Costs
Attachment C: Calculation of Levelized Cost of Energy

1.0 Introduction

This feasibility analysis examines the future viability of Newfoundland Power's Heart's Content hydroelectric development. The continued long-term operation of the Hearts Content hydroelectric development is reliant on the completion of capital improvement in 2014. Planned work includes replacement of the woodstave penstock and intake structure as contained in this application. It also includes a generator rewind, upgrading of the governor controls and rebuilding the forebay distribution and communication line that will be described in further detail in the 2014 capital budget application.

With substantial investment required in the near-term to permit the continued reliable operation of this plant, an economic analysis of this development was completed. The analysis includes all costs and benefits for the next 50 years to determine the levelized cost of energy from the plant.

2.0 Capital Costs

All significant capital expenditures for the hydroelectric development over the next 50 years have been identified. The majority of these expenditures are planned for 2013 and 2014 with the remaining expenditures planned for future years. The capital expenditures required to maintain the safe and reliable operation of the facilities are summarized in Table 1.

Table 1
Hydroelectric Development
Capital Expenditures
(000s)

Year	Expenditure
2013-2017	$6,135
2018-2022	-
2023-2027	$33
2028-2032	-
2033-2038	$252
Total	**$6,420**

The total capital expenditure of all of the projects listed above is $6.42 million. A more comprehensive breakdown of capital costs is provided in Attachment A.

3.0 Operating Costs

Operating costs for this hydroelectric system are estimated to be $57,735 per year. This estimate is based upon recent historical operating experience. The operating cost represents both direct charges for operations and maintenance at this plant as well as indirect costs such as those related to managing the environment, safety, dam safety inspections, and staff training. A summary of operating costs is provided in Attachment B.

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

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 $47,735 to include a reduction of $10,000 per year to reflect the penstock and intake replacement project.

4.0 Lost Production

The downtime associated with the 2014 capital works at this plant will result in a minimal amount of spill from the system. To minimize spill it has been determined that June to September 2014 would be the most economic time to complete the project. Spill from Heart's Content forebay will be in the order of 1.70 GWH.

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 analysis has taken into account the additional energy generation associated with an improved intake design.

The estimated levelized cost of energy from the Heart's Content plant over the next 50 years is 5.93¢ 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.[1]

The future capacity benefits of the continued availability of Heart's Content hydro plant have not been considered in this analysis. If factored into the feasibility analysis, the financial benefit associated with system capacity would further support the viability of continued plant operations.

6.0 Recommendation

The results of this feasibility analysis show that the continued operation of the Heart's Content hydroelectric development is economically viable. Investing in the life extension of facilities at

[1] The cost of electricity from the Holyrood thermal generating plant is estimated at 18.9 ¢ per kWh. This is based upon a 630 kWh per barrel conversion efficiency and oil price forecast from Hydro of $118.80 per barrel for 2012 as per Newfoundland Hydro letter regarding Rate Stabilization plan – Fuel Price Projection dated March 31, 2012.

Heart's Content guarantees the availability of low cost energy to the Province. Otherwise the 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. Newfoundland Power should proceed with this project in 2013 and 2014. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

Attachment A
Summary of Capital Costs

Heart's Content Feasibility Analysis Summary of Capital Costs ($000s)						
Description	**2013**	**2014**	**2025**	**2033**	**2038**	**2039**
Civil						
Dam, Spillways and Gates				50		
Penstock & intake	200	3,495				200
Powerhouse					180	
Mechanical						
Governor Overhaul		20				
Cooling Water		50				
Heat and Ventilation		25				
Electrical						
P&C and Governor Controls		675				
Generator Rewind		1,000				
Switchgear		575				
AC & DC Systems		95				
Battery/Charger			33	22		
Annual Totals ($2012)	**200**	**5,935**	**33**	**72**	**180**	**200**

Attachment B
Summary of Operating Costs

Heart's Content Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs

Year	Amount
2007	$65,776
2008	36,848
2009	45,907
2010	48,713
2011	91,431
Average	**$57,735**

5-Year Average Operating Cost	57,735
Reduced Future Penstock Maintenance	- 10,000
Total Forecast Annual Operating Cost	$47,735

Attachment C
Calculation of Levelized Cost of Energy

Weighted Average Incremental Cost of Capital	7.40%
Escalation Rate	See following worksheet
PW Year	2012

YEAR	Generation Hydro 64.4yrs 8% CCA	Generation Hydro 64.4yrs 50% CCA	Capital Revenue Requireme	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
2013	200,000	0	19,578	47,735	0	-67,313	-62,675	-62,675	-5,804,906	-5,867,580	0.811	5.9299
2014	2,440,000	3,495,000	592,412	48,717	0	-641,129	-555,824	-618,498	-5,291,317	-5,909,815	7.724	5.9299
2015	0	0	609,820	49,711	0	-659,531	-532,381	-1,150,879	-4,799,064	-5,949,943	7.946	5.9299
2016	0	0	572,070	50,680	0	-622,750	-468,055	-1,618,933	-4,369,100	-5,988,033	7.503	5.9299
2017	0	0	547,461	51,595	0	-599,056	-419,224	-2,038,158	-3,985,983	-6,024,140	7.218	5.9299
2018	0	0	529,591	52,522	0	-582,113	-379,299	-2,417,457	-3,640,906	-6,058,363	7.013	5.9299
2019	0	0	515,246	53,441	0	-568,688	-345,020	-2,762,476	-3,328,309	-6,090,785	6.852	5.9299
2020	0	0	502,806	54,374	0	-557,181	-314,747	-3,077,223	-3,044,278	-6,121,501	6.713	5.9299
2021	0	0	491,450	55,295	0	-546,745	-287,572	-3,364,795	-2,785,789	-6,150,585	6.587	5.9299
2022	0	0	480,756	56,265	0	-537,021	-262,996	-3,627,791	-2,550,348	-6,178,139	6.470	5.9299
2023	0	0	470,505	57,252	0	-527,756	-240,650	-3,868,441	-2,335,804	-6,204,245	6.359	5.9299
2024	0	0	460,576	58,263	0	-518,840	-220,284	-4,088,725	-2,140,257	-6,228,982	6.251	5.9299
2025	40,743	0	454,892	59,294	0	-514,186	-203,266	-4,291,991	-1,960,431	-6,252,422	6.195	5.9299
2026	0	0	445,716	60,349	0	-506,065	-186,272	-4,478,262	-1,796,373	-6,274,635	6.097	5.9299
2027	0	0	436,318	61,436	0	-497,754	-170,589	-4,648,851	-1,646,839	-6,295,691	5.997	5.9299
2028	0	0	427,093	62,520	0	-489,614	-156,237	-4,805,088	-1,510,553	-6,315,641	5.899	5.9299
2029	0	0	418,025	63,656	0	-481,681	-143,115	-4,948,204	-1,386,350	-6,334,554	5.803	5.9299
2030	0	0	409,099	64,814	0	-473,913	-131,106	-5,079,310	-1,273,175	-6,352,485	5.710	5.9299
2031	0	0	400,304	65,990	0	-466,294	-120,110	-5,199,419	-1,170,063	-6,369,483	5.618	5.9299
2032	0	0	391,628	67,186	0	-458,814	-110,040	-5,309,459	-1,076,137	-6,385,596	5.528	5.9299
2033	103,033	0	393,148	68,405	0	-461,552	-103,070	-5,412,529	-988,343	-6,400,872	5.561	5.9299
2034	0	0	385,396	69,639	0	-455,035	-94,613	-5,507,142	-908,209	-6,415,351	5.482	5.9299
2035	0	0	376,705	70,881	0	-447,587	-86,652	-5,593,794	-835,280	-6,429,074	5.393	5.9299
2036	0	0	368,116	72,146	0	-440,262	-79,361	-5,673,155	-768,924	-6,442,079	5.304	5.9299
2037	0	0	359,620	73,433	0	-433,054	-72,683	-5,745,839	-708,565	-6,454,404	5.218	5.9299
2038	281,845	0	378,799	74,744	0	-453,543	-70,877	-5,816,716	-649,369	-6,466,084	5.464	5.9299
2039	318,748	0	403,618	76,077	0	-479,696	-69,799	-5,886,515	-590,639	-6,477,154	5.779	5.9299
2040	53,207	0	401,900	77,435	0	-479,335	-64,941	-5,951,456	-536,189	-6,487,645	5.775	5.9299
2041	0	0	392,261	78,816	0	-471,077	-59,425	-6,010,881	-486,707	-6,497,588	5.676	5.9299
2042	0	0	382,239	80,223	0	-462,462	-54,318	-6,065,199	-441,811	-6,507,010	5.572	5.9299
2043	171,057	0	389,107	81,654	0	-470,761	-51,483	-6,116,683	-399,257	-6,515,940	5.672	5.9299
2044	0	0	380,548	83,111	0	-463,659	-47,213	-6,163,896	-360,507	-6,524,403	5.586	5.9299
2045	0	0	370,401	84,594	0	-454,995	-43,138	-6,207,034	-325,389	-6,532,423	5.482	5.9299
2046	0	0	360,393	86,103	0	-446,496	-39,416	-6,246,450	-293,574	-6,540,024	5.379	5.9299
2047	0	0	350,514	87,640	0	-438,153	-36,014	-6,282,465	-264,763	-6,547,228	5.279	5.9299
2048	0	0	340,753	89,203	0	-429,956	-32,906	-6,315,370	-238,685	-6,554,055	5.180	5.9299
2049	0	0	331,101	90,795	0	-421,896	-30,064	-6,345,434	-215,091	-6,560,525	5.083	5.9299
2050	0	0	321,549	92,415	0	-413,964	-27,466	-6,372,901	-193,756	-6,566,657	4.988	5.9299
2051	0	0	312,089	94,064	0	-406,153	-25,091	-6,397,992	-174,476	-6,572,468	4.893	5.9299
2052	0	0	302,714	95,742	0	-398,456	-22,920	-6,420,911	-157,063	-6,577,975	4.801	5.9299
2053	204,149	0	313,400	97,450	0	-410,851	-22,004	-6,442,916	-140,278	-6,583,194	4.950	5.9299
2054	0	0	305,587	99,189	0	-404,776	-20,185	-6,463,101	-125,039	-6,588,141	4.877	5.9299
2055	0	0	295,796	100,959	0	-396,755	-18,422	-6,481,523	-111,305	-6,592,828	4.780	5.9299
2056	0	0	286,097	102,760	0	-388,857	-16,811	-6,498,335	-98,936	-6,597,271	4.685	5.9299
2057	0	0	276,483	104,594	0	-381,077	-15,340	-6,513,674	-87,807	-6,601,481	4.591	5.9299
2058	0	0	266,946	106,460	0	-373,406	-13,995	-6,527,670	-77,802	-6,605,471	4.499	5.9299
2059	0	0	257,481	108,360	0	-365,841	-12,767	-6,540,437	-68,816	-6,609,253	4.408	5.9299
2060	0	0	248,082	110,293	0	-358,375	-11,645	-6,552,082	-60,755	-6,612,837	4.318	5.9299
2061	0	0	238,743	112,261	0	-351,004	-10,619	-6,562,701	-53,532	-6,616,233	4.229	5.9299
2062	0	0	229,460	114,264	0	-343,724	-9,683	-6,572,384	-47,068	-6,619,452	4.141	5.9299

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 2011 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%	8.380%	3.77%
Total	**100.00%**		**7.40%**

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, February 2, 2012.

New Chelsea Hydro Plant
Runner Replacement and Rewind

June 2012

Prepared by:

Jeremy Decker, P.Eng.

Todd Hynes, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
TODD HYNES
Todd Hynes
SIGNATURE
June/2 2012
DATE
NEWFOUNDLAND & LAB

NEWFOUNDLAND POWER
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Appendix A: Feasibility Analysis

1.0 Introduction

New Chelsea hydroelectric generating plant (the "Plant") is located on the Avalon Peninsula near the community of New Chelsea. The Plant was placed into service in 1956 and has one vertical generating unit with a capacity of 3.70 MW under a net head of 83.8 m. The normal annual production at New Chelsea is approximately 16.3 GWh or 3.8% of the total hydroelectric production of Newfoundland Power.

This 2013 project involves the replacement of the 56 year old generator windings and the replacement of the turbine runner with a high efficiency runner. Investing in the life extension of the Plant at this time ensures the availability of 16.3 GWh of energy to the Island Interconnected electrical system. It is estimated that replacing the turbine runner with a high efficiency unit will increase annual production by 1.0 GWh. The estimated levelized cost of energy from the Plant over the next 50 years, including the capital expenditure associated with the 2013 project, is 1.37¢ per kWh.

2.0 Background

There have been a number of upgrades to the original plant and equipment. In 2004 the Plant underwent a refurbishment when the penstock was replaced. At that time the generator windings and turbine runner were assessed to be capable of providing another 5 or more years of service.

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

2009 – Revenue meter replaced
2008 – Fibre communications cable installed to forebay
2006 – Water level monitoring equipment replaced
2004 – Penstock replaced, steel penstock installed
2004 – Butterfly valve and actuator replaced, PRV overhauled
2004 – Governor replaced, electric governor with digital control installed
2004 – Cooling water system upgraded
2004 – Protection and control panel replaced and unit control panel added
2004 – Switchgear cubicle installed
2004 – Network communications panel replaced and Gateway added
2004 – Battery charger replaced
1999 – Air compressor replaced
1998 – Partial discharge couplers installed
1996 – Battery bank replaced
1989 – Power cables from switchgear to substation replaced

This report provides a summary of the engineering assessment of the turbine and generator and the rationale for the refurbishment proposed for 2013.

3.0 Turbine Runner

The turbine runner at the Plant is 56 years old. With the exception of the wicket gates and linkages that were replaced in 1985, no upgrading to the turbine has been completed.

The generator has a maximum load rating of 4.0 MW. The turbine is rated at 5,600 Hp or 4.2 MW, but maximum power cannot be achieved due to the low efficiency of the runner design. Figure 1 demonstrates the low turbine efficiency from testing completed on this unit by Hatch as part of the Water Management Study.[1] The peak unit efficiency of the generator and turbine combination is 83% at 3.3 MW corresponding to 85% gate opening. Using a generator efficiency of 97%, this translates into a peak turbine efficiency of 85.5% which is considered low for a unit of this vintage and head.[2] These numbers are almost 5% less than guaranteed efficiency. At the maximum load of 3.7 MW, the unit efficiency drops to 82%.[3]

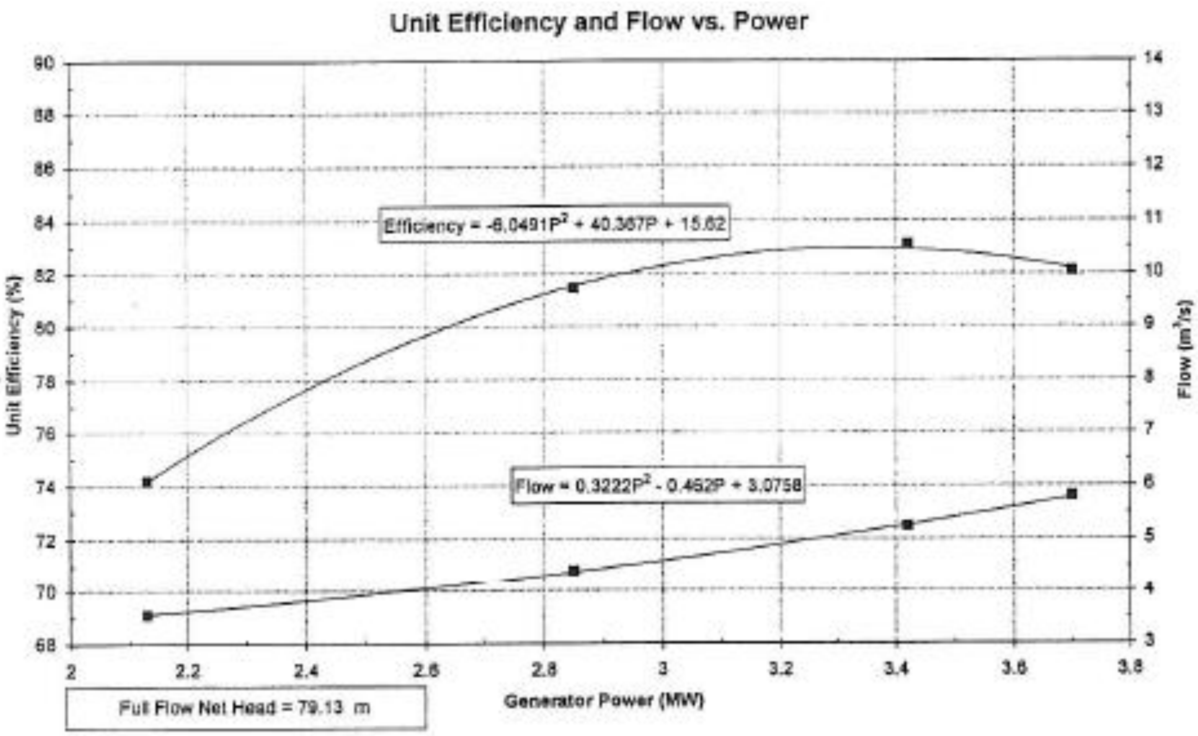

Figure 1 – Hatch Efficiency Test Summary

1 Hatch, formerly ACRES, completed a Water Management Study in 2001 titled *Hydroelectric Systems Strategic Planning Study*.

2 The 97% generator efficiency is a typical value for a generator of this size. The 3% loss is the amount of energy required to overcome the internal impedance in the generator winding, commonly referred to as I^2R losses, the result of which is heating of the stator. Energy consumed to produce this heating is the portion of the generator's capacity that is not available to supply load.

3 It was also found that the turbine power is lower than its rated power. During the test, turbine power was calculated to be 4.15 MW, while the nameplate rating is 4.20 MW, a difference of 50 kWs.

The report *Potential Projects to Increase Energy Production* filed with the 2010 Capital Budget Application identifies the New Chelsea turbine runner replacement as a potential project to increase hydro plant production.[4] A new runner design is estimated to increase unit and turbine efficiencies to approximately 89% and 86% respectively. This would result in a 10% increase in full load power output to 4.07 MW and a 6.1% increase in energy production or 1.0 GWH per year.

4.0 Generator

The generator at the Plant was manufactured by Canadian Westinghouse in 1956 and the stator and rotor windings are original to the 56 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.[5]

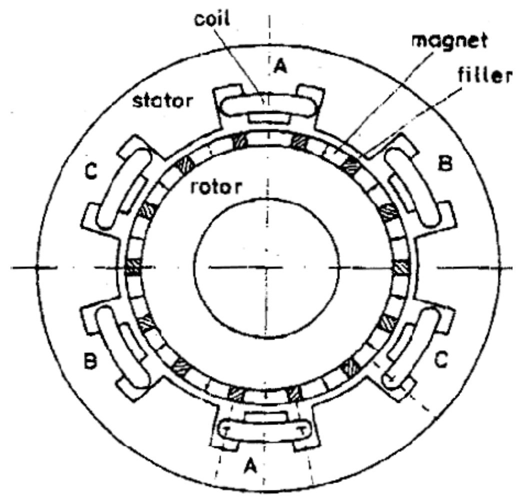

Figure 2 – Stator and Rotor Cross Section

Insulation for the rotor is subjected to similar thermal stresses as the stator due to normal operation of the unit. 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.

The Plant generator stator windings, which operate at 6,900 volts, are among the oldest windings remaining in service in the Company's fleet of generating plants.[6] Replacing the existing turbine runner with a more efficient design will effectively increase the efficient and peak load settings for the generator. These higher load settings will further stress the stator windings.

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

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

6 Newfoundland Power currently has fifteen generators operating at 6,900 volts with an average winding age of 31 years. Eight of the fifteen generators have been rewound. The average age of the windings when rewound was 50 years. The New Chelsea generator is 56 years old.

5.0 Project Description

This project involves 2 phases. The 1st phase involves replacement of the existing turbine runner with a high efficiency stainless steel unit and replacement of the wicket gates with stainless steel gates. The current wicket gate bushings are brass and require greasing to ensure continued operation. When the turbine is dismantled the bushings will be replaced with a self-lubricating type, which is the industry standard in new turbine installations and overhauls. These bushings require no maintenance and reduce the amount of petroleum products required to operate the generator systems.[7]

The 2nd phase involves the generator stator rewind and the re-insulation of the rotor to avoid the possibility of an in-service failure. This project includes removal and disassembly of the rotor, removal of the rotor pole insulation and installation of new insulation. The stator windings will be completely removed and a new set of windings installed. Improvements in insulating materials have resulted in the ability to use less insulation providing space for more copper conductor. The increase in the amount of copper in the windings makes them more efficient by reducing heating losses. In addition the maximum load rating of the generator will increase. Rewinding the generator in conjunction with replacing the turbine runner offers efficiencies as outlined above.

Both the turbine runner replacement and the generator rewind require the generator to be completely disassembled. This is a labour intensive procedure that results in a significant amount of down time to the Plant. Combining the two upgrades into one project offers significant cost savings. Overall labour costs and lost revenue due to water spillage will be reduced. In addition, both upgrades will improve efficiency and reliability, while increasing energy and maximum power output of the plant.

6.0 Project Execution

The Plant will be taken out of service for 12 weeks from July to September 2013 to complete this project. This time period was chosen to minimize spillage. Based on normal inflows, it is estimated that spillage will result in lost energy production of 1.36 GWh.

It is anticipated that the overhaul will take 10 weeks followed by 2 weeks of commissioning tests before the plant is returned to service.

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[7] Having less petroleum products in a hydro plant reduces the environmental risk of petroleum being released into the water used by the plant.

7.0 Project Cost

The total project cost is estimated at $1,500,000. Table 1 below provides the cost breakdown by plant refurbishment and runner replacement.

Table 1
Projected Expenditures

	Estimated Cost	
Cost Category	**Generator Rewind**	**Runner Replacement**[8]
Material	$718,000	$375,000
Labour - Internal	63,000	236,000
Labour - Contract	-	-
Engineering	45,000	12,000
Other	21,000	30,000
Total	**$847,000**	**$653,000**

8.0 Feasibility Analysis

Appendix A provides an economic feasibility analysis for the continued operation of the Plant. The results of the analysis show that the continued operation of the Plant is economical over the long term. Investing in the life extension of the Plant ensures the availability of 16.3 GWh of energy to the Island Interconnected electrical system. It is estimated that replacing the turbine runner with a high efficiency unit will increase this to 17.3 GWh.

The estimated levelized cost of energy from the Plant over the next 50 years, including the capital expenditure of $1,989,000 over the next 25 years, is 1.37¢ per kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation.[9]

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[8] The runner replacement is included in the *Hydro Plant Production Increase* project found in Schedule B at page 4 of 93.

[9] The cost of electricity from the Holyrood thermal generating plant is estimated at 18.9 ¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $118.80 per barrel for 2012 as per Newfoundland Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated March 31, 2012.

Appendix A
Feasibility Analysis

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2.0 Capital Costs and Energy Benefits A-1

3.0 Operating Costs A-1

4.0 Benefits A-2

5.0 Financial Analysis A-2

6.0 Conclusion A-2

Attachment A: Summary of Capital Costs
Attachment B: Summary of Operating Costs
Attachment C: Calculation of Levelized Cost of Energy

1.0 Introduction

This feasibility analysis was completed to determine the viability of replacing the runner and completing the rewind at Newfoundland Power's New Chelsea plant.

With investment required in 2013 to provide increased energy production and 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 and Energy Benefits

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
New Chelsea Hydroelectric Plant
Capital Expenditures

Year	($000s)
2013	$1,500
2024	$324
2026	$20
2034	$145
Total	**$1,989**

The estimated capital expenditure for the Plant over the next 25 years is $1,989,000. A more comprehensive breakdown of capital costs is provided in Attachment A.

3.0 Operating Costs

Operating costs for the Plant are estimated to be approximately $72,435[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.

1 2012 dollars.

4.0 Benefits

The maximum output from the Plant is 3,700 kW. The Plant normally operates at an efficient load of 3,400 kW to maximize the energy from the water.

The estimated long-term normal production of the Plant under present operating conditions is 16.3 GWh per year. The estimated long-term normal production with the generator equipped with a high efficiency turbine runner is 17.3 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 1.374¢ per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from New Chelsea hydro plant can be produced at a significantly lower price than the cost of replacement energy, assumed to come from Newfoundland and Labrador Hydro's Holyrood thermal generating station.[2]

The future capacity benefits of the continued availability of the Plant have not been considered in this analysis. If factored into the feasibility analysis, the financial benefit associated with system capacity would further support the viability of continued plant operations.

6.0 Conclusion

The results of the feasibility analysis show that the levelized cost of rewinding the generator and replacing the turbine runner is lower in cost than energy from other sources such as a new hydroelectric development or additional Holyrood thermal generation.

Based on these results it is recommended that Newfoundland Power proceed with the project to rewind the generator and replace the runner at New Chelsea plant. Replacing the runner will result in an increase in annual energy of 1.0 GWh. The expected annual energy output at New Chelsea is 17.3 GWh.

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[2] The cost of electricity from the Holyrood thermal generating plant is estimated at 18.9 ¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $118.80 per barrel for 2012 as per Newfoundland Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated March 31, 2012.

Attachment A
Summary of Capital Costs

New Chelsea Feasibility Analysis Summary of Capital Costs ($000s)				
Description	**2013**	**2024**	**2026**	**2034**
Civil				
Penstock		300		
Powerhouse				
Mechanical				
Turbine Upgrades - Runner	653			
Governor Upgrades				50
Main Inlet and Plant Bypass Valves				
Cooling Water				
Heat and Ventilation				10
Compressed Air				
Electrical				
P&C and Governor Controls		15		60
Generator Rewind	847			
Switchgear				
AC & DC Systems		9	20	
Power Cables				25
Annual Totals ($2012)	**1,500**	**324**	**20**	**145**

Attachment B
Summary of Operating Costs

New Chelsea Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs
($2012)

Year	**Amount**
2007	$55,506
2008	$49,634
2009	$40,908
2010	$52,140
2011	$97,987
Average	**$59,235**

5 -Year Average Operating Cost	$59,235[1]
Water Use Rental Fee (with increased output)	$ 13,200[2]
Total Forecast Annual Operating Cost	$72,435

[1] 2012 dollars.
[2] Provincial Department of Environment and Conservation annual fee based on $ 0.80 per MWhr.

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted Average Incremental Cost of Capital 7.40%

PW Year 2012

YEAR	Generation Hydro 64.4yrs 8% CCA	Generation Hydro 64.4yrs 50% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit +ve	Cumulative Present Value Benefit +ve	Present Worth of Sunk Costs	Total Present Worth Benefit +ve	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2013	1,500,000	0	146,832	72,435	0	-219,267	-204,159	-204,159	-1,775,564	-1,979,722	1.267	1.3735
2014	0	0	157,206	73,925	0	-231,130	-200,377	-404,536	-1,639,275	-2,043,811	1.336	1.3735
2015	0	0	152,565	75,434	0	-227,999	-184,043	-588,579	-1,516,122	-2,104,702	1.318	1.3735
2016	0	0	148,154	76,904	0	-225,058	-169,152	-757,731	-1,404,771	-2,162,502	1.301	1.3735
2017	0	0	143,954	78,293	0	-222,246	-155,530	-913,261	-1,304,031	-2,217,292	1.285	1.3735
2018	0	0	139,948	79,699	0	-219,646	-143,119	-1,056,380	-1,212,842	-2,269,223	1.270	1.3735
2019	0	0	136,120	81,093	0	-217,214	-131,782	-1,188,162	-1,130,259	-2,318,422	1.256	1.3735
2020	0	0	132,457	82,509	0	-214,966	-121,433	-1,309,595	-1,055,435	-2,365,031	1.243	1.3735
2021	0	0	128,945	83,907	0	-212,852	-111,954	-1,421,549	-987,614	-2,409,163	1.230	1.3735
2022	0	0	125,572	85,378	0	-210,950	-103,309	-1,524,858	-926,118	-2,450,976	1.219	1.3735
2023	0	0	122,327	86,876	0	-209,202	-95,394	-1,620,252	-870,338	-2,490,590	1.209	1.3735
2024	395,462	0	157,910	88,411	0	-246,321	-104,580	-1,724,832	-803,294	-2,528,127	1.424	1.3735
2025	0	0	157,626	89,975	0	-247,601	-97,881	-1,822,713	-740,982	-2,563,695	1.431	1.3735
2026	25,285	0	155,958	91,576	0	-247,535	-91,112	-1,913,825	-683,577	-2,597,402	1.431	1.3735
2027	0	0	152,142	93,225	0	-245,367	-84,092	-1,997,917	-631,436	-2,629,352	1.418	1.3735
2028	0	0	148,213	94,870	0	-243,084	-77,569	-2,075,485	-584,140	-2,659,626	1.405	1.3735
2029	0	0	144,417	96,594	0	-241,011	-71,608	-2,147,094	-541,232	-2,688,325	1.393	1.3735
2030	0	0	140,742	98,351	0	-239,093	-66,144	-2,213,238	-502,296	-2,715,534	1.382	1.3735
2031	0	0	137,180	100,135	0	-237,316	-61,129	-2,274,367	-466,960	-2,741,327	1.372	1.3735
2032	0	0	133,721	101,951	0	-235,672	-56,523	-2,330,889	-434,889	-2,765,778	1.362	1.3735
2033	0	0	130,357	103,800	0	-234,157	-52,290	-2,383,179	-405,779	-2,788,958	1.354	1.3735
2034	211,535	0	147,788	105,673	0	-253,460	-52,701	-2,435,879	-375,050	-2,810,930	1.465	1.3735
2035	0	0	146,054	107,558	0	-253,612	-49,099	-2,484,978	-346,775	-2,831,753	1.466	1.3735
2036	0	0	142,278	109,477	0	-251,755	-45,381	-2,530,360	-321,128	-2,851,487	1.455	1.3735
2037	0	0	138,602	111,431	0	-250,032	-41,965	-2,572,325	-297,865	-2,870,190	1.445	1.3735
2038	0	0	135,018	113,419	0	-248,437	-38,824	-2,611,149	-276,765	-2,887,914	1.436	1.3735
2039	0	0	131,519	115,442	0	-246,961	-35,935	-2,647,084	-257,628	-2,904,712	1.428	1.3735
2040	0	0	128,098	117,502	0	-245,601	-33,274	-2,680,358	-240,273	-2,920,631	1.420	1.3735
2041	115,579	0	136,063	119,599	0	-255,662	-32,251	-2,712,609	-223,109	-2,935,718	1.478	1.3735
2042	0	0	133,580	121,733	0	-255,313	-29,988	-2,742,597	-207,419	-2,950,016	1.476	1.3735
2043	0	0	130,001	123,905	0	-253,906	-27,768	-2,770,364	-193,202	-2,963,567	1.468	1.3735
2044	537,997	0	179,159	126,116	0	-305,274	-31,085	-2,801,450	-174,959	-2,976,409	1.765	1.3735
2045	0	0	179,442	128,366	0	-307,808	-29,184	-2,830,633	-157,946	-2,988,579	1.779	1.3735
2046	0	0	174,402	130,656	0	-305,058	-26,930	-2,857,563	-142,550	-3,000,113	1.763	1.3735
2047	0	0	169,502	132,987	0	-302,489	-24,863	-2,882,427	-128,618	-3,011,044	1.748	1.3735
2048	0	0	164,730	135,360	0	-300,091	-22,967	-2,905,393	-116,010	-3,021,404	1.735	1.3735
2049	0	0	160,077	137,775	0	-297,852	-21,225	-2,926,618	-104,603	-3,031,222	1.722	1.3735
2050	0	0	155,532	140,234	0	-295,766	-19,624	-2,946,242	-94,284	-3,040,526	1.710	1.3735
2051	0	0	151,087	142,736	0	-293,823	-18,152	-2,964,394	-84,950	-3,049,344	1.698	1.3735
2052	0	0	146,735	145,283	0	-292,017	-16,797	-2,981,191	-76,510	-3,057,701	1.688	1.3735
2053	0	0	142,466	147,875	0	-290,341	-15,550	-2,996,741	-68,880	-3,065,621	1.678	1.3735
2054	0	0	138,276	150,513	0	-288,790	-14,401	-3,011,142	-61,984	-3,073,126	1.669	1.3735
2055	0	0	134,158	153,199	0	-287,357	-13,343	-3,024,485	-55,755	-3,080,240	1.661	1.3735
2056	43,055	0	134,320	155,932	0	-290,252	-12,548	-3,037,033	-49,948	-3,086,981	1.678	1.3735
2057	0	0	130,626	158,715	0	-289,340	-11,647	-3,048,680	-44,690	-3,093,370	1.672	1.3735
2058	0	0	126,556	161,547	0	-288,103	-10,798	-3,059,478	-39,946	-3,099,425	1.665	1.3735
2059	0	0	122,545	164,429	0	-286,974	-10,015	-3,069,493	-35,670	-3,105,163	1.659	1.3735
2060	0	0	118,587	167,363	0	-285,950	-9,291	-3,078,785	-31,816	-3,110,601	1.653	1.3735
2061	0	0	114,678	170,349	0	-285,027	-8,623	-3,087,408	-28,347	-3,115,755	1.648	1.3735
2062	0	0	110,814	173,389	0	-284,202	-8,006	-3,095,414	-25,225	-3,120,639	1.643	1.3735

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 2012 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%	8.380%	3.77%
Total	**100.00%**		**7.40%**

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, February 2, 2012.

Pitmans Pond Hydro Plant Refurbishment

June 2012

Prepared by:

Jeremy Decker, P.Eng.

Todd Hynes, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
TODD HYNES
SIGNATURE
Jun 12 2012
DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
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Appendix A: Feasibility Analysis
Appendix B: Pitmans Pond Switchgear Arc Flash Study

1.0 Introduction

The Pitmans Pond hydroelectric generating plant (the "Plant"), located on the Avalon Peninsula near the community of New Chelsea, was commissioned in 1959 with a capacity of 625 kW under a net head of approximately 21.3 m. The plant contains a single horizontal 1,200 hp Francis turbine manufactured by Gilkes and a Westinghouse 1,000 kVA induction generator.[1] The Plant is connected to the Island interconnected electrical system at New Chelsea substation via Newfoundland Power's 12.5 kV distribution feeder, NCH-03.

The refurbishment and life extension of the Pitmans Pond Hydro Plant includes the modernization of the gate positioner control, upgraded protection and controls and replacement of equipment that has surpassed its reliable service life. In addition, the replacement of the existing runner with a high efficiency stainless steel runner, will increase plant production by an additional 0.7 GWH per year. The estimated levelized cost of energy from the Plant over the next 50 years, including the capital expenditure of $2.2 million over the next 25 years, is 6.90¢ per kWh.

2.0 General

The Plant has a capacity of 625 kVA and an annual production of 2.8 GWH of energy. It will be refurbished to provide reliable peaking capacity and to operate at base load during periods of high inflows and when operating isolated from the grid.

There have been a number of upgrades to the original plant and equipment. The following is a list of the upgrades that have been completed in the past 25 years:

- 2011 – Battery bank and battery charger replaced
- 2009 – Revenue meter replaced
- 2009 – Cooling water system upgraded
- 2005 – Forebay water level transducer replaced
- 2004 – Intruder and fire alarm systems added
- 2002 – Generator circuit breaker and power cables replaced
- 1999 – Air compressor replaced
- 1987 – Control system improvements (start-up/shutdown)
- 1987 – Battery bank and battery charger replaced
- 1986 – Surge protection replaced

This report provides a summary of the engineering assessment of the Pitmans Pond hydroelectric plant and the refurbishment proposed for 2013.

3.0 Civil

The wooden double garage doors are deteriorated and will be replaced with a roll-up overhead door that will provide additional security for the building. The plant windows have wooden

[1] The generator is rated at 1,000 kVA at 85% power factor, which equates to a 850 kW load rating.

frames that are exhibiting rot. The windows will be replaced with maintenance free aluminum or vinyl style frame.

4.0 Gate Positioner

The Gilkes gate positioner is the original unit. It uses a fractional horsepower DC motor and reduction gear mechanism to operate a lever and connecting rod on the turbine. The reduction gear mechanism contains 114 litres of lubricating oil. The gate positioner controls were manufactured by Igranic Electric Co. Ltd. This type of gate positioner is now obsolete and no longer supported by the manufacturer.

A new gate positioner with a PLC based digital control system will be installed. A Request for Proposals will be issued to governor suppliers to determine hydraulic and electric options available to operate the wicket gates. The optimum solution proposed by the vendors will be implemented. The logic program for the new gate positioner control system will be installed on the plant unit control programmable logic controller (PLC).

Figure 1 - Gate Positioner

More advanced control of the gate positioner setpoints will facilitate the implementation of a Water Management System in the PLC. This will optimize energy production from the available water, increasing the energy output of the plant.

5.0 Generator

The generator stator and rotor windings are original to the 1959 installation but there is no evidence that they require upgrading at this time. The cables from the resistance temperature detectors (“RTDs”) in the existing stator windings will be reterminated and the temperature signals monitored by the new control system.

The generator neutral is solidly connected to ground through a disconnect switch. This method of grounding does not provide optimum protection of the generator windings. It permits high ground fault currents to flow, which can result in significant winding damage. To minimize the magnitude of fault currents, high impedance grounding is the preferred method of generator neutral to ground connection. A neutral grounding transformer with secondary resistor and a station ground bus will be installed in the generator pit to provide this protection. The grounding transformer will be connected to the station ground bus in the pit, removing the existing connection near the control panel.

The generator surge protection capacitor and lightning arresters are connected to the 2.4 kV bus in the switchgear. A three phase capacitor and type MOV surge arresters were installed in 1986 and will not be replaced.

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 testing system will be installed to provide a warning and prompt corrective action when the insulation value is reduced.[2] To enable the testing to be completed, the insulation testing system must include a neutral contactor to automatically disconnect the stator windings from ground when the generator shuts down.

The three generator protection neutral current transformers and a ground current transformer, located in the generator pit, are original units. The ground CT will be eliminated since this sensing will be provided by the neutral grounding transformer. The neutral CTs, which provide the critical sensing for all the generator protection elements, will be replaced.

6.0 Switchgear

The switchgear is original to the 1959 installation. Several upgrades have been completed over the years. The surge protection was replaced in 1986, the generator circuit breaker was replaced with an ABB Type VD4 vacuum unit in 2002, and the power cables from the substation to the switchgear and on to the generator were also replaced at that time. The switchgear, circuit breaker, power cables and surge protection are in excellent condition and will not be replaced.[3] The potential transformers (PTs) and current transformers (CTs) are original to the 1959 installation. The PTs and CTs are critical to the the electrical protection of the generator and will be replaced.[4]

Figure 2 - Switchgear and Control Panel (doors open)

The relatively low fault energy levels associated with the switchgear at this location require an arc flash boundary of 0.94 metres.[5] Most of the protection and control equipment is located in a separate Relaying & Metering panel adjacent to the switchgear. The only equipment mounted in the switchgear doors are a breaker control switch and revenue meter. These will be relocated to the new unit control panel outside the arc flash boundary, providing increased employee safety.

2 The Company has installed 15 MegAlert® insulation testing systems on generators that have been similarly refurbished. The MegAlert® system will also prevent re-energizing the generator should the insulation measurement falls below a safe value. It will continuously monitor the integrity of the insulation while the unit is shut down, ensuring it can be re-energized when required.

3 There is presently no spare generator breaker for the Pitmans Pond plant. A spare breaker of the same type will be purchased as part of this project.

4 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 An arc flash study for the Pitmans Pond switchgear is included as Appendix B.

7.0 AC Distribution System

A 10kVA, 120/240 V single phase station service transformer is pole mounted on NCH-03 feeder just outside the Pitmans Pond substation yard. It is a new stainless steel unit and does not require replacement.

