NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

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DELIVERED BY HAND

July 15, 2010

Board of Commissioners of Public Utilities
P.O. Box 21040
120 Torbay Road
St. John's, NF A1A 5B2

Attention: G. Cheryl Blundon
Director of Corporate Services
and Board Secretary

Ladies and Gentlemen:

Re: Newfoundland Power's 2011 Capital Budget Application

A. 2011 Capital Budget Application

Enclosed are the original and 10 copies of Newfoundland Power Inc.'s (the "Company") 2011 Capital Budget Application and supporting materials (the "Filing").

The Filing outlines proposed 2011 capital expenditures totaling $72,969,000. In addition, it seeks approval of a 2009 rate base in the amount of $848,493,000.

B. Compliance Matters

B.1 Board Orders

In Order No. P.U. 41 (2009) (the "2010 Capital Order"), the Board required a progress report on 2010 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. *2010 Capital Expenditure Status Report*: this meets the requirements of the 2010 Capital Order;

2. *2011 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 *2011 Capital Plan* provides a breakdown of the overall 2011 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 by project of these categorizations.

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 & 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,

Peter Alteen
Vice President, Regulation and Planning

Enclosures

c. Geoffrey Young
Newfoundland & Labrador Hydro

Thomas Johnson
O'Dea Earle Law Offices

Newfoundland Power Inc.
2011 Capital Budget Application
Filing Contents

Application

Application

Schedule A *2011 Capital Budget Summary*
Schedule B *2011 Capital Projects*
Schedule C *Future Required Expenditures*
Schedule D *Computation of Average Rate Base*

2011 Capital Plan

2010 Capital Expenditure Status Report

Supporting Materials

Generation

1.1 2011 Facility Rehabilitation
1.2 Horse Chops Rewind and Rotor Re-insulation
1.3 Rattling Brook Dam Refurbishment
1.4 Sandy Brook Hydro Plant Refurbishment

Substations

2.1 2011 Substation Refurbishment and Modernization
2.2 2011 Additions Due to Load Growth
2.3 2011 PCB Removal Strategy

Transmission

3.1 Transmission Line Rebuild

Distribution

4.1 Distribution Reliability Initiative
4.2 Feeder Additions for Load Growth
4.3 2011 AMR Project

Information Systems

5.1 2011 Application Enhancements
5.2 2011 System Upgrades
5.3 2011 Shared Server Infrastructure
5.4 Vehicle Mobile Computing

Deferred Charges

6.1 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 its 2011 Capital Budget of $72,969,000; and

(b) fixing and determining its 2009 rate base at $848,493,000

2011 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 its 2011 Capital Budget of $72,969,000; and
(b) fixing and determining its 2009 rate base at $848,493,000

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 2011 Capital Budget in the amount of $72,969,000, 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 2011. 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 comprising Newfoundland Power's 2011 Capital Budget are required.

4. The proposed expenditures as set out in Schedules A and B 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.

5. Schedule C to this Application is an estimate of future required expenditures on improvements or additions to the property of Newfoundland Power that are included in the 2011 Capital Budget but will not be completed in 2011.

6. Schedule D to this Application shows Newfoundland Power's actual average rate base for 2009 of $848,493,000.

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 2011 of the improvements and additions to its property in the amount of $72,969,000 as set out in Schedules A and B to the Application;

   (b) pursuant to Section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2009 in the amount of $848,493,000 as set out in Schedule D to the Application.

DATED at St. John's, Newfoundland and Labrador, this 15th day of July, 2010.

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 its 2011 Capital Budget of $72,969,000; and
(b) fixing and determining its 2009 rate base at $848,493,000

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 15th day of July, 2010:

Barrister

Peter Alteen

2011 CAPITAL BUDGET SUMMARY

Asset Class	**Budget (000s)**
1. Generation - Hydro	$ 7,696
2. Generation - Thermal	268
3. Substations	11,647
4. Transmission	4,745
5. Distribution	36,842
6. General Property	1,792
7. Transportation	2,254
8. Telecommunications	572
9. Information Systems	3,603
10. Unforeseen Allowance	750
11. General Expenses Capitalized	2,800
Total	**$ 72,969**