The AC panel and meter have been upgraded from the original installation. The existing 40-circuit, 200 A panel does not have enough spare circuits to accommodate the heating and ventilation upgrades that will be completed as part of this project. It will be replaced with a 60-circuit, 250A panel.

Figure 3 - AC Panel

8.0 DC System

The existing GNB Exide Absolyte gel-cell battery bank and the temperature compensated C-Can battery charger were installed in 2011. The battery charger will be relocated closer to the battery bank to make room for the new unit control panel.

The 12-circuit DC distribution panel has three spare two-pole circuits which are not adequate for the additional requirements of the plant controls upgrade. A new 60-circuit panel will be installed to ensure adequate circuit capacity and the availability of replacement circuit breakers.

9.0 Protective Relaying

The generator electrical protection is provided by General Electric electromechanical relays. The following protective elements are in service:

32	Reverse Power
46	Stator Unbalance Current (Negative Sequence)
49	Thermal Protection
50/51	Phase Overcurrent
50/51 N	Neutral Overcurrent
59	Overvoltage
87	Differential

The existing protective relaying at Pitmans Pond plant lacks three elements[6] of the minimum protection set. In addition there is no Residual Neutral Overvoltage 59GN element, which is required to implement the protection provided by the neutral grounding transformer. The existing relaying will be replaced with a digital multifunction generator protection relay located in the unit control panel. Improved protection reduces stresses due to electrical faults and in turn extends the life of the generator.

[6] The existing generator protection does not include Sensitive Ground Fault 87GN, Frequency 81 and System Backup 51V protection elements, which are recommended by the IEEE for these generators.

10.0 Plant Control

There is no programmable logic controller at Pitmans Pond. The existing plant control utilizes relay-based logic. An Allan-Bradley CompactLogix® programmable logic controller will be installed to replace the relay-based logic.[7] It will provide local and remote control of the plant and generator functions. Standard control, protection and automation functionality will be implemented.

The plant is remotely monitored from the System Control Centre. The unit has remote control functions that are limited to start, stop and loading capability. At present, there is no automation with respect to water management and the setting of machine loads to optimize the use of the water resources. The installation of the PLC will provide processing power that will greatly improve the local and remote monitoring and control functionality. It will facilitate the implementation of a variety of control modes to ensure efficient operation of the plant and utilization of available water.

Since the New Chelsea plant utilizes the same water, the water management routine at New Chelsea will be modified to incorporate the Pitmans Pond plant.[8] The ability to monitor and control the Pitmans Pond plant from New Chelsea plant will also be added. This will permit remote operation of the Pitmans Pond Plant from New Chelsea without having to travel over the 3 kilometre access road, which is not ploughed in the winter. This will be especially useful when these two plants are supplying isolated load.

The existing electromechanical annunciator, located in the Relaying & Metering panel will be replaced with an Allan-Bradley Industrial Computer human-machine interface (“HMI”). The 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 will be installed in the unit control panel to replace the existing SCADA Remote Terminal Unit. This will improve communications to the SCADA system. This communications system in conjunction with the upgraded processor will enhance remote monitoring and control of plant operations. It will provide additional information about the performance of key plant components. Improved communications infrastructure will also 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 outside the arc flash boundary of the switchgear, will contain the processor, associated monitoring and control equipment, control switches, generator multifunction protection relay and network communications equipment.

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[7] 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.

[8] Pitmans Pond plant is located upstream of New Chelsea in the same watershed. Pitmans Pond is the main reservoir in the system and the water flows through Pitmans Pond plant to Seal Cove Pond to New Chelsea plant.

The following equipment will be located in the panel:

a) Allan Bradley CompactLogix® PLC
b) Industrial Computer HMI with keyboard
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) Speed raise/lower control switch (ANSI device No. 15CS)
j) Gate limit control switch (ANSI device No. 65CS)
k) Generator lock out relay (ANSI Device No. 86G)
l) Three position local/remote control switch (ANSI Device No. 43CS)
m) Schweitzer SEL-700G1 relay and SEL-2664 rotor ground module
n) Cooper Power Systems Distribution Concentrator
o) Ethernet Switch

11.0 Instrumentation

The original Gilkes mercury temperature switch on the thrust bearing is still in service and is the only existing bearing temperature sensor. An Airpax Tach-Pac 3 speed switch was installed in the Relaying & Metering panel as part of the 1987 controls upgrade.[9] As part of the 2009 cooling water upgrade, an oil level sensor was installed on the thrust bearing, which is the only water-cooled bearing. There are analog scroll case and draft tube pressure gauges in the gate positioner.

The thrust bearing oil level sensor will be reused. The speed switch will be returned to inventory and dual speed sensors installed on the existing toothgear. This will provide analog speed signals to the new gate positioner and PLC. The PLC will perform speed processing functions previously performed by the speed switch. Bearing temperature thermocouples and vibration sensors will be added to all three bearings and a digital scroll case pressure transducer will be installed. The bearing temperature thrust bearing oil level, vibration sensors and cooling water monitoring and control will be integrated into the PLC.

A Schneider PowerLogic ION 7550 revenue meter was installed in Cubicle No. 2 of the switchgear in 2009. It will be removed from the switchgear and installed in the new unit control panel.

12.0 Heating and Ventilation

There is no exhaust fan and no automatic cooling in the Plant. The two intake louvers, located in the front of the powerhouse, and the two exhaust vents, located at the rear of the building near the ceiling, must be manually operated.[10] The two anti-condensation blower type heaters in the

9 It uses a magnetic speed sensor on a toothgear attached to the end of the generator shaft.
10 The exhaust vents can only be accessed by climbing a ladder.

generator pit are individually controlled by built-in thermostats. There are no infrared heaters and as a result temperature is not adequately maintained during cold periods.

The heat and ventilation controls will be consolidated into one plant control panel and integrated with the PLC. A thermostat/humidistat will be installed on the main floor and used by the PLC to control all heat and ventilation equipment. The two intake louvers will be replaced and actuators added. An exhaust fan with dampers will be installed in one of the exhaust vent openings. It will no longer be necessary to operate the second exhaust vent and it will be left as is. Additional blower heaters will be installed in the generator gallery.

Figure 4 – Exhaust Vent

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 probe was installed in 2005 and the signal is sent from the forebay to the plant via a radio link. This system is in good condition and no upgrading is required.

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 setpoints:

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 Water	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 upgraded with a new duplex filter, pressure gauge and solenoid valves in 2009 and no additional work is required. The controls will be integrated into the new CompactLogix PLC.

15.0 Turbine

The Pitmans Pond generator has capacity of 850 kW and the runner is rated at 895 kW, but maximum power cannot be achieved. The existing maximum power output of the plant is 625 kW.

The runner at Pitmans Pond is 53 years old and no refurbishment has been completed. An analysis of SCADA data completed by Acres International estimates that the maximum efficiency is 71% and the peak load efficiency is 66%.[11] If the runner were replaced with a high efficiency unit with a maximum efficiency of 88% and a peak load efficiency of 84%, the simulation model of the system indicates that an increase in annual energy production of 0.7 GWh would be realized. As a result, the turbine runner will be replaced with a high efficiency stainless steel runner as part of this project.

When the turbine is disassembled the wicket gates will be inspected and, if necessary, replaced with the complete set of spare gates stored on site as spares. The current wicket gate bushings at Pitmans Pond are brass and require greasing to ensure continued operation. When the turbine is dismantled the bushings will be replaced with self-lubricating bushings. Self-lubricating bushings are industry standard in new turbine installations or overhauls.

The turbine seal has been leaking excessively for a number of years. Currently a guard is installed over the shaft to redirect the leakage to the turbine drain. As part of the overhaul, the seal sleeve will be replaced on the shaft and a new seal will be installed.

16.0 Main Inlet Valve

The main inlet valve is a 54-inch butterfly valve, which is original equipment. Although there is some leakage, the valve is still in good condition and will not be replaced or overhauled as part of this project.

17.0 Overhead Crane

The overhead crane is the original 10-ton Morris unit consisting of two separate 5-ton hoists. All horizontal travel and vertical lifting is manual and accomplished via chain operated mechanical mechanisms. Operation of the crane is labour intensive and difficult for one person operation. The crane will be replaced with a new electric operated unit with pendant control.

Figure 5 – Overhead Crane

[11] Hydroelectric Systems Strategic Planning Study completed by Acres International, January 2001.

18.0 Project Cost

The total project cost is estimated at $1,350,000. Table 1 below provides the cost breakdown by plant refurbishment and runner replacement.

Table 1
Projected Expenditures

Cost Category	Estimated Cost Plant Refurbishment	Estimated Cost Runner Replacement[12]
Material	$625,000	$300,000
Labour - Internal	100,000	100,000
Labour - Contract	-	-
Engineering	85,000	25,000
Other	65,000	50,000
Total	**$875,000**	**$475,000**

19.0 Summary of Work

The following is a summary of the work proposed to be completed during the 2013 refurbishment project:

a) Replace garage door
b) Replace gate positioner with PLC based digitally controlled unit
c) Install neutral grounding transformer and resistor
d) Install automatic stator insulation testing system
e) Replace the generator neutral current transformers
f) Replace the switchgear potential transformers and current transformers
g) Replace the AC distribution panel
h) Replace the DC distribution panel
i) Replace generator protective relaying with a digital multifunction relay
j) Install a PLC system that will monitor and control plant and generator functions
k) Implement a Water Management System in the PLC and integrate with the New Chelsea plant Water Management System
l) Add capability to monitor and control the Pitmans Pond plant from New Chelsea plant
m) Install computer base HMI to replace existing electromechanical annunciator and provide enhanced functionality
n) Install a data concentrator to communicate with SCADA and provide remote administration of the new equipment

[12] The runner replacement is included in the *Hydro Plant Production Increase* project found in Schedule B at page 4 of 93.

o) Install new unit control panel outside arc flash boundary of the switchgear where all protection, control and network communications equipment will be located
p) Upgrade the speed sensing
q) Replace thrust bearing temperature sensor and add sensors to other two bearings
r) Add vibration sensors to all bearings
s) Replace scroll case pressure sensor
t) Relocate revenue meter from switchgear to unit control panel
u) Install heating and ventilation system control panel
v) Replace intake louvers and install actuators
w) Add an exhaust fan and dampers
x) Install additional heaters in generator gallery
y) Replace turbine runner
z) Replace overhead crane

20.0 Feasibility Analysis

Appendix A provides an economic feasibility analysis for the continued operation of the Plant. The results of the analysis show that the continued operation of the Plant is economical over the long term. Investing in the life extension of the Plant ensures the availability of 2.8 GWh of energy to the Island Interconnected electrical system. It is estimated that replacing the turbine runner with a high efficiency unit will increase this to 3.5 GWh.

The estimated levelized cost of energy from the Plant over the next 50 years, including the capital expenditure of $2.2 million over the next 25 years, is 6.90¢ per kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation.[13]

21.0 Concluding

Engineering assessments have identified necessary work associated with the refurbishment and life extension of the Pitmans Pond Hydro Plant. In addition, the replacement of the existing runner with a high efficiency stainless steel runner, will increase plant production by an additional 0.7 GWH per year.

Installation of a PLC based gate positioner control system, PLC based plant control system, automatic stator insulation testing system, upgraded protection and controls 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 A verifies the financial viability of completing this project. The 3.5 GWh of energy that will be available from Pitmans Pond 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

[13] The cost of electricity from the Holyrood thermal generating plant is estimated at 18.90 ¢/kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $118.80/barrel for 2011 as per Newfoundland Hydro letter regarding Rate Stabilization plan – Fuel Price Projection dated March 31, 2012.

spill. Based upon these considerations, and others outlined in this report and attached analysis, the project is recommended to proceed in 2013.

Appendix A
Feasibility Analysis

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1.0 Introduction A-1

2.0 Capital Costs A-1

3.0 Operating Costs A-1

4.0 Benefits A-2

5.0 Financial Analysis A-2

6.0 Conclusion A-2

Attachment A: Summary of Capital Costs
Attachment B: Summary of Operating Costs
Attachment C: Calculation of Levelized Cost of Energy

1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Pitmans Pond hydroelectric plant (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2013.

With investment required in 2013 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
Pitmans Pond Hydroelectric Plant
Capital Expenditures

Year	($000s)
2013	$1,350
2023	$765
2026	$75
Total	**$2,190**

The estimated capital expenditure for the Plant over the next 25 years is $2,190,000. A more comprehensive breakdown of capital costs is provided in Attachment A.

3.0 Operating Costs

Operating costs for the Plant are estimated to be approximately $25,959[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.

[1] 2012 dollars.

4.0 Benefits

The maximum output from the Plant is 625 kW. The Plant normally operates at an efficient load of 610 kW to maximize the energy from the water.

The estimated long-term normal production of the Plant under present operating conditions is 2.8 GWh per year. The estimated long-term normal production at the Plant after the installation of the high efficiency turbine runner is 3.5 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 6.90¢ per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Pitmans Pond 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 Pitmans Pond guarantees the availability of low cost energy to the Province. Otherwise, the projected annual production of 3.5 GWh would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood thermal generating station. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

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[2] The cost of electricity from the Holyrood thermal generating plant is estimated at 18.90 ¢/kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $118.80/barrel for 2011 as per Newfoundland Hydro letter regarding Rate Stabilization plan – Fuel Price Projection dated March 31, 2012.

Attachment A
Summary of Capital Costs

Pitmans Pond Feasibility Analysis Summary of Capital Costs ($000s)			
Description	**2013**	**2023**	**2026**
Civil			
Penstock			
Powerhouse	59		
Mechanical			
Turbine Upgrades	475		
Gate Positioner Upgrades	190		
Main Inlet and Plant Bypass Valves		350	
Cooling Water			
Heat and Ventilation	44		
Compressed Air			
Electrical			
P&C and Gate Positioner Controls	427	15	50
Generator Rewind		400	
Switchgear	67		
AC & DC Systems	88		25
Annual Totals ($2012)	**1,350**	**765**	**75**

Attachment B
Summary of Operating Costs

Pitmans Pond Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs
($2012)

Year	Amount
2007	$29,648
2008	$12,824
2009	$17,103
2010	$32,921
2011	$22,899
Average	**$23,079**

5 -Year Average Operating Cost	$23,079[1]
Water Use Rental Fee	$ 2,880[2]
Total Forecast Annual Operating Cost	$25,959

1 2012 dollars.
2 Provincial Department of Environment and Conservation annual fee based on $ 0.80 per MWhr.

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted Average Incremental Cost of Capital 7.40%
PW Year 2012

YEAR	Generation Hydro 64.4yrs 8% CCA	Generation Hydro 64.4yrs 50% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit +ve	Cumulative Present Value Benefit +ve	Present Worth of Sunk Costs	Total Present Worth Benefit +ve	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2013	1,350,000	0	132,149	25,959	0	-158,107	-147,214	-147,214	-2,614,058	-2,761,272	4.517	6.8969
2014	0	0	141,485	26,493	0	-167,978	-145,628	-292,841	-2,491,398	-2,784,239	4.799	6.8969
2015	0	0	137,309	27,034	0	-164,342	-132,659	-425,500	-2,380,561	-2,806,061	4.695	6.8969
2016	0	0	133,339	27,560	0	-160,899	-120,931	-546,431	-2,280,345	-2,826,775	4.597	6.8969
2017	0	0	129,558	28,058	0	-157,617	-110,301	-656,732	-2,189,679	-2,846,411	4.503	6.8969
2018	0	0	125,953	28,562	0	-154,515	-100,680	-757,412	-2,107,609	-2,865,021	4.415	6.8969
2019	0	0	122,508	29,062	0	-151,570	-91,957	-849,369	-2,033,284	-2,882,653	4.331	6.8969
2020	0	0	119,211	29,569	0	-148,781	-84,045	-933,414	-1,965,942	-2,899,357	4.251	6.8969
2021	0	0	116,050	30,070	0	-146,121	-76,855	-1,010,269	-1,904,903	-2,915,173	4.175	6.8969
2022	0	0	113,015	30,598	0	-143,612	-70,331	-1,080,600	-1,849,557	-2,930,157	4.103	6.8969
2023	917,512	0	199,907	31,134	0	-231,041	-105,352	-1,185,952	-1,758,401	-2,944,354	6.601	6.8969
2024	0	0	203,438	31,684	0	-235,123	-99,826	-1,285,778	-1,672,028	-2,957,806	6.718	6.8969
2025	0	0	197,882	32,245	0	-230,127	-90,973	-1,376,751	-1,593,802	-2,970,553	6.575	6.8969
2026	94,819	0	201,838	32,819	0	-234,657	-86,372	-1,463,123	-1,519,509	-2,982,633	6.704	6.8969
2027	0	0	197,380	33,409	0	-230,789	-79,095	-1,542,219	-1,451,864	-2,994,083	6.594	6.8969
2028	0	0	192,167	33,999	0	-226,166	-72,170	-1,614,389	-1,390,543	-3,004,932	6.462	6.8969
2029	0	0	187,148	34,617	0	-221,765	-65,890	-1,680,279	-1,334,938	-3,015,217	6.336	6.8969
2030	0	0	182,306	35,247	0	-217,553	-60,185	-1,740,464	-1,284,504	-3,024,968	6.216	6.8969
2031	0	0	177,629	35,886	0	-213,515	-54,998	-1,795,462	-1,238,750	-3,034,212	6.100	6.8969
2032	0	0	173,102	36,537	0	-209,639	-50,279	-1,845,741	-1,197,234	-3,042,975	5.990	6.8969
2033	0	0	168,714	37,199	0	-205,913	-45,983	-1,891,724	-1,159,558	-3,051,282	5.883	6.8969
2034	0	0	164,453	37,870	0	-202,324	-42,068	-1,933,792	-1,125,364	-3,059,156	5.781	6.8969
2035	0	0	160,310	38,546	0	-198,856	-38,498	-1,972,290	-1,094,328	-3,066,618	5.682	6.8969
2036	0	0	156,275	39,234	0	-195,509	-35,242	-2,007,532	-1,066,158	-3,073,691	5.586	6.8969
2037	0	0	152,339	39,934	0	-192,273	-32,271	-2,039,803	-1,040,590	-3,080,393	5.494	6.8969
2038	0	0	148,495	40,646	0	-189,141	-29,558	-2,069,361	-1,017,384	-3,086,745	5.404	6.8969
2039	0	0	144,734	41,372	0	-186,106	-27,080	-2,096,441	-996,324	-3,092,765	5.317	6.8969
2040	0	0	141,051	42,110	0	-183,161	-24,815	-2,121,256	-977,214	-3,098,470	5.233	6.8969
2041	5,564,283	0	682,115	42,861	0	-724,976	-91,453	-2,212,709	-891,168	-3,103,877	20.714	6.8969
2042	0	0	717,051	43,626	0	-760,677	-89,345	-2,302,054	-806,946	-3,109,001	21.734	6.8969
2043	0	0	696,350	44,404	0	-740,755	-81,011	-2,383,065	-730,792	-3,113,857	21.164	6.8969
2044	0	0	676,556	45,197	0	-721,753	-73,494	-2,456,559	-661,900	-3,118,459	20.622	6.8969
2045	0	0	657,595	46,003	0	-703,599	-66,709	-2,523,268	-599,553	-3,122,821	20.103	6.8969
2046	0	0	639,402	46,824	0	-686,226	-60,579	-2,583,847	-543,108	-3,126,955	19.606	6.8969
2047	0	0	621,914	47,659	0	-669,573	-55,036	-2,638,883	-491,989	-3,130,872	19.131	6.8969
2048	0	0	605,075	48,510	0	-653,584	-50,020	-2,688,903	-445,681	-3,134,585	18.674	6.8969
2049	0	0	588,833	49,375	0	-638,208	-45,478	-2,734,382	-403,721	-3,138,103	18.235	6.8969
2050	0	0	573,141	50,256	0	-623,397	-41,362	-2,775,744	-365,694	-3,141,437	17.811	6.8969
2051	0	0	557,954	51,153	0	-609,107	-37,629	-2,813,373	-331,224	-3,144,598	17.403	6.8969
2052	0	0	543,232	52,066	0	-595,298	-34,242	-2,847,615	-299,977	-3,147,592	17.009	6.8969
2053	0	0	528,938	52,995	0	-581,933	-31,167	-2,878,783	-271,648	-3,150,431	16.627	6.8969
2054	0	0	515,038	53,940	0	-568,978	-28,374	-2,907,156	-245,964	-3,153,121	16.257	6.8969
2055	0	0	501,500	54,903	0	-556,403	-25,835	-2,932,991	-222,679	-3,155,670	15.897	6.8969
2056	161,455	0	504,100	55,882	0	-559,982	-24,209	-2,957,201	-200,885	-3,158,086	15.999	6.8969
2057	0	0	492,318	56,879	0	-549,197	-22,107	-2,979,308	-181,068	-3,160,375	15.691	6.8969
2058	0	0	479,202	57,894	0	-537,096	-20,131	-2,999,438	-163,107	-3,162,545	15.346	6.8969
2059	0	0	466,370	58,927	0	-525,297	-18,332	-3,017,770	-146,832	-3,164,602	15.008	6.8969
2060	0	0	453,799	59,979	0	-513,778	-16,694	-3,034,465	-132,086	-3,166,551	14.679	6.8969
2061	0	0	441,470	61,049	0	-502,518	-15,203	-3,049,668	-118,730	-3,168,398	14.358	6.8969
2062	0	0	429,361	62,138	0	-491,499	-13,845	-3,063,513	-106,635	-3,170,148	14.043	6.8969

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 2012 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%	8.380%	3.77%
Total	**100.00%**		**7.40%**

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, February 2, 2012.

Appendix B
Pitmans Pond Switchgear Arc Flash Study

ELECTRICAL ENGINEERING

ARC FLASH HAZARD STUDY

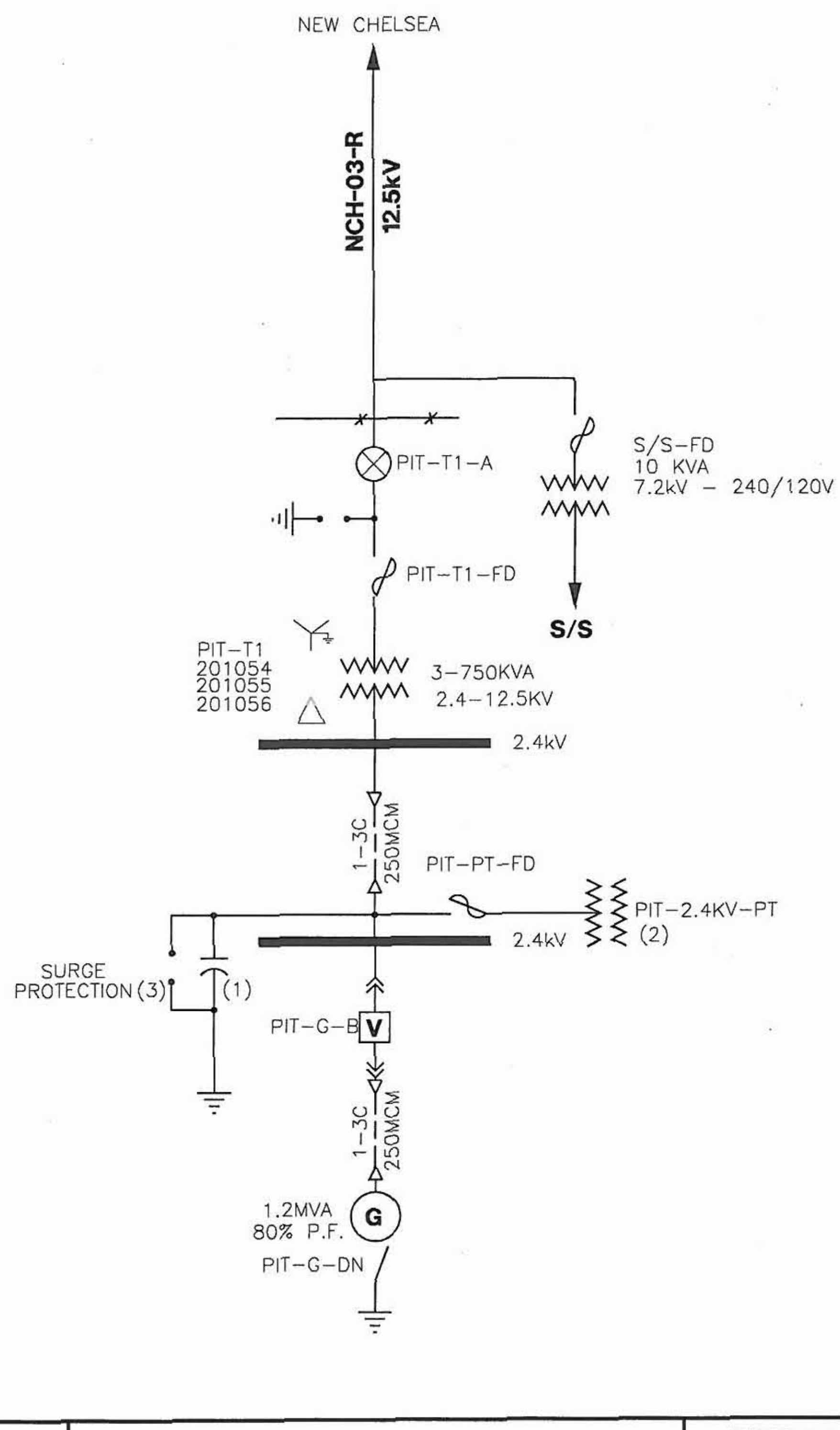
Company Area:	Avalon		
Switchgear Included:	PIT 2.4kV		
Prepared by:	D Jones	**Date:**	3/6/2006

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



REGISTERED PROFESSIONAL ENGINEER
G. Richard Spurrell
SIGNATURE
2005-07-14
DATE
PROVINCE OF NEWFOUNDLAND

SINGLE LINE DIAGRAM

NEWFOUNDLAND POWER
A FORTIS COMPANY

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 C0060 which is valid for the year 2005

PITTMAN'S POND (PIT)

Page 1 Of 1

App.	Drawn: FWA	SLD No. **2-917**

Maximum Generation Fault PIT 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 ->													
PIT 02		2.4	0	LLL	20	4872.9321	-76.4984	4872.9321	163.5016	4872.9321	43.5016	0	0
First Ring Contributions													
PIT G1	Generator	2.4	0	LLL	6.7	1611.7694	-90	1611.7694	150	1611.7694	30	0	0
PIT-T1	Fixed-Tap Xmer	2.4	0	LLL	14	3326.4466	-70.0017	3326.4465	169.9983	3326.4465	49.9983	0	0

Current Multiplier for CYMTCC PIT-T1-FD

= 20 MVA / 14 MVA

Current Multiplier = 1.43

Minimum Generation Fault PIT 2.4 kV. PIT 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 ->													
PIT 02		2.4	0	LLL	20	4810.482	-76.4392	4810.482	163.5608	4810.482	43.5608	0	0
First Ring Contributions													
PIT-T1	Fixed-Tap Xmer	2.4	0	LLL	14	3265.0814	-69.7893	3265.0814	170.2107	3265.0814	50.2107	0	0
PIT G1	Generator	2.4	0	LLL	6.7	1611.7694	-90	1611.7694	150	1611.7694	30	0	0

Current Multiplier for CYMTCC PIT-T1-FD

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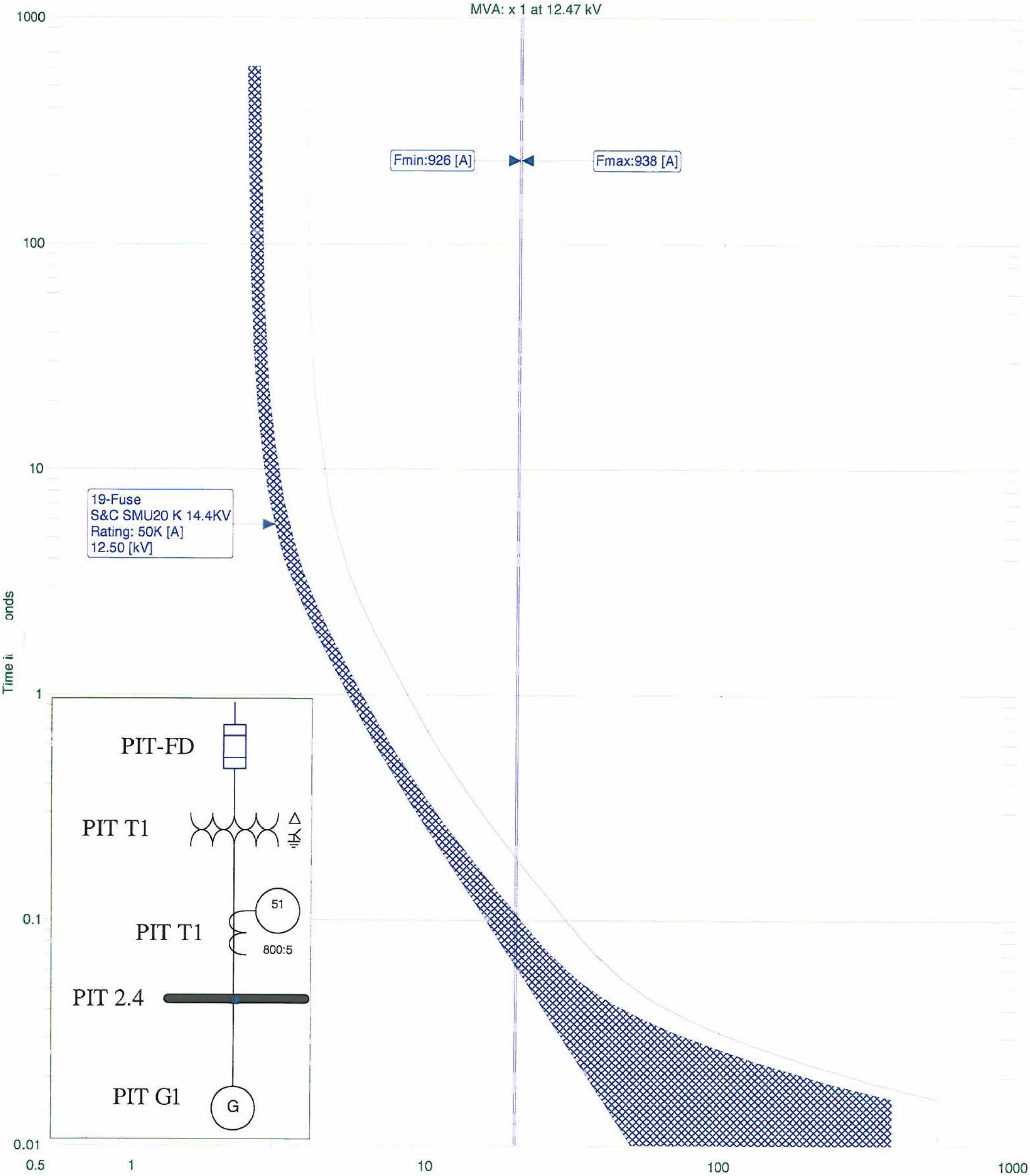

For LLL PIT 2.4 kV fault at Maximum Generation PIT-FD CT is 0.1863 seconds.
For LLL PIT 2.4 kV fault at Minimum Generation PIT-FD CT is 0.1903 seconds.
PIT-T1 S & C 50 K fuse link.

Dave Jones

March 07, 2006

Study: C:\Arc Flash\Plants\PIT\PIT T1 Fuse Max and MIN Gen LLL.tcc

Arc Flash Hazard PIT 2.4 kV.
IEEE standard

Faulted Bus	Generation	Fault	Fault Current	CT	CT Plus Fuses	Working Distance	Flash Hazard Boundry	cal / cm2	PPE Level	L.A.B.	R.A.B.	P.A.B.
PIT 2.4	Max	LLL	4873	0.1863	0.1863	16"	37"	2.7	1	60"	26"	7"
PIT 2.4	Min	LLL	4810	0.1903	0.1903	16"	37"	2.7	1	60"	26"	7"

Faulted Bus	Generation	Fault	Fault Current	CT	CT Plus Fuses	Working Distance	Flash Hazard Boundry	cal / cm2	PPE Level	L.A.B.	R.A.B.	P.A.B.
PIT 2.4	Max	LLL	4873	0.1863	0.1863	36"	37"	1.2	1	60"	26"	7"
PIT 2.4	Min	LLL	4810	0.1903	0.1903	36"	37"	1.2	1	60"	26"	7"

***Arc Flash Calculated for Switchgear and fixed conductor.**
Software won't supply Arc Flash results for clearing times over one second.

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

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

37 inches	Flash Hazard Boundary
2.7	cal / cm2 Flash Hazard at 16 inches
class 1	PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
2400 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name: PIT 02

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

37 inches	Flash Hazard Boundary
2.7	cal / cm2 Flash Hazard at 16 inches
class 1	PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
2400 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name: PIT 02

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Arc Flash and Shock Hazard
Appropriate PPE Required

37 inches	Flash Hazard Boundary
1.2	cal / cm2 Flash Hazard at 36 inches
class ~~0~~ 1	PPE Level, Non-melting, flammable materials (i.e., untreated cotton, wool, rayo or blends of these materials) with a fabric weight at least 4.5 oz/yd2 Safety glasses.
2400 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:PIT 02

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37 inches	Flash Hazard Boundary
1.2	cal / cm2 Flash Hazard at 36 inches
class 0	PPE Level, Non-melting, flammable materials (i.e., untreated cotton, wool, rayo or blends of these materials) with a fabric weight at least 4.5 oz/yd2 Safety glasses.
2400 VAC	Shock Hazard
60 inches	Limited Approach
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2400 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name: PIT 02

2013 Substation Refurbishment and Modernization

June 2012

Prepared by:

John Pardy, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
J. W. PARDY
SIGNATURE
2012-06-12
PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
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Appendix A: Substation Refurbishment and Modernization Plan
Five-Year Forecast 2013 to 2017

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 will 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 with major equipment maintenance and replacement activities.[1] Where practical the substation plan is coordinated with the maintenance cycle for major substation equipment. This coordination minimizes customer service interruptions and ensures optimum use of resources.

When updating the substation strategic refurbishment and modernization plan substations are assessed with particular consideration given to the condition of the infrastructure and equipment, and the need to upgrade and modernize protection and control systems. This assessment is used to determine substation work.

Much of this work requires the power transformer to be removed from service; and, therefore, the timing of the work is restricted to the availability of the portable substation and the capacity of the portable substation to meet the load requirement. In many circumstances, this requires the work to be completed in the late spring and summer when the 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 2013 Projects

The 2013 Substation Refurbishment and Modernization Project includes planned refurbishment and modernization projects of 5 substations and one portable substation. This work is estimated to cost a total of $4,020,000 which comprises approximately 90% of the total 2013 project costs. The remaining project cost of $432,000 is associated with Substation Monitoring and Operations upgrades to substation communication systems to accommodate increased data requirements and the addition of new metering at infeed points on the Island Interconnected System.[2]

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[1] The Company's Substation Refurbishment and Modernization Project is the result of the *Substation Strategic Plan* filed with the 2007 Capital Budget Application.

[2] These infeed points are some of the locations where Newfoundland Power takes delivery of electricity from Newfoundland Hydro.

Table 1 identifies the 2013 Substation Refurbishment and Modernization Project expenditures for 2013.

Table 1
2013 Substation Refurbishment and Modernization Projects
(000s)

Project	Budget
St. Catherine's Substation (SCT)	$561
Portable Substation 4 (P4)	$790
Stephenville Gas Turbine Substation (STV)	$732
Glenwood Substation (GLN)	$967
Twillingate Substation (TWG)	$770
Kenmount Substation (KEN)	$200
Substation Monitoring and Operations (SMU)	$432
Total	**$4,452**

The following pages outline the capital work required for each substation.

2.1 2013 Substation Projects ($4,020,000)

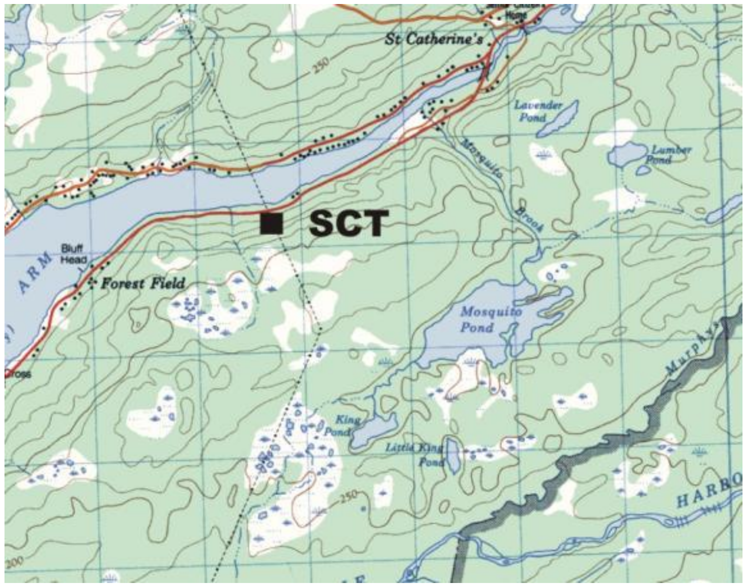
St. Catherine's Substation ($561,000)

St. Catherine's Substation (SCT) was built in 2000 as a distribution substation. The substation contains one 66 kV to 25 kV distribution power transformer (T1) with a capacity of 5 MVA, and one 25kV to 12.5 kV step down power transformer (T2) with a capacity of 4 MVA.

The substation directly serves approximately 924 customers in the St Catherine's area through one 25 kV feeder and one 12.5 kV feeder. In the substation there are two 66 kV transmission lines terminated in the high voltage bus, these being transmission lines 94L to Blaketown substation and 94L to Riverhead substation.

In 2013, the Company has transformer maintenance activities scheduled for both transformer T1 and T2 at St. Catherine's substation. The Company will also undertake other substation refurbishment and modernization work at St. Catherine's substation to take advantage of the installation of the portable substation, which is being installed to minimize the number and duration of customer outages.[3]

[3] Wherever possible, the Company coordinates maintenance work on individual substations with capital substation refurbishment and modernization projects to minimize service interruptions to customers.



St. Catherine's Substation Location

Maintenance records and on-site engineering assessments show that the 66 kV wood pole structures and bus and 25 kV wood pole structures and bus are in good condition.

66 kV & 15 kV Wood Pole Structures and Bus

A portable substation will be installed to bypass St. Catherine's substation to refurbish the transformers and upgrade the transformer's auxiliary protection.[4] Maintenance is scheduled on both transformers. The oil in transformer T2 has PCB concentration tested at over 50 ppm so

4 Substation transformers are maintained on 10 year cycles. This will be the first transformer refurbishment since the substation was built in 2000.

while the transformer is de-energized the oil will be replaced to comply with current PCB regulations. Upgrades will be completed on both transformers including replacement of temperature gauges and gas detection relays. The silicon carbide lightning arrestors will be replaced with metal oxide arrestors.[5]

Potential transformers and current transformers will be installed for metering of the transformer load and to provide current and voltage signals for protective relays. Engineering staff use transformer load metering data for system modeling and planning.

The two existing feeder reclosers are hydraulic type, and have 40 and 43 years in service. They will be replaced with new Nulec type reclosers and will be automated for control from the System Control Center.[6] Varmint proofing will be installed on the 15 kV bus equipment.

The ground grid for the substation will be extended to improve safety for personnel inside the substation.

Portable Substation P4 ($790,000)

Portable substation P4 was purchased in 1992. It is used to respond to power transformer failures and for planned transformer maintenance and substation refurbishment and modernization work. P4 can provide backup for 70% of the 192 power transformers in service on Newfoundland Power's system.