2011 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
1. Generation – Hydro		
Facility Rehabilitation	$1,610	2
Horse Chops Rewind and Rotor Re-insulation	1,276	4
Rattling Brook Dam Refurbishment	2,600	6
Hydro Plant Production Increase	650	8
Sandy Brook Plant Refurbishment	1,560	10
Total Generation – Hydro	**$ 7,696**	
2. Generation – Thermal		
Facility Rehabilitation Thermal	$ 268	13
Total Generation – Thermal	**$ 268**	
3. Substations		
Substations Refurbishment and Modernization	$ 3,074	16
Replacements Due to In-Service Failures	2,221	18
Additions Due to Load Growth	4,852	20
PCB Bushing Phase-out	1,500	22
Total Substations	**$11,647**	
4. Transmission		
Transmission Line Rebuild	$ 4,745	25
Total Transmission	**$ 4,745**	

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

2011 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
5. Distribution		
Extensions	$ 11,568	28
Meters	1,810	30
Services	3,073	33
Street Lighting	2,195	36
Replace Mercury Vapour Street Lights	581	39
Transformers	7,999	41
Reconstruction	3,609	43
Rebuild Distribution Lines	3,088	45
Relocate/Replace Distribution Lines for Third Parties	782	48
Distribution Reliability Initiative	521	50
St. John's Trunk Feeders	160	53
Feeder Additions for Growth	1,281	55
Allowance for Funds Used During Construction	175	57
Total Distribution	**$ 36,842**	
6. General Property		
Tools and Equipment	$ 508	60
Additions to Real Property	224	63
Kenmount Road 2nd Floor HVAC	435	65
Kenmount Road Building Flooring Replacement	150	67
Kenmount Road Building Entrance Renovation	125	69
Purchase Bill Inserter for Production Centre	350	72
Total General Property	**$ 1,792**	
7. Transportation		
Purchase Vehicles and Aerial Devices	$ 2,254	75
Total Transportation	**$ 2,254**	

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

2011 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
8. Telecommunications		
Replace/Upgrade Communications Equipment	$ 146	79
Fibre Optic Circuit Replacement	426	81
Total Telecommunications	**$ 572**	
9. Information Systems		
Application Enhancements	$ 983	84
System Upgrades[2]	808	86
Personal Computer Infrastructure	390	88
Shared Server Infrastructure	1,092	91
Network Infrastructure	152	93
Vehicle Mobile Computing Infrastructure	178	95
Total Information Systems	**$ 3,603**	
10. Unforeseen Allowance		
Allowance for Unforeseen Items	$ 750	98
Total Unforeseen Allowance	**$ 750**	
11. General Expenses Capitalized		
General Expenses Capitalized	$ 2,800	100
Total General Expenses Capitalized	**$ 2,800**	

[1] Project descriptions can be found in Schedule B at the page indicated.
[2] Includes the Microsoft Enterprise Agreement; included as a multi-year project in Schedule C of this application.

2011 CAPITAL PROJECTS: MULTI-YEAR
(000s)

Capital Project	Approved	2009	2010	2011
Microsoft Enterprise Agreement[3]	Order No. P.U. 27 (2008)	$200	$200	$200

[3] The Microsoft Enterprise Agreement is a multi-year project included in Schedule C of this application.

2011 CAPITAL PROJECTS SUMMARY

2011 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 2011 Capital Project Summary provides a summary of the planned capital expenditures contained in Newfoundland Power's 2011 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
2011 Capital Projects by Definition
(000's)

Clustered	**$4,905**	**Page**
Distribution	**160**	
St. John's Trunk Feeders	160	53
Transmission	**4,745**	
Transmission Line Rebuild	4,745	25

Pooled	**$56,421**	**Page**
Distribution	**36,161**	
Allowance for Funds Used During Construction	175	57
Extensions	11,568	28
Feeder Additions for Growth	1,281	55
Replace Mercury Vapour Street Lights	581	39
Meters	1,810	30
Rebuild Distribution Lines	3,088	45
Reconstruction	3,609	43
Relocate/Replace Distribution Lines for Third Parties	782	48
Services	3,073	33
Street Lighting	2,195	36
Transformers	7,999	41
General Property	**732**	
Additions to Real Property	224	63
Tools and Equipment	508	60
Generation-Hydro	**1,610**	
Facility Rehabilitation	1,610	2
Generation-Thermal	**268**	
Facility Rehabilitation Thermal	268	13
Information Services	**3,603**	
Application Enhancements	983	84
Network Infrastructure	152	93
Personal Computer Infrastructure	390	88
Shared Server Infrastructure	1,092	91
System Upgrades	808	86
Vehicle Mobile Computing Infrastructure	178	95
Substations	**11,647**	
Additions Due to Load Growth	4,852	20
PCB Bushings Phase-out	1,500	22
Replacements Due to In-Service Failures	2,221	18
Substations Refurbishment & Modernization	3,074	16

Telecommunications	**146**	
Replace/Upgrade Communications Equipment	146	79
Transportation	**2,254**	
Purchase Vehicles and Aerial Devices	2,254	75