Portable Substation P4

5 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that until the early 1980's silicon carbide lightning arrestors were standard. The Company has experienced many failures of silicon carbide lightning arrestors as they age due to water leaking into the arrestor through failed seals.

6 Monitoring and control of Nuclec reclosers from the System Control Center will result in real time detection of trouble on the distribution feeder and provide for remote restoration of service. Also, the System Control Center will be able to remotely de-energize feeders in emergency situations thus enhancing employee and public safety.

Engineering for the refurbishment will be completed in 2012 with the actual refurbishment taking place in 2013.[7] This is the first comprehensive refurbishment of this portable substation since its purchase in 1992. Refurbishment of portable substation P4 will ensure its continued availability for the next decade.

The trailer will undergo an overhaul addressing rust damage and applying a rust inhibiting coating to the chassis. A fall arrest system and work platforms will be installed in areas where employees have to work aloft. External lighting will be provided at locations around the trailer.

Deterioration on Chassis above Axle

Deterioration on Axle

[7] The engineering work in 2012 on Portable Substation P4 was included in the ***2.1*** *Substation Refurbishment and Modernization* project approved in Order No. P.U. 26 (2011).

The alarm annunciation panel has had several failures and will be replaced. The original protection relays will be replaced with microprocessor based protection relays.[8] A digital metering system for power, voltage and current will be provided.

The wiring associated with the protection and control of the portable substation is original wiring showing signs of deterioration. Deteriorated wiring, termination and junction boxes will be replaced.

Online monitoring of transformer gas and oil analysis will be provided to protect the transformer. High voltage linkages connecting the power transformer to the switches are deteriorated and will be replaced. The batteries and charging system are at the end of life and will be replaced.

A SCADA remote terminal unit will be installed on the portable substation to provide remote monitoring and control capability of the unit.

Stephenville Gas Turbine Substation ($732,000)

The Stephenville Gas Turbine substation was built in 1976 as a transmission substation, and is located on a site containing assets for both Newfoundland Power and Newfoundland and Labrador Hydro ("Hydro"). The transmission portion of the substation contains a 66 kV bus and associated isolating devices for three transmission lines, 401L to Gallants, 405L to Harmon, and 407L to Stephenville Crossing. A fourth transmission line, 404L to Wheelers, is tapped off of 401L approximately 4.6 km away from the substation fence. The Stephenville Gas Turbine substation indirectly serves 5,569 customers in the greater Stephenville and Port aux Port Peninsula area through this transmission network.

Stephenville Gas Turbine Substation Location

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8 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. In the past 5 years the Company has experienced increasing numbers of electro-mechanical relay failures.

Maintenance records and on-site engineering assessments show that the substation steel structures, foundations, bus work, and insulators are all in good condition.

66kV Steel Structures & Bus

The switches on the structures are all in good condition, with the exception that the 401L-DB switch is deteriorated and as a result is difficult to operate. The switch is 1976 vintage and will be replaced due to its age and recent operating history.

The steel cable trench covers are corroded and will be replaced. In addition, all substation light fixtures will be replaced.

Currently, the Company uses a set of Hydro's 66 kV potential transformers terminated on their bus to provide the voltage signal for protection of the 3 Newfoundland Power transmission lines that terminate in the station. During switching activity the 66 kV bus can be split into 2 isolated buses resulting in the loss of protection for the 3 transmission lines. To address this shortcoming a new set of 66 kV potential transformers will be installed on the Newfoundland Power side of the 66 kV bus, along with a single fuse-protected potential transformer on transmission line 407L for synchronization monitoring. With this upgrade, service to customers normally supplied via 407L can be maintained, from local generation, while completing transmission line maintenance and reconnected to the grid without an interruption in service.[9]

The relays for the transmission lines and bus protection are 1976 vintage electromechanical type and will be replaced with new microprocessor based relays.[10] In addition, a complete

9 Transmission line 407L connects the Lookout Brook hydro plant to the Island Interconnected System at Stephenville Gas Turbine substation via St. George's substation.

10 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. In the past five years Newfoundland Power has experienced increasing numbers of electro-mechanical relay failures.

communications package will be installed, to facilitate both automated and remote control of the various protection elements within the substation. This will provide the capability of remote management of the relays to monitor power system operation and analyze disturbances without travelling to the site.

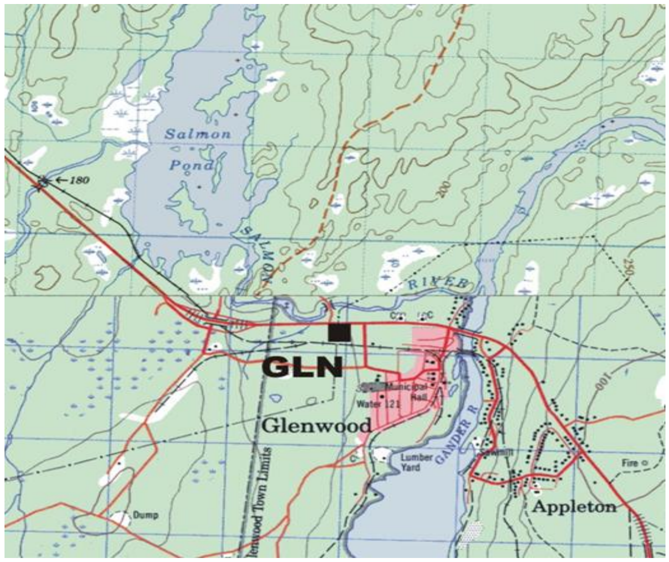
Transmission Line Electromechanical Relays

The ground grid for the substation will be extended to improve safety for personnel inside the substation.

Glenwood Substation ($967,000)

Glenwood substation was built in 1968. Today it is both a transmission and distribution substation. The transmission portion of the substation contains two 138 kV transmission line links; Hydro's TL210 to Cobbs Pond and Stoney Brook. There is a single 8.3 MVA, 138 kV to 25 kV power transformer GLN-T1 terminated at a voltage regulation bank leading to a 25 kV bus infrastructure. The substation services 707 customers in the area of Glenwood through a single feeder GLN-01.

In 2013, the Company has transformer maintenance activities scheduled for T1 at Glenwood substation. The Company will also undertake other substation refurbishment and modernization work at Glenwood substation to take advantage of the installation of the portable substation, which is being installed to minimize the number and duration of customer outages.



Glenwood Substation Location

Maintenance records and on-site engineering assessments show that the 138kV and 25 kV wooden structures, foundations, buses and insulators are all in good condition. Standard varmint protection and vegetation management practices will be implemented.

138kV & 25 kV Wooden Structures & Bus

The portable substation will be installed and the power transformer GLN-T1 will be refurbished.[11] The lightning arrestors on this transformer are silicon carbide and will be replaced with metal oxide arrestors.[12]

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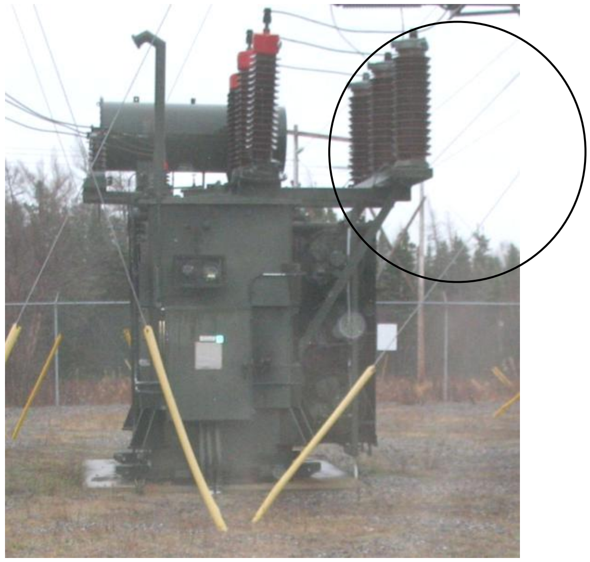
11 Substation transformers are maintained on 10 year cycles. The last transformer maintenance on GLN-T1 was in 1999.

12 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that until the early 1980's silicon carbide lightning arrestors were standard. The Company has experienced many failures of silicon carbide lightning arrestors as they age due to water leaking into the arrestor through failed seals.



Power Transformer with Silicon Carbide Arrestors

The 27 year old 138 kV motorized air break switch and high speed ground switch for power transformer GLN-T1 will be replaced, to permit integration of the motor operator and the high speed ground switch with the transformer protection relay. The transformer protection relays will be replaced with microprocessor based relays and the transformer protection panel will be installed in a new small control building.[13] Upgraded transformer protection will isolate the transformer from system disturbances more quickly than existing protection.[14]

New 25 kV potential transformers will be installed on the 25 kV bus to facilitate metering and protection upgrades. In addition, the voltage regulator structure will be relocated to a location just outside the substation fence. The existing regulator location does not permit maintenance to be safely performed on the units without a service interruption due to space limitation on the substation low voltage structure. Relocation of the voltage regulators to a standard voltage regulator structure outside the substation will permit safe, unrestricted access.

A grounding study will be completed and the ground grid for the substation will be extended to improve safety for personnel inside the substation. An access gate on the main substation driveway will be installed and crushed stone added to the yard.

[13] 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. In the past five years Newfoundland Power has experienced increasing numbers of electro-mechanical relay failures.

[14] The potential for transformer damage is decreased with improved protection.

Twillingate Substation ($770,000)

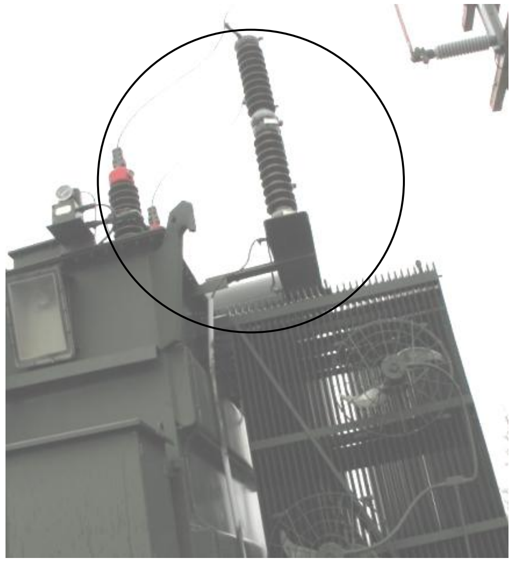
Twillingate ("TWG") substation was built in 1976 as a distribution substation. Transmission line 140L from Summerford terminates at switch T1-A. Transformer TWG-T1 is a 13.3 MVA, 66 kV to 12.5 kV power transformer terminated at a 12.5 kV bus structure. The substation services 1,650 customers in the area of Twillingate through 3 feeders.

Twillingate Substation Location

Maintenance records and on-site engineering assessments show that the 66kV and 12.5 kV wooden structures, foundations, buses and insulators are all in good condition. Standard varmint protection and vegetation management practices will be implemented.

12.5 kV Wooden Structures & Bus

The power transformer TWG-T1 is in good condition. However, the lightning arrestors on this transformer are silicon carbide and will be replaced with metal oxide arrestors.[15]



Power Transformer with Silicon Carbide Arrestors

The 66 kV air-break switch used to isolate power transformer TWG-T1 is deteriorated and will be replaced with a motorized air-break switch to improve the transformer protection.

The 3 hydraulic reclosers will be replaced with Nulec reclosers and will be automated for monitoring and control from the System Control Center.[16] The automation equipment, transformer protection and recloser controls will be installed in a new small control building. A 125 VDC battery bank and charger will be added. With feeder automation, the Twillingate feeders will be added to the provincial under-frequency load shedding scheme.

15 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that until the early 1980's silicon carbide lightning arrestors were standard. The Company has experienced increasing failures of this type of arrestor as they age due to water leaking into the arrestor through failed seals.

16 Monitoring and control of Nuclec reclosers from the System Control Center will result in real time detection of trouble on the distribution feeder and provide for remote restoration of service. Also, the System Control Center will be able to remotely de-energize feeders in emergency situations thus enhancing employee and public safety.

Hydraulic Recloser on TWG-03 Feeder

The 12.5 kV oil-filled metering tank is deteriorated and will be replaced with an oil free unit.

The ground grid for the substation will be extended to improve safety for personnel inside the substation.

Kenmount Substation ($200,000)

Kenmount Substation (KEN) was built in 1975 as a transmission and distribution substation. The substation contains two 66 kV to 25 kV distribution power transformers each with a capacity of 25 MVA. The substation serves approximately 7,184 customers in the Kenmount Road area and west end of the City of St. John's through four 25 kV feeders. In the substation there are three 66 kV transmission lines terminated in the high voltage bus, these being transmission lines 54L to Hardwoods substation, 69L to Stamps Lane substation and 35L to Oxen Pond substation.

During significant rain events the access road to the substation has flooded.[17] Access to the substation was disrupted during each flooding event. The photo below shows the substation access road during Hurricane Igor on September 21, 2010. Water also entered the substation and flooded the cable trenches and the control building.[18] Access to the substation was disrupted for two days during Hurricane Igor.[19]

[17] Recent flood events include hurricane Gabrielle in 2001, a heavy rain storm in November 2009 and the most recent during Hurricane Igor in 2010.

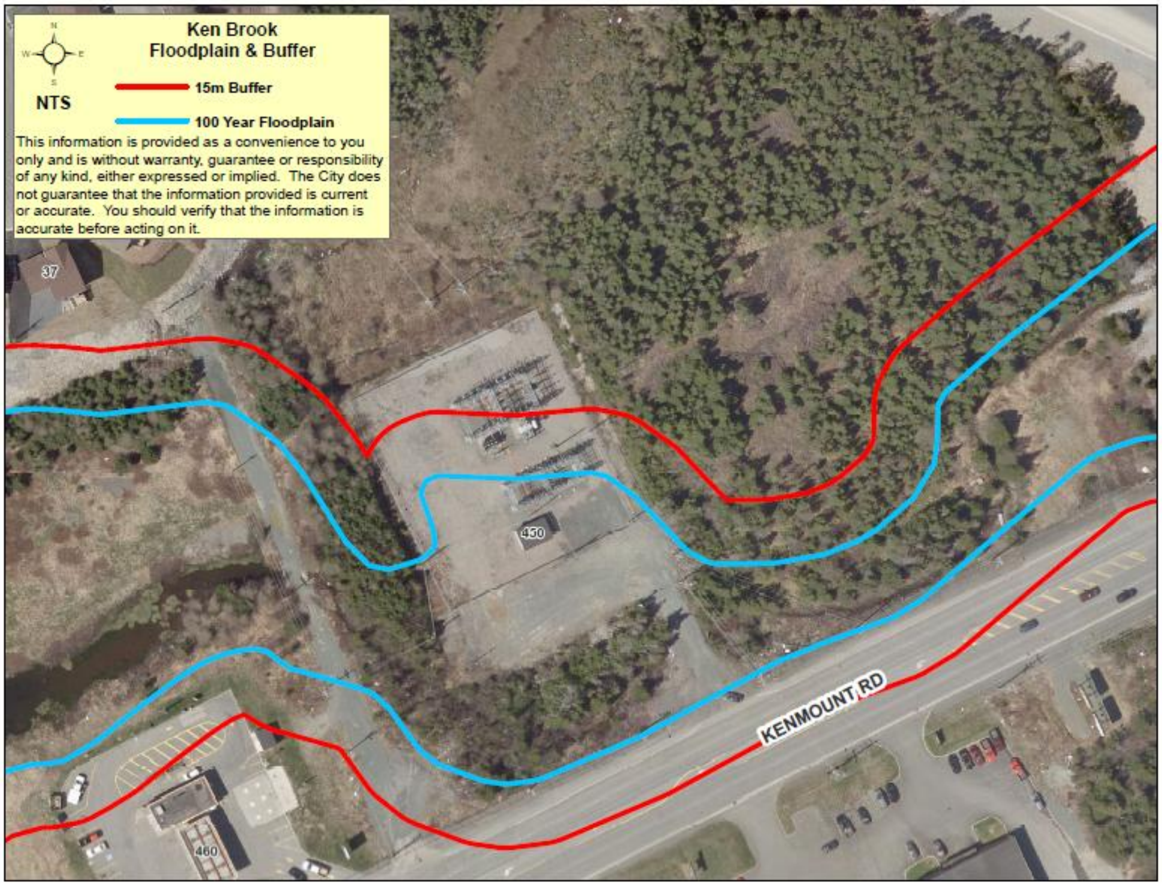
[18] Standing flood water in a substation poses a significant safety hazard to workers.

[19] Completing work in Kenmount substation during flood conditions will reduce response time and result in longer customer outages if line trucks or other equipment are unable to access the substation.

Flooded Access Road to Kenmount Substation During Hurricane Igor

Flood mapping provided by the City of St. John's shows that the Kenmount Substation is located within a flood plain. With the amount of housing and commercial development ongoing in the area it is anticipated that flood events will be more severe in the future as runoff from these developments is adding to the stream flow on the south side of the substation.[20] Due to the development in the area the design capacity of the access road culvert is no longer adequate for the change in flow during peak rain events. The existing access road to the substation has a 1,525 mm culvert with a cross sectional area of 1.82 m^2 to pass water. In comparison about 150 metres downstream on Ladysmith Drive the City of St. John's has recently installed a 6100 mm × 2290 mm box culvert with a cross sectional area of 14 m^2. The box culvert installed by the City of St. John's has a cross sectional area 7.7 times larger to pass flow from the same stream.

[20] Runoff from a drainage area is a function of the ground surface. Undeveloped areas have a low runoff as the lack of development allows much of the water to infiltrate the soil. Fully developed areas have a higher runoff as these areas tend to have harder asphalt and concrete surfaces which allow less water to infiltrate the soil.



Kenmount Road Substation
1 in 100 Year Flood Plain[21]

To address the flooding problems a new access road will be constructed on the west end of the substation with a larger culvert system to handle the design flood. In addition, a berm will be constructed along the west side of the substation and connected to the access road to provide improved flood protection to the substation.

2.2 Substation Monitoring and Operations ($432,000)

Over the past decade, there has been a substantial increase of computer-based equipment in electrical system control and operations. Periodic upgrades of this equipment are necessary to ensure continued effective electrical system control and operations.

In 2013, 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.

21 The blue contour line identifies the 100 year floodplain, while the red contour line identifies a 15 metre buffer around the floodplain. Photograph provided by the City of St. John's Planning Department.

In 2013, 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.

Newfoundland Power receives electricity supply from multiple Hydro infeed locations at various substations throughout its service territory. Many of these infeed locations are monitored through meters connected to the Company's SCADA system. This item involves installing meters and communications equipment at 13 Hydro infeed locations to collect these data points on the Company's SCADA system. These additional data points will provide Newfoundland Power with a more accurate measurement of the total instantaneous system load.

Appendix A
Substation Refurbishment and Modernization Plan
Five-Year Forecast 2013 to 2017

Substation Refurbishment and Modernization Plan
Five-Year Forecast
2013 to 2017
(000s)

2013		**2014**		**2015**		**2016**		**2017**	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
STV	732	CAR	1,269	BRB	1,796	CAT	2,267	BVA	804
P4	790	ILC	227	BVS	1,090	HUM	2,221	CLV	2,497
SCT	561	MAS	676	RRD	1,084	P1	736	HCP	502
GLN	967	SPR	589	SPO	1,417	SMU	165	TBS	313
TWG	770	STX	372	VIC	1,539			WAL	1,630
KEN	200	SMU	155	SMU	160			NCH	1,510
SMU	432							SMU	170
	$4,452		**$3,288**		**$7,086**		**$5,389**		**$7,426**

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.

2013 Transmission Line Rebuild

June 2012

Prepared by:

M. R. Murphy, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
M. R. MURPHY
SIGNATURE
12 JUNE 2012
DATE
NEWFOUNDLAND & LABRADOR

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Appendix B: Maps of Transmission Lines 110L and 12L
Appendix C: Photographs of Transmission Lines 110L and 12L

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 2013 Transmission Line Rebuild Projects

In 2013, the Company will rebuild a 21.1 kilometre section of 110L transmission line and a 1.1 kilometre section of 12L transmission line. Appendix B contains maps of each of the lines to be rebuilt. Appendix C contains photographs of the existing lines.

By 2013, both of these sections of transmission line will be in excess of 55 years old. They 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.

In addition, the replacement of the conductor from 1/0 copper to 477 ASC on both lines will increase the load carrying capability of the line which will improve the overall reliability of the transmission system that services customers in these areas.

2.1 Transmission Line 110L ($2,739,000)

The Bonavista Peninsula is supplied electricity by two separate transmission circuits. The first is 123L, a 138 kV H-Frame transmission line running between Clarenville and Catalina. The second transmission circuit consists of a pair of 66 kV single pole lines, 110L and 111L. They run between Clarenville and Lockston and between Lockston and Catalina respectively.

Newfoundland Power filed with its 2006 Capital Budget Application the *Bonavista Loop Transmission Planning* report comparing alternatives for addressing transmission line requirements on the Bonavista Peninsula. The analysis completed in the *Bonavista Loop Transmission Planning* report determined that the rebuilding of 110L/111L transmission circuit and increasing conductor sizing is the least cost alternative to ensuring the continued provision of safe, reliable electrical service to the area.

Rebuilding the 110L/111L transmission circuit to current construction standards improves the mechanical strength of the transmission line by replacing poles, crossarms and guy wires. Also, increasing conductor sizing increases the load carrying capacity of the transmission lines. The use of larger conductor increases the period of time each year where the entire Bonavista Peninsula load can be carried by the 110L/111L transmission circuit.[1]

In the 7 years since the report was filed the Company has undertaken approximately $11 million in capital projects to rebuild these critical transmission lines. In 2013, the final section of transmission line 110L will be rebuilt, and the Bonavista transmission loop upgrade will be completed.

110L was constructed in 1958 and is 79 kilometres in length. It helps service approximately 4,300 customers on the Bonavista Peninsula between Milton and Lockston. This line also connects the Company's Lockston hydro plant to the main electricity grid.

By the end of 2012, 58 kilometres of 110L will have been upgraded. The remaining 21.1 kilometres of the original construction consists of 227 structures with 1/0 ACSR conductor located between the substation in Lethbridge and the substation in Summerville.

Recent inspections have identified deterioration of the existing conductor along this 21 kilometre section.[2] At times the conductor has been subjected to heavy electrical loading and also heavy ice loading. The steel core and the aluminum strands are corroded which has reduced the physical strength and the electrical capacity of the conductor. This deterioration is such that the line has been de-rated to about one-half of its original electrical current carrying capacity for safety reasons.

It is recommended the line be rebuilt in 2013 at an estimated cost of $2,738,633.

2.2 Transmission Line 12L ($380,000 in 2013 and $358,000 in 2014)

12L is a 66kV transmission line running between Memorial University Substation ("MUN") and King's Bridge Road Substation ("KBR"). The line consists of a 2.2 kilometre aerial section and a 1.0 kilometre underground cable section located through the university campus area.[3] 12L in conjunction with transmission line 14L, are the transmission lines that provide service to Memorial University, the Health Science Centre and the Janeway Children's Health and Rehabilitation Centre.

---

1 The principle benefit of the increase in load carrying capability for the 110L/111L transmission circuit is the ability of the Bonavista transmission system to tolerate a planned or unplanned outage on transmission line 123L. Following the rebuild of the final 21.1 kilometres of 110L in 2013, the 110L/111L transmission circuit will be capable of carrying the entire Bonavista customer load for approximately 38 weeks of the year. For the remaining 14 weeks of the year the 110L/111L transmission circuit will be able to carry 75% of the Bonavista customer load. This is a significant improvement for the Bonavista transmission system as the existing conductor limits the 110L/111L transmission circuit to only 6 weeks of the year when it is capable of carrying the entire Bonavista customer load.

2 Photographs of deteriorated conductor are included in figures 1 and 4 of Appendix C.

3 The 2013 and 2014 projects only involve the rebuild of the 2.2 kilometre aerial section of transmission line.

The aerial section of transmission line was originally constructed in 1950 and consists of 59 single pole structures all of which has under built distribution circuitry. The route taken by the transmission line, as shown by Figure 2 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.[4] 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.[5] 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.

Based on the overall deteriorated condition of the line, it is recommended the line be rebuilt at an estimated cost of $380,000 in 2013 and $358,000 in 2014.

3.0 Concluding

In 2013, the Company will rebuild the remaining section of 110L and a section of 12L, with the remainder of 12L to be rebuilt in 2014. Each of these transmission lines is more than 55 years old, with 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.

---

4 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.

5 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.

Appendix A
Transmission Line Rebuild Strategy Schedule

Transmission Line Rebuilds 2013 – 2017 ($000s)						
Line	**Year**	**2013**	**2014**	**2015**	**2016**	**2017**
012L KBR-MUN	1950	380	358			
110L CLV-LOK	1958	2,739				
013L SJM-SLA	1962		658			
018L GOU-GDL	1951		772			
035L KEN-OXP	1959		567			
068L HGR-CAR	1951		828			
015L SLA-MOL	1958			163		
030L RRD-KBR	1959			554	539	
032L OXP-RRD	1963			353		
400L BBK-WHE	1967			1,863	1,947	
069L KEN-SLA	1951			1,013		
014L SLA-MUN	1950				260	
057L BRB-HGR	1958				1,608	1,655
302L SPO-LAU	1959					1,582
041L CAR-HCT	1958					1,472
	Total	**3,119**	**3,183**	**3,946**	**4,354**	**4,709**

Transmission Line Rebuilds 2018 – 2024 ($000s)								
Line	**Year**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
041L CAR-HCT	1958	1,151						
101L GFS-RBK	1957	2,408						
302L SPO-LAU	1959	3,894						
102L GAN-RBK	1958		4,659	4,705	4,991			
049L HWD-CHA	1966				674			
100L SUN-CLV	1964						2,643	3,363
124L CLV-GAM	1964					3,990	4,677	2,418
403L TAP-ROB	1960					1,060		
146L GAN-GAM	1964						2,907	3,895
363L BVJ-SCR	1963		3,156	3,338	3,532	4,429		
	Total	**7,453**	**7,815**	**8,043**	**9,197**	**9,479**	**10,227**	**9,676**

Appendix B
Maps of Transmission Lines
110L and 12L

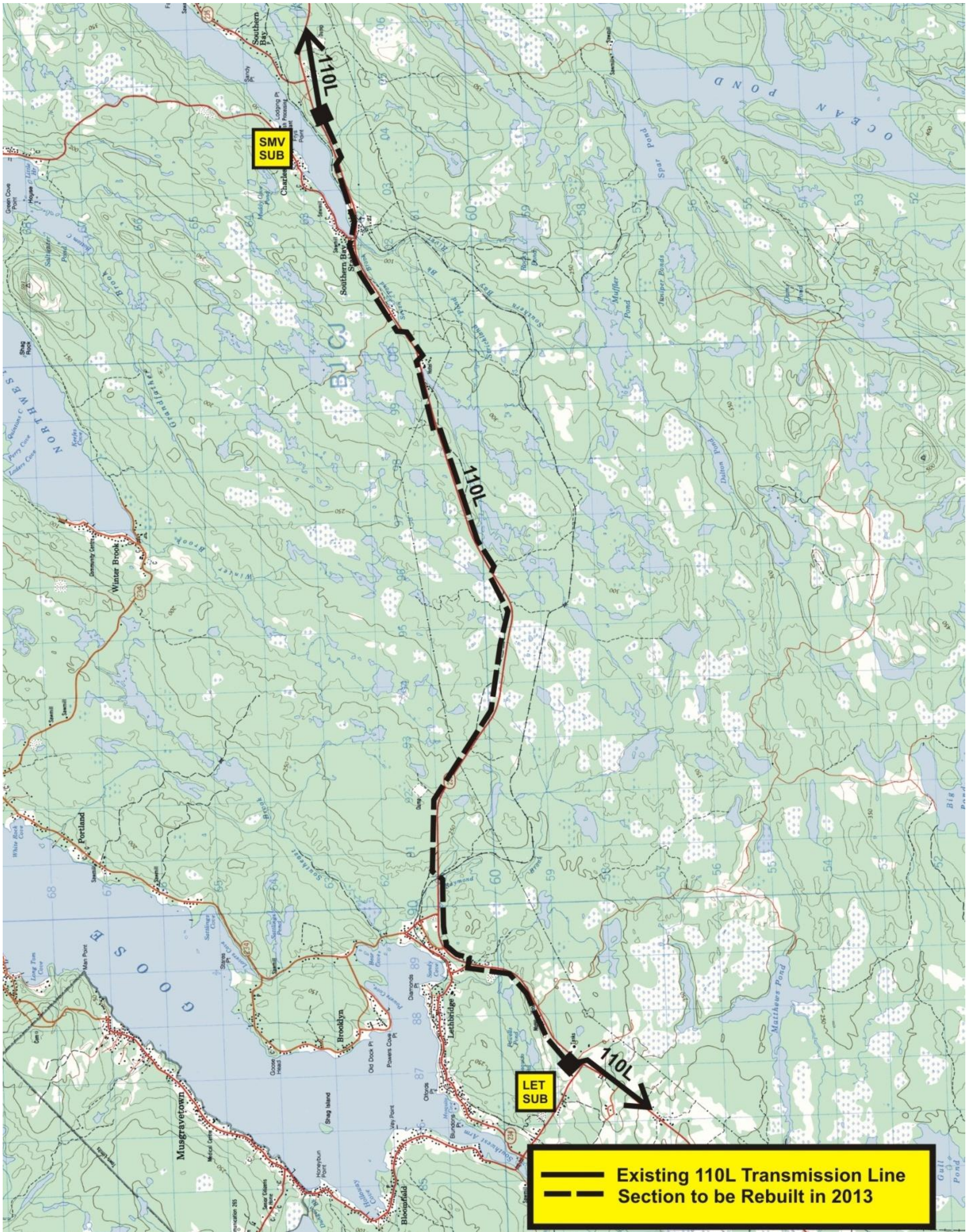


Figure 1 – Map of 110L route

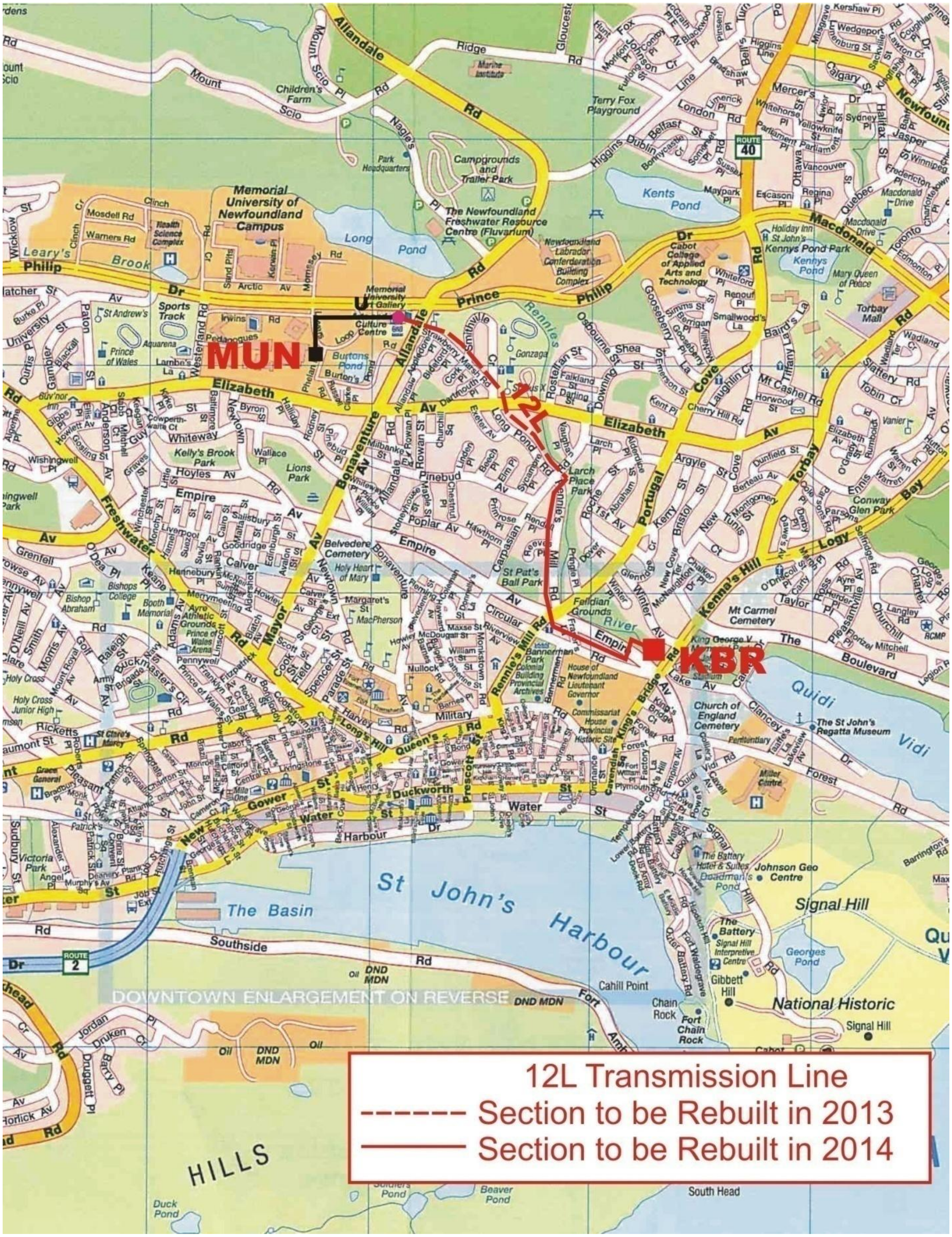


Figure 2 – Map of 12L route

Appendix C
Photographs of Transmission Lines
110L and 12L

<u>Transmission Line 110L</u>

Figure 1 – 110L – Multiple sleeves to repair conductor damage

Figure 2 – 110L – Checks in pole

Figure 3 – 110L – Deteriorated pole and crib

Figure 4 – 110L – Damaged conductor removed from 110L in December 2011

Transmission Line 12L

Figure 5 – 12L - Pole showing checking around bolts

Figure 6 – 12L – Pole showing shell separation and damage

Figure 7 – 12L – Pole bent due to significant loading

Figure 8 – 12L – Deteriorated crossarms

Figure 9 – 12L – Distribution aerial cable arrangement (1)

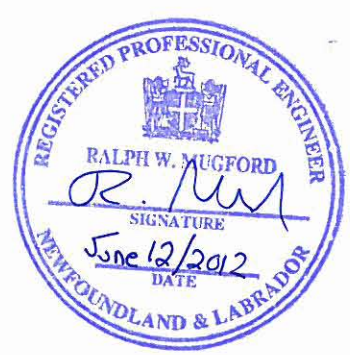
Figure 10 – 12L – Distribution aerial cable arrangement (2)

Distribution Reliability Initiative

June 2012

Prepared by:

Ralph Mugford, P.Eng.



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Appendix B: Worst Performing Feeders Summary of Data Analysis

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 of the 15 worst performing feeders based on data for 2007 - 2011.

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: 2011

The 2009 Capital Budget Application proposed a three year project to improve reliability on the NWB-02 feeder. The work was detailed in *4.1.1 Northwest Brook NWB-02 Feeder Study* filed with the 2009 Capital Budget Application. The project was presented as a three year project starting in 2009 with additional work planned for 2010 and 2011. In 2009 and 2010, the Company completed work project costs of $455,000 and $334,000 respectively. The project was completed in 2011 with $380,000 being spent.

3.0 Distribution Reliability Initiative Projects: 2012

There are no Distribution Reliability Initiative projects planned for 2012.

4.0 Distribution Reliability Initiative Projects: 2013

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 2007-2011 Sorted By Customer Minutes of Interruption				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
DOY-01	3,968	449,872	2.42	4.57
DLK-03	2,379	424,122	1.93	5.73
RRD-09	3,585	412,167	2.36	4.53
GLV-02	2,651	403,396	2.02	5.13
BOT-01	2,488	376,868	1.50	3.79
DUN-01	2,092	365,749	2.18	6.34
GBY-03	2,436	338,521	3.16	7.32
CHA-02	4,397	318,688	2.13	2.58
SLA-09	3,189	317,686	2.24	3.72
GFS-06	3,130	303,334	1.81	2.93
GIL-01	2,510	297,595	2.52	4.98
HWD-07	5,906	287,310	2.53	2.05
CAB-01	3,692	284,177	2.97	3.82
HWD-08	3,184	269,213	1.30	1.84
LEW-02	1,758	268,604	1.22	3.10
Company Average	**862**	**73,885**	**1.10**	**1.58**

Unscheduled Distribution Related Outages Five-Year Average 2007-2011 Sorted By Distribution SAIFI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
GDL-01	1,937	93,786	3.48	2.81
HOL-01	6,651	232,394	3.17	1.85
GBY-03	2,436	338,521	3.16	7.32
CAB-01	3,692	284,177	2.97	3.82
GLV-01	3,000	183,379	2.76	2.81
MOB-01	3,546	168,730	2.65	2.10
GFS-02	3,974	232,540	2.59	2.53
MMT-01	1,207	105,998	2.58	3.78
FER-01	1,619	154,662	2.57	4.09
MIL-02	3,577	249,923	2.55	2.97
GOU-01	3,771	127,398	2.54	1.43
HWD-07	5,906	287,310	2.53	2.05
GIL-01	2,510	297,595	2.52	4.98
DOY-01	3,968	449,872	2.42	4.57
RRD-09	3,585	412,167	2.36	4.53
Company Average	**862**	**73,885**	**1.10**	**1.58**

Unscheduled Distribution Related Outages Five-Year Average 2007-2011 Sorted By Distribution SAIDI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
GBY-03	2,436	338,521	3.16	7.32
BUC-02	292	66,608	1.85	7.03
DUN-01	2,092	365,749	2.18	6.34
SCT-02	541	92,186	2.14	6.07
DLK-03	2,379	424,122	1.93	5.73
ABC-01	1,832	242,395	2.35	5.19
GLV-02	2,651	403,396	2.02	5.13
MKS-01	744	140,818	1.58	4.99
GIL-01	2,510	297,595	2.52	4.98
HOL-02	1,200	152,990	2.34	4.97
NCH-02	1,119	191,207	1.70	4.84
DOY-01	3,968	449,872	2.42	4.57
SUM-02	406	165,727	0.67	4.54
RRD-09	3,585	412,167	2.36	4.53
SCR-01	979	256,985	1.02	4.47
Company Average	**862**	**73,885**	**1.10**	**1.58**

Appendix B
Worst Performing Feeders
Summary of Data Analysis

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
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. No further work is required at this time.
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. No work is proposed for 2013.
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.
SLA-09	Poor overall reliability is due to an underground cable fault in 2011. No work is required at this time.
GLV-01	Poor overall reliability is due to several insulator failures in 2007. No work is required at this time.
HOL-02	Poor overall reliability is due to a storm 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. No work is required at this time.
CAB-01	Poor statistics in 2008 were due to a broken cutout and a broken insulator. No work is required at this time.
DOY-01	Overall reliability statistics on this feeder have been good. The poor average statistics are driven by a single weather related issue in each of 2009 and 2010. No 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 2007 and 2008 there were several tree related outages contributing to poor reliability statistics. No work is required at this time.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
GOU-01	Overall reliability statistics on this feeder have been good. The poor average statistics were caused by isolated events, a pothead failure in 2009 and a single incidence of a failed insulator in 2010.
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.
SCT-02	Reliability problems in 2008 were due to a storm in March. 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.
HWD-08	Reliability problems relate to a pole fire and a broken insulator in 2007. No work is required at this time.
GDL-01	Reliability statistics were driven by isolated weather related events in 2007 and 2008. No work is required at this time.
HOL-01	Reliability problems were due to a single event, a broken cutout in January 2007. No work is required at this time.
MKS-01	Reliability statistics were driven by a single event, a broken cutout in March 2008. 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.
GIL-01	Reliability statistics were driven by a single sleet related event in March 2009. No work is required at this time.
LEW-02	Reliability statistics were driven by a single tree related event in October 2009. No work is required at this time.
GBY–03	Reliability statistics were driven by isolated weather related events in 2009 and 2010. No work is required at this time.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
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.
SCR-01	Reliability statistics were driven by a single wind related event in November 2011. 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.
MOB-01	Reliability statistics were driven by a single event, broken conductor in December 2011. No work is required at this time.
FER-01	Reliability statistics were driven by a single tree related event in January 2007. No work is required at this time.
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.
GLV-02	Reliability statistics were driven by two broken primary incidents in 2007 and a tree related event in 2010. No 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.
HWD-07	Reliability statistics were driven by a sleet storm in 2008 and a faulty cutout in 2010. 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.
SUM-02	Reliability statistics were driven by two tree related events in May and December 2011. No work is required at this time.

Feeder Additions for Load Growth

June 2012

Prepared by:

Bob Cahill, P.Tech

Byron Chubbs, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
BYRON A. CHUBBS
SIGNATURE
June 12/12
DATE
NEWFOUNDLAND & LABRADOR

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Appendix A: Photographs

1.0 Introduction

As load increases on an electrical system, the components of the system can become overloaded. These overload conditions occur at the substation level, on equipment such as transformers, breakers and reclosers, or on specific sections of the distribution system.

When an overload condition has been identified, it can often be mitigated through operating practices such as feeder balancing or load transfers.[1] Such practices are low cost solutions and are completed as normal operating procedures. However, in some cases it becomes necessary to complete upgrades to the distribution system to either increase capacity or alter system configuration in order to complete a load transfer.

This report indentifies three projects to be included as part of the 2013 Capital Budget. These projects address overload conditions and provide additional capacity to address growth in customers and sales. One project involves the construction of two new distribution feeders at Glendale substation. The second project addresses available capacity for growth in the St. John's downtown. The third project involves the installation of voltage regulators to provide adequate voltage to customers on a portion of KEL-02 feeder in Conception Bay South.

The overload conditions described in this report can each be attributed to commercial and residential customer growth in the Northeast Avalon portion of the Company's service territory.

2.0 Glendale Feeder Additions ($451,000)

The St. John's South/Mount Pearl area includes customers serviced from Hardwoods ("HWD"), Glendale ("GDL") and Goulds ("GOU") substations. An engineering study has been completed on the distribution system upgrades required to meet the electrical demands in the St. John's South/Mount Pearl area.[2]

The study examined alternatives to determine the least cost approach to dealing with the forecast overload conditions in the St. John's South/Mount Pearl area. Each alternative was evaluated using a 20 year load forecast. Based on net present value calculations, the least cost alternative was selected.

The study identified a distribution project to be included in the Company's 2013 Capital Budget. The project involves the addition of two feeders at GDL substation. The additional distribution feeders are required in order to transfer load from GOU substation to GDL substation and from HWD substation to GDL substation. Due to the proximity of HWD and GOU distribution feeders to GDL substation, the installation of these additional feeders provides the least cost alternative to dealing with the existing and forecasted transformer overloads at HWD and GOU substations.

---

[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.

[2] The study is included as Attachment B to the report ***2.2*** *2012 Additions Due to Load Growth*, filed with the Newfoundland Power 2012 Capital Budget.

The estimated cost of this project is $451,000.

3.0 St. John's Main Feeder Additions ($680,000)

The St. John's Main ("SJM") substation is located on Southside Road, just east of the Pitts Memorial Drive overpass. It supplies electricity to the area surrounding St. John's harbour, including the downtown core of the City of St. John's (the "City").

The distribution system supplied from the SJM substation includes both overhead distribution feeders and an underground system that consists of a series of duct banks, manholes, switches and cables. The underground system supplies the St. John's downtown core, which has a dense population of large commercial customers. This underground system also includes a major duct bank that exits the substation and runs under the Waterford River containing the main trunks of nine distribution feeders.

Newfoundland Power submitted a planning study with the 2011 Capital Budget Application.[3] The purpose of this planning study was to develop a five year plan to address the deteriorated underground primary infrastructure as well as provide adequate capacity to supply new development in the St. John's downtown area.

3.1 Aerial Feeders SJM Substation

Commercial development in the downtown area of the City will require additional capacity from the electricity system. However, several components of the underground system are already approaching their capacity limitations. As a result, modifications to system configuration and additional distribution capacity are required to accommodate growth in electrical load.

The St. John's Main Planning Study included a project in the 2011 Capital Budget to reconfigure five feeders that cross under Waterford River inside the existing duct bank into four aerial feeders that cross over the river.[4] Figure 1 in Appendix A shows the proposed route for the 2011 project. Due to delays in obtaining the necessary approvals from a property owner adjacent to the Waterford River this project was not completed in 2011.

A revised distribution system design acceptable to the property owner has now been completed. Figure 2 in Appendix A shows the revised route for the project. The revised route involves additional duct bank to avoid aerial distribution lines in the vicinity of a section of the Waterford River where access to a silt interceptor is required. The additional duct bank, and change to the aerial feeder route will increase the overall cost of the project.[5]

---

[3] The *St. John's Main Planning Study* was included as Attachment A to the report ***4.2** Feeder Additions for Load Growth* included in the 2011 Capital Budget Application.

[4] This project was approved in Order No. P.U. 26 (2011)

[5] The complete project is now estimated to cost $637,000, approximately $146,000 more than the 2011 estimated cost.

In 2012, the Company will complete work approved for 2011 in Order No. P.U. 28 (2010) associated with aerial feeders 1 and 2 as shown in Figure 2 of Appendix A. The estimated cost for this work is $385,000.

The 2013 feeder additions project includes the installation of the double circuit aerial distribution line associated with aerial feeders 3 and 4 as shown in Figure 2 of Appendix A. The estimated cost for this work is $252,000.

Once installed the 4 feeders will increase distribution capacity to allow for additional growth in the downtown underground system, and address reliability and safety risks in the existing system.[6]

3.2 Relocate SJM-07

The 2013 project involves relocation of the section of SJM-07 feeder between Hutchings Street and Beck's Cove as recommended in the planning study.[7] This section of the feeder will be relocated from existing duct banks on the north side of Water Street to new duct banks on the south side of Water Street and Harbour Drive. The relocation of SJM-07 to new duct banks on the south side of Water Street and Harbour Drive will allow the feeder to be reconfigured to remove the oil switch in manhole 5. Also, this project addresses the potential risk of failure of the deteriorated duct banks currently housing the main trunk of SJM-07.

This feeder relocation project includes the installation of three 1,100 metre 500 MCM cross-linked polyethylene single phase cables, more commonly known as XLPE cables, in the new duct banks.

The estimated cost of this project is $428,000.

4.0 KEL-02 Voltage Regulators ($73,000)

Adequate voltage levels along a distribution feeder are fundamental in providing safe and reliable electrical service to customers. An analysis of distribution feeders in the Northeast Avalon area was completed using a distribution feeder computer modelling application to identify sections of feeders that may have inadequate line voltages.[8] This analysis identified a low voltage condition on a portion of KEL-02 distribution feeder on Incinerator Road. Field visits followed to ensure the accuracy of the input information and field measurements were taken to verify the results of the computer modeling.

This portion of KEL-02 feeder consists of a three phase 12.47kV branch line approximately 10 km in length that originates from the intersection of the Conception Bay South Highway and

6 Technical and space considerations limit the number of aerial feeders that can currently be established in this area to four. This will require maintaining 4 underground feeders within the existing duct bank which is planned to be replaced in 2015.

7 See footnote 3.

8 CSA Standard C235 defines the preferred voltage levels on a 120V base for normal operating conditions at the customer's point of utilization as 108V minimum and 125V maximum.

Peachytown Road to the end of Incinerator Road. Due to the length of the distribution line and increasing customer growth in the area, there is a significant drop in the voltage at the end of the branch line at Incinerator Road.

This project includes the purchase and installation of three (3) voltage regulators and associated wood pole structure.[9]

The estimated cost of this project is $73,000.

5.0 Project Cost

Table 1 shows the estimated project costs for 2013.

Table 1
Project Costs

Description	Cost Estimate
Glendale Feeder Additions	$451,000
St. John's Main Feeder Additions	$680,000
KEL-02 Voltage Regulators	$73,000
Total	**$1,204,000**

6.0 Concluding

The Feeder Additions for Load Growth project for 2013 includes distribution system upgrades to:

- Install two new distribution feeders at Glendale Substation,
- Install aerial feeders at St. John's Main Substation,
- Relocate SJM-07 feeder to new ductbank infrastructure along Harbour Drive, and
- Install voltage regulators on KEL-02 feeder.

The estimated cost to complete this work in 2013 is $1,204,000.

9 Voltage regulators are commonly used on the distribution system as a low cost alternative to upgrading to a larger conductor size to improve the voltage level provided to customers.

Appendix A
Photographs

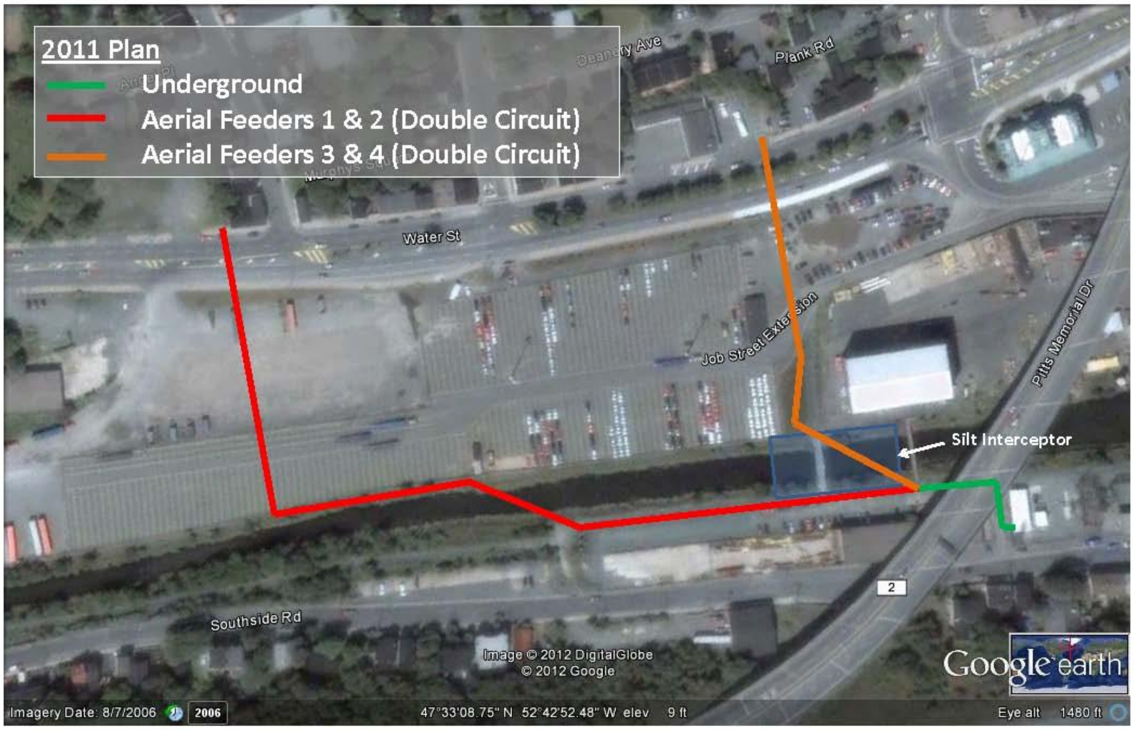

Figure 1 – 2011 Project Plan

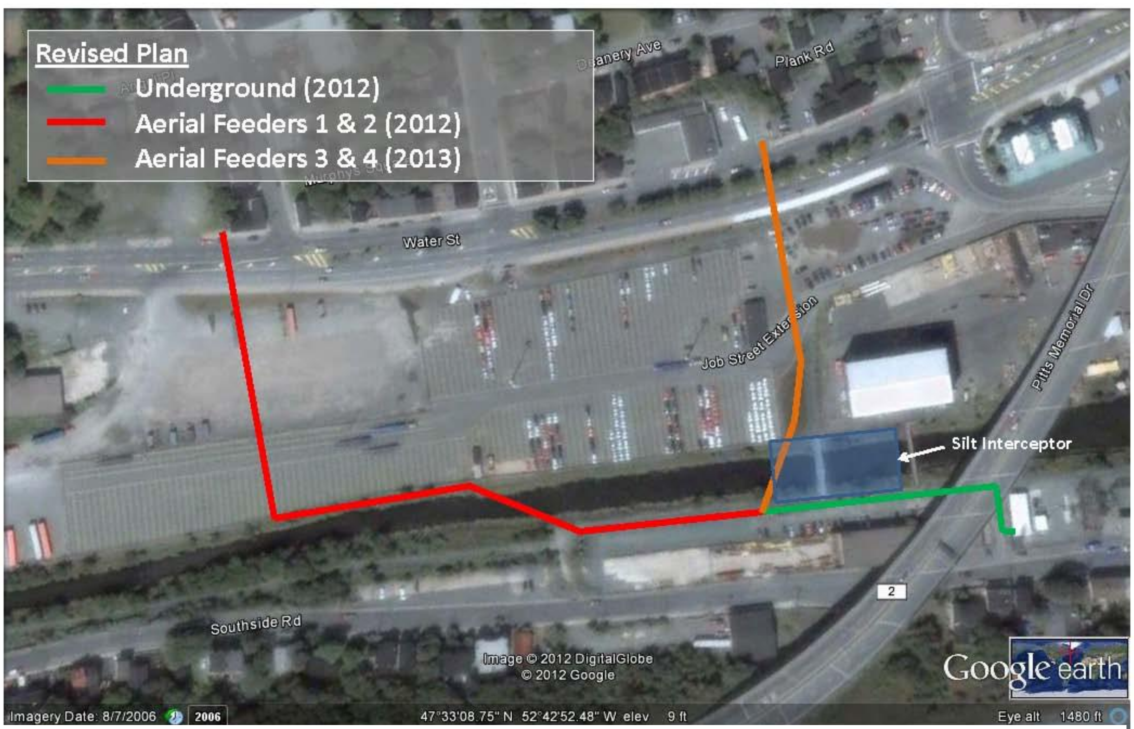

Figure 2 – Revised Project Plan

2013 Metering Strategy

June 2012

Prepared by:

Byron Chubbs, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
PEG
BYRON A. CHUBBS
SIGNATURE
June 12/12
DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

Metering is a core function of Newfoundland Power's ("the Company's") business. The Company provides electrical service to approximately 247,000 customers, the majority of which are supplied through an electricity meter that is read on a monthly basis.

Each year, the Company's capital budget provides for expenditures to purchase and install electrical demand and energy meters. Capital expenditures are driven by connecting new customers to the electrical system, federal regulations governing revenue meters, and improving safety and productivity.

The Company periodically reviews and updates its metering strategy to reflect the current state of metering (technology improvements, federal regulations, etc), in an effort to continually improve safety and operational efficiency at least cost to the customer. The purpose of this report is to identify the current and future direction of metering at Newfoundland Power.

2.0 Background

The Company last submitted its metering strategy to the Board of Commissioners of Public Utilities ("the Board") in its 2006 capital budget application. The strategy outlined four key metering objectives:

- <u>Accuracy & Timeliness</u> – the Company will continue to monitor and maintain existing meter reading accuracy and timeliness, and will continue to seek cost effective ways to improve the process through Automated Meter Reading ("AMR") technology or otherwise.[1]
- <u>Cost Management</u> – the Company will manage metering costs by identifying and eliminating inefficiencies and by further use of AMR where the cost benefits clearly justify it.
- <u>Worker Safety</u> – the Company will continue to focus on the safety of its Meter Readers through existing programs. In addition to the targeted deployment of AMR devices in locations that pose safety risks, the Company will seek additional opportunities to deploy AMR technology in a cost-effective manner to enhance safety.
- <u>Ratemaking</u> – the Company will adjust its metering function as necessary to meet the requirements of changes in rates and rate structures as they arise.

These metering objectives have helped to achieve improved productivity and safety performance in meter reading since 2006.

2.1 Route Optimization

The primary means by which the Company manages the cost of the meter reading function is through Route Optimization. Route Optimization is the process of evaluating meter reading

[1] Automated Meter Reading ("AMR") technology enables a meter to be read remotely via a handheld receiver, eliminating the need for a meter reader to approach the meter for a visual read.

routes and making appropriate changes to ensure efficiency is achieved.[2] This evaluation requires taking a number of variables into consideration, such as the total reading time and driving time in the route, the total number of meters in the route along with the amount of AMR penetration, the length and location of adjacent routes, etc. For example, a route in a high growth area may become too large to be read in a single day, at which point some meters may be moved to an adjacent route, or some meters in the route may be converted to AMR to reduce the total read time. Another route may take less time to read as more and more meters get replaced with AMR meters. In this case meters may be added from an adjacent route, or in some situations two shorter routes can be merged into one route.

From 2007 through 2011, the Company connected 23,923 new customers. The meter reading requirements of these additional customers would have involved approximately 70 new meter reading routes. However, through the strategy of using route optimization and AMR technology for new customer connections, there has been no additional meter reading routes added due to customer growth.

2.2 Safety Performance

Safety performance associated with meter reading has improved since 2006. This is largely due to the continual improvement of the meter reader safety program. An important aspect of this program has been the use of AMR meters in locations that pose a safety hazard to meter readers. Such hazards may include unsafe terrain, deteriorated steps or walkways, and dogs.

Table 1 shows the number of lost time and medical aid incidents associated with the meter reading group over the past 5 years.

Table 1
Meter Reading Safety Performance

Year	**2007**	**2008**	**2009**	**2010**	**2011**
Lost Time Incidents	1	6	0	0	2
Medical Aid Incidents	4	1	0	3	1
Total	**5**	**7**	**0**	**3**	**3**

Meter Readers drive a total of approximately 1 million kilometres and take approximately 6 million steps per year to obtain meter readings. The use of AMR technology in general can reduce the total driving time required to read meters, eliminate the need for a meter reader to exit their vehicle, and reduce the total time spent walking on customers' property, all of which provides an opportunity for safer working conditions and reduced incidents.

[2] One meter reading "route" represents a volume of work that can be completed by one meter reader during a regular 8 hour day. On average, 345 meters can be read in one route. However, the number of actual meters in a route varies depending on factors such as:

- the density of meters in the route (urban routes typically have more meters than rural routes)
- percent of AMR meters in the route
- driving time to and from the route
- number of commercial customers in the route (high commercial routes typically have fewer meters than high residential routes)

2.3 Operating Costs

Operating costs for the Company's metering function are comprised of labour, vehicle and travel costs, and related administrative costs. Table 2 shows the total operating costs of the Company's metering function and the cost per customer for the years 2007 through 2011.

Table 2
Expenditure History and Unit Cost Projection

Year	2007	2008	2009	2010	2011
Operating Cost (000s)	$3,191	$3,365	$3,318	$3,225	$3,198
Average Number of Customers	230,881	234,020	237,542	241,366	245,294
Operating Cost per Customer	$13.82	$14.38	$13.97	$13.36	$13.04

As shown in Table 2, the total operating cost per customer for the Company's metering function has decreased since 2008, from $14.38 in 2008 to $13.04 in 2011. Although labour and fuel costs have increased over this period, the decrease in operating cost per customer is largely attributable to above average customer growth coupled with increased meter reading efficiency through the use of AMR technology for new customer connections and specific AMR projects.

2.4 Capital Costs

Table 3 shows the capital expenditures of the Company's metering function for 2007 through 2011, as outlined in the Company's 2012 Capital Budget Application.

Table 3
Expenditure History and Unit Cost Projection

Year	2007	2008	2009	2010	2011
Quantity of New or Replacement Meters					
New Connections	4,038	4,625	5,051	5,300	4,909
GROs/CSOs[3]	3,546	13,691	14,188	10,284	13,671
Other[4]	1,667	2,156	1,097	7,494	8,366
Total	9,251	20,472	20,336	23,078	26,946
Meter Costs					
Actual (000s)	$1,154	$1,474	$ 1,962	$ 1,872	$ 1,763
Adjusted[5] (000s)	$1,302	$1,634	$ 2,083	$ 1,980	$ 1,815

[3] Government Removal Orders ("GROs") and Compliance Sampling Orders ("CSOs") are completed in accordance with Measurement Canada regulations under the *Electricity and Gas Inspection Act (Canada)*.

[4] Meter requirements classified as "Other" include AMR meters installed for safety or winter accessibility purposes, meters replacements as part of specific AMR projects, or replacements for defective or broken meters.

[5] Cost in 2012 dollars.

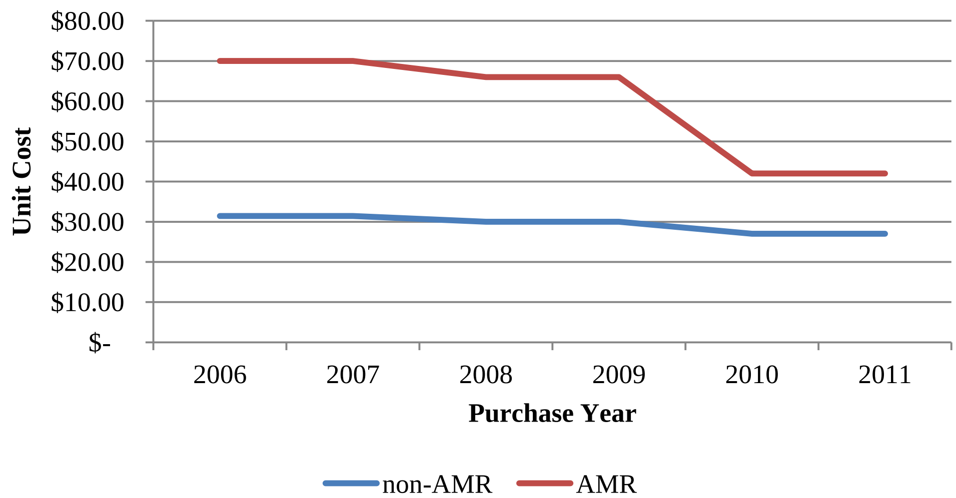
Capital expenditures have been driven by purchasing meters to connect new customers to the electrical system, replacing expired meters as a requirement of federal government regulations, installing AMR meters to improve safety and productivity, and replacing defective or broken meters.

3.0 Metering Landscape

3.1 AMR Technology

The cost of AMR vs non-AMR meters has also decreased in recent years. Graph 1 below shows the changes in unit cost between AMR equipped meters and standard domestic non-AMR equipped meters since 2006.[6]

Graph 1
Unit Cost of Meters



In 2006, a standard domestic non-AMR meter cost $31.45, compared to an AMR meter cost of $70.00, a difference of $38.55. Today, the same non-AMR meter costs $27.00, while the AMR version costs $42.00, a difference of $15.00.

3.2 Changes to Measurement Canada Regulations

In Canada electricity metering is regulated by Measurement Canada under the Weights and Measures Act. Newfoundland Power is responsible to ensure all federal regulations governing revenue meters are followed. Two important metering functions related to Measurement Canada compliance are Government Removal Orders (“GROs”) and Compliance Sampling Orders (“CSOs”). A GRO is an order to remove an electricity meter from service once it has reached its seal expiry date. A CSO is an order to remove a meter as part of a process to sample test a group of meters for measurement accuracy. The meters removed under CSOs are tested to determine if the expiry date for the group of meters will be extended and if so by how long.

[6] The standard domestic meter accounts for 88% of all meters purchased by Newfoundland Power since 2006.

In 2011, Measurement Canada amended the legislation and applicable procedures and specifications regulating the sample testing of electricity meters.[7] The changes in legislation have resulted in two significant changes in how the Company manages its meter inventory.

The first change is related to the length and number of extensions that can be granted to a group of meters tested under the CSO process. Under the previous specifications, the Company could sample test a group of meters indefinitely until the test results indicated the group was no longer operating accurately. Under the new procedures, the number of times a meter group can be tested is now finite, and the length of the seal extension is reduced with each round of testing.

The second change is related to the actual testing results of the sampled meters. These changes are statistical and complex in nature. However, the most significant change was made to the acceptable accuracy of a group of meters. Under the previous specifications, meters could receive a seal extension as long as the accuracy test showed the meters were within $\pm$ 3% of specification. The new specifications allow for an accuracy of $\pm$ 2% of specification. This reduction in the acceptable accuracy range will result in more groups of electromechanical meters failing the sample testing process and an increase in the number of meter replacements.

Measurement Canada required utilities to be fully compliant with the new regulations for electronic meters by January 2011, and for electromechanical meters by January 2014. In advance of the 2014 deadline for electromechanical meters, the Company has developed a transition strategy for compliance with the new legislation. The transition strategy includes a combination of sample testing electromechanical meters early under previous specifications, as well as the advance replacement of groups of electromechanical meters that are expected to fail testing in 2014 and beyond.

Table 4 below outlines the forecast number of meter replacements required from 2013 to 2017.[8]

Table 4
Required Meter Replacements – 2013 – 2017

	2013	2014	2015	2016	2017	Average[9]
GRO/CSO Meter Replacements	20,255	19,271	17,631	18,287	13,732	17,835

3.3 Ratemaking

Metering requirements can be significantly influenced by ratemaking requirements. For example, demand management, alternative rates and energy conservation initiatives are typically

7 Measurement Canada changes include the implementation of a new sampling standard S-S-06, replacing the old standard LMB-EG-04. A copy of the S-S-06 Specification is included in Appendix A.

8 The number of meter replacements shown in Table 4 include the forecast GROs and CSOs for both electronic and electromechanical meters. The actual number of meter replacements will vary from forecast depending on compliance sampling test results for both electronic and electromechanical meters as each group of meters is tested.

9 The average number of GRO/CSO meter replacements from 2007 to 2011 was 11,076 per year.

supported with the collection of more detailed energy consumption and demand information than is provided by conventional metering systems.

Rate initiatives currently supported by the Company's metering function include (i) the Curtailable Service Option, which is supported by load recorder type meters that can verify the success of requested curtailments via telephone, (ii) the Company's metering program for its largest General Service customers (i.e. those with demands of 1,000 kVA and above), which uses load recorder type meters to obtain detailed load information and (iii) the Time of Day ("TOD") Rate Study which also uses load recorder type meters to obtain energy usage by time of day for use in customer billing.

The TOD Rate Study is a 2-year study involving 240 domestic customers and 4 large General Service customers. If TOD rates are determined to be a cost-effective rate option, changes will be required in the Company's metering function.[10]

4.0 AMR Cost Benefit Analysis

The Company currently uses AMR meters for (1) new customer connections, (2) to address safety and access concerns, and (3) specific projects involving route optimization. Based on current productivity improvements realized through the use of AMR meters, as well as the reduction in cost differential between AMR and non-AMR meters, an analysis was completed to determine if purchasing AMR meters for all meter replacements, particularly for GROs and CSOs, can further reduce the cost of meter reading.

Operating cost savings from purchasing AMR meters for all meter replacements would be achieved through increased meter reading productivity. As the penetration of AMR meters increases, so does the total number of meters that can be read per route, therefore reducing the total number of meter reading routes required.

---

[10] To implement TOD rates to a broad range of customers would require smart meters to record consumption in intervals as determined by the rate parameters, a communications infrastructure and changes to the data collection and billing systems. The AMR meters being purchased under this strategy are not considered smart meters and will *not* be compatible with TOD rates.

4.1 Economic Analysis

Table 5 shows the forecast number of new customer connections for 2012 through 2017, an estimate of the number of GROs and CSOs to be completed during each year, as well as an estimate of the number of meter replacements required for safety, accessibility and route optimization.

Table 5
Customer and Meter Replacement Forecast

	2013	**2014**	**2015**	**2016**	**2017**
Metered Services[11]	243,561	246,665	249,784	252,956	255,987
Gross New Connections	4,657	4,554	4,586	4,659	4,524
GROs/CSOs[12]	20,255	19,271	17,631	18,287	13,732
Other (Safety, Access, etc.)[13]	4,156	4,156	4,156	4,156	4,156
Total	29,068	27,981	26,373	27,102	22,412
Incremental Capital Cost (000s)[14]	**$349**	**$332**	**$304**	**$315**	**$237**
Total AMRs Installed[15]	102,488	130,469	156,842	183,944	206,356
AMR Penetration[16]	42.1%	52.9%	62.8%	72.7%	80.6%

[11] Forecast number of customer connections by year end, minus street and area lighting which are not metered services.

[12] The GRO/CSO forecast is based on changes to Measurement Canada legislation and following the Company's transition strategy as outlined in Table 4. This forecast will change as the result of actual compliance sampling results.

[13] Forecast number for "Other" is based on a five-year historical average of meters installed for safety or winter accessibility, route optimization, or defective or broken meters.

[14] The incremental capital cost is the total number of GRO/CSO meter replacements multiplied by the $15 incremental cost of AMR meter versus non-AMR meters.

[15] Total AMRs Installed is equivalent to the number of AMR meters in service at the end of the previous year plus the number of New Connections, GRO/CSOs and Other meters installed in the current year.

[16] AMR Penetration is the Total AMRs Installed divided by the number of Metered Services.

Table 6 provides an estimate of the number of meter reading routes that will be required in each year based on the forecast penetration of AMR meters. The productivity improvements (meter reads per route) were determined using a regression line analysis based on current meter reading data. See Appendix B for details on the regression line analysis.

Table 6
Forecast Reduction in Meter Reading Routes[17]

	2012	2013	2014	2015	2016	2017
Metered Services	240,350	243,561	246,665	249,784	252,956	255,987
Meters Read per Route	371	411	458	507	562	611
Required # of Routes[18]	648	592	539	493	450	419

AMR meter installations and associated route optimization would occur throughout the year shown, with forecast numbers achieved by year end. Operating savings would be fully realized in the year following the meter installations, and for each year for the 25 year life of the AMR meter. Table 7 provides an estimate of the potential operating cost savings in each year based on the forecast penetration of AMR meters.

Table 7
Meter Reading Operating Cost Reduction
(000s)

	2014	2015	2016	2017	2018
Compared to Previous Year	$163	$150	$125	$115	$73
Cumulative	$163	$313	$439	$554	$627

A net present value ("NPV") analysis was completed using the incremental capital costs to purchase only AMR meters and the corresponding reduction in operating costs. The results of the NPV show that purchasing only AMR meters provides a total benefit to the customer of $5,828,011.[19] See Appendix C for details on the NPV calculation.

4.2 Sensitivity Analysis

The economic analysis was based on average route sizes increasing as the percent of AMR meters on the route increases. The average route size was calculated using an equation relating route size to the percentage of AMR meters installed. This equation was developed using the regression line analysis from Appendix B.

17 Numbers shown are values forecast to be achieved by the end of each year.
18 Required # of Routes is equal to the number of Metered Services divided by the estimated Meters Read per Route.
19 Financial calculations also show that a positive benefit to the customer is achieved 3 years after an AMR meter is installed.

A sensitivity analysis was completed to determine the sensitivity of the NPV to the relationship between average route size and percent AMR (See Appendix D). This was done by selecting two additional equations, one that calculates a lower degree of productivity improvement as the percent AMR increases compared to the base case, and another that represents no productivity improvements from installing AMR meters. The results of this analysis are shown in Table 8.

Table 8
Sensitivity Analysis

	Calculated NPV
Base Case	$5,828,011
25% of Base Case	$2,232,886
No Productivity	-$1,538,794

The sensitivity analysis shows that for the scenario where only 25% of the assumed productivity is achieved, the approach of purchasing only AMR meters still provides a benefit to the customer of $2,232,886. If no productivity were achieved through AMR installation, the project would result in additional cost of $1,538,794. Based on current results from the use of AMR in the Company's service territory, it is reasonable to assume that average route size can be increased through the deployment of AMR meters at an amount that provides an overall benefit to the customer.

5.0 Concluding

The metering function at Newfoundland Power continues to evolve as changes occur with federal regulations, technology and metering costs. As a result, the Company must re-evaluate and adjust its metering strategy to ensure that core objectives such as worker safety and meter accuracy are achieved in a manner that is least cost to the customer.

Based on the current review of metering at Newfoundland Power, the Company will:

- Continue with the objectives outlined in the 2006 Metering Strategy with respect to Accuracy & Timeliness, Cost Management, Worker Safety and Ratemaking.
- Implement the recommended transition strategy to comply with changes to Measurement Canada regulations.
- Proceed with purchasing only AMR meters for all meter replacements and new installations.
- Maintain its focus on route optimization in order to achieve productivity improvements through AMR and reduce costs.

Appendix A
S-S-06 Specification

Measurement Canada | Mesures Canada
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Specifications

Category: **STATISTICAL METHODS**	Specification: **S-S-06**	
Document(s): **S-S-06 Implementation, Information Bulletin (2010-02-08)**	Issue Date: **2010-06-21**	Effective Date: **2011-01-01**
	Supersedes: **PS-S-04, LMB-EG-04**	

Sampling Plans for the Inspection of Isolated Lots of Meters in Service

1.0 Scope

This specification establishes the requirements that are applicable to in-service isolated lots of homogeneous electricity or gas meters, where a meter owner has chosen to utilize sampling inspection for the purposes of extending the reverification period of an in-service lot of meters. Where applicable, this specification may be utilized as an alternative to performing 100% meter reverification, upon expiry of a meter lot's initial or subsequent reverification period.

NOTE: Sampling plans, by design, contain inherent risks and limitations with regard to their usage and the conclusions they may or may not provide. Meter owners are therefore advised that, although conformity with the requirements of this specification may allow for the extension of a meter's reverification period, relying solely on the use of the sampling plans contained in this specification will not provide users with an assurance of compliance with the metering accuracy obligations prescribed under the *Electricity and Gas Inspection Act*.

2.0 Authority

This specification is issued under the authority of section 19 of the *Electricity and Gas Inspection Regulations*.

3.0 Normative References

3.1 ISO 2859-2:1985, *Sampling procedures for inspection by attributes – Part 2: Sampling plans indexed by limiting quality (LQ) for isolated lot inspection*. Table A - Single sampling plans indexed by limiting quality (LQ) (Procedure A).

3.2 S-S-01, *Specifications for Random Sampling and Randomization*

3.3 Relevant Measurement Canada specification for the verification and reverification of the meter under test.

4.0 Administrative Requirements

Sampling inspection shall be carried out well in advance of the expiry of the reverification period of the meters so that in the case of non-conformity with the requirements, all meters forming part of the lot can be removed from service prior to the expiry of the reverification period.

Canada

5.0 Sampling Inspection Requirements

5.1 Lot Formation

5.1.1 The lot shall be formed from meters that are homogeneous with respect to the requirements in Annex A.

5.1.2 At the discretion of a meter owner, larger lots may be reformed into multiple lots of smaller size.

5.2 Sample Selection

5.2.1 The sample shall be drawn at random, without replacement, from the lot listing, using authorized random sampling software that meets the requirements referenced in section 3.2. (Systematic sampling shall not be used).

5.2.2 The size of the sample shall be one obtained from the table in Annex C as per the sampling instructions provided by this specification. The sample representing the lot shall correspond to a value between n_{min} and n_{max} as identified in the table of Annex B.

5.2.3 Meter owners shall be responsible for assuring that the meters which are included in the sample meet the following criteria:

(a) the identified meter is one which is currently installed in service;

(b) the identified meter's metrological parameters have not been adjusted post installation;

(c) the identified meter is homogeneous with regard to the criteria of A.1 of Annex A: and

(d) the identified meter meets the total time on test criteria of A.2 of Annex A.

5.2.4 Where a sample meter does not qualify for inclusion as per the requirements of 5.2.3, meter owners shall not consider this meter as part of the sample group for performance testing purposes, and shall replace it with the sequentially subsequent meter on the preselected unsorted sample meter listing meeting the applicable criteria. The exclusion rationale for the subject meter(s) shall be reported as per the requirements of 5.3.4.

5.2.5 Where a meter, which has been removed from service, is not capable of having its performance assessed in accordance with the requirements of this document, the meter owner shall replace it with the sequentially subsequent meter on the preselected unsorted sample listing of meters available for testing. All meters and their associated test results shall be included unless compelling evidence for exclusion is identified and reported as per the requirements of 5.3.4.

5.2.6 Meters which have been excluded as sample meters as a result of not satisfying either 5.2.3 (a), 5.2.3 (b), 5.2.3 (c), 5.2.3 (d) or 5.2.5 shall not be returned to the parent lot.

5.2.7 Lots failing to meet the minimum sample size (n_{min}) criterion as a result of the total number of exclusions under 5.2.3, are not considered to be homogeneous and are not acceptable for seal extension. Where a lot is deemed to be nonhomogeneous, meter owners shall implement one of the following actions:

(a) Re-form the lot on the basis of both the lot and sample homogeneity criteria contained in Annex A;

(b) Assign a lower initial reverification period to the lot as per the requirements of section 5.7; or

(c) Remove the lot from service.

5.3 Meter Sampling Records

5.3.1 For each lot assessed, a meter owner shall maintain records documenting:

(a) a unique, owner-assigned lot number or record reference which includes an ordinal number indicating the lot's occurrence for assessment under this specification (including the current - i.e. 1st, 2nd, 3rd, etc.);

(b) the homogeneity criteria details specified in A.1;

(c) the utility number and manufacturer's serial number for each meter.

5.3.2 All meters identified by the owner as forming part of the lot, shall be listed in ascending order based on meter identification numbers or an inventory number generated by the associated informatics system.

5.3.3 The identification of each unsorted sample meter (n to n_{max}) selected from the lot, the sample meters tested, the quality characteristics examined, and the test results obtained, shall be documented.

5.3.4 All sample meters selected but not involved in the final calculations shall be accounted for by the meter owner and the reasons for exclusion shall be documented and, on request, made available for Measurement Canada review. Evidence of deliberate exclusion or improper accounting may disqualify the results of the sample's analysis.

5.4 Meter Inspection, Quality Characteristics, and Corrective Actions

5.4.1 Each sample meter shall be examined for conformance to all pertinent requirements as prescribed by reference 3.3.

5.4.2 Sample meters shall be inspected under identical conditions and within as short a time period as is practicable to achieve valid inspection results.

5.4.3 Each defective meter excluded from the final calculations shall be preserved for Measurement Canada review and shall be the subject of an investigation by the meter owner to determine the cause of the defect or defects. In the case of defective meters, a report shall be prepared and shall include the following information associated with this investigation:

(a) details of the meter's make, model, Notice of Approval number, seal year, and identification numbers;

(b) a description of the defect and its effect on the meter's operation, including performance test results where feasible;

(c) a description of the steps taken to investigate the cause of the defect, including identification of the personnel both performing the investigation and providing information for its purpose;

(d) an explanation of how the defect occurred, including where it occurred in the process;

(e) an evaluation of the extent of the defect in the immediate situation as well as in situations likely to be similarly affected; and

(f) details of the corrective and preventive action proposed or performed to address the cause and symptoms of the defect.

5.4.4 In cases where a defective meter is encountered, the report required by clause 5.4.3 shall be provided to the local Measurement Canada representative for review prior to deciding upon the acceptability of the affected lot. Decisions regarding acceptability of the affected lot and the possible need for further investigation or corrective action shall not be made until Measurement Canada has evaluated the report and the statistical analysis of the data from the sample meters involved in the final calculations.