Other	**$11,643**	**Page**
Allowance for Unforeseen	**750**	
Allowance for Unforeseen Items	750	98
Distribution	**521**	
Distribution Reliability Initiative	521	50
General Expenses Capitalized	**2,800**	
General Expenses Capitalized	2,800	100
General Property	**1,060**	
Kenmount Road Building 2nd Floor HVAC	435	65
Kenmount Road Building Flooring Replacement	150	67
Kenmount Road Building Entrance Renovations	125	69
Purchase Bill Inserter for Production Centre	350	72
Generation-Hydro	**6,086**	
Horse Chops Rewind and Rotor Re-insulation	1,276	4
Hydro Plant Production Increase	650	8
Rattling Brook Dam Refurbishment	2,600	6
Sandy Brook Plant Refurbishment	1,560	10
Telecommunications	**426**	
Fibre Optic Circuit Replacement	426	81

Summary of
2011 Capital Projects by Classification
(000's)

Normal Capital	**$68,651**	**Page**
Allowance for Unforeseen	**750**	
Allowance for Unforeseen Items	750	98
Distribution	**36,261**	
Allowance for Funds Used During Construction	175	57
Distribution Reliability Initiative	521	50
Extensions	11,568	28
Feeder Additions for Growth	1,281	55
Meters	1,810	30
Rebuild Distribution Lines	3,088	45
Reconstruction	3,609	43
Relocate/Replace Distribution Lines for 3rd Parties	782	48
Services	3,073	33
Street Lighting	2,195	36
Transformers	7,999	41
St. John's Trunk Feeders	160	55
General Expenses Capitalized	**2,800**	
General Expenses Capitalized	2,800	100
General Property	**1,792**	
Additions to Real Property	224	63
Tools and Equipment	508	60
Kenmount Road 2nd Floor HVAC	435	65
Kenmount Road Flooring Replacement	150	67
Kenmount Road Entrance Renovation	125	69
Purchase Bill Inserter for Production Centre	350	72
Generation-Hydro	**7,046**	
Facility Rehabilitation	1,610	2
Horse Chops Generator Rewind	1,276	4
Rattling Brook Dam Refurbishment	2,600	6
Sandy Brook Plant Refurbishment	1,560	10
Generation-Thermal	**268**	
Facility Rehabilitation Thermal	268	13
Information Services	**2,442**	
Network Infrastructure	152	93
Personal Computer Infrastructure	390	88
Shared Server Infrastructure	1,092	91
System Upgrades	808	86
Substations	**10,147**	
Additions Due to Load Growth	4,852	20
Replacements Due to In-Service Failures	2,221	18
Substations Refurbishment & Modernization	3,074	16

Telecommunications	**146**	
Replace/Upgrade Communications Equipment	146	79
Transmission	**4,745**	
Transmission Line Rebuild	4,745	25
Transportation	**2,254**	
Purchase Vehicles and Aerial Devices	2,254	75

Justifiable	**$2,818**	**Page**
Distribution	**581**	
Replace Mercury Vapour Street Lights	581	39
Generation-Hydro	**650**	
Hydro Plant Production Increase	650	8
Information Services	**1,161**	
Application Enhancements	983	84
Vehicle Mobile Computing Infrastructure	178	95
Telecommunications	**426**	
Fibre Optic Circuit Replacement	426	81

Mandatory	**$1,500**	**Page**
Substations	**1,500**	
PCB Bushings Phase-out	1,500	22

**Summary of
2011 Capital Projects by Materiality
(000's)**

Large – Greater than $500	**$69,790**	**Page**
Allowance for Unforeseen	**750**	
Allowance for Unforeseen Items	750	98
Distribution	**36,507**	
Distribution Reliability Initiative	521	50
Extensions	11,568	28
Feeder Additions for Growth	1,281	55
Meters	1,810	30
Rebuild Distribution Lines	3,088	45
Reconstruction	3,609	43
Relocate/Replace Distribution Lines for Third Parties	782	48
Replace Mercury Vapour Street Lights	581	39
Services	3,073	33
Street Lighting	2,195	36
Transformers	7,999	41
General Expenses Capitalized	**2,800**	
General Expenses Capitalized	2,800	100
General Property	**508**	
Tools and Equipment	508	60
Generation-Hydro	**7,696**	
Horse Chops Generator Rewind	1,276	4
Hydro Plant Production Increase	650	8
Facility Rehabilitation	1,610	2
Rattling Brook Dam Refurbishment	2,600	6
Sandy Brook Plant Refurbishment	1,560	10
Information Services	**2,883**	
Application Enhancements	983	84
Shared Server Infrastructure	1,092	91
System Upgrades	808	86
Substations	**11,647**	
Additions Due to Load Growth	4,852	20
PCB Bushings Phase-out	1,500	22
Replacements Due to In-Service Failures	2,221	18
Substations Refurbishment & Modernization	3,074	16
Transmission	**4,745**	
Transmission Line Rebuild	4,745	25
Transportation	**2,254**	
Purchase Vehicles and Aerial Devices	2,254	75