5.5 Acceptance Criteria

5.5.1 Individual Meters

5.5.1.1
Each meter in the sample can be considered acceptable if the following conditions are met:

(a) the meter complies with all specified reverification performance requirements (reference 3.3);

(b) the meter does not possess any defect which could affect its ability to meet specified requirements during its usage;

(c) the meter has been obtained from a population whose seal year is still valid;

(d) the meter has been received with a broken seal and an exclusion as per 5.3.4 cannot be justified.

5.5.1.2
To maintain overall homogeneity of the lot, sample meters, obtained from lots qualifying for an extension, which meet reverification requirements and which have been granted the same extension as the parent lot, shall, wherever possible, be returned to the parent lot and reinstalled following acceptance of the lot. Alternatively, these meters can be reverified.

5.5.1.3
Where sample meters require their seals to be broken in order to conduct meter performance testing, precautions should be taken to ensure the integrity of the results. If the lot is acceptable, the individual sample meters that are also acceptable shall be resealed with an additional identifier indicating the original seal year in the sealing assembly. Alternatively, these meters shall be reverified.

5.5.1.4
Sample meters that meet reverification requirements, yet have been obtained from lots not qualifying for an extension or sample meters not returned to the parent lot, shall be governed by Measurement Canada bulletins E-26 *Reverification Periods for Electricity Meters and Metering Installations* or G-18 *Reverification Periods for Gas Meters, Ancillary Devices and Metering Installations,* with respect to the assigned reverification period.

5.5.2 Meter Lots

5.5.2.1
The sampling plan parameters of ISO 2859-2 (reference 3.1) as modified in Annex C of this document, shall be utilized for the inspection of isolated lots of meters in service.

5.5.2.2
The acceptability of the lot for the purposes of extending its reverification period, shall be established on the basis of the performance results of the sample with regard to the number of marginally conforming meters (C_1) and the number of nonconforming meters (C_2) evidenced, as defined in section 5.5.3.

5.5.2.3
Contractors are responsible for ensuring the performance quality of the in-service meter lots which they own. Where a seal extension period is available under this specification, contractors shall give consideration to their statutory obligation for keeping meters in good repair, when selecting the seal extension period to be applied from those which are available. Specifically, the conformance quality of an in-service lot of meters shall, in all cases, meet or exceed the declared limiting quality that is associated with level 5.

5.5.3 Meter Performance Test Limits

5.5.3.1
For all performance tests, required to be conducted as per the reverification specification applicable to the subject meter type or class, a Type 1 (C_1) marginally conforming meter is one whose performance error exceeds ± 2.0% at any test point.

5.5.3.2
For all performance tests, required to be conducted as per the reverification specification applicable to the subject meter type or class, a Type 2 (C_2) nonconforming meter is one whose performance error exceeds ± 2.9% at any test point.

5.5.3.3
For the purposes of section 5.5.2.2, a Type 2 (C_2) nonconforming meter is also counted as a Type 1 (C_1) marginally conforming meter.

5.5.4 Seal Extension Levels

5.5.4.1
Where a lot of meters is assessed against the requirements of this specification, the maximum seal extension level available for application to the lot, shall be established on the basis of satisfying the following criteria when applied to the n_{min} sample size as specified in a column of the applicable Annex C table:

Maximum Extension Level Criteria:

(i) $c1 \leq Ac_{\textbf{type 1}}$
(ii) $c2 \leq Ac_{\textbf{type 2}}$

5.5.4.2
Subject to the requirements of section 5.6, the maximum seal extension level that may be available for application to a lot, is the seal extension level associated with the limiting quality column of the applicable table in Annex C, C-1 or C-2 which satisfies the requirements of 5.5.4.1 for the established sample size n_{min}.

5.5.4.3
Where the maximum level of extension available to a lot of meters is determined to be level 4, the applicable seal extension period, as determined under Annex E, may be repeated without limitation on an ongoing basis where the applicable level 4 limiting quality criteria of Annex C, C-1 or C-2 and the Time on Test criteria of Annex E are met.

5.5.4.4
Subject to section 5.5.4.5, lots failing to meet at least level 4 criteria are not acceptable for extension. All meters in non-acceptable lots shall be removed from service.

5.5.4.5
Where a lot failing to meet level 4 criteria is capable of meeting the limiting quality criteria of level 5 (where available), the applicable level 4 extension period available as per Annex E, may be applied to the lot. However, upon expiry of this period, the lot cannot be re-sampled and must be removed from service.

5.5.4.6
Where a lot fails to meet at least level 4 criteria and this failure is as a result of not meeting the requirements of sec 5.5.4.1(ii), all sample meters identified as C_2 meters under section 5.5.3.2 shall be held in storage until Measurement Canada authorizes their further processing. Sample meters shall not be required to be held in storage (without just cause) after December 31st of the calendar year in which the sampling was conducted.

5.6 Use of Sampling Tables (Annex C, C-1, and C-2)

5.6.1 The value of n_{min} shall be established on the basis of the lot size and the maximum seal extension level being targeted. Once the n_{min} sample size has been determined, it is this value that shall be utilized for establishing the maximum seal extension level, where further movement within the table is limited to either the horizontal or a diagonal downward direction for the same n_{min}.

5.6.2 Notwithstanding the seal extension level available under the requirements of section 5.5.4.1, and subject to section 5.6.3, the maximum seal extension level that may be applied to the lot shall be established on the basis of the lot's ordinal sampling occurrence under this specification as specified in Annex D.

5.6.3 Where the maximum seal extension level available to the lot under Annex D is longer in duration than the previous seal extension period granted to the lot, the period applied shall not be greater than one level better than the previous extension level and this eligibility for the application of a longer period, is limited to a single occurrence within a meter lot's in-service life.

5.6.4 Where a lot population has never been assessed against the requirements of this specification, the seal extension period of reference for the purposes of 5.6.3, shall be the last extension period granted to the lot under the previously authorized compliance sampling program.

5.6.5 Where a lot population is re-formed under the requirements of 5.1.2 or 5.2.7, the maximum seal extension levels available to the re-formed lot shall be established in accordance with the requirements of 5.6.2, 5.6.3, and 5.6.4, as applicable to the parent lot before re-formation.

5.6.6 Where a lot's population size is 500 meters or less, a meter owner may, at their discretion, utilize the sampling plan as specified in Annex C-1. Where the sampling plan of Annex C-1 is utilized, the seal extension periods available under Annex E are reduced by 50% (rounded down to the nearest whole year).

5.6.7 Where a lot's population size is 60 meters or less, a meter owner may, at their discretion, utilize the sampling plan as specified in Annex C-2. Where the sampling plan of Annex C-2 is utilized, the only seal extension periods available under Annex E are those associated with a level 4 extension.

5.7 Seal Extension Periods (Annex E)

5.7.1 For meter lots still within their initial reverification period, the time on test (TT) requirements which need to be met or surpassed by each meter in the sample (as per the homogeneity requirements of A.2), shall be established on the basis of the meter's initial reverification period and the minimum period (in months) prescribed under Annex E.

5.7.2 For meter lots still within their initial reverification period, a sample meter's time on test (in months) is established from the date the sample meter is placed into service, to the date that it is removed from service (rounded down to the nearest whole month). For the purposes of this section and section 5.7.4, where months are established on the basis of day counts, one month is to be considered 31 days. Alternatively, months may be established on the basis of actual month days where this information is tracked on an ongoing basis relative to true months completed within a calendar period.

5.7.3 Subject to section 5.7.5, where a meter lot is no longer within its initial reverification period, the time on test (TT) requirements that need to be met or surpassed by each meter in the sample (as per the homogeneity requirements of A.2), shall be established on the basis of the previous seal extension period granted to the lot and the applicable subsequent extension percentage prescribed for the subject row as per Annex E.

5.7.4 For meter lots no longer within their initial reverification period, a sample meter's time on test (in months) is established from the date that the certificate was issued relative to the meter lot's last seal extension, to the date that the sample meter is removed from service (rounded down to the nearest whole month). Alternatively, a meter's time on test requirement is satisfied where it can be demonstrated that the sample meter has continuous uninterrupted service.

5.7.5 Meter lots that are sampled on an annual basis under this plan, are not subject to the time on test requirements of Annex E.

5.7.6 Where the time on test requirements for the 1st extension or subsequent extensions of a lot have not been met or where a sample is deemed non-homogeneous relative to the applicable time on test requirement, a lower initial reverification period (where the time on test requirements are satisfied) may be assigned to the lot.

5.7.7 Once a lower initial reverification period row has been assigned to a lot, further movement within the table is limited to either the horizontal, downward or diagonal downward directions (i.e. the initial reverification period reference cannot be increased on subsequent samplings of the lot).

5.8 Reverification Date Calculations

5.8.1 Subject to 5.8.2 , where a seal period extension is granted under Annex E, the meters in the lot, less any nonconforming meters, shall be considered due for reverification on or before December 31 of the calendar year calculated as the sum of the year in which the first sample meter was removed from service and the extension period granted under Annex E (in years).

5.8.2 Where the first sample meter is removed from service in the calendar year which immediately precedes the meter lot's seal expiration year, the meters in the lot, less any nonconforming meters, shall be considered due for reverification on or before December 31 of the calendar year calculated as the sum of the lot's seal expiration year and the extension period granted under Annex E (in years).

5.8.3 Subject to 5.8.4, where a lot of meters fails to meet the requirements for an extension of its reverification period, the meters in the lot shall be considered due for reverification on the date established by the previous verification or reverification, as the case may be.

5.8.4 In the case of a lot of meters which fails to meet the requirements for an extension of its reverification period and the first sample meter was removed from service in a calendar year which preceded the meter lot's seal expiration year by more than one (1) calendar year, the meters in the lot shall be considered due for 100% reverification, on or before December 31st of the calendar year which postdates the year in which the first sample meter was removed from service.

Annex A
(normative)

A.1 Lot Homogeneity Requirements

Where applicable, the meters in the lot shall be homogeneous with respect to the following characteristics:

Electricity Meters

(a) type (transformer or self contained);

(b) manufacturer and model, unless otherwise authorized in accordance with clause A.1.1;

(c) voltage or voltage range;

(d) maximum current range, unless otherwise authorized in accordance with clause A.1.1;

(e) measurement functions (e.g. measured quantities, energy, demand), unless otherwise authorized in accordance with clause A.1.1;

(f) firmware version, unless otherwise authorized in accordance with clause A.1.1;

(g) frequency rating;

(h) same model or type of telemetering device (if so equipped), unless otherwise authorized in accordance with clause A.1.1;

(i) configuration / form (i.e. number of elements*, wye, delta or auto configuration);

(j) status at time of last inspection (i.e. new, renewed, or reserviced);and

(k) seal year (same seal year or two consecutive seal years, provided both are valid);

***With the exception that 1-element and 1.5-element meters may be mixed to form a lot.**

Natural Gas Meters

(a) manufacturer and model, unless otherwise authorized in accordance with clause A.1.1.

(b) same or similar capacity rating, unless otherwise authorized in accordance with clause A.1.1.

(c) measurement functions (e.g. measured quantities, temperature/pressure conversion).

(d) firmware version, unless otherwise authorized in accordance with clause A.1.1.

(e) same model or type of telemetering device or auxiliary attachment (if so equipped), unless otherwise authorized in accordance with clause A.1.1.

(f) status at time of last inspection (i.e. new, renewed, or reserviced).

(g) seal year (same seal year or two consecutive seal years, provided both are valid).

A.1.1 Forming Lots with Mixed Meters

Where a lot includes meters which, for the purposes of lot homogeneity, are ones which possess a similar characteristic rather than a characteristic which can be readily identified as being the same, meter owners are responsible for maintaining documented records identifying the similarities which support the homogeneity conclusion (as concerns including these meters within the subject lot). For the purposes of compliance sampling, if an accredited organization wishes to combine, in one lot, various models or vintages of meters, and/or meters equipped with and without a telemetering device, the accredited organization shall submit a request to MC with accompanying documentation in support of their claim that these differing meters can be considered homogeneous.

A.2 Sample Homogeneity Requirements

The meters in a sample shall be homogeneous with respect to similar time in usage. For a sample meter to be considered homogeneous with regard to similar time in use, a meter shall have been in service for a time period that meets or exceeds the applicable time on test (TT) requirements of Annex E. Where n_{min} is not achieved with regard to this criteria, a meter owner may re-form the lot or reduce the seal period extensions available as per the requirements of section 5.7.

Annex B
(normative)

Table of n_{min} to n_{max} Sample Sizes

Single Sampling	
n_{min}	n_{max}
30	37
42	52
44	55
65	81
80	100
125	156
200	250
315	394

Annex C - Single Sampling Plans Indexed by Quality Level (LQ)
(normative)

Lot Size		**Limiting Quality (LQ)**				
		3.15 (Level 1)	**5.0** (Level 2)	**8.0** (Level 3)	**12.5** (Level 4)	**20** (Level 5)
Up to 500	n_{min}	80	65			
	Ac $_{\text{type 1}}$	0	0	↓	↓	↓
	Ac $_{\text{type 2}}$	0	0			
501 to 1200	n_{min}	125	80	65	42	42
	Ac $_{\text{type 1}}$	1	1	1	2	4
	Ac $_{\text{type 2}}$	1	0	0	0	0
1201 to 3200	n_{min}	125	125	80	65	65
	Ac $_{\text{type 1}}$	1	3	3	4	8
	Ac $_{\text{type 2}}$	1	1	0	0	0
3201 to 10000	n_{min}	200	200	125	80	80
	Ac $_{\text{type 1}}$	3	5	5	5	10
	Ac $_{\text{type 2}}$	3	3	1	1	1
10001 to 35 000	n_{min}	315	315	200	125	125
	Ac $_{\text{type 1}}$	5	10	10	10	18
	Ac $_{\text{type 2}}$	5	5	3	3	3
	n_{min}			315	200	200
	Ac $_{\text{type 1}}$			18	18	32
	Ac $_{\text{type 2}}$			5	5	5

NOTE:
As per 5.5.3.1, Type 1 (C_1) > 2.0%
As per 5.5.3.2, Type 2 (C_2) > 2.9%

Annex C1 - Single Sampling Plans Indexed by Quality Level (LQ)
Small Lot Size Plan (with increased sampling frequency)
(normative)

Lot Size		**Limiting Quality (LQ)**			
		5.0 (*Level 1)	**8.0** (*Level 2)	**12.5** (*Level 3)	**20** (*Level 4)
Up to 500	n_{min}	44	44	44	44
	$Ac_{type\ 1}$	0	1	2	4
	$Ac_{type\ 2}$	0	0	0	0

NOTE:
* Extension period as per section 5.6.6.
As per 5.5.3.1, Type 1 (C_1) > 2.0%
As per 5.5.3.2, Type 2 (C_2) > 2.9%

Annex C2 - Single Sampling Plans Indexed by Quality Level (LQ)
Very Small Lot Size Plan
(normative)

Lot Size		**Limiting Quality (LQ) 5.0 (Nonconforming)**
		Level 4
Up to 60	n_{min}	30
	$Ac_{type\ 1}$	0
	$Ac_{type\ 2}$	0

NOTE:
As per 5.5.3.1, Type 1 (C_1) > 2.0%
As per 5.5.3.2, Type 2 (C_2) > 2.9%

Annex D - Available Extension Levels
(normative)

Ordinal Sampling Occurrence	Maximum Seal Period Extension Levels Available			
1st	Level 1	Level 2	Level 3	Level 4
2nd		Level 2	Level 3	Level 4
3rd			Level 3	Level 4
4th (and higher)				Level 4

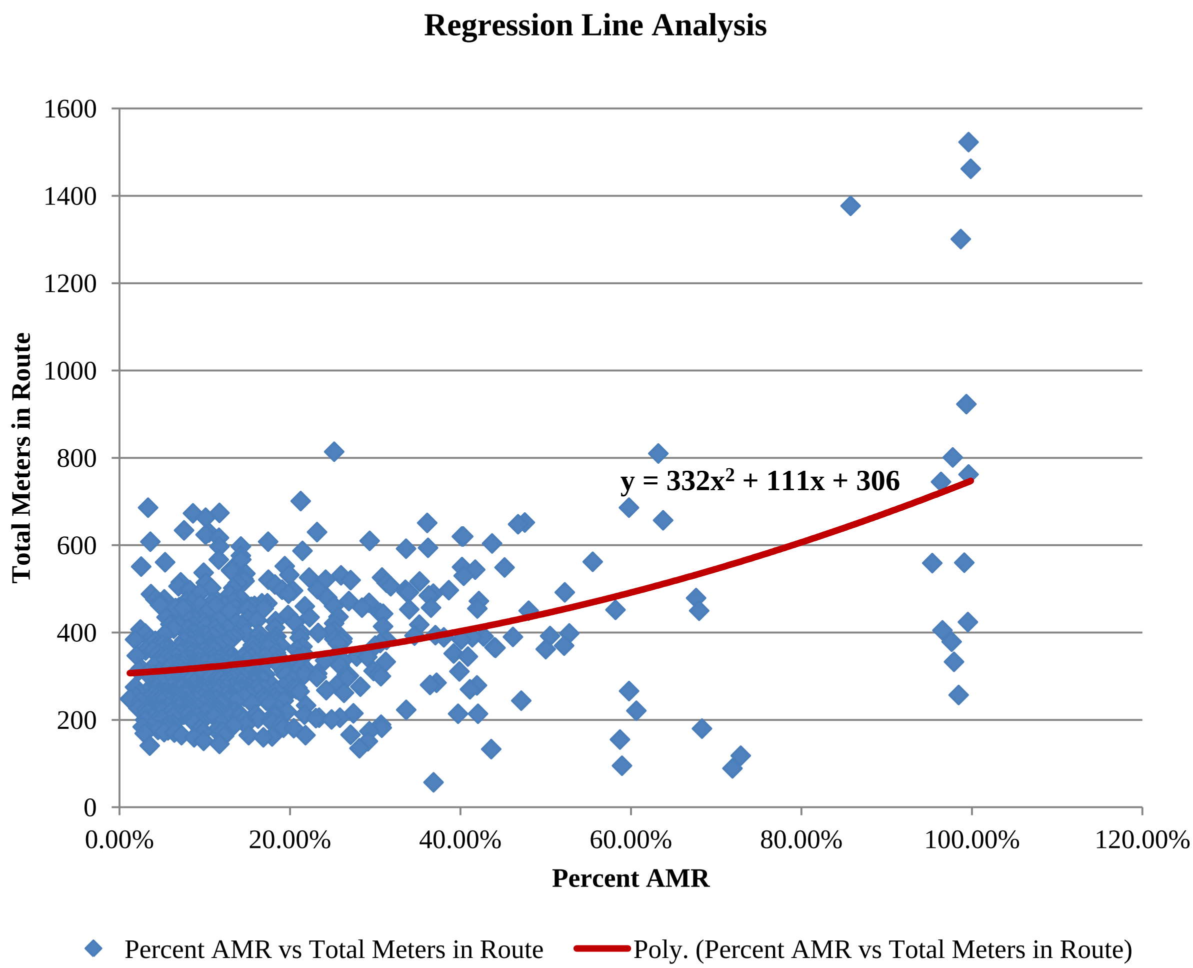
Annex E - Time on Test (TT) Requirements and Maximum Seal Period Extensions
(normative)

Initial Reverification Period (years)	1st Extension (Months)	Subsequent Extensions*	Maximum Seal Period Extension (years)			
			Level 1	Level 2	Level 3	Level 4
12	115	75%	10	8	5	2
11	105	75%	9	7	5	2
10	84	70%	8	6	4	2
9	75	70%	7	5	3	2
8	67	70%	6	4	3	2
7	58	70%	5	4	2	1
6	50	70%	4	3	2	1
5	42	70%		3	2	1

***Subsequent extension TT based on indicated percentage multiplied by the previous extension (rounded up to the next whole month).**

Alan E. Johnston
President

Appendix B
Regression Line Analysis



A Regression Line Analysis has been completed using current meter reading data to estimate the number of meters that can be read per route as the percent of AMR meters increases.

In the graph above, the total number of meters in each of the Company's 686 meter reading routes is plotted versus the percent of AMR meters in each route (a sample data set is shown in the table below). From this data, a 2nd order polynomial regression line is plotted and can be represented by the equation **$y=332x^2+111x+306$**, where x represents the percentage of AMR meters in the route and y represents the total meters that can be read in each route.

Although this equation represents current meter reading data at a specific point in time, it also provides a method for calculating the optimal average route size as a function of the percentage of AMR meters. For example, if 50% of the Company's meters were converted to AMR (x = 0.50), the estimated average route size can be calculated as follows:

$$y = 332x^2 + 111x + 306 = 332(0.5)^2 + 111(0.5) + 306 = \textbf{445 meters}$$

If 100% of meters were converted to AMR (x = 1.00), it is estimated that the average route size would be 749 meters.

$$y = 332x^2 + 111x + 306 = 332(1.00)^2 + 111(1.00) + 306 = \mathbf{749\ meters}$$

Currently, 20.76% of the Company's meters are AMR (x = 0.2076). The regression line equation calculates an optimal average route size of 343 meters (99.4% of the Company's actual average route size of 345 meters).

$$y = 332x^2 + 111x + 306 = 332(0.2076)^2 + 111(0.2076) + 306 = \mathbf{343\ meters}$$

Sample Data Set (Representing 32 of 686 Total Routes)

Route ID	Percent AMR	Total Meters in Route
1-111	14.01%	207
1-112	20.21%	292
1-113	18.87%	371
1-114	21.26%	701
1-115	11.08%	361
1-116	25.60%	375
1-117	18.71%	326
1-118	13.60%	456
1-221	21.74%	460
1-222	16.12%	428
1-223	25.69%	436
1-224	16.40%	378
1-225	17.49%	366
1-226	15.87%	315
1-331	4.89%	327
1-332	8.22%	304

Route ID	Percent AMR	Total Meters in Route
2-111	17.10%	345
2-112	14.29%	273
2-113	99.35%	923
2-114	8.71%	402
2-115	11.44%	472
2-116	24.75%	400
2-117	55.52%	562
2-118	52.24%	492
2-119	10.50%	381
2-221	9.83%	356
2-222	15.01%	453
2-223	10.72%	373
2-224	35.20%	517
2-226	11.81%	237
2-227	18.40%	375
2-331	10.18%	393

Appendix C
NPV Calculation

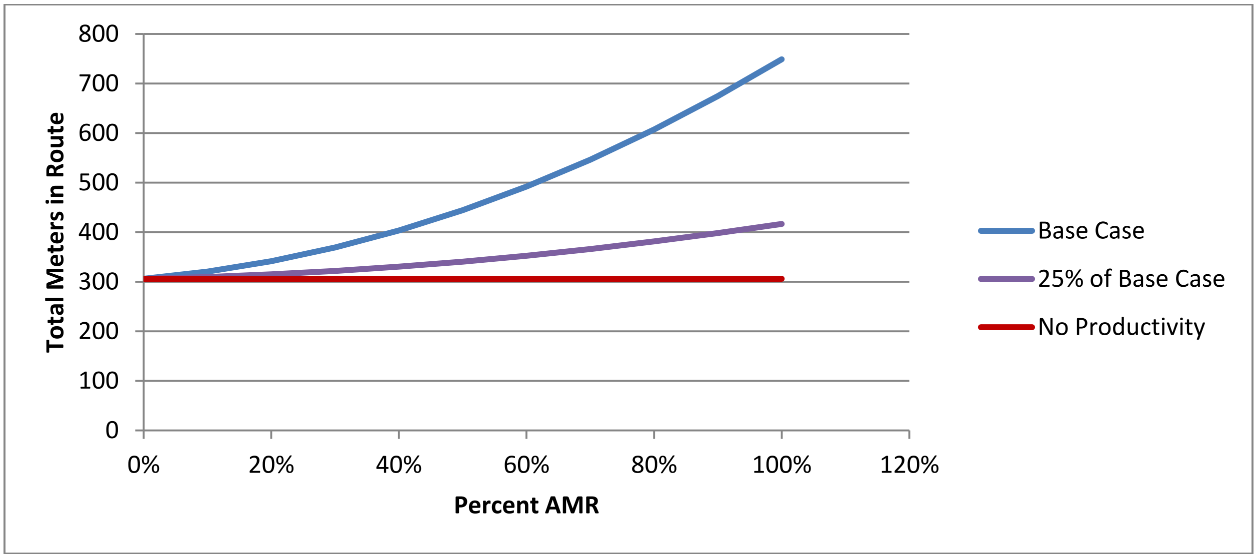
NPV Calculation

Average Incremental Cost of Capital: 7.4%
CCA Rate: 8.00%

Year	Capital Expenditure	Capital Revenue Requirement	Operating Costs	Net Benefit	Present Worth
2013	$356,980	$38,637	$0	-$38,637	-$35,975
2014	$346,624	$82,072	-$170,205	$88,133	$76,406
2015	$323,598	$121,255	-$333,273	$212,018	$171,143
2016	$342,180	$160,580	-$475,802	$315,223	$236,919
2017	$261,589	$190,153	-$611,687	$421,534	$294,993
2018	$0	$188,700	-$704,680	$515,980	$336,208
2019	$0	$181,930	-$717,013	$535,083	$324,632
2020	$0	$175,370	-$729,533	$554,163	$313,042
2021	$0	$169,004	-$741,892	$572,888	$301,322
2022	$0	$162,816	-$754,900	$592,083	$289,961
2023	$0	$156,792	-$768,138	$611,345	$278,766
2024	$0	$150,919	-$781,715	$630,796	$267,816
2025	$0	$145,184	-$795,545	$650,361	$257,098
2026	$0	$139,577	-$809,701	$670,124	$246,658
2027	$0	$134,087	-$824,276	$690,189	$236,539
2028	$0	$128,705	-$838,827	$710,121	$226,602
2029	$0	$123,423	-$854,065	$730,643	$217,086
2030	$0	$118,231	-$869,602	$751,370	$207,863
2031	$0	$113,124	-$885,379	$772,255	$198,920
2032	$0	$108,095	-$901,428	$793,333	$190,270
2033	$0	$103,136	-$917,776	$814,640	$181,918
2034	$0	$98,243	-$934,337	$836,094	$173,845
2035	$0	$93,410	-$951,008	$857,598	$166,030
2036	$0	$88,632	-$967,976	$879,344	$158,510
2037	$0	$98,250	-$985,248	$886,998	$148,873
2038	$0	$77,722	-$1,002,827	$925,105	$144,570
2039	$0	$58,175	-$754,925	$696,750	$101,382
2040	$0	$42,296	-$519,796	$477,499	$64,692
2041	$0	$22,557	-$317,514	$294,957	$37,208
2042	$0	$0	-$125,260	$125,260	$14,712
			Net Present Value		**$5,828,011**

Appendix D
Sensitivity Analysis

Sensitivity Analysis



The 2nd order polynomial equation **$y=332x^2+111x+306$**, determined from the Regression Line Analysis in Appendix A, is shown as the 'Base Case' in the graph above. An additional equation, shown as the '25% of Base Case', was selected to represent a lower degree of productivity improvement as the percent AMR increases. The 'No Productivity' equation was also selected to represent a scenario where no productivity improvements are achieved through installing AMR.

Distribution Rebuild Update

June 2012

Prepared by:

Byron Chubbs, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
BYRON A. CHUBBS
SIGNATURE
June 12/12
DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

Newfoundland Power (the "Company") has over 9,000 kilometres of distribution lines in service and has an obligation to maintain this plant in good condition to safeguard employees and the public and to maintain reliable electrical service. The replacement of deteriorated distribution structures and equipment is an important part of fulfilling this obligation.

The *Rebuild Distribution Lines* project involves rebuilding sections of lines or the selective replacement of various line components based on preventive maintenance inspections or engineering reviews. This typically includes the replacement of poles, crossarms, conductor, cutouts, lightning arrestors, insulators and transformers.

This report provides an update to information provided in the 2004 Capital Budget Application in support of the *Rebuild Distribution Lines* project.

2.0 Preventative Maintenance Inspections

As part of the Company's preventative maintenance program, all overhead primary distribution lines are required to have a minimum of one detailed ground inspection every seven years.[1] The Company has a total of 303 distribution feeders throughout its operating area, and inspects approximately 43 feeders annually.

The Company's Distribution Inspection Standard outlines the requirements to complete distribution line inspections. It is a guide for inspectors and job planners to ensure consistency in the preventative maintenance program.[2] The inspection standard is regularly reviewed and updated to adapt to changes in operating procedures, outage statistics and trending, or industry practices.

Capital work identified through distribution line inspections is completed under the *Rebuild Distribution Lines* project in the following year. High priority capital work that cannot wait to the next budget year is completed under the *Reconstruction* project.[3]

Planning and scheduling of work under the *Rebuild Distribution Lines* project is done by prioritizing deficiencies. For example, items of concern related to reliability are typically addressed on the main trunks of distribution feeders before feeder taps or laterals.[4] The amount of work completed is based on the amount of work identified through the distribution line inspections, which will vary depending on the age, length and condition of the feeders being inspected. At times, unanticipated work requirements such as new customer connections, third party work requests and storm-related work requires the Company to adjust the amount of work

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[1] The Company also completes distribution vegetation inspections every three and a half years for brush clearing and tree trimming. Distribution pad mounted transformers are inspected annually. These inspections are typically completed at the same time as the distribution line inspections for feeders undergoing inspections during the same year.

[2] This includes type and frequency of inspections, qualifications of inspectors, details for job planning, and specific guidelines for identifying and prioritizing deficiencies.

[3] Deteriorated or damaged distribution structures and electrical equipment deemed to present a risk to safety or reliability are addressed through the *Reconstruction* project in the year in which they are identified.

[4] This is done because failures on the main trunks of distribution feeders will affect more customers.

to be completed under the *Rebuild Distribution Lines* project.[5] This is done by focusing on the selective replacement of high priority items.[6] In keeping with the Company's normal preventative maintenance program, the lower priority work that is not completed in the budget year will be identified during the next distribution line inspection to be completed in a future *Rebuild Distribution Lines* project.[7]

3.0 Distribution Line Deficiencies

The Company's preventative maintenance program addresses deficiencies associated with distribution structures and electrical equipment that have been identified through inspections. This typically includes the repair or replacement of poles, crossarms, conductor, insulators, switches and transformers.

Deficiencies included in the *Rebuild Distribution Lines* project are those deemed to present a risk of failure before the next scheduled inspection in seven years. Examples of such deficiencies include:

- Heavily rusted transformers showing no signs of leaking or weeping
- Rotten or damaged poles or pole cribs requiring repairs
- Rotten or broken crossarms
- Insulators, bushings or switches with cracked porcelain insulation or skirts missing
- Deteriorated conductor with broken strands

Examples of deficiencies that would be identified during distribution line inspections are shown in the figures below.

Figure 1: Damaged Wooden Pole

Figure 2: Rotten Crossarm

5 For example, in 2010 unplanned work related to the March ice storm and Hurricane Igor resulted in a significant decrease in the amount of planned distribution maintenance completed during that year.

6 Examples of higher priority work include the replacement of automatic sleeves and porcelain cutouts on the main trunk of distribution feeders.

7 Examples of lower priority work include the replacement of 2-piece insulators and porcelain cutouts not showing signs of failure, or the installation of lightning arrestors and current-limiting fuses.

Figure 3: Pole Crib Requiring Repairs

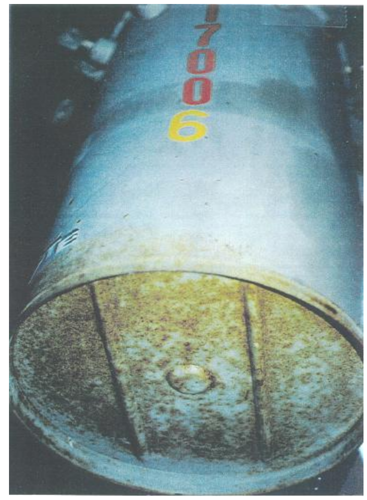


Figure 4: Rusted Transformer

4.0 Replacement Programs

The *Rebuild Distribution Lines* project includes selective replacement of specific line components to address known causes of safety and reliability issues. These programs are established based on engineering reviews of specific line components. Several replacement programs were identified in the Company's 2004 Capital Budget Application, including lightning arrestors, CP8080 and 2-piece insulators, current limiting fuses, automatic sleeves and porcelain cutouts.[8] The following is a discussion on each of the replacement programs that are currently part of the *Rebuild Distribution Lines* project.

4.1 Lightning Arrestors

Prior to the mid 1990s, Newfoundland Power did not install lightning arrestors on pole mounted distribution transformers. One of the reasons for this was that Newfoundland was not considered to be a high isokeraunic area.[9] There were also reliability and safety concerns with the porcelain housing of arrestors at the time.[10]

Over time, lightning arrestors became more reliable and less expensive. Also, arrestors became available in polymer housing, eliminating the safety concern from exploding porcelain glass. In the mid to late 1990s, the Company began installing arrestors in areas that were prone to lightning strikes. Since October 2002, Newfoundland Power has considered an arrestor to be an integral part of the transformer and all new transformer installations since that time have an arrestor included.[11]

---

[8] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2 for further details.

[9] The Isokeraunic Level (IKL) is a universally accepted measure to help utilities make some determination of the incidence of lightning in their service areas. It is defined as the number of days in a year (or month) that thunder is heard in a particular location.

[10] Porcelain housing was a safety concern for employees because catastrophic failure of arrestors resulted in the shattering of porcelain, potentially causing serious injury.

[11] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment B for further details on lightning arrestor requirements.

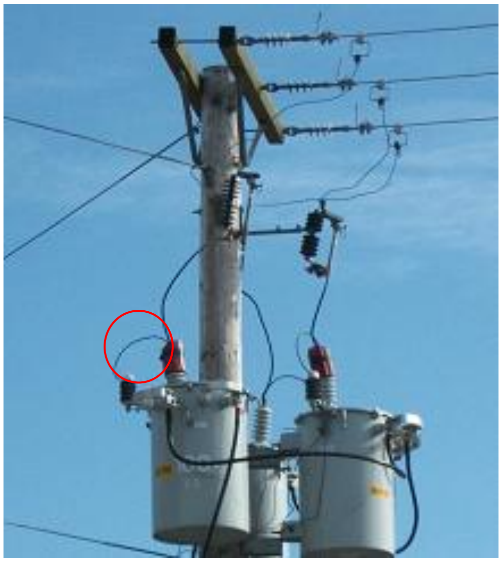


Figure 5: Lightning Arrestors In Service

4.2 CP8080 and 2-Piece Insulators

Premature failure of porcelain insulators due to "cement growth" is a known problem through the utility industry.[12] Newfoundland Power began to experience abnormal failures of porcelain insulation in the early 1980s.[13] Since that time, the Company has replaced a significant number of defective CP8080 suspension insulators and 2-Piece pin-type insulators.[14]

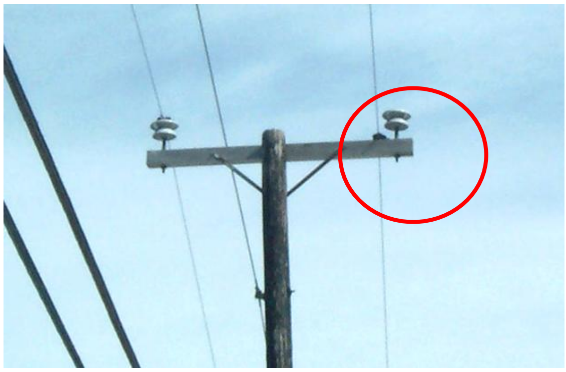


Figure 6: Broken Insulator In Service

Figure 7: Broken Insulator Removed From Service

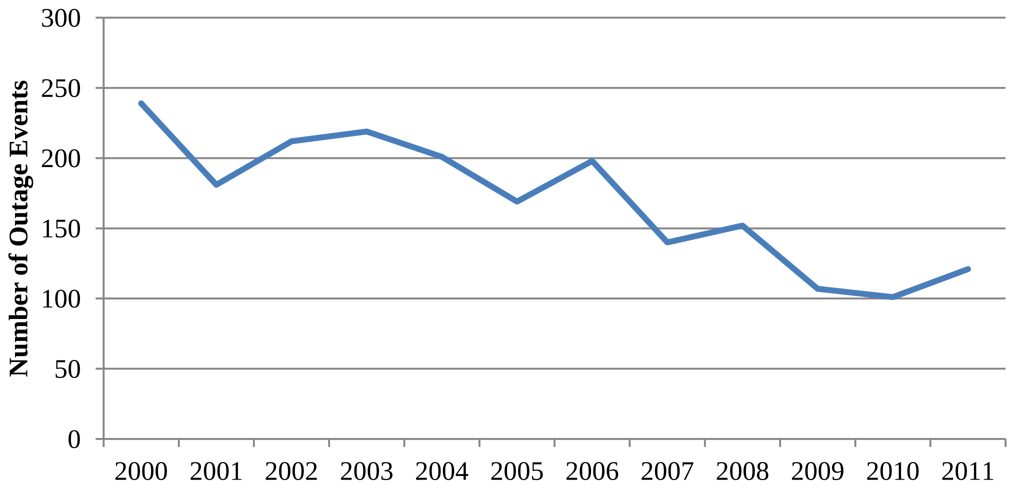
[12] Since the early 1960s the term "cement growth" has been used to categorize a problem for premature failure of porcelain insulators. The volume expansion of the cement occurs in the presence of moisture and is attributed to a chemical change in the cement that occurs with age. The expansion typically occurs over 10 or more years. As the cement expands it produces stress on the porcelain that fails in tension by cracking.

[13] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment C for further details on problem insulators.

[14] CP8080 suspension insulators fail by radial cracks, which are sometimes contained inside the metal cap and are not visible. The crack causes a current path between the metal cap and pin and shorts out the insulator. Pin type and pin cap type (2-Piece) insulators fail by circumferential cracks. Failure is usually mechanical; the top shears off the insulator causing the conductor to float clear of the structure.

As shown in Graph 1 below, since 2000 the number of outages resulting from insulator failures has reduced to nearly half as a result of removing CP8080 and 2-Piece insulators from service as part of the *Rebuild Distribution Lines* project.[15] This has resulted in a positive impact on reliability.

Graph 1
Outages Caused by Insulator Failure



4.3 Current Limiting Fuses

Pole top distribution transformers are generally a very reliable component of the distribution system. However, they do eventually fail.[16] On rare occasions, transformer failures can lead to a buildup of pressure inside the tank, resulting in tank ruptures, oil spillage, or other *eventful* conditions. The probability of an eventful failure increases in locations with higher available fault current.

---

15 In 2000 there were 239 outages resulting from insulator failures while in 2011 the number of outages related to insulator failure had reduced to 121, or 50.6% (121/239 = 0.506)

16 The large majority of transformer failures are uneventful, resulting in voltage abnormalities, electrical noise, power quality issues, open circuit conditions, or an electrical fault which blows the transformer protection fuse. Other types of failure may include leaking tanks, broken or cracked bushings, or other mechanical component failures.

Figure 8: Current Limiting Fuses In Service

To reduce the probability of eventful transformer failures, the Company uses Current Limiting Fuses ("CLFs") to limit the available current when a fault occurs.[17] The Company installs CLFs in the following locations:

- All fused cutouts located where fault current may exceed their maximum interrupting rating of 10,000 and 12,000 amps asymmetrical at 12.5kV and 25kV respectively.
- Transformers located in areas where fault levels exceed 5,000 amps symmetrical.
- Transformers located within 7 meters of sensitive locations where fault levels exceed 3,000 amps symmetrical.
- Other specified locations such as capacitor banks and primary metering installations.

4.4 Automatic Sleeves

Newfoundland Power adopted automatic sleeves for use as an alternative to joining conductors by means of compression sleeves.[18] This was done on a limited basis in 1993, and in 1999 the Company approved automatic sleeves for use on the entire distribution system. However after

[17] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment D for further detail on current limiting fuse requirements.