Medium - Between $200 and $500	**$2,093**	**Page**
General Property	**1,009**	
Additions to Real Property	224	63
Purchase Bill Inserter for Production Centre	350	72
Kenmount Road 2nd Floor HVAC	435	65
Generation-Thermal	**268**	
Facility Rehabilitation Thermal	268	13
Information Services	**390**	
Personal Computer Infrastructure	390	88
Telecommunications	**426**	
Fibre Optic Circuit Replacement	426	81

Small – Under $200	**$1,086**	**Page**
Distribution	**335**	
Allowance for Funds Used During Construction	175	57
St. John’s Trunk Feeders	160	53
General Property	**275**	
Kenmount Road Flooring Replacement	150	67
Kenmount Road Entrance Renovation	125	69
Information Services	**330**	
Network Infrastructure	152	93
Vehicle Mobile Computing Infrastructure	178	95
Telecommunications	**146**	
Replace/Upgrade Communications Equipment	146	79

GENERATION - HYDRO

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

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

Project Description

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

- Refurbishment of 4 hydro dams and spillways;
- Refurbishment of 1 gatehouse structure;
- Replacement of the main valve at West Brook Plant; 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 2011 proposed expenditures are included in ***1.1*** *2011 Facility Rehabilitation*.

Justification

The Company's 23 hydroelectric plants range in age from 11 to 110 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 428.8 GWh. Replacing the energy produced by these facilities by increasing production at Newfoundland and Labrador Hydro's Holyrood generation facility would require approximately 680,000 barrels of fuel annually. At an oil price of $73.30 per barrel, this translates into approximately $50 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 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$1,231	-	-	-
Labour – Internal	95	-	-	-
Labour – Contract	2	-	-	-
Engineering	233	-	-	-
Other	49	-	-	-
Total	**$1,610**	**$1,175**	**$3,625**	**$6,410**

Costing Methodology

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

Table 2

Expenditure History
(000s)

Year	2006	2007	2008	2009	2010F
Total	**$1,234**	**$780**	**$3,551**[1]	**$2,519**[2]	**$1,340**

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: **Horse Chops Rewind and Rotor Re-insulation (Other)**

Project Cost: **$1,276,000**

Project Description

This 2011 generation hydro project involves replacing stator coils and re-insulating rotor poles of the generator at the Horse Chops Plant. The generator stator coils and rotor poles are original to the 1954 installation of the Canadian General Electric generator. Both the stator coils and rotor poles have degraded insulation which compromises the integrity of the generator. The stator coils will be replaced and the rotor poles re-insulated during the same plant outage to minimize plant downtime and maximize overall construction efficiency.

Details on the proposed expenditures are included in ***1.2*** *Horse Chops Rewind and Rotor Re-insulation*.

Justification

The Horse Chops Plant was commissioned in 1954 and continues to provide normal annual production of approximately 41.8 GWh of energy, or about 9.7% of Newfoundland Power's total hydroelectric generation.

In 2009, 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 2011 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 Horse Chops Plant has determined the levelized cost of energy from the plant over the next 50 years to be 1.015¢ 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 11.63¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $73.30 per barrel for 2010 as per Newfoundland Hydro 2010 Capital Budget Application, Generation Planning Issues 2009 Mid Year Report dated July 2009.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2011 to 2015.

Table 1
Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$1,050	-	-	-
Labour – Internal	30	-	-	-
Labour – Contract	23	-	-	-
Engineering	90	-	-	-
Other	83	-	-	-
Total	**$1,276**	**-**	**-**	**$1,276**

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: **Rattling Brook Dam Refurbishment (Other)**

Project Cost: **$2,600,000**

Project Description

The Rattling Brook hydroelectric development is the largest generating station operated by Newfoundland Power. The development was placed into service in December 1958 and has provided 52 years of reliable energy production. The normal annual plant production is approximately 78.1 GWh of energy, or about 18.2% of Newfoundland Power's total hydroelectric system.

In 2007, significant upgrades were completed at Rattling Brook, which included the replacement of the woodstave penstock, refurbishment