[18] Compression sleeves require the use of a specialized compression tool and are relatively labour intensive to install. Automatic or "quick" sleeves were quick and easy to install and did not require the use of a specialized tool. While the automatic sleeve was more expensive to purchase, the additional cost was justified by the increase in productivity.

nine years in service these automatic sleeves began showing signs of premature deterioration, in large part due to our severe environmental conditions.[19]

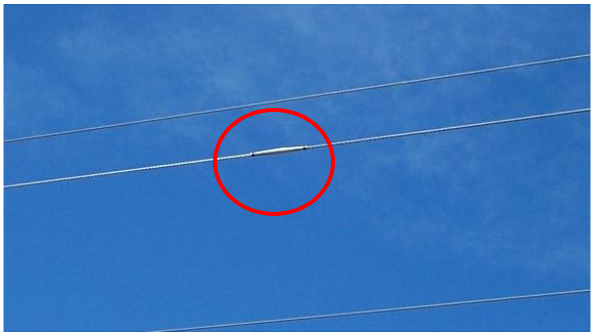


Figure 9: Automatic Sleeve In Service

Figure 10: Disassembled Automatic Sleeve Showing Corrosion

First indications of a problem surfaced in early 2002 when an automatic sleeve failed. An investigation followed which showed a high percentage of sleeves were experiencing signs of water ingress and internal corrosion.[20] The potential risks to public and employee safety, as well as system reliability prompted the Company to discontinue the use of automatic sleeves by the fall of 2002.[21]

4.5 Porcelain Cutouts

Porcelain insulated cutouts have been in use in the electrical industry for many decades.[22] Throughout that time, design and manufacturing processes have changed somewhat, but porcelain remained as the basic insulating material. In 2000 and 2001, the Company began to experience incidents of failed porcelain cutouts. Through 2002 and into 2003, hundreds of cutout failures were reported, and line personnel became increasingly concerned with the safety hazards associated with cutout failures.[23]

---

[19] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment E for further detail on automatic sleeves.

[20] In the Fall of 2002, a total of 35 sleeves were removed from various areas throughout the Company and inspected. The results indicated widespread internal deterioration of automatic sleeves. 71% of the sleeves removed showed at least some corrosion with 37% being severely corroded.

[21] Mechanical failure of a corroded automatic sleeve would result in line separation and the potential of an energized line dropping to the ground, presenting a public safety hazard. This hazard would also exist for line personnel performing energized work. In addition to mechanical failure, there is the risk of electrical failure of the sleeve creating an open circuit. This is particularly hazardous if a sleeve is on a neutral conductor. Voltage differences could be present across an electrically open sleeve on a neutral conductor that would be hazardous to line personnel. Mechanical or electrical failure of automatic sleeves can each result in customer outages.

[22] The cutout is a pole-mounted device used to disconnect or reconnect equipment to a source of electricity.

[23] Throughout the Company cutouts are opened and closed as part of regular system operations. This is typically done by line personnel positioned in the pole or the bucket of a line truck using a 10' long *hotstick*. Operating a cutout that is close to failure while it is energized may result in the cutout breaking, placing line personnel in an unsafe situation.

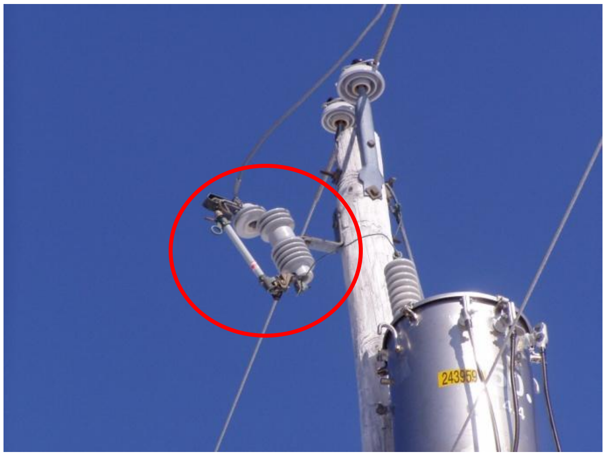


Figure 11: Broken Porcelain Cutout In Service

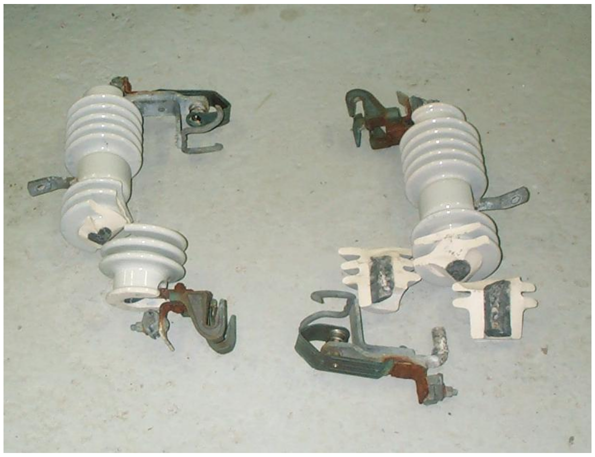
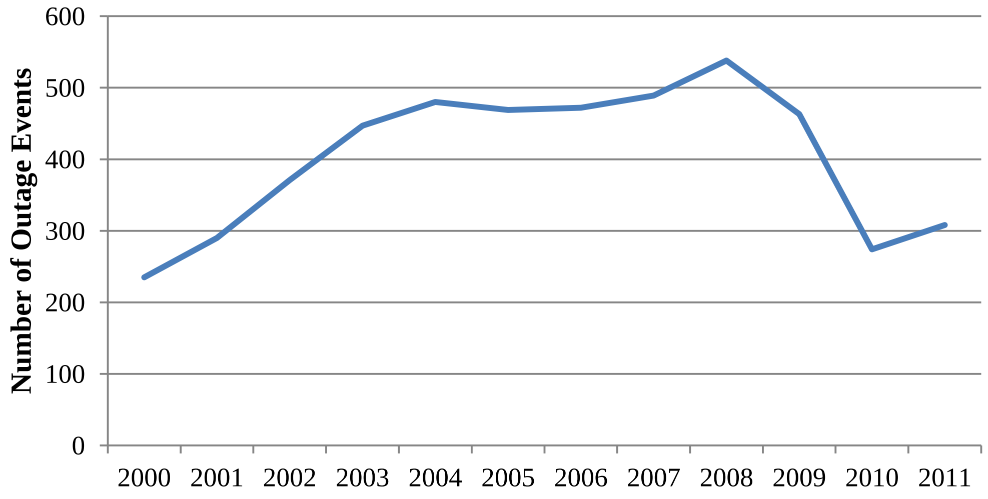


Figure 12: Two Broken Porcelain Cutouts Removed From Service

In 2003, as a result of the increasing rate of failures, the Company decided to discontinue the use of porcelain insulated cutouts and adopt the polymer insulated cutout as its new standard.[24]

Porcelain cutout failures continued to increase after 2003, and since that time, the Company has expanded the replacement program to all porcelain cutouts on the main trunk of distribution feeders, as well as lateral taps and large customers.

Graph 2
Outages Caused by Cutout Failure



As shown in Graph 2 above, the number of outages resulting from cutout failures steadily increased up until 2008, but declined in recent years as a result of removing porcelain

24 See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment F for further detail on porcelain cutouts.

cutouts from service as part of the *Rebuild Distribution Lines* project.[25] This has improved reliability.

4.6 Stainless Steel Pole Mounted Transformer Hanging Brackets

The Company began purchasing pole mounted transformers manufactured with 316L stainless steel in 2001. This was done as a result of numerous failures due to rusting transformer tanks, largely due to higher levels of salt contamination in Newfoundland. After several years of using the new stainless steel tank design, the issue of broken hanging brackets began to surface on 25 kVA and 50 kVA transformers.[26]

Following discussions with the manufacturer it was determined that the hanging brackets were not sufficient for the mechanical forces exerted by higher wind conditions in the Newfoundland environment. To address this issue, the Company changed its specification for stainless steel transformers in 2007, requiring a hanging bracket made of a thicker gauge stainless steel.

Figure 13: Stainless Steel Pole Mounted Transformer

Figure 14: Broken Stainless Steel Transformer Hanging Bracket

In total there have been 27 transformer bracket failures reported on stainless steel transformers manufactured from 2001 to 2006, inclusive.[27] As a result, the Company has worked with the manufacturer to develop a reinforcing bracket that can be installed on in-service transformers. Beginning in 2013, 25 kVA and 50 kVA transformers manufactured between 2001 and 2006 will be identified and retrofitted with a reinforcing bracket as part of the *Rebuild Distribution Lines* project.

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25 Over the period from 2004 to 2009 the annual average number of outages caused by cutout failure was 485, peaking at 538 in 2008. By 2011 the number of outages caused by cutout failure had declined to 308.

26 The first reported bracket failure occurred in 2003 when a lower bracket split after being in service for several months. A second reported bracket failure occurred in February 2006.

27 Of the reported failures, 19 were 50 kVA units, 7 were 25 kVA units and 2 others did not have the size reported.

5.0 Concluding

This *Rebuild Distribution Lines* 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. It 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 will continue its ongoing preventative maintenance program to identify damaged, broken or defective equipment, and will continue with the specific programs targeting lightning arrestors, CP8080 and 2-piece insulators, current limiting fuses, automatic sleeves and porcelain cutouts. The Company will also identify stainless steel transformers manufactured between 2001 and 2006 as part of annual distribution line inspections and retrofit these transformers with reinforcing brackets as part of the *Rebuild Distribution Lines* project.

The annual distribution line inspection program will identify:

- *Locations where transformers not equipped with a lightning arrestor in areas prone to lightning strikes*. In the year following the inspection, lightning arrestors are installed on identified transformers as part of the *Rebuild Distribution Lines* project.

- *Locations where CP8080 and 2-Piece insulators remain in service*. In the year following the inspection, insulators identified for replacement are included as part of the *Rebuild Distribution Lines* project.

- *Locations where a CLF is required and not installed*. In the year following the inspection, CLFs are installed as part of the *Rebuild Distribution Lines* project.

- *Locations where automatic sleeves remain in service*. In the year following the inspection, automatic sleeves identified for replacement are removed as part of the *Rebuild Distribution Lines* project.

- *Locations where porcelain cutouts remain in service* on the main trunk of distribution feeders, as well as lateral taps and large customers. In the following year porcelain cutouts identified for replacement are removed as part of the *Rebuild Distribution Lines* project.

- *Locations of stainless steel transformers manufactured from 2001 to 2006*. In the year following the inspection, transformers identified to be retrofitted with a reinforcing bracket will be included as part of the *Rebuild Distribution Lines* project.

2013 Company Building Renovations

June 2012

Prepared by:

David Ball, B.Eng.

Gary K. Humby, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
GARY K. HUMBY
SIGNATURE
June/12/2012
DATE
PROVINCE OF NEWFOUNDLAND

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Appendix A: Carbonear Service Building Photographs
Appendix B: Kenmount Road Building Photographs

1.0 Introduction

Newfoundland Power ("the Company") operates from 13 buildings across its service territory, including the St. John's Head Office, Carbonear Service Building and 11 other offices and service centers. Maintaining these properties is vital to the safe, reliable and efficient operation of the electricity system.

The 2013 Company Building Renovations project is necessary to ensure the continued safe and reliable operation of Newfoundland Power facilities, properties and workplaces. This project consists primarily of upgrading, refurbishment or replacement of equipment and facilities due to damage or deterioration identified during inspections and maintenance activities. Improvements to the security of the Company's facilities have also been included in this project.

The 2013 Company Building Renovations project expenditure is estimated at $950,000 and is comprised of the renovations to Carbonear Service Building, renovations to Kenmount Road Building and security upgrades.

2.0 Carbonear Service Building Refurbishment ($375,000)

The Carbonear service building is the Company's main facility for the Avalon operating area. It was originally constructed in 1977 and is 35 years old.[1] The structure consists of a standard pre-engineered steel frame. Metal siding and roof panels are screwed to the steel purlins which are attached to the steel frame. The building is insulated with fibreglass batt and foam insulation. The interior finishes of the office building consist of painted or vinyl covered drywall, tee-bar ceilings, and carpet or tile floors. The warehouse area is finished with painted plywood walls, painted concrete or tile floors, and open or tee-bar ceilings.

The building is located within a flood plain with flowing water on and adjacent to the property boundary. Surface drainage on the property is poor and water has flooded the building on 3 occasions in the past 10 years. The storm sewer has also become clogged, and the backflow of water through the drainage system resulted in flooding in the warehouse area.

In recent years, the building envelope has become deteriorated. A number of the double pane glass panels in the atrium roof have broken seals. There is water ingress in the panels and at times the roof leaks. The brick exterior of the atrium is deteriorated and in places the brick has separated from the building. This is likely due to water ingress behind the brick and subsequent freeze and thaw cycles.

The metal roof of the warehouse as well as most of the metal siding on the building exterior is in a deteriorated condition due to corrosion and mildew growth and requires replacement. Corrosion on the exterior siding is particularly evident at ground level where drainage issues have resulted in the buildup of mildew.

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[1] The Carbonear Service building was originally constructed as two separate buildings; an office building and a warehouse. In 1989 the two buildings were joined through the expansion of the office building. Since the 1989 expansion the more significant renovations to the building include roof repairs in 1993 and a renovation to the warehouse area in 1997.

The customer and employee parking areas are degraded and walkways are cracked and deformed in several locations. Concrete walkways exhibit spalling in several locations and present a tripping hazard to employees and customers. Cracks in the asphalt and settlement of the sub-grade material have occurred.

The interior finishes of the building are in fair condition with the exception of the flooring. The carpet in the office area is 23 years old. The pile of the carpet is worn significantly and requires replacement.

This item involves the following scope of work to be completed in 2013:

1. Improve drainage around building and install back water valves on floor drains.
2. Address leaks and repair brick exterior of the atrium.
3. Replace the exterior metal siding and metal roofing on the warehouse.
4. Repair sections of paving on employee parking lot and replace cracked and deteriorated walkways.
5. Replace worn carpet in the office area.

See Appendix A for photographs.

3.0 Kenmount Road Office Renovations ($475,000)

This item consists of the replacement of flooring and wall coverings on the 2nd and basement floors as well as the refurbishment of all 8 washrooms at the Kenmount Road Building.

Floor and wall coverings on the 2nd floor and basement have been in place since the mid 1990s and have deteriorated to the point where replacement is required. During almost 20 years of service, the pile of the carpet has been stained and worn significantly. In many locations the wall coverings have edges that have separated from the wall substrate. Other notable items in this area that show excessive wear include baseboards losing adhesion and plaster cracking on walls and corners. As well the rear entrance has deteriorated walls and tiling after many years of service.

The Kenmount Road building was constructed in two phases. The lower two floors were constructed in 1968 and the upper two floors were added in 1979. Each floor has a male and female washroom for a total of 8 washrooms for the entire building. The washroom finishes and fixtures throughout the building are original except for the completion of minor accessibility modifications. The washrooms require complete retrofit including replacing tiles and fixtures, and upgrading the plumbing and ventilation.

See Appendix B for photographs.

4.0 Security Upgrades ($100,000)

This item consists of upgrades to the Company's security infrastructure, including renovations and security system upgrades to our service and district buildings as well as improvements in surveillance, fencing and lighting of our storage yards.

In 2011 Newfoundland Power recorded 8 incidents involving theft or vandalism in its substation and building yards. In one particular instance, a vandal gained access to a substation and caused an outage to approximately 5,100 customers, accumulating a total of over 380,000 outage minutes.

Theft of valuable metals, such as copper, is often the reason for the breach in security. In many cases storage yards are not configured in such a way to promote secure access and valuable items are often stored inside service buildings. Upgrades are required to ensure the security of the various materials.

This project will consist of several smaller projects across the company.

Projects planned for 2013 include:

- Card access for the Port Aux Basques Building.
- Storage yard configuration and gate improvements, Grand Falls Service Building.
- Storage yard configuration improvements, Burin Service Building.
- Creation of secure areas in stores in Gander and Clarenville.
- Improvements to secure areas for valuable items at various district buildings.

The project is justified on the basis of providing a safe work environment for employees and reducing losses due to theft.

5.0 Project Cost

Table 1 includes the estimated cost for the project.

Table 1
Project Cost
($000s)

Cost Category	Amount
Material	845
Labour-Internal	30
Labour-Contract	-
Engineering	55
Other	20
Total	**950**

6.0 Concluding

This project is required in order to ensure the continued provision of safe and functional office space for employees as well as adequate building security. There are no feasible alternatives for the renovations proposed. A 2013 budget of $950,000 for Company Building Renovations is as follows:

- $375,000 for Refurbishment of Carbonear Service Building ,
- $475,000 for Kenmount Road Office Renovations, and
- $100,000 for Corporate Security Upgrades.

Appendix A
Carbonear Service Building Photographs

Figure 1 - Carbonear Service Building

Figure 2 – Cracked Exterior Brick on Atrium

Figure 3 – Cracked Exterior Brick on Atrium

Figure 4 – Mildew on Atrium Roof Glass

Figure 5 – Corrosion on Warehouse Metal Roof

Figure 6 – Corrosion on Exterior Siding and Eave

Figure 7 – Corrosion and Mildew on Exterior Siding

Figure 8 – Deteriorated Concrete Walkway

Figure 9 – Deteriorated Asphalt and Concrete Walkway

Figure 10 – Deteriorated Asphalt

Appendix B
Kenmount Road Building Photographs

Figure 1 – Deteriorated Carpet

Figure 2 - Deteriorated Carpet in High Traffic Areas

Figure 3 - Deteriorated Wall Coverings

Figure 4 –Baseboards Losing Adhesion

Figure 5 - Deteriorated Drywall

Figure 6 – Deteriorated Rear Building Entrance (Basement Floor)

Figure 7 – Typical Bathroom Finishes

Figure 8 - Deteriorated Bathroom Finishes

Figure 9 – Typical Bathroom Fixtures

Figure 10 – Typical Bathroom Fixtures

Duffy Place
Uninterruptible Power Supply Replacement

June 2012

Prepared by:

Ed O'Keefe

Gary K. Humby, P.Eng.

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Appendix A: UPS Technical Description
Appendix B: Letter from Maintenance Provider

1.0 Introduction

Newfoundland Power's (the "Company's") computer systems and communications equipment are integral to the provision of reliable service to customers at the lowest possible cost. Computers and many network components are sensitive to power quality, and their operation can be disrupted by interruptions, or even fluctuations, in the power supply. The quality and efficiency of the service provided to the Company's customers is therefore dependent on the quality of the power supplying this equipment.

Newfoundland Power's computer systems and communications equipment are protected from power quality problems and interruptions by an uninterruptible power supply ("UPS"). A UPS provides a continuous supply of electrical power that is *conditioned* by eliminating harmful voltage fluctuations and power spikes that can damage sensitive equipment.

A UPS was installed in 2000 at Newfoundland Power's Duffy Place building to provide conditioned and emergency power for the Company's computer systems, particularly those supporting the Customer Contact Center and the Customer Service System ("CSS"). Since that time, the Company continues to become increasingly dependent on information technology to support efficient operations and serve customers.[1]

Newfoundland Power's maintenance service provider advises that UPS systems like the one in service at Duffy Place can be expected to provide reliable service for approximately 10 years. At 13 years in service, the UPS has reached the end of its reliable service life and must be replaced.[2] The replacement UPS will have additional capacity to protect computer systems used by engineering, operations and central stores not currently protected by the existing UPS.

2.0 What is a UPS?

A UPS is a power supply system that is installed between the external AC power supply and the equipment to be protected. Typical UPS designs involve a rectifier to convert AC electricity to DC electricity, a battery bank to act as both a storage medium and a filter to block transients, and an inverter to convert DC electricity back to *conditioned* AC electricity.

A UPS protects sensitive equipment from unexpected interruptions or power quality problems with the commercial AC power supply. Interruptions and disturbances on the electricity system have the potential to damage sensitive electronic components inside computer systems, resulting in outages to software applications and corruption of data. A loss of critical software

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1 The expanded use of information technology involves additional applications that depend on UPS protected computer systems and communications equipment. For example the Avantis asset management application, the CLICK work scheduling application and Technical Work Request management application are used extensively in everyday operations throughout the Company. While the potential inability to access these applications presents a risk to the operations of the Company, this risk is mitigated by the presence of a reliable UPS protecting the computer systems and communications equipment.

2 In Order No. P.U. 26 (2005) the Board approved the replacement of the Kenmount Road building UPS, which had been in service for 13 years prior to being replaced. The technology used in the UPS replaced at Kenmount Road in 2005 was similar to the technology used in the existing Duffy Place UPS.

applications and corruption of data has the potential to affect both productivity and customer service.

During normal operations, a UPS supplies *conditioned* power, eliminating fluctuations in both the frequency and amplitude of the AC power supply signal. During emergency conditions, when the regular AC power supply is interrupted, a UPS is designed to provide power to protected equipment via its battery banks until either the regular AC power supply is restored or a backup AC generator is operational.[3] This emergency power supply is limited, and is intended to provide enough time to start emergency generation so that normal operations may continue.

Appendix A provides a technical description of the Duffy Place UPS.

3.0 Duffy Place Regional Operations Centre

3.1 General

The Duffy Place Regional Operations Centre is the headquarters for St. John's Region which is responsible for a service territory extending from Cappahayden in the south to Cape St. Francis in the north and from Cape Spear in the east to Holyrood in the west. St. John's Region services approximately 102,000 customers from the Duffy Place building.

In addition to regional operations the Duffy Place building also houses the Customer Relations Department including the Customer Contact Centre, Energy Conservation and other head office groups including Central Stores.[4] There are approximately 246 employees working out of the Duffy Place building.

The Company operates 3 computer rooms in the Metro St. John's region. The System Control Centre on Topsail Road hosts the SCADA computer systems along with other servers and communications equipment. The Kenmount Road and Duffy Place computer rooms host servers to support business applications and communications equipment. While most business applications are hosted on shared servers, there remain some dedicated servers for specific applications.

3.2 Protected Systems

The computer room at the Duffy Place building houses over 35 shared servers and the network infrastructure that enables Company employees to access them. The following information technology resources, which are accommodated in the computer room and protected by the UPS, are essential to the efficient and continuous delivery of service to customers:

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[3] The length of time the UPS can power the critical load after the loss of commercial AC power will depend upon (i) the amount of energy stored in the battery bank at the start of the outage, (ii) the amount of load actually connected to the UPS during the outage and (iii) the conversion efficiency of the inverter.

[4] The Customer Contact Centre provides customer service to all 248,000 Newfoundland Power customers, not just the 102,000 customers in St. John's Region.

- The Aspect customer contact technology used by the Customer Contact Centre staff to communicate with customers through the public telephone network or the Internet.[5]

- The CSS, which is the main customer service application and database, is the principal repository of information on customer accounts. The CSS contains all of the Company's billing and account information, as well as a record of all customer requests for technical service.

- The SCADA system Disaster Recovery infrastructure. The SCADA System is used for monitoring and controlling the Company's substations and generating facilities on a continuous basis. The Duffy Place computer room houses all systems necessary to monitor and control the electricity system in the event that the System Control Centre has to be evacuated.

- Newfoundland Power's corporate network provides employees with efficient access to essential information regarding the Company's operations, policies and procedures, and customer service offerings.

In addition to providing conditioned power to these computer room based resources, the UPS supplies electrical circuits to the Production Centre which prints and sorts customer bills for distribution through Canada Post.

3.3 Unprotected Systems

The capacity of the existing UPS limits the number of employee computers and other critical equipment that can be protected.[6] As a result many of the computer systems and associated hardware used by the regional operations and Central Stores staff remain unprotected. There is approximately an additional 30 to 40 KVA of load in the Duffy Place building that requires the protection provided by a UPS.

4.0 Consequences of UPS Failure

4.1 General

The UPS has two principal functions: (i) it *conditions* the power supply by removing voltage spikes and fluctuations, thereby protecting sensitive electronic equipment from damage; and (ii) in the event of an interruption in the commercial AC power supply to the building, it supplies emergency AC power from the battery bank to enable protected equipment to operate normally until the backup diesel generator is operational.

---

5 Each business day the Customer Contact Centre receives between 1,100 and 1,200 calls to agents, processes between 700 and 800 interactive voice response calls and receives over 200 emails from customers. Interactive voice response calls and emails are also received outside of normal business hours.

6 The existing UPS protects approximately 120 of the approximate total of 165 personal computers, or 73% (120/165 = 0.73) of those located at the Duffy Place building.

The reliability of the Company's computer and internal communications systems is dependent on a reliable UPS. The Duffy Place facility supports critical customer service and operations functions for both normal business and emergency response situations.

4.2 Computer System Integrity

Computer crashes and data corruption disrupt normal business operations, resulting in costs associated with lost customer, financial, and operations data and the restoration of available data and applications from back-up. Newfoundland Power has disaster recovery plans in place to respond to such events. However, the action required to restore systems and business operations to normal can be costly.

Business records and service requests generated from customer calls to the Customer Contact Centre are recorded electronically in the CSS database, and paper records are not kept. If the CSS were disrupted as a result of a power supply problem, data in the CSS database could be corrupted. Recovery from such a *crash* could involve loading the server with a backup copy of the CSS database from the previous business day.[7] All data entered into the system the day of the system failure could be lost, including records of all new customer service requests and account activity such as bill payments, credit arrangements, and requests for final reads taken on the day the CSS was disrupted. Depending upon the timing of the UPS failure, an entire business day's data could be irretrievably lost.[8]

The abrupt loss of power to enterprise computer systems or servers can lead to hardware failure. Replacement of failed hardware will affect restoration time, and carry a high cost.

4.3 Business Impacts

In addition to the problems associated with lost data, loss of UPS power would impact business operations in the Customer Contact Centre. The loss of CSS and the customer contact technology would severely impede the Company's ability to deliver customer service through the Customer Contact Centre. The Company has a contingency plan for operating without the CSS or the Aspect customer contact technology; however, employees' ability to access customer and outage information to assist with customer enquiries would be limited until the systems could be returned to service.

Customers themselves would also be impacted by a crash of the CSS as they would be unable to access their customer account information on-line or through the interactive voice response interface which is normally available to customers on a 24×7 basis.

CSS is used by meter readers to process their readings. The loss of CSS caused by a UPS interruption at Duffy Place would result in a day's worth of meter readings not being processed on schedule. This would delay the printing and distribution of customer bills.

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[7] The Company's disaster recovery plans provide for the generation of a backup copy of the CSS database at the end of each business day.

[8] The Company responds to over 2,000 customer contacts per business day involving the CSS database.

In addition to the business impacts associated with the loss of CSS, Duffy Place regional operations would also be affected by an extended power interruption. The unavailability to operations employees of applications such as the Avantis asset management system, CLICK work scheduling application and TWR work request application would negatively impact service to customers. At present the computer systems used by the operations staff, and the central stores staff, are not protected by the Duffy Place UPS due to capacity limitations.

4.4 Major Weather Events

During major storms, access to the Company's computer systems and communications equipment enables employees to record and analyze customer trouble calls, to coordinate power restoration efforts, and to keep customers informed. During such storms, there is an increased likelihood of power spikes and surges on the electrical system caused by faults related to storm damage. The importance of the protection provided by the UPS is therefore heightened in these circumstances.

5.0 Vendor Support

The existing Duffy Place UPS was manufactured and sold for a 15 year period ending in 2000. At the time of installation it was considered a mature and reliable technology. The design is based upon discrete components and incorporates many control boards and cables for controlling and monitoring vital functions. Experience with this UPS is that it operates reliably for approximately 10 years of continuous service before discrete component failure impacts the reliability of the UPS.[9]

The Duffy Place UPS is essentially obsolete. As electronic equipment such as a UPS approach the end of life, manufacturers no longer produce replacement parts. Consequently, replacement parts are limited to like purposed or refurbished components. These are often difficult to acquire expeditiously, increasing the exposure of sensitive electronic equipment to an unconditioned power supply whenever a part fails.

Appendix B contains a letter from the UPS maintenance provider stating that the Duffy Place UPS has reached the point where continued use will mean reduced reliability.

[9] In 2005 Newfoundland Power replaced the Kenmount Road UPS manufactured with similar technology to the Duffy Place UPS. That Kenmount Road UPS was purchased in 1992 and operated reliably with only 2 failures during the initial 11 years of service. During its final year of service the Kenmount Road UPS failed on 6 separate occasions.

6.0 Project Cost

Table 1 provides a breakdown of the estimated costs for replacing the existing UPS system.

Table 1
Project Cost
($000s)

Cost Category	Amount
Material	140
Labour-Internal	5
Labour-Contract	
Engineering	10
Other	5
Total	**160**

7.0 Concluding

The Duffy Place facility supports critical customer service and operations functions for both normal business and emergency response situations The reliability of the Duffy Place based computer systems and communications equipment is dependent on a reliable UPS. The existing UPS has recently failed in service, and due to the unit's age and the Company's experience with the Kenmount Road UPS, is an indication that components are becoming unreliable. The planned replacement of the Duffy Place UPS will ensure that the Company's ability to service customers, through the Customer Contact Centre, and effectively dispatch work from the Regional Operations Centre, is not impeded. Allowing the UPS to fail in service would impact both customer service and the dispatch of work while exposing critical computer systems and communications equipment to unprotected power while a replacement UPS system is being delivered.

The Duffy Place UPS will be replaced with a unit sized appropriately to provide the necessary protection for all business functions, including customer services, engineering, operations and central stores, in the Duffy Place building.

Appendix A
UPS Technical Description

Duffy Place UPS – Technical Description

The UPS installed in 2000 at the Duffy Place regional operations building is a Powerware 9315. The unit is rated for 100 KVA and 80 KW. The UPS is equipped with an internal bypass and a battery bank. The battery bank is comprised of 240 Absolyte IIP dry type batteries. There is a second bypass that will isolate the electrical components of the UPS for maintenance purposes.

Figure 1 shows a single line diagram representation of the existing Duffy Place UPS and how it is connected to the building electrical system.

Power is supplied to the building in one of two ways. Commercial power, supplied from Kenmount Substation, is the principal source of supply. There is also a diesel generator at Duffy Place, which provides emergency backup power for the entire building in the event of a failure of the commercial supply.

During normal operation, the UPS is supplied with either commercial power or power from the diesel generator. The UPS in turn provides “conditioned power” to the critical electrical circuits in the building. “Conditioned power” means that the UPS has eliminated harmful voltage fluctuations and power spikes that can damage the protected load, such as computer systems and communications equipment.

In the event of a loss of commercial power, the diesel generator is designed to start automatically and supply power to the building until commercial power is restored. The transfer of the electrical load in the building from commercial power to the diesel generator cannot be done instantaneously. It requires a start-up sequence that allows the diesel engine to bring the generator up to synchronous speed ensuring conditions are appropriate before electrical connectivity is initiated. This effectively results in a temporary power outage to the UPS. During this power outage, the UPS and its batteries provide continuous power to the protected load until the diesel generator is operating properly. The UPS batteries are capable of supplying power to the protected load for a period of only about thirty minutes, after which time the batteries become depleted and need to be recharged.

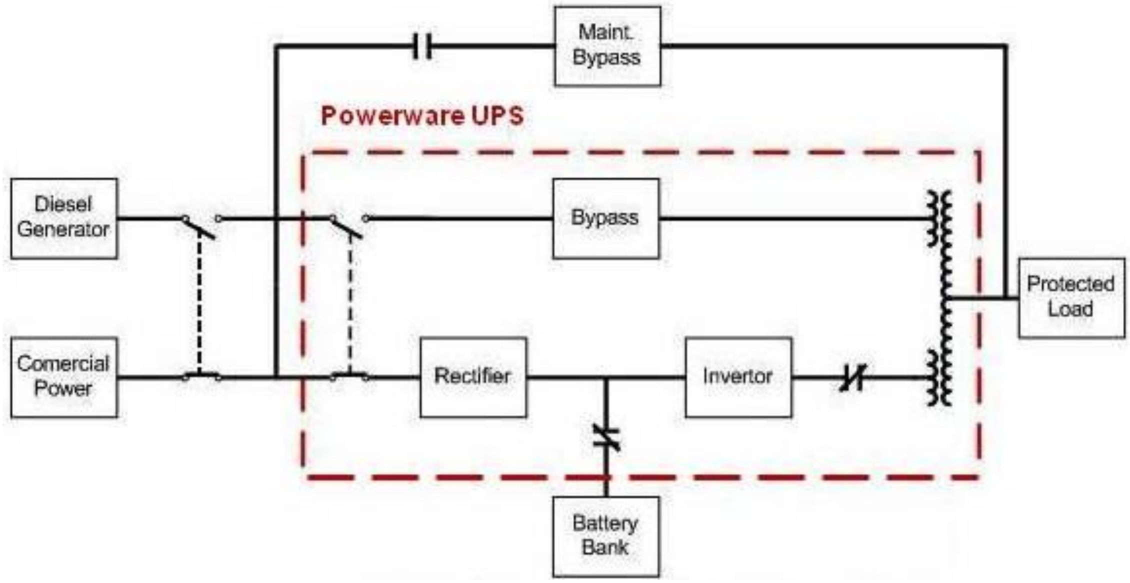

Figure 1 - Single line diagram of UPS System at Duffy Place

The UPS operates in one of three modes; *Normal*, *On Battery* or *On Bypass*.

- *Normal* means that the power being supplied to the protected load in the building is being produced by the UPS using power from either commercial power or the diesel generator.

- *On Battery* means that there is a complete loss of power to the UPS and the battery bank is now the sole supplier of power for the protected load.

- *On Bypass* means that the UPS is not available and the protected load is now being powered directly by unconditioned power from either commercial power or the diesel generator.

Appendix B
Letter from Maintenance Provider

UNIVERSAL POWER SOLUTIONS INC.

Newfoundland Power Monday, June 04, 2012

Ref: 9315 UPS

Duffy Place, St. Johns, NL

Dear Sir/Madam

As per your request below is a current condition summary of the Powerware 9315 -160/ Model 100 UPS System located at Duffy Place. St. Johns, NF.

This family of Powerware UPS Systems were designed and sold from the late eighties though to the early twentieth century and was based on technology from the eighties. The design of these systems incorporated many control boards, cables and discrete components for control and monitoring of vital functions.

These systems generally operated quite well for the first ten years of continuous use but due to the large number of boards, connections and discrete components have proven to become unreliable after they pass this point.

Through service and Maintenance it is possible to increase their reliability by replacing key components which are known to fail with age such as the AC & DC caps but it is impossible and impractical to replace all parts that may become unreliable over time.

My records indicate that your UPS System was installed in 2000 and is now going on thirteen years old and has reached the point were continued use will mean reduced reliability. Current repairs of approx. 8,000.00 are required to replace the DC and AC filter caps! Current loading is approx 65-70KVA.

The new UPS Systems have been designed around microprocessor based technology and a modular concept which has allowed manufactures to eliminate discrete boards, connections, cables etc.. that pose a single point failure in the vital operation of the UPS System. A New 120KVA UPS expandable to 160KVA would alow you to place additional load on your UPS Systems as required moving forward.

This next generation of UPS's will offer higher efficiency (94%) and have a longer expected life as a result with the infrastructure lasting up to 20+ years.

Please feel free to contact us if you have any questions or have any UPS requirements. Thank you for your time and we look forward to being of service to you in the near future.

We would recommend replacing the UPS with a 120KVA Expandable to 160KVA Modular redundant UPS solution.

Thank you for your time and we look forward to being of service to you in the near future.

GAMATRONIC Our Power, Your Confidence — TRIPP·LITE — GE Industrial Systems

Yours very truly,

Mr. Bruce Simms, CET
President
bsimms@UPSpower.ca

Universal Power Solutions Inc.
Head Office: 100 Wright Avenue, Unit 12, Dartmouth, Nova Scotia B3B 1L2
Tel: 902-468-6968 Fax: 902-468-3743 TF: 888-472-3919
Field Office: 2 O'Donovan's Lane, Carbonear, NL A1Y 1B5
Ph: 709-683-4236 Fax: 709-596-4232
www.upsPower.ca

Mobile Radio System Replacement

June 2012

Prepared by:

Dena Senior, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
PEG
DENA S.A. SENIOR
SIGNATURE
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DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

A strong communication network is important in maintaining safe and reliable service for an electric utility. Newfoundland Power (the "Company") currently owns and maintains a VHF mobile radio system (the "System"), which is a key component of the Company's operational voice communications.[1] The System is primarily used for communication in locations on the island that do not have adequate cellular coverage and as a backup to the cellular network. The system plays a critical role in maintaining communications to field operations during emergencies, especially when the provincial cellular network or landline phones are out of service.[2]

The Company's VHF radio system is approaching the end of its life as components are up to 28 years old. In addition, some of the equipment has been discontinued by the manufacturer and is no longer supported. In 2004, the Company hired a technical consultant to assist in defining functional and technical requirements for a mobile radio system. The consultant's analysis concluded that the Company's VHF mobile radio system would require replacement in 2011.

Newfoundland Power has considered two alternatives for the replacement of the System. Alternative 1 considers rebuilding and maintaining the Company's VHF radio system. Alternative 2 considers removing the current infrastructure and moving to the Bell Mobility ("Bell") trunked radio system.[3]

2.0 Background

In its 2003 capital budget application Newfoundland and Labrador Hydro ("Hydro") proposed a total replacement of its VHF mobile radio system. In Order No. P.U. 29 (2003), the Board of Commissioners of Public Utilities (the "Board") declined to approve the project as submitted, and outlined a process whereby Newfoundland Power and Hydro would cooperate in a review of their respective mobile radio requirements. Both utilities engaged engineering consultants to assist in defining their functional and technical requirements for a mobile radio system, and to perform comparative cost analysis of the alternatives identified.

Hydro's report was presented in its 2005 capital budget application.[4] Newfoundland Power's report was presented in Response to Request for Information PUB-22 NP, Attachment A of the same proceeding. The analysis completed by the consultant led to the recommendation that the Newfoundland Power's VHF mobile radio system did not require replacement before 2011. Based upon the consultant's recommendation, participation in Hydro's VHF Mobile Radio Replacement Project in 2005 while there was significant remaining service life in the existing mobile radio system, was not the most economic solution for providing mobile radio service for the Company's operations.

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[1] The System provides wireless voice communications to workers throughout the operating territory.

[2] During the Bonavista ice storm in March 2010 cellular service was unavailable. Personnel relied on the mobile radio system for all communications. Without a reliable communication system, the restoration of power to thousands of customers would have been prolonged and safety of work crews and the public placed at risk.

[3] The Bell trunked radio system is used by Hydro and shared with other large users of mobile radio services.

[4] The Hydro report can be found at Section G, Tab 4 titled *Mobile Radio System Replacement – Summary of Findings*.

Hydro proposed the least cost approach was for Hydro to replace its existing system, include the provincial Department of Transportation and Works on the system and allow for the possible integration of Newfoundland Power at a later date. The Board approved this approach in Order No. P.U. 53 (2004). Hydro then proceeded to replace its VHF mobile radio system with a trunk radio system installed by Bell. Hydro shares the trunk radio system with the Department of Transportation and Works and other users who rent capacity on the system from Bell.

3.0 Existing System

The Company's operational voice communications network is comprised of cell phones, land lines and the VHF radio system.[5] The Company designed and built the VHF radio system in the early 1980s. When constructed, it became the primary method of communication for field operations. Since that time wireless communication technology has evolved and cellular phones are now most commonly used.[6] However, no significant changes have been made to the Company's VHF radio system in over 25 years.

3.1 System Operation

Newfoundland Power's VHF system is divided into 9 operating areas with each area having at least one repeater site (see Figure 1). The 9 operating areas for the mobile radio system correspond to the 9 operating areas for the Company's workforce.[7] The system currently contains a total of 24 repeater sites, 207 vehicle mounted mobile radios, 85 portable hand held radios and 23 base stations distributed throughout the 9 operating areas.

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[5] Operational voice communications for a utility is defined as the communications required for the operations and security of the electric power system. The communications typically occurs between the control authority, which in the case of Newfoundland Power is the System Control Centre ("SCC"), and the field staff.

[6] Changes in communication technology since the early 1980's has included the use of pagers, analogue cell phones and eventually digital cell phones. The use of smart phones as well as laptops in line trucks has also increased in recent years.

[7] The 9 operating areas include Port aux Basques/Stephenville, Corner Brook, Grand Falls, Gander, Bonavista, Burin, Whitbourne, Avalon and St. John's.

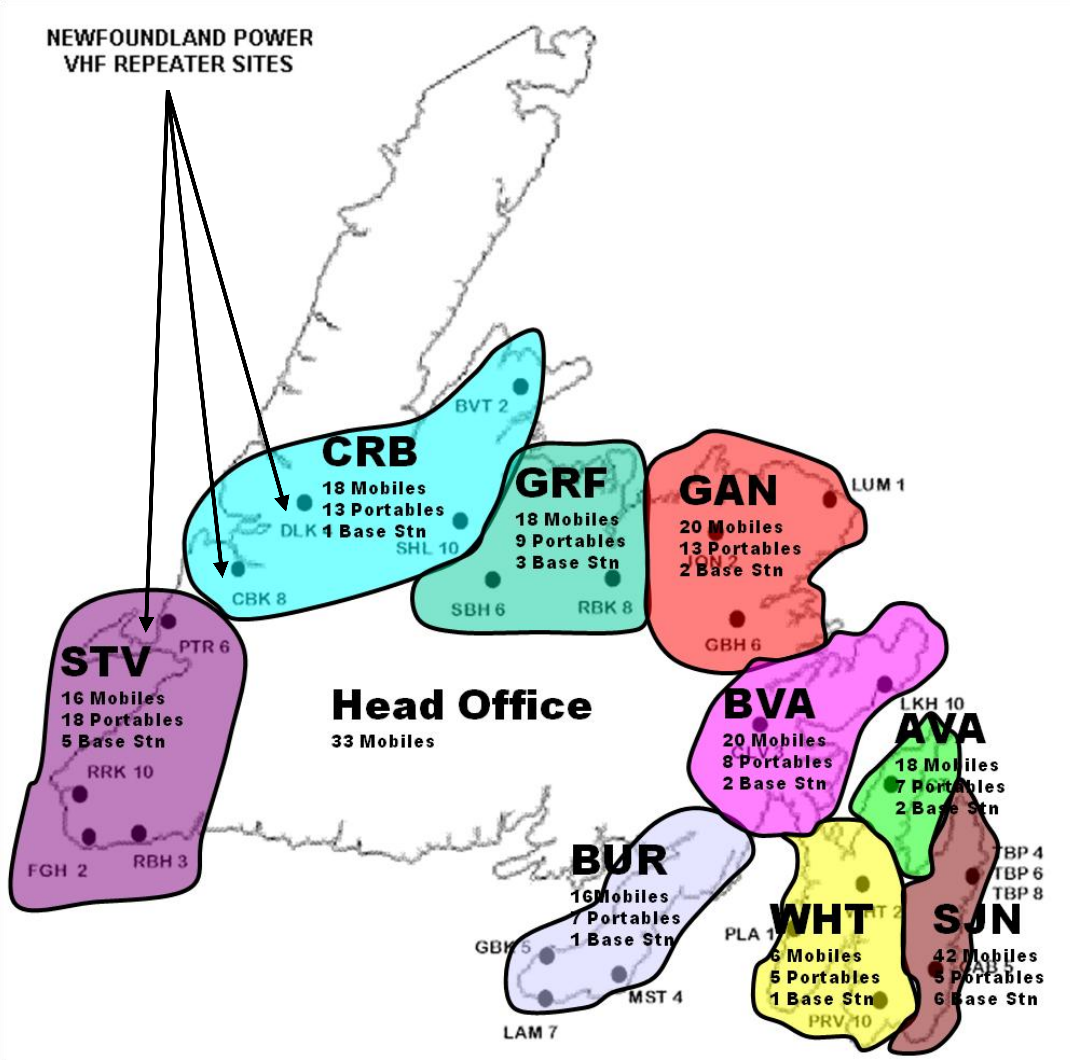

Figure 1 – Newfoundland Power Repeater Sites and Radios

All 9 operating areas are connected through a central switch integrated with the System Control Centre ("SCC") telephone system. Radio-telephone interconnect devices along with the Bell Aliant wide area network and other Company owned IP routers are used to link areas.[8] The repeater sites within each operating area are also bridged together. Every mobile radio is programmed for operation in all 9 operating areas plus they can use 3 simplex frequencies.[9]

This system offers mobile radio users ability to communicate with other mobiles and/or base stations within their operating area, the SCC, or other areas on the system.[10] Figure 2 illustrates

8 This interconnection is accomplished over the corporate intranet using Voice over Internet Protocol ("VoIP"). It has had multiple upgrades over the years to keep up with networking technology.

9 Simplex frequencies, sometimes referred to as truck to truck channels, allow direct communication from radio to radio. They essentially bypass repeater sites and allow direct communications between vehicles in an area.

10 Switching is accomplished using dual-tone multi-frequency ("DTMF") microphones. DTMF is used extensively throughout the public telephone network, and is sometimes referred to as *touch tone*.

the mobile radio system operation for the Grand Falls operating area.[11] In addition, the SCC also has a crew emergency line.[12]

Figure 2 - System Operation

3.2 Utility Practice

In 2010, Newfoundland Power, with assistance from the Centre for Energy Advancement through Technological Innovation ("CEATI"), completed a review of utility operational voice communications. The survey was issued to utilities participating in Distribution Assets Life Cycle Management ("DALCM") and Life Cycle Management of Substation Equipment and Apparatus ("LCMSEA") Interest Groups. Of the 19 utilities that responded all either own or lease a mobile radio system for operational voice communications. They all have multiple means of communicating with operational staff such as radios, cell phones, satellite phones and/or computers.[13]

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[11] Communication within an area is established by selecting the channel on the mobile, portable or base station radio corresponding to the local VHF repeater site. Each radio channel has a specific frequency range of operation. However, one channel can be assigned to multiple repeaters. Communication with the SCC and other areas require specific access codes. When the '#' key is entered on a radio the radio-telephone interconnect device establishes a connection on its telephone interconnect port. With the link established, the user can enter a valid access code to communicate with their desired destination.

[12] The crew emergency line is a dedicated facility to the SCC communications console which has a unique ring tone. Entering #911 on a mobile radio will cause the crew emergency line on the SCC communications console to ring indicating an emergency. Dialing 737-2911 on a cell phone or land line accesses the same crew emergency line on the SCC communications console.

[13] Survey results from the 19 utilities can be found in Appendix A. Newfoundland Power either maintaining its own radio system or leasing a system from Bell is in line with best practice of the utility industry.

4.0 Development of Alternatives

In some operating areas cell phone usage has significantly reduced VHF mobile radio traffic for daily operations. However, VHF radio is used extensively in geographic locations where cell coverage is not adequate and for electrical system switching activities.[14] Newfoundland Power must maintain a VHF radio system for operational and safety purposes, particularly in event of loss of provincial cellular or land line phone systems.

Two (2) alternatives have been considered for the replacement of the existing VHF radio system. Alternative 1 involves replacing the existing VHF Radio system with a new Company owned and maintained VHF radio system. Alternative 2 involves retiring the existing VHF radio system and moving to the Bell trunked radio system. The following is an assessment of both alternatives.

4.1 Alternative 1

Alternative 1 proposes to replace the Company's existing VHF radio equipment over a 3 year period beginning in 2013.[15] This would include replacement of radio repeaters, filtering equipment, cabling and antennas. Upgrades and refurbishment would also be required for towers, buildings, battery banks and back-up generating equipment.

Project implementation will take place over a 3 year period with equipment being replaced by operating area. In 2013 the replacement of equipment in the Gander and Grand Falls operating areas will be completed, involving 5 VHF repeaters and 2 UHF point to point radio links.[16]

In 2014, sites and equipment will be upgraded in Stephenville, Corner Brook, Clarenville and Burin. In 2015, sites and equipment will be upgraded in Avalon, Whitbourne and St. John's.

The new radio system will be strategically placed in service to minimize impact on operations. This may result in the old and new systems co-existing during for a short period of time. All out of date equipment will be decommissioned including towers and buildings where necessary.

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[14] As a standard practice, VHF radios are required for use for switching activities. This is done to keep other operations staff informed of switching operations by broadcasting over the VHF radio system, and as means to keep staff trained in using VHF radios in the event of an emergency.

[15] The 3 year implementation period is necessary due to the need to maintain VHF radio communications throughout the changeover period. The logistics around maintaining both the new and old equipment in the existing sites during construction requires more time to complete the work as opposed to building a parallel system in other radio sites.

[16] One UHF link is between Jonathan's Pond and Gambo Hilltop radio sites and the other is between Sandy Brook and Rattling Brook radio sites. Due to the large geographic area and the unavailability of leased circuits in the vicinity of the radio sites, the Gander and Grand Falls radio systems require UHF radio links between the remote radio sites to provide adequate VHF radio coverage

Table 1 includes capital cost associated with the 3 year implementation plan.

Table 1
Alternative 1 Capital Costs
($000)

Year	**2013**	**2014**	**2015**	**TOTAL**
Cost	851	686	593	2,130

The 3-year total capital cost is estimated at $2.13 million. In addition to the initial capital cost, there will be both annual capital and operating costs associated with this alternative.[17] Annual capital costs involve mobile radio replacement due to age and deterioration and refurbishment work associated with radio towers. Annual operating costs include internal labour, radio site rental costs and routine maintenance.[18]

The radio system operation would remain the same with 9 operating areas and 24 repeater sites. Communications functionality between mobile radios, portable radios, base stations, SCC and other areas would remain essentially unchanged.

For the purpose of developing estimates for the operating cost associated with Alternative 1, the provision of ongoing maintenance associated with a Newfoundland Power owned VHF radio system was further considered. Two technical support alternatives were considered for the radio system. A technologist from Newfoundland Power can provide the support required or a separate service contract with Bell can be utilized. Details of the analysis are available in Appendix B.

4.2 Alternative 2

Alternative 2 involves retiring the existing VHF mobile radio system and moving to the Bell trunk radio system, known as PassPort.[19] The PassPort trunk radio system is computer-controlled and more efficient than a conventional network. The PassPort trunk radio system was installed by Bell at the request of Hydro to replace its existing VHF mobile radio system in 2005.[20] The Department of Transportation and Works also uses the PassPort trunk radio system.

Trunked radio systems communicate with multiple user groups on a single frequency pair where conventional radio systems have dedicated frequencies for each user group. In a trunked system, user groups are given priorities which dictate their access level during high traffic periods.

17 Annual capital costs are estimated at $58,000 and annual operating costs are estimated at $282,000.
18 Appendix B contains estimates of the capital and operating cost estimates for Alternative 1.
19 Retiring the existing radio site infrastructure will include decommissioning cost for Alternative 2 that is additional to the costs associated with Alternative 1. These costs are not included at this time because (i) it may be necessary to include some existing Newfoundland Power sites to the Bell trunked radio system if the coverage provided is insufficient and (ii) the salvage value of the existing radio sites cannot be determined without first going to market.
20 This Hydro capital project was approved by the Board in Order No. P.U. 53 (2004).

The Bell PassPort network consists of 34 radio sites providing a broad area of coverage as shown in Figure 3. The existing zones and areas of operation can be added to and configured for Newfoundland Power's specific needs.

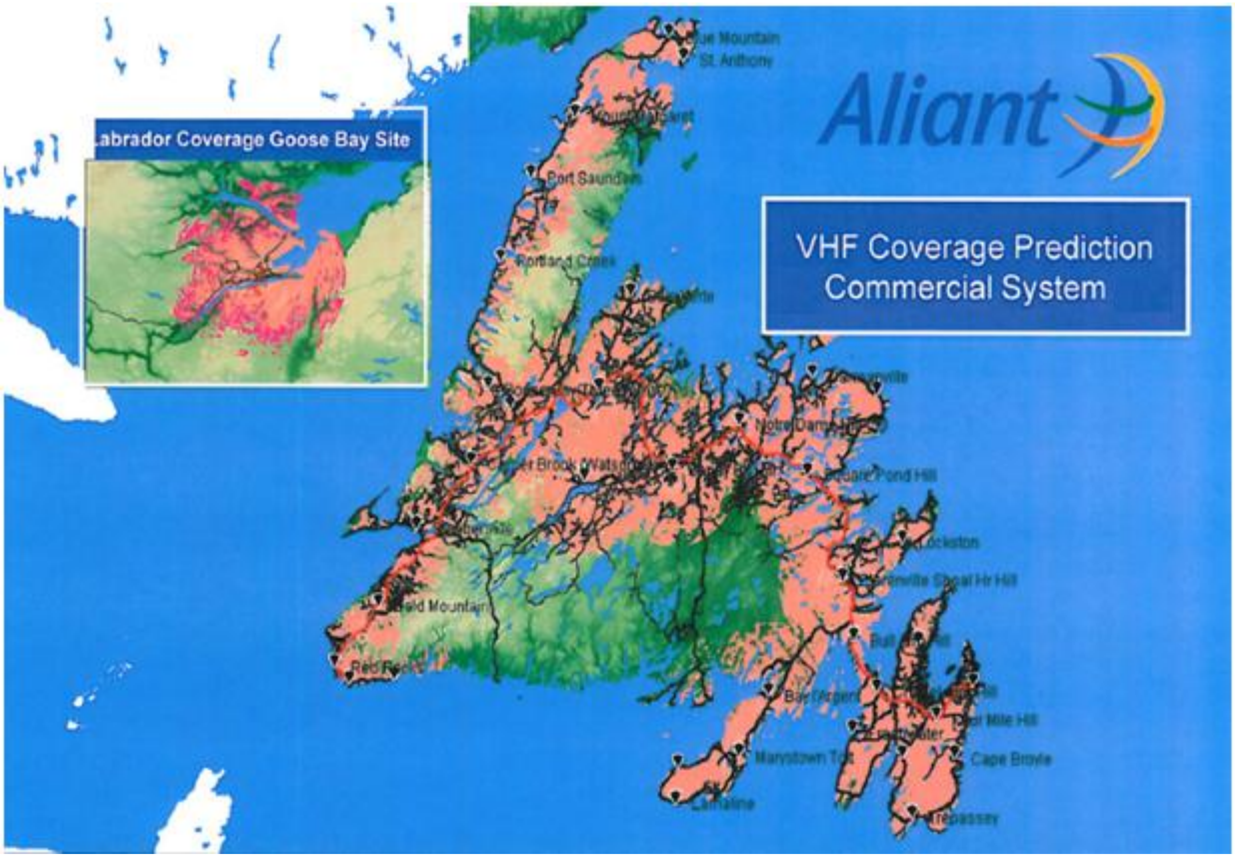

Figure 3 - Bell Trunk Radio Sites

The scope of the capital project to move Newfoundland Power to the Bell trunk radio system will include:

1. Purchase and install an operator's console at the SCC;
2. Purchase and install replacement VHF mobile radios;
3. Purchase replacement VHF portable radios; and
4. Purchase and install replacement VHF base stations.

The estimated 2013 capital expenditure associated with the move to the Bell trunk radio system is $750,000. The estimated annual operating expenditure of $280,000 will cover cost associated with monthly rental, annual Industry Canada licensing fees and a maintenance agreement with Bell to provide maintenance and servicing of the equipment.[21]

[21] Capital and Operating expenditure estimates are based upon quotes received from Bell in 2011. The $280,000 operating cost estimate includes $240,000 for access to the PassPort system and radio licenses, $30,000 for maintenance and repairs, and $10,000 for system administration by Newfoundland Power employees.

5.0 Evaluation of Alternatives

Two (2) alternatives have been considered for the replacement of the existing VHF radio system.

Alternative 1	involves replacing the existing VHF Radio system with a new Company owned and maintained VHF radio system.
Alternative 2	involves retiring the existing VHF radio system and moving to the Bell trunked radio system.

For the purposes of providing a comparison of alternatives, Alternative 1 is being further subdivided into Alternative 1A and Alternative 1B.

Alternative 1A	maintenance on the new equipment will utilize internal Newfoundland Power resources
Alternative 1B	maintenance on the new equipment will be completed under contract by Bell

In order to compare the economic impact of the 3 alternatives, a 25 year net present value ("NPV") calculation was completed for each alternative.[22] A sensitivity analysis was conducted for Alternative 1A and 1B to determine the impact of providing maintenance support internally or through 3rd party contract.[23]

Table 2 provides the result of the NPV analysis.

Table 2
Net Present Value Analysis
($000)

Alternative 1A – Newfoundland Power Owned and Maintained	6,457
Alternative 1B - Newfoundland Power Owned, Bell Maintained	7,611
Alternative 2 – Bell PassPort Trunk Radio System (Rented)	4,560

Based on results of the NPV analysis, Alternative 2 is the least cost alternative.

22 Twenty five years was chosen for the analysis based on the anticipated life expectancy of VHF radio equipment.
23 Refer to Appendix C for the sensitivity analysis.

6.0 Project Cost

Table 3 shows the estimated project costs for Alternative 2 to be included in the 2013 Capital Budget Application.

Table 3
Project Cost Estimate
($000)

Engineering	40
Labour - Internal	-
Materials	692
Other	18
Total	**750**

7.0 Concluding

Newfoundland Power's VHF mobile radio system has reached the end of its useful life. The equipment is typically in excess of 25 years old and the individual electronic components which comprise the system are discontinued by the manufacturer and no longer supported.

The Company will replace its existing VHF radio system with a rented trunk radio system alternative owned by Bell and used by Hydro. An evaluation of alternatives has determined that at this time the least cost alternative for mobile radio communications is the PassPort system provided by Bell. Newfoundland Power will join Hydro on the PassPort trunk radio system. The estimated 2013 capital cost of this project is $750,000.

Appendix A
Radio System Survey Results.

CEATI Survey of Utility Operational Voice Communications
October 2010

In 2010, Newfoundland Power, with assistance from the Centre for Energy Advancement through Technological Innovation ("CEATI"), completed a survey of utility operational voice communications. The survey was issued to utilities participating in Distribution Assets Life Cycle Management ("DALCM") and Life Cycle Management of Substation Equipment and Apparatus ("LCMSEA") Interest Groups. The results of the survey were presented at the DALCM 2010 fall meeting in Halifax Nova Scotia.

The follow is a summary of the results of the survey:

System ownership	Utility owned **13 or 68%** Shared with others **3 or 16%** Leased from others **3 or 16%**
Other wireless technologies	Radio, Cell Phone and Satellite Phone **9 or 47%** Radio, Cell Phone and Computers **2 or 11%** Radio and Cell Phone **8 or 42%**
Method used most for "work" purposes	VHF Radio **12 or 63%** Cell Phone **7 or 37**%
Primary means of communication with field staff	VHF Radio **15 or 79%** Cell Phone **3 or 16**% telephone **1 or 5**%
Backup for loss of primary communications	VHF Radio backed up by Cell Phone **11 or 58%** VHF Radio backed up by Cell and Satellite Phone **3 or 16%** VHF Radio backed up by other radio frequencies **3 or 16%** Redundant VHF radio Systems **2 or 10%**

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Appendix B
Alternative 1 Capital and Operating Cost

Alternative 1

Alternative 1 proposes to replace the Company's existing VHF radio equipment over a 3 year period beginning in 2013. For the purposes of providing a comparison of alternatives, Alternative 1 is being further subdivided into Alternative 1A and Alternative 1B.

Alternative 1A maintenance on the new equipment will utilize internal Newfoundland Power resources

Alternative 1B maintenance on the new equipment will utilize completed under contract by Bell

Capital Cost Estimate

Table 1
Capital Cost Estimate – Alternative 1A
($000s)

	2013	**2014**	**2015**
Engineering	66	57	49
Labour	153	135	121
Materials	601	470	402
Other	31	24	21
Total	**851**	**686**	**593**

Table 2
Capital Cost Estimate – Alternative 1B
($000s)

	2013	**2014**	**2015**
Engineering	66	57	49
Labour	155	135	121
Materials	552	470	402
Other	28	24	21
Total	**801**	**686**	**593**

Operating Cost Estimate

Table 3
Annual Operating Cost Estimate – Alternative 1A
($000s)

Description	Estimate
Maintenance and Repairs	30
Technical Support[1]	30
Licensing and Rentals	222
Total	**282**

Table 4
Annual Operating Cost Estimate – Alternative 1B
($000s)

Description	Estimate
Maintenance and Repairs	30
Technical Support[2]	120
Licensing and Rentals	222
Total	**372**

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[1] Technical support costs are based on a 5 year average from 2006 to 2010.
[2] Technical support costs are based on a service contract estimated at $120,000 annually.

Appendix C
Net Present Value

Present Worth Calculation
Alternative 1A – Newfoundland Power Owned and Maintained

Capital Investment Year 1 ($2013):	$850,680
Capital Investment Year 2 ($2013):	$685,247
Capital Investment Year 3 ($2013):	$593,068
Capital Investment Year 4+ ($2013):	$58,000[1]
Operating Costs ($2013)	$281,783 per year
CCA Rate:	20.00%

Year	Capital Expenditure	Capital Revenue Requirement	Net Benefit	Cumulative PW Benefit	Total PW
2013	850,680	98,500	-380,283	-354,081	-2,992,671
2014	699,341	198,408	-485,987	-775,404	-3,241,986
2015	617,621	278,825	-572,273	-1,237,350	-3,478,861
2016	61,578	288,278	-587,446	-1,678,870	-3,703,713
2017	62,690	281,807	-586,378	-2,089,222	-3,916,854
2018	63,816	276,455	-586,495	-2,471,376	-4,118,873
2019	64,933	271,975	-587,441	-2,827,773	-4,310,265
2020	66,067	268,170	-589,145	-3,160,576	-4,491,581
2021	67,186	264,881	-591,294	-3,471,580	-4,663,265
2022	68,364	261,986	-594,122	-3,762,539	-4,825,922
2023	69,563	259,385	-597,345	-4,034,921	-4,980,027
2024	70,793	256,999	-600,932	-4,290,058	-5,126,051
2025	72,045	254,762	-604,780	-4,529,137	-5,264,418
2026	73,327	252,623	-608,870	-4,753,249	-5,395,545
2027	74,647	250,542	-613,201	-4,963,403	-5,519,834
2028	75,965	248,481	-617,542	-5,160,463	-5,637,603
2029	77,345	246,416	-622,182	-5,345,324	-5,749,249
2030	78,752	251,163	-633,765	-5,520,651	-5,855,094
2031	80,180	200,352	-589,895	-5,672,599	-5,955,434
2032	81,634	161,653	-558,257	-5,806,489	-6,050,554
2033	83,114	126,219	-530,015	-5,924,847	-6,140,726
2034	84,614	128,475	-539,558	-6,037,035	-6,226,201
2035	86,124	130,772	-549,190	-6,143,357	-6,307,206
2036	87,661	133,108	-558,992	-6,244,120	-6,383,975
2037	89,225	135,488	-568,970	-6,339,616	-6,456,730

[1] Annual capital cost of tower refurbishment and mobile radio replacements.

Present Worth Calculation
Alternative 1B – Newfoundland Power Owned, Bell Maintained [2]

Capital Investment Year 1 ($2013):	$800,680
Capital Investment Year 2 ($2013):	$685,247
Capital Investment Year 3 ($2013):	$593,068
Capital Investment Year 4+ ($2013):	$58,000[3]
Operating Costs ($2013):	$372,882 per year
CCA Rate:	20.00%

Year	Capital Expenditure	Capital Revenue Requirement	Net Benefit	Cumulative PW Benefit	Total PW
2013	800,680	92,710	-465,592	-433,512	-3,026,849
2014	699,341	191,506	-572,058	-929,454	-3,356,766
2015	617,621	272,314	-660,633	-1,462,725	-3,670,221
2016	61,578	282,116	-678,004	-1,972,308	-3,967,768
2017	62,690	275,962	-678,998	-2,447,476	-4,249,816
2018	63,816	270,899	-681,173	-2,891,322	-4,517,147
2019	64,933	266,686	-684,141	-3,306,386	-4,770,414
2020	66,067	263,132	-687,876	-3,694,962	-5,010,349
2021	67,186	260,079	-692,020	-4,058,944	-5,237,537
2022	68,364	257,410	-696,923	-4,400,249	-5,452,780
2023	69,563	255,026	-702,246	-4,720,464	-5,656,707
2024	70,793	252,849	-707,974	-5,021,049	-5,849,939
2025	72,045	250,816	-713,994	-5,303,302	-6,033,041
2026	73,327	248,877	-720,296	-5,568,427	-6,206,560
2027	74,647	246,992	-726,897	-5,817,547	-6,371,032
2028	75,965	245,124	-733,501	-6,051,609	-6,526,874
2029	77,345	243,250	-740,499	-6,271,624	-6,674,615
2030	78,752	247,785	-754,079	-6,480,236	-6,814,679
2031	80,180	200,352	-715,832	-6,664,623	-6,947,458
2032	81,634	161,653	-686,477	-6,829,265	-7,073,330
2033	83,114	126,219	-660,561	-6,976,776	-7,192,655
2034	84,614	128,475	-672,459	-7,116,597	-7,305,762
2035	86,124	130,772	-684,462	-7,249,107	-7,412,956
2036	87,661	133,108	-696,678	-7,374,690	-7,514,544
2037	89,225	135,488	-709,113	-7,493,707	-7,610,821

[2] Service contract estimated at $120,000 annually, which is included in the operating costs.
[3] Annual capital cost of tower refurbishment and mobile radio replacements.

Present Worth Calculation
Alternative 2 - Bell PassPort Trunk Radio System (Rented)

Capital Investment Year 1 ($2013):	$750,000
Capital Investment Year 10+ ($2013):	$16,000[4]
Operating Costs ($2013):	$280,000 per year[5]
CCA Rate:	20.00%

Year	Capital Expenditure	Capital Revenue Requirement	Net Benefit	Cumulative PW Benefit	Total PW
2013	750,000	86,842	-366,628	-341,367	-1,120,903
2014	0	103,534	-389,074	-678,673	-1,368,451
2015	0	97,661	-389,030	-992,702	-1,603,647
2016	0	92,418	-389,466	-1,285,422	-1,826,906
2017	0	87,679	-390,091	-1,558,410	-2,038,537
2018	0	83,343	-391,186	-1,813,303	-2,239,124
2019	0	79,330	-392,560	-2,051,467	-2,429,159
2020	0	75,574	-394,274	-2,274,190	-2,609,191
2021	0	72,025	-396,125	-2,482,540	-2,779,657
2022	0	68,641	-398,423	-2,677,660	-2,941,162
2023	19,190	67,612	-403,176	-2,861,503	-3,094,175
2024	19,529	67,154	-408,650	-3,035,003	-3,239,164
2025	19,874	66,678	-414,216	-3,198,749	-3,376,551
2026	20,228	66,182	-419,903	-3,353,307	-3,506,748
2027	20,592	65,663	-425,752	-3,499,219	-3,630,157
2028	20,956	65,120	-431,565	-3,636,933	-3,747,091
2029	21,336	64,551	-437,654	-3,766,967	-3,857,946
2030	21,725	69,983	-449,873	-3,891,422	-3,963,041
2031	22,119	21,489	-408,271	-3,996,586	-4,062,669
2032	22,520	23,631	-417,424	-4,096,700	-4,157,115
2033	22,928	25,729	-426,664	-4,191,979	-4,246,648
2034	23,342	27,785	-435,954	-4,282,624	-4,331,517
2035	23,758	29,799	-445,251	-4,368,824	-4,411,948
2036	24,182	31,772	-454,637	-4,450,777	-4,488,173
2037	24,614	33,705	-464,115	-4,528,673	-4,560,413

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4 Assuming a 10 year contract and service agreement, once the contract has expired Newfoundland Power may have to replace/repair mobile radios. The value is based on current annual radio repair/replacement costs.

5 The $280,000 operating cost estimate is based on a quote received from Bell. It includes $240,000 for access to the PassPort system and radio licenses, $30,000 for maintenance and repairs, and $10,000 for system administration by Newfoundland Power employees.

2013 Application Enhancements

June 2012

NEWFOUNDLAND POWER
A FORTIS COMPANY

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Appendix A: Net Present Value Analyses

1.0 Introduction

Newfoundland Power ("the Company") operates and supports over 50 computer applications including 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: Operations and Engineering Systems, Customer Service Systems, Internet/Intranet Systems and Business Support Systems. In addition, the Company budgets for minor enhancements to respond to unforeseen requirements routinely encountered during the course of the 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 items budgeted for 2013.

2.0 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 2013, enhancements to the Company's distribution applications through the consolidation of location and connectivity information are proposed.

Table 1 summarizes the estimated cost associated with this item.

Table 1
Operations and Engineering Enhancements
Project Expenditures
($000s)

Cost Category	2013 Estimate
Material	190
Labour – Internal	232
Labour – Contract	-
Engineering	-
Other	150
Total	**572**

2.1 Distribution System Information Management Improvements ($572,000)

Description

The purpose of this project is to streamline the manual processes used to maintain and distribute information associated with the Company's various distribution assets. At present there are multiple applications that use geographic location and electrical connectivity information to support the engineering and operation of the distribution system and to provide customers with information on field operations. The information flow into and from these applications is largely a series of manual processes. The information associated with several of these existing applications will be integrated into a centralized system reducing the amount of manual intervention necessary.

The centralized system will provide information about the geographic location and electrical connectivity of the Company's distribution network. Currently this information is restricted to only the technical specialist trained to use specific engineering applications. Ease of access to this information through a graphical user interface will increase the efficiency of Company work, ranging from subdivision planning to line patrols during storm situations. One centralized system will enable information to be updated in a more efficient and timely manner, will eliminate manual processes and will make information available to a broader group of employees.[1]

The centralized system will provide the functionality necessary to display the electrical connectivity of the distribution system from the substation to the customer meter. The ability to manage network connectivity at this level of detail will improve the Company's distribution design processes and will improve the quality of communication to customers.[2]

Operating Experience

The Company operates and maintains over 9,000 kilometres of electrical distribution lines, comprised of approximately 400 individual distribution feeders and underground loops. This electrical distribution network is continuously changing. Every day sections of new lines are being constructed and existing lines upgraded.[3] On a regular basis the network is temporarily reconfigured. Temporary network reconfiguration is completed to de-energize sections of line

[1] Standardizing the presentation of distribution network connectivity will assist in the transfer of local knowledge to more junior employees, without having to rely solely on more senior employees. In effect, this will reduce the exclusive requirement for technical specialists to provide this information.

[2] The Company has location information on many of its Distribution assets including streetlights, poles and some meters. Network connectivity information exists for distribution feeders. Consolidating this information, and relating it to local geography, will improve the quality of information available to employees who are responding to customer enquiries regarding the progress of field work.

[3] Every year the Company constructs approximately 100 kilometers of new distribution lines and rebuilds approximately 30 kilometers of existing distribution lines.

for construction and maintenance work.[4] Permanent reconfigurations are completed to balance and transfer load on and between distribution feeders.[5]

It is important that accurate records be kept of the current state of the electrical distribution network and that this information is available to all field and technical employees.[6] Several systems currently exist for managing different forms of electrical distribution information.

Single line diagrams ("SLDs") are maintained for all 400 of the Company's distribution circuits. These diagrams are the primary reference used to determine the location and configuration of the distribution network and are accessible by all employees. Refer to Figure 1 for an example of a SLD showing a section of distribution feeder HWD-04 which supplies a residential area. Disconnect switch HWD-04-D1 is identified on the SLD.[7]

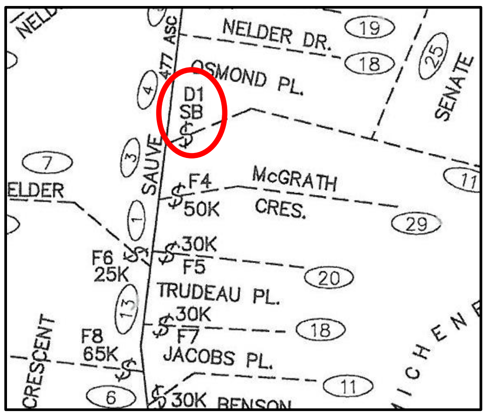

Figure 1: Example SLD of HWD-04
with switch HWD-04-D1 identified

An in-house database application, Device Numbering System ("DNS"), is used to manage the numbering of distribution devices and to record their location in the form of a description and

4 During construction season the Company receives on average 10 requests per week from municipalities, other utilities and customers to de-energize sections of distribution feeders. For example, underground loop circuits which include a series of padmount transformers with buried cables connected between each transformer are energized in two directions. To facilitate the repair of sidewalks the Company will re-configure the loop and de-energize the cables between two adjacent padmount transformers. When the sidewalk repair between the two transformers is completed, the Company will return to re-energize the cables and then de-energize the next set of cables in the circuit to allow the work to continue between the next two transformers.

5 As loads on the distribution network change, to accommodate the addition of a new residential subdivision or the removal of a large commercial customer, lines are reconfigured to ensure current and voltage levels are maintained within the Company's operating requirements. Single phase sections of line can be moved to a different phase to balance load equally across the three phases of a distribution feeder. Three phase sections of line can be transferred from one feeder to another to balance load equally across all feeders originating from a substation.

6 For example, crews responding to outages must know the current configuration of the distribution network to troubleshoot and restore power in a safe and timely manner.

7 If work requires a line to be de-energized a disconnect switch can be opened to minimize the number of customers affected. Engineering staff planning jobs must be able to determine which switch should be opened to isolate the section of line and crews need to know where this switch is located in the field.

GPS coordinates. This application is accessible by technical and support employees who have computer access to the corporate network. Refer to Figure 2 for the DNS record for the same switch that was identified on the SLD example in Figure 1.

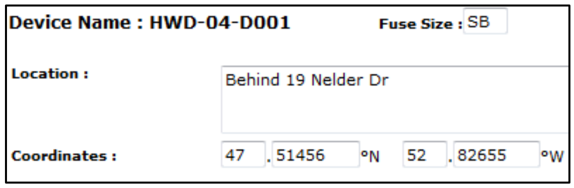
Device Name : HWD-04-D001 Fuse Size : SB
Location : Behind 19 Nelder Dr
Coordinates : 47 .51456 °N 52 .82655 °W

Figure 2: Example DNS record of switch HWD-04-D1

CYME, a 3rd party software application, is used to maintain engineering models of the Company's electrical distribution network and provide information on voltage and current levels before and after proposed changes to network configuration. These models are stored in a geographic format and can be overlaid on AutoCAD drawings. The CYME application is used by trained technical employees in the office. Refer to Figure 3 for the CYME model of the same section of distribution feeder HWD-04 shown in the SLD example in Figure 1.

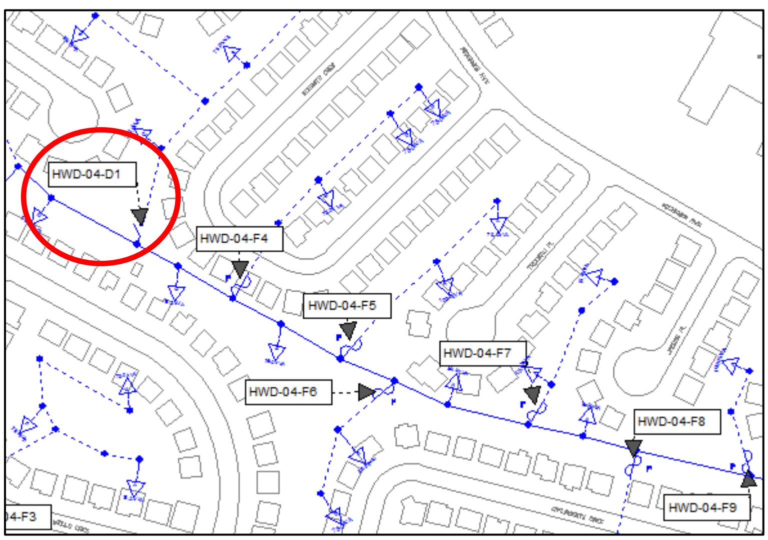

Figure 3: Example CYME feeder model of HWD-04 with switch HWD-04-D1 identified

Changes to the distribution network require each system database to be updated independently. Every system database has its own manual update process which can result in delays of several days to several weeks for changes to be updated and accessible.[8]

[8] Typical changes include adding new lines constructed to service new residential and commercial developments and changing the configuration of normally opened and normally closed switches to permanently re-configure the distribution network.

This project will consolidate all distribution information currently stored in the independent applications into a centralized system. Processes surrounding the creating of information like that demonstrated in Figures 1, 2 and 3 are repetitive and inefficient, since all three applications use essentially the same geographic location and network connectivity information. Working with a centralized system will eliminate the duplication and inefficiencies. Also, with a centralized system information previously available only to network connected computers, such as the geographic location of lines and transformers stored in DNS and CYME, will be accessible to all employees through a variety of devices such as smart phones and laptop computers. The simple presentation of the distribution network can be further used by customer service staff to communicate the most current information in response to customer enquiries.

Figure 4 shows a mock-up of a view that employees will access in the office and in the field.[9]

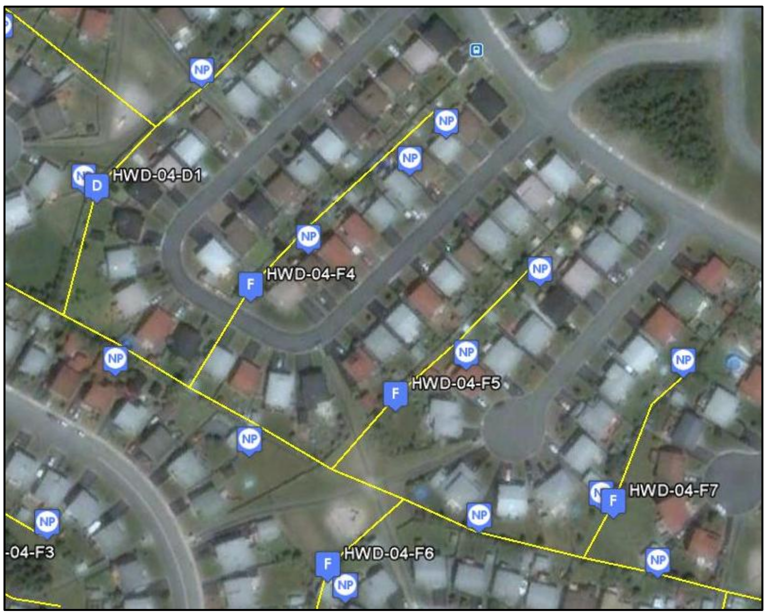

Figure 4: Mock-up of a view that will be available in the proposed system

Justification

This item is justified based on improved operational effectiveness, customer service and economics. The Company's distribution system information is now compiled in discrete applications, and not broadly available to employees working outside the engineering group. Employees, especially those new to the Company or to the area in which they are working, will benefit from easy access to all distribution system information from one central system. The manual processes that are currently necessary to maintain information in multiple systems will be significantly reduced. This improvement will benefit customers who rely on the Company for technical services, such as service pole locations, feeder extensions, and relocations. Making

[9] The new system will be accessible from all Company computers and electronic devices including the 80 laptops presently installed in line vehicles.

this information available to customer service representatives in a timely manner will improve the quality of information provided to customers. The improvements will result in quicker turnaround times for customer driven work and improved operations efficiency.

The additional electrical connectivity information enabled by this system will be used when performing distribution system design to reduce the number of field visits required during planned and unplanned outages. Reducing field visits will result in quicker turnaround times for customer driven work.

This project has a net present value of approximately $117,000 over an expected application life-cycle of 15 years, and will improve customer service.[10]

3.0 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 2013, enhancements are proposed in the areas of customer call-back technology and group billing.

Table 2 summarizes the estimated cost associated with this item.

Table 2
Customer Service Systems Enhancements
Project Expenditures
($000s)

Cost Category	2013 Estimate
Material	75
Labour – Internal	171
Labour – Contract	-
Engineering	-
Other	40
Total	**286**

3.1 Customer Call-back Technology ($170,000)

Description

The purpose of this item is to improve the process of handling customer calls to the Customer Contact Centre ("CCC"). Customer call-back technology, also known as *virtual hold*, will allow CCC staff to manage incoming calls by providing customers with a choice to either wait on-hold to speak with an agent or to receive a call-back within a specified period of time. This

[10] Refer to Appendix A Net Present Value Analysis page A-1 for details on the NPV calculation.

technology will improve the Company's ability to effectively match staffing levels with call volume, based on historical trends.

Operating Experience

The Company's CCC is staffed based on expected customer call volumes and cyclical patterns. Temporary employees are called in to offset shortfalls in regular staff availability. These shortfalls can occur due to illness, scheduled vacation or other requirements for regular employees to be away from their normal on-phone duties.

The CCC has a limited number of inbound telephone lines and agents to respond to customer calls. At peak times, customers wait in queue for an agent to become available. This situation becomes more significant during outages when customers can experience longer wait times. Outage and emergency calls receive a higher priority, often resulting in other call types being put on hold while agents are handling the higher priority calls. Outage situations are often isolated to a specific area of the Company's service territory. This situation can result in customers who reside in an area not experiencing an outage event to experience a degraded level of service while agents handle the incoming calls related to the outage.

Also, during large outage situations customers can experience a busy signal when calling Newfoundland Power. This could occur when all inbound telephone lines are being used to hold callers in the queue. When this occurs, customers cannot reach the contact centre to complete self service functions or speak with an agent.

Justification

This item is justified on improved customer service, increased customer satisfaction and cost savings.

Providing customers with alternatives for handing their inquiry improves the overall customer experience. The *virtual hold* technology will give the customer an alternative to waiting on the phone. This technology will call the customer back at the time provided and immediately connect the customer to an agent. By using this option, customers avoid a long on-hold wait time which leads to some customers choosing to terminate the call and having to call back later.

Utilizing the *virtual hold* technology will reduce the Company's overall requirement for temporary labour in the CCC and reduce long distance phone charges related to customers waiting in the call queue.

This project has a net present value of approximately $62,000 over an expected application life-cycle of 7 years and will improve customer service.[11]

[11] Refer to Appendix A Net Present Value Analysis page A-2 for details on the NPV calculation.

3.2 Group Billing Enhancements ($116,000)

Description

The purpose of this item is to improve the Company's ability to respond to requests for alternate billing programs for customers with multiple accounts.[12] This enhancement will eliminate the manual effort required to customize an electricity bill and the attachments for customers with multiple accounts. This enhancement will provide customers with a consolidated electronic bill which is easier to understand and remit payment against. It will provide the flexibility asked for by customers who want to use this offering.

Operating Experience

The Company currently offers Group Billing to customers with multiple electricity accounts. Group Billing options are currently offered to approximately 300 customers and 6,500 accounts. In the past 12 months, customers using this option were billed approximately $58 million in electricity charges.

Group Billing provides a consolidated electricity bill for customers with multiple accounts and an electronic data file containing billing details for each individual account owned by the customer. With this information, customers can better manage their electricity charges and payments.

Components of the Group Billing program are approximately 20 years old and are difficult to tailor to the individual requirements of large customers. In order to provide an acceptable level of service to these customers, CCC representatives often manually revise bills to meet customer needs. These changes are complex and require CCC representatives' significant effort on a daily basis to ensure the changes are done properly and the billing statements are acceptable to customers.

Justification

This item is justified on improved customer service and reduced manual effort currently associated with offering multiple group billing options.

Addressing the Group Billing program shortcomings and consolidating group billing programs into a single offering will reduce complexities of multiple accounts billing for CCC staff and customers. This improvement will reduce customer contacts and improve customer satisfaction. It will also reduce the amount and complexity of software to be maintained.

This project has a net present value of approximately $26,837 over an expected application life-cycle of 5 years.[13]

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[12] Customers that use group billing include apartment building owners, school boards, corporations, municipalities and others who would be responsible for multiple serviced properties.

[13] Refer to Appendix A Net Present Value Analysis page A-3 for details on the NPV calculation.

4.0 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 2013, 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	2013 Estimate
Material	60
Labour – Internal	197
Labour – Contract	-
Engineering	-
Other	65
Total	**322**

4.1 Customer Service Internet Enhancements ($272,000)

Description

For 2013, this item includes (i) enhancements to the self-service functionality used by customers to make payment arrangements for accounts that are in arrears, (ii) improvements to the website navigation and search capabilities and (iii) expanding the options available for customers to access the Company through the Internet. These 3 improvements to the customer contact functionality expand overall customer choice and flexibility when contacting or receiving information from the Company.

Operating Experience

In 2010, the Company implemented a self-service functionality that allows customers with overdue accounts to make an alternate payment arrangement without having to speak directly with a customer service representative.[14] Since 2010 over 6,900 alternate payment arrangements have been made online. These customers typically have accounts that have gone unpaid for multiple months. This functionality provides customers increased flexibility while reducing the number of agent handled credit calls. The 2013 project will extend the current service to include more complex customer arrangements such as the capability to address the amount in arrears over multiple payments which currently requires customers to speak directly with a customer service representative.

The use of electronic communications between customers and the Company continues to increase. In 2011, the Company's website recorded over 540,000 site visits, up 17% over 2010. In 2011, the number of customer visits to the website via mobile device was 32,000, up 175% over 2010. As well, at the end of 2011 the number of customers using eBills was 45,389, up 30% over 2010.

Customers continue to leverage email to connect with the Company. In 2011 the number of customer emails received was over 46,000, up 13% over 2010. Ensuring prompt response to these emails improves customer service and reduces the likelihood that further inquiries are required to satisfy the request.

Justification

Enhancing the online payment arrangement functionality will allow customers to make more complex payment arrangements at their convenience resulting in decreasing number of incoming agent handled calls to the CCC. Based on an estimated cost of $50,000 to improve the online payment arrangement functionality, a net present value benefit of $5,223 is estimated over an expected 7 year life.[15]

Enhancing the Company's website navigation, search and information management functionality will improve the overall customer experience in assisting customers with their information requests.

Expanding the options available for customers to access the Company through the Internet will improve the overall customer experience by allowing the customer to determine how and when they do business with the Company.

These proposed changes will improve customer service and provide cost savings.

4.2 Energy Conservation Website Enhancements ($50,000)

Description

The purpose of this item is to enhance the Internet based functionality which supports the Company's energy conservation initiatives.

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14 This functionality can be accessed through either the interactive voice response technology or online through the Company's website.

15 Refer to Appendix A Net Present Value Analysis page A-4 for details on the NPV calculation

For 2013, enhancements will include capabilities for additional rebate and customer incentive programs and supporting functionality, Including expanded programs and information for commercial customers.

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 2011, the Company provided rebates to over 6,300 residential customers and recorded approximately 73,000 visits to the takeCHARGE! website. Energy efficiency education and awareness has also been expanded to include the use of social media, including use of Facebook and YouTube as new avenues of customer communication. The takeCHARGE! Facebook page had over 6,000 followers at the end of 2011, up from 650 in 2010.

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.

5.0 Various Minor Enhancements ($200,000)

Description

The purpose of this item is to complete enhancements to the Company's computer applications in response to unforeseen requirements such as legislative and compliance changes, vendor driven changes or employee identified enhancements designed to improve customer service or operational efficiency.

Operating Experience

Examples of previous work completed under this budget item include developing an application to improve the dispatch of field work to third party contractors, providing engineering technologists with a GPS location function used in assisting line construction crews in finding the location of worksites, as well as employee time-entry functionality for field personnel to be able to enter their daily time while in the field via mobile computers.

Justification

Work completed as part of Various Minor Enhancements is justified on the basis of improved customer service, operating efficiencies, or compliance with regulatory and legislative requirements.

Appendix A
Net Present Value Analysis

NET PRESENT VALUE ANALYSIS

Distribution System Design Improvements

		Capital Impacts											Operating Cost Impacts						
		Capital Additions		CCA Tax Deductions				Savings	CCA Tax Deductions			Cost Increases		Cost Benefits					
	YEAR	New Software A	New Hardware B	Software	Hardware C	Residual CCA	Total	T&D Savings D	T&D	Residual CCA	Total	Labour E	Non-Lab	Labour F	Non-Lab	Net Operating Savings G	Income Tax H	After-Tax Cash Flow I	After-Tax Discounted Cash Flow J
0	2013	($511,500)	($60,000)	$255,750	$16,500		$272,250	$0	($0)		($0)	($17,000)	($27,000)	$0	$0	($44,000)	$91,712	($523,788)	($523,788)
1	2014	$0	$0	$255,750	$23,925		$279,675	$93,996	($3,760)		($3,760)	($7,280)	($27,586)	$0	$0	($34,866)	$90,126	$149,257	$140,344
2	2015	$0	$0	$0	$10,766		$10,766	$95,930	($11,056)		($11,056)	($7,571)	($28,153)	$0	$0	($35,724)	$10,276	$70,481	$62,315
3	2016	$0	$0	$0	$4,845		$4,845	$97,888	($17,924)		($17,924)	($7,874)	($28,728)	$0	$0	($36,602)	$6,822	$68,107	$56,620
4	2017	$0	$0	$0	$2,180		$2,180	$99,796	($24,398)		($24,398)	($8,189)	($29,288)	$0	$0	($37,477)	$4,425	$66,744	$52,174
5	2018	$0	$0	$0	$981		$981	$101,598	($30,502)		($30,502)	($8,517)	($29,817)	$0	$0	($38,333)	$2,556	$65,820	$48,379
6	2019	$0	$0	$0	$441		$441	$103,422	($36,262)		($36,262)	($8,857)	($30,352)	$0	$0	($39,209)	$983	$65,196	$45,059
7	2020	$0	$0	$0	$199		$199	$105,232	($41,707)		($41,707)	($9,212)	($30,883)	$0	$0	($40,095)	($410)	$64,727	$42,064
8	2021	$0	$0	$0	$89		$89	$107,070	($46,863)		($46,863)	($9,580)	($31,423)	$0	$0	($41,003)	($1,674)	$64,394	$39,348
9	2022	$0	$0	$0	$40		$40	$108,884	($51,752)		($51,752)	($9,963)	($31,955)	$0	$0	($41,918)	($2,840)	$64,125	$36,844
10	2023	$0	$0	$0	$18		$18	$110,793	($56,399)		($56,399)	($10,362)	($32,515)	$0	$0	($42,877)	($3,916)	$64,000	$34,576
11	2024	$0	$0	$0	$8		$8	$112,736	($60,828)		($60,828)	($10,776)	($33,085)	$0	$0	($43,862)	($4,918)	$63,956	$32,489
12	2025	$0	$0	$0	$4		$4	$114,728	($65,061)		($65,061)	($11,207)	($33,670)	$0	$0	($44,877)	($5,852)	$63,999	$30,570
13	2026	$0	$0	$0	$2		$2	$116,758	($69,115)		($69,115)	($11,656)	($34,266)	$0	$0	($45,921)	($6,726)	$64,111	$28,795
14	2027	$0	$0	$0	$1		$1	$118,824	($73,009)		($73,009)	($12,122)	($36,756)	$0	$0	($48,878)	($6,998)	$62,948	$26,584
15	2028	$0	$0	$0	$0	$0	$1	$120,926	($76,758)	($525,794)	($602,552)	($12,607)	($37,406)	$0	$0	($50,013)	($160,236)	($89,323)	($35,470)
15 Yr	Present Value (See Note I)	@		6.35%														$116,903	$116,903

NOTES: A is the sum of the software additions by year.
B is the sum of the computer network hardware additions by year.
C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.
D is any savings related to Capital Labour Savings associated with the implementation of th eproject
E is any software maintenance fees and internal support costs associated with the project. The labour cost estimates are escalated to current year using the GDP Deflator Index. The non-labour costs are escalated by The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.
F is the reduced operating costs. The labour cost estimates are escalated to current year using the GDP Deflator Index. The non-labour costs are escalated by The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.
G is the sum of columns E, and F.
H is the impact on taxes from the CCA and operating cost deductions. It is equal to column C (total) less column G times the tax rate.
I is the after tax cash flow which is the sum of the capital expenditure (columns A + B) plus operating expenditures (column G) plus income tax (column H).
J is the present value of column I. Column H is discounted using the weighted after-tax cost of capital.

NET PRESENT VALUE ANALYSIS

Virtual Hold

		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	2013	($165,600)	$0	$82,800	$0		$82,800	$0	$0	$0	$0	$0	$24,012	($141,588)
1	2014	$0	$0	$82,800	$0		$82,800	$0	$0	$41,600	$0	$41,600	$11,948	$53,548
2	2015	$0	$0	$0	$0		$0	$0	$0	$43,264	$0	$43,264	($12,547)	$30,717
3	2016	$0	$0	$0	$0		$0	$0	$0	$44,995	$0	$44,995	($13,048)	$31,946
4	2017	$0	$0	$0	$0		$0	$0	$0	$46,794	$0	$46,794	($13,570)	$33,224
5	2018	$0	$0	$0	$0		$0	$0	$0	$48,666	$0	$48,666	($14,113)	$34,553
6	2019	$0	$0	$0	$0		$0	$0	$0	$50,613	$0	$50,613	($14,678)	$35,935
7	2020	$0	$0	$0	$0		$0	$0	$0	$52,637	$0	$52,637	($15,265)	$37,372
8	2021	$0	$0	$0	$0		$0	$0	$0	$0	$0	$0	$0	$0
9	2022	$0	$0	$0	$0		$0	$0	$0	$0	$0	$0	$0	$0
10	2023			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7 Yr	Present Value (See Note I)	@		6.35%										$62,970

NOTES: A is the sum of the software additions by year.
B is the sum of the computer network hardware additions by year.
c is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.
D is any software maintenance fees and internal support costs associated with the project. The labour cost estimates are escalated to current year using the GDP Deflator Index. The non-labour costs are escalated by The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.
E is the reduced operating costs. The labour cost estimates are escalated to current year using the GDP Deflator Index. The non-labour costs are escalated by The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.
F is the sum of columns D, and E.
G is the impact on taxes from the CCA and operating cost deductions. It is equal to column C (total) less column F times the tax rate.
H is the after tax cash flow which is the sum of the capital expenditure (columns A + B) plus operating expenditures (column F) plus income tax (column G).

NET PRESENT VALUE ANALYSIS

Group Billing Enhancements

		Capital Impacts						Operating Cost Impacts						
		Capital Additions		CCA Tax Deductions				Cost Increases		Cost Benefits				
	YEAR	New Software A	New Hardware B	Software	Hardware	Residual CCA C	Total	Labour	Non-Lab D	Labour	Non-Lab E	Net Operating Savings F	Income Tax G	After-Tax Cash Flow H
0	2013	($115,800)	$0	$57,900	$0		$57,900	$0	$0	$27,300	$0	$27,300	$8,874	($79,626)
1	2014	$0	$0	$57,900	$0		$57,900	$0	$0	$28,392	$0	$28,392	$8,557	$36,949
2	2015	$0	$0	$0	$0		$0	$0	$0	$29,528	$0	$29,528	($8,563)	$20,965
3	2016	$0	$0	$0	$0		$0	$0	$0	$30,709	$0	$30,709	($8,906)	$21,803
4	2017	$0	$0	$0	$0		$0	$0	$0	$31,937	$0	$31,937	($9,262)	$22,675
5	2018	$0	$0	$0	$0		$0	$0	$0	$33,215	$0	$33,215	($9,632)	$23,582
6	2019	$0	$0	$0	$0		$0	$0	$0	$0	$0	$0	$0	$0
7	2020	$0	$0	$0	$0		$0	$0	$0	$0	$0	$0	$0	$0
5 Yr	Present Value (See Note I)	@		6.35%										$26,837

NOTES: A is the sum of the software additions by year.
B is the sum of the computer network hardware additions by year.
c is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.
D is any software maintenance fees and internal support costs associated with the project. The labour cost estimates are escalated to current year using the GDP Deflator Index. The non-labour costs are escalated by The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.
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F is the sum of columns D, and E.
G is the impact on taxes from the CCA and operating cost deductions. It is equal to column C (total) less column F times the tax rate.
H is the after tax cash flow which is the sum of the capital expenditure (columns A + B) plus operating expenditures (column F) plus income tax (column G).

NET PRESENT VALUE ANALYSIS

Enhance Payment Arrangements

		Capital Impacts						Operating Cost Impacts						
		Capital Additions		CCA Tax Deductions				Cost Increases		Cost Benefits				
	YEAR	New Software A	New Hardware B	Software	Hardware	Residual CCA C	Total	Labour D	Non-Lab	Labour E	Non-Lab	Net Operating Savings F	Income Tax G	After-Tax Cash Flow H
0	2013	($50,000)	$0	$25,000	$0		$25,000	$0	$0	$3,500	$0	$3,500	$6,235	($40,265)
1	2014	$0	$0	$25,000	$0		$25,000	$0	$0	$8,840	$0	$8,840	$4,686	$13,526
2	2015	$0	$0	$0	$0		$0	$0	$0	$9,194	$0	$9,194	($2,666)	$6,527
3	2016	$0	$0	$0	$0		$0	$0	$0	$9,561	$0	$9,561	($2,773)	$6,789
4	2017	$0	$0	$0	$0		$0	$0	$0	$9,944	$0	$9,944	($2,884)	$7,060
5	2018	$0	$0	$0	$0		$0	$0	$0	$10,342	$0	$10,342	($2,999)	$7,343
6	2019	$0	$0	$0	$0		$0	$0	$0	$10,755	$0	$10,755	($3,119)	$7,636
7	2020	$0	$0	$0	$0		$0	$0	$0	$11,185	$0	$11,185	($3,244)	$7,942
7 Yr	Present Value (See Note I)		@	6.35%										$5,223

NOTES: A is the sum of the software additions by year.
B is the sum of the computer network hardware additions by year.
c is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.
D is any software maintenance fees and internal support costs associated with the project. The labour cost estimates are escalated to current year using the GDP Deflator Index. The non-labour costs are escalated by The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.
E is the reduced operating costs. The labour cost estimates are escalated to current year using the GDP Deflator Index. The non-labour costs are escalated by The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.
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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).

2013 System Upgrades

June 2012

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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 Application Upgrades and continuation of the Microsoft Enterprise Agreement.

2.0 Business Application Upgrades ($1,008,000)

Business Application Upgrades involve third party software that supports the Company's business applications. For 2013, upgrades are proposed for the Company's financial system, asset management system, safety management system and database management software.

Table 1 summarizes the cost associated with these items.

Table 1
Business Applications Upgrades
Project Expenditures
($000s)

Cost Category	**2013 estimate**
Material	130
Labour – Internal	713
Labour – Contract	-
Other	165
	1,008

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 2013, upgrades include:

1) *Asset Management System (Avantis) Upgrade ($278,000)*

This item involves upgrades to the Company's asset management system Avantis to the most current vendor supported version of the application.

Avantis is used by employees to manage work associated with the inspection, maintenance, and upgrading of electrical system components. The version currently used by the Company will no longer be supported by the vendor after 2013.

The work associated with the upgrade involves ensuring that the new version of the software continues to support Company operations. This includes system integration to ensure data integrity and completeness between Avantis and other Company applications such as the Click work scheduling application, Technical Work Request management, Great Plains and the Customer Service System ("CSS").

2) Safety Management System Replacement ($249,000)

This item involves replacing the Company's current Safety Management System ("SMS") which has been discontinued by the vendor.

The Company currently operates a SMS from Utility Risk Management ("URM") that was originally implemented in 2002. This application known as Safety FIRST is used to manage components of our Health and Safety program including safety training, inspections, meetings, and work crew observations. Compliance with occupational health and safety legislation is mandatory and at the core of any health and safety program. The effective management of these components assists in ensuring our legislative compliance and supports our overall safety management system.

In December 2011 the Company received notice from URM that it was no longer able to provide support and maintenance for the Safety FIRST application and would be discontinuing the product. Continuing to operate an unsupported application to manage safety related tasks is not practical and results in the Company being exposed to an unacceptable level of operational risk.

In order to continue to provide the functionality delivered by the Safety FIRST application the Company will need to replace the current software with a new solution.

3) Financial Management System Upgrade ($345,000)

This item involves an upgrade to the Company's financial management system Great Plains to the most current vendor supported version of the software. The version currently used by the Company will no longer be supported by the vendor after July 1, 2013. Great Plains is used to manage Company resources including financial resources, project accounting, human resources/payroll and materials management/purchasing. The Great Plains application was initially implemented in 2001.

The upgrade involves ensuring the new version of the software continues to support Company operations. Modifications were made to the original application to meet Company requirements during the initial implementation (primarily purchasing requisition functionality) to integrate with other Company applications including CSS and Avantis. These modifications will have to be transferred to the new version. In addition, the replacement of vendor supplied financial reporting capabilities will be assessed and replacement components tested and implemented as required to meet the Company's requirements.

4) Database Management System Upgrade ($136,000)

This item involves upgrading the Company's database management software ("DBMS"), Microsoft SQL Server, to the latest version supported by the vendor. The Company operates multiple versions of DBMS from Microsoft and Oracle to support the over 50 applications the Company has in service. The version of DBMS selected for a particular application is typically tied to the implementation date of the application it supports. One version of Microsoft SQL Server currently in use by the Company will no longer be supported as of April 2013. The impacted databases are used for several applications in Customer Relations, Operations, Engineering and Environment.

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 Application 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 ($169,000)

Description

This Agreement covers the purchase of Microsoft software and provides access to the latest versions of each software product purchased under this agreement.

Through the Microsoft Enterprise Agreement, Newfoundland Power achieves an 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.[1] The terms of the agreements are typically of 3 years duration, with requirements reviewed and adjusted annually. The current agreement expires on May 31, 2015.

Justification

The Microsoft Enterprise Agreement is the least cost option to ensuring access to current Microsoft software products.

[1] The agreement covers software applications such as Office, Outlook, SharePoint, SQL Server and other applications used by employees in the completion of their normal duties.

2013 Shared Server Infrastructure

June 2012

NEWFOUNDLAND POWER
A FORTIS COMPANY

Introduction

Shared server infrastructure consists of approximately 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	**2013 Estimate**
Material	494
Labour – Internal	323
Labour – Contract	-
Engineering	-
Other	60
Total	**877**

For 2013, this project includes:

1. The replacement of technology used to provide employees with access to the Company's Great Plains Financial System. The existing servers will be in service for seven (7) years as of 2013 and will have reached the end of their useful lives. The estimate for this item is $172,000.

2. The Company relies on electronic documents as part of daily business operations.[1] The volume and size of files stored electronically increases through normal business operations.[2] In order to ensure the effective back-up and retention of electronic documents, additional infrastructure is required. Current infrastructure is nearing capacity and would result in overnight procedures for backup and retention of information not being completed in time to support normal Company operations the next morning. The estimated project cost for this infrastructure is $103,000.

3. The upgrading and replacement of infrastructure that hosts the Citrix Application Platform used to deliver enterprise applications such as Great Plains, Avantis, Outage Management, Click Scheduling, the SCADA terminal servers used to provide communications and control of the electrical system field devices and the Safety Management System. The Citrix application platform has been in service for 8 years, and vendor support on the installed version of Citrix ends in 2013. The estimated cost for this Infrastructure is $330,000.

4. The replacement of Infrastructure used to provide secure and effective internet services to employees. The current infrastructure has been in service for over 7 years and is at the end of its useful life. The estimated cost for this infrastructure is $131,000.

5. The replacement of the Company's Internet Intrusion Prevention System technology that has been in service for more than 7 years and is at the end of its useful life. The estimated project cost for this infrastructure is $141,000.

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 current performance of the components; the level of support provided by the vendor; 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.

[1] More than 20 terabytes of corporate and customer data is used as part of the Company's daily business operations.

[2] Examples of electronic files include AutoCAD drawing files, electronic forms related to various Company workflows (e.g. safety, environment, regulatory, mobile) as well as content rich formats such as pictures, videos and mapping (GPS) files.

Gartner Inc. has indicated that computer servers have a useful life of approximately five (5) years.[3] 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 seven (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 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.

[3] Gartner Inc. is the leading provider of research and analysis on the global Information Technology industry.

Rate Base:
Additions, Deductions & Allowances

June 2012

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1.0 Introduction

1.1 General

In the 2013 Capital Budget Application (the "Application"), Newfoundland Power seeks final approval of its 2011 average rate base. This is consistent with current regulatory practice before the Board.

Newfoundland Power's 2011 average rate base of $876,356,000 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 2011, Newfoundland Power made a number of presentation changes to its rate base to provide clarity and more accurately reflect its regulated assets and liabilities. The unamortized credit facility costs and deferred pension costs for 2011 are presented as separate line items. In 2010, these costs were shown together as deferred charges. The Weather Normalization Reserve for 2011 reflects that at December 31, 2011 there was an amount due to customers. In 2010, the Weather Normalization Reserve was shown as a negative addition to rate base. In 2011, the rate base also shows a reduction for Other Post Employment Benefit ("OPEBs") costs.[1] In 2010, Newfoundland Power used the cash method of accounting for OPEBs. Under the cash method, there was no rate base impact. Finally in 2011, Newfoundland Power's rate base has been reduced by $6,000 to adjust recovery of its 2010 hearing costs to reflect total costs of $750,000.[2]

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.

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1 This change is the result of the adoption of the accrual method of accounting for OPEBs approved by the Board in Order No. P.U. 31 (2010).

2 This adjustment was required under Order No. P.U. 26 (2011). Newfoundland Power's 2010 rate base reflected recovery of actual hearing costs totalling $759,000.

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. In the circumstances, 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. 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 2010 and 2011 and the forecast additions for 2012 and 2013.

Table 1
Additions to Rate Base
2010-2013F
($000s)

	2010	2011	2012F	2013F
Deferred Pension Costs	102,549	97,628	99,961	104,438
Credit Facility Costs	258	270	140	10
Cost Recovery Deferral – Seasonal/TOD Rates	-	228	133	150
Cost Recovery Deferral – Hearing Costs	507	253	-	-
Cost Recovery Deferral – Amortizations	-	1,642	3,319	3,319
Cost Recovery Deferral - Conservation	682	454	227	-
Customer Finance Programs	1,647	1,527	1,499	1,499
Total Additions	105,643	102,002	105,279	109,416

Additions to rate base were approximately $102.0 million in 2011. This is approximately $3.6 million less than 2010. The lower forecast additions to rate base through 2011 reflect (i) a reduction in deferred pension costs, and (ii) the amortizations of a number of deferred costs approved by the Board in Order No. P.U. 32 (2007). These reductions are partially offset in 2011 by the deferred recovery of costs related to the conclusion in 2010 of a number of specific regulatory amortizations.[3]

This section outlines the additions to rate base in further detail.

3 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.

2.2. Deferred Pension Costs

Table 2 shows details of changes in Newfoundland Power's deferred pension costs from 2010 through 2013.

Table 2
Deferred Pension Costs
2010-2013F
($000s)

	2010	2011	2012F	2013F
Deferred Pension Costs	102,549	97,628	99,961	104,438

The difference between pension plan *funding* and pension plan *expense* associated with the Company's defined benefit pension plan is captured as a deferred pension cost in accordance with Order No. P.U. 17 (1987).[4]

Table 3 shows details of changes in Newfoundland Power's deferred pension costs from 2010 through 2013.

Table 3
Deferred Pension Costs
2010-2013F
($000s)

	2010	2011	2012F	2013F
Deferred Pension Costs, January 1st	103,723	102,549	97,628	99,961
Pension Plan Funding[5]	4,999	5,137	13,486	13,599
Pension Plan Expense	(6,173)	(10,058)	(11,153)	(9,122)
Deferred Pension Costs, December 31st	102,549	97,628	99,961	104,438

For 2011, deferred pension costs were approximately $98 million.

4 Deferred pension costs were approved for inclusion in average rate base in Order No. P.U. 19 (2003).
5 Pension funding for 2012 and 2013 is based on the latest actuarial information and assumes special funding payments of $10.7 million per year.

2.3. Credit Facility Costs

In Order P.U. 1 (2005), the Board approved Newfoundland Power's issue of a $100 million committed revolving term credit facility.

On June 10th 2011, the committed credit facility was renegotiated to extend the maturity date to August 27th, 2015 and implement a revised pricing schedule. Legal and other administration costs of $130,000 resulting from the amendment are being amortized over a 3-year period (i.e. life of the agreement) beginning in June 2011.

Table 4 shows details of Newfoundland Power's amortization of deferred credit facility issue costs from 2010 through 2013.

Table 4
Deferred Credit Facility Issue Costs
2010-2013F
($000s)

	2010	**2011**	**2012F**	**2013F**
Balance, January 1st	-	258	270	140
Cost	300	130	-	-
Amortization	(42)	(118)	(130)	(130)
Balance, December 31st	258	270	140	10

2.4 Cost Recovery Deferral – Seasonal/TOD Rates

In April, 2011, Newfoundland Power submitted an application to the Board requesting, amongst other things, the approval of a revenue and cost recovery account to address the revenue and cost impacts of the Optional Seasonal Rate and the TOD Rate Study. In Order No. P.U. 8 (2011), the Board approved the Optional Seasonal Rate Revenue and Cost Recovery account.

This account is charged with: (i) the current year revenue impact of making the Domestic Seasonal – Optional Rate available to customers and (ii) the operating costs associated with implementing the Domestic Seasonal - Optional and the Time-of-Day Rate Study.

Newfoundland Power is required to file an application with the Board no later than the 1st day of March each year for the disposition to the Rate Stabilization Account of any balance in this account.

Table 5 shows details of the Optional Seasonal Rate Revenue and Cost Recovery account for 2010 through 2013.

Table 5
Seasonal/TOD Rates
2010-2013F
($000s)

	2010	**2011**	**2012F**	**2013F**
Balance, January 1st	-	-	228	133
Additions	-	228	133	150
Reductions	-	-	(228)	(133)
Balance, December 31st	-	228	133	150

2.5 Cost Recovery Deferral-Conservation

Table 6 shows details of forecast amortization of the deferred cost recovery related to conservation for 2010 through 2013.

Table 6
Cost Recovery Deferral-Conservation
2010-2013F
($000s)

	2010	**2011**	**2012F**	**2013F**
Balance, January 1st	948	682	454	227
Cost	-	-	-	-
Amortization	(266)	(228)	(227)	(227)
Balance, December 31st	682	454	227	-

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.

2.6 Cost Recovery Deferral-Hearing Costs

In Order No. P.U. 32 (2007), the Board approved the estimated external costs related to the Company's 2008 General Rate Application be deferred and amortized equally over three years beginning in 2008.

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.

Table 7 shows details of the changes in Newfoundland Power's deferred hearing costs from 2010 through 2013.

Table 7
Deferred Hearing Costs
2010-2013F
($000s)

	2010	**2011**	**2012F**	**2013F**
Balance, January 1st	201	507	253	-
Cost	760	-	-	-
Amortization	(454)[6]	(254)	(253)	-
Balance, December 31st	507	253	-	-
2010 Hearing Cost Adjustments[7]	-	6	3	-

The deferred hearing costs associated with the Company's 2008 General Rate Application were fully amortized in 2010. The deferred hearing costs associated with the Company's 2010 General Rate Application will be fully amortized in 2012.

2.7 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.

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[6] Amortization of hearing costs for the 2008 General Rate Application and the 2010 General Rate Application were $201,000 and $253,000 respectively.

[7] 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.

Table 8 shows the cost recovery deferral for 2011 through 2013 related to the expiry of regulatory amortizations in 2010.

Table 8
Cost Recovery Deferral - Regulatory Amortizations
2010-2013F
($000s)

	2010	2011	2012F	2013F
Balance, January 1st	-	-	1,642	3,319
Cost	-	1,642	1,677	-
Amortization	-	-	-	-
Balance, December 31st	-	1,642	3,319	3,319

2.8 Customer Finance Programs

Customer finance programs are loans provided to customers for the purchase and installation of products and services related to conservation programs and contributions in aid of construction (“CIAC”).

Table 9 shows details of changes to balances related to customer finance programs for 2010 through 2013.

Table 9
Customer Finance Programs
2010-2013F
($000s)

	2010	2011	2012F	2013F
Balance, January 1st	1,679	1,647	1,527	1,499
Change	(32)	(120)	(28)	-
Balance, December 31st	1,647	1,527	1,499	1,499

For 2011, the customer finance programs balance was $1.5 million.

3.0 Deductions from Rate Base

3.1 Summary

Table 10 summarizes Newfoundland Power's deductions from rate base for 2010 and 2011 and the Company's forecasts for 2012 and 2013.

Table 10
Deductions from Rate Base
2010-2013F
($000s)

	2010	2011	2012F	2013F
Weather Normalization Reserve	1,954	5,020	6,682	6,682
Other Post Employment Benefits	-	7,199	14,403	21,207
Customer Security Deposits	705	695	759	759
Accrued Pension Liabilities	3,548	3,778	4,041	4,312
Future Income Taxes	3,617	862	110	519
Demand Management Incentive Account	676	1,252	923	1,182
Total Deductions	10,500	18,806	26,918	34,661

Deductions from rate base were approximately $18.8 million in 2011. Newfoundland Power's deductions from rate base in 2011 have increased approximately $8.3 million from 2010. The reduction in rate base primarily reflects the adoption of the accrual method of accounting for Other Post Employment Benefits beginning in 2011 and an increase in the weather normalization reserve.

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.

Table 11 shows details of changes in the balance of the Weather Normalization Reserve from 2010 through 2013.

Table 11
Weather Normalization Reserve
2010-2013F
($000s)

	2010	**2011**	**2012F**	**2013F**
Balance, January 1st	3,919	(1,955)	(5,020)	(6,682)
Operation of the reserve	(4,507)	(1,699)	(296)	-
Amortization	(1,366)	(1,366)	(1,366)	-
Balance, December 31st	(1,954)	(5,020)	(6,682)	(6,682)

For 2011, the Weather Normalization Reserve balance showed a credit balance of approximately $5.0 million. In Order No. P.U. 19 (2012) the Board approved the December 31, 2011 balance of $5,019,776 in the Weather Normalization Reserve.

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. Newfoundland Power accounted for OPEBs costs using the cash method in 2010.

Table 12 shows details of the changes related to the accrued OPEBs liability from 2010 through 2013.

Table 12
Other Post Employment Benefits
2010-2013F
($000)

	2010	2011	2012F	2013F
Regulatory Asset	52,560	49,056	45,552	42,048
Regulatory Liability	52,560	56,255	59,955	63,255
Net OPEBs Liability	-	7,199	14,403	21,207

3.4 Customer Security Deposits

Customer security deposits are provided by customers in accordance with the Schedule of Rates, Rules and Regulations.

Table 13 shows details on the changes in customer security deposits from 2010 through 2013.

Table 13
Customer Security Deposits
2010-2013F
($000)

	2010	2011	2012F	2013F
Balance, January 1st	581	705	695	759
Change	124	(10)	64	-
Balance, December 31st	705	695	759	759

For 2011, the balance of customer security deposits was $0.7 million.

3.5 Accrued Pension Liabilities

Accrued pension liabilities are the cumulative costs of Newfoundland Power's unfunded pension plans net of associated benefit payments.

Table 14 shows details of changes related to accrued pension liabilities for 2010 through 2013.

Table 14
Accrued Pension Liabilities
2010-2013F
($000)

	2010	2011	2012F	2013F
Balance, January 1st	3,379	3,548	3,778	4,041
Change	169	230	263	271
Balance, December 31st	3,548	3,778	4,041	4,312

For 2011, the accrued pension liabilities were $3.8 million.

3.6 Future Income Taxes

Future 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 future income taxes with respect to timing differences related to plant investment,[8] pension costs[9] and other employee future benefit costs.[10]

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[8] 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 future income tax liabilities associated with plant investment.

[9] In Order No. P.U. 32 (2007), the Board approved the use of tax accrual accounting to recognize future income taxes related to timing differences between pension funding and pension expense.

[10] In Order No. P.U. 31 (2010), the Board approved the use of tax accrual accounting to recognize future income taxes related to timing differences between other employee future benefits recognized for tax purposes (cash payments) and other employee future benefit expense recognized for accounting purposes (accrual basis).

Table 15 shows details of changes in the future income taxes from 2010 through 2013.

Table 15
Future Income Taxes
2010-2013F
($000)

	2010	2011	2012F	2013F
Balance, January 1st	2,297	3,617	862	110
Change	1,320	(2,755)	(752)	409
Balance, December 31st	3,617	862	110	519

For 2011, future income taxes were $0.9 million.

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 16 shows details of the amortization of the DMI Account from 2010 through 2013.

Table 16
DMI Account
2010-2013F
($000)

	2010	2011	2012F	2013F
Balance, January 1st	-	676	1,252	923
Change	676	576	(329)	259
Balance, December 31st	676	1,252	923	1,182

For 2011, the balance in the DMI account was $1.3 million. In Order No. P.U. 9 (2012), the Board approved the transfer to the RSA at March 31, 2012, of $1.8 million equal to the balance in the DMI account for 2011 and related income tax effects.

4.0 Rate Base Allowances

The cash working capital allowance together with the materials and supplies allowance form the total allowances that are included in the Company's rate base. This represents the average amount of investor-supplied working capital necessary to provide service.

4.1 Cash Working Capital Allowance

The cash working capital allowance recognizes that a utility must finance the cost of its operations until it collects the revenues to recover those costs.

Table 17 shows details on changes in the cash working capital allowance from 2010 through 2013.

Table 17
Rate Base Allowances
Cash Working Capital Allowance
2010-2013F
($000)

	2010	2011	2012F	2013F
Gross Operating Costs	415,097	432,485	449,138	459,435
Income Taxes	17,773	19,631	13,416	12,544
Municipal Taxes Paid	13,421	13,348	15,618	15,700
Non-Regulated Expenses	(979)	(1,604)	(954)	(1,467)
Total Operating Expenses	445,312	463,860	477,218	486,212
Cash Working Capital Factor	2.0%[11]	2.0%	2.0%	2.0%
	8,906	9,277	9,544	9,724
HST Adjustment	386	386	386	386
Cash Working Capital Allowance	9,292	9,663	9,930	10,110

For 2011, the cash working capital allowance was $9.7 million.

[11] The calculation of the 2011 rate base including a cash working capital allowance based upon a cash working capital factor of 2.0% was approved by the Board in Order No. P.U. 43 (2009).

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.[12]

Table 18 shows details on changes in the materials and supplies allowance from 2010 through 2013.

Table 18
Rate Base Allowances
Materials and Supplies Allowance
2010-2013F
($000)

	2010	2011	2012F	2013F
Average Materials and Supplies	5,609	6,281	6,532	6,635
Expansion Factor[13]	20.2%[14]	20.2%	20.2%	20.2%
Expansion	1,133	1,269	1,319	1,340
Materials and Supplies Allowance	4,476	5,012	5,213	5,295

For 2011, the materials and supplies allowance was $5.0 million.

12 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.
13 The expansion factor is based on a review of actual inventories used for expansion projects. The calculation of the 2009 rate base including a materials and supplies allowance based upon an expansion factor of 19.4% was approved by the Board in Order No. P.U. 32 (2007).
14 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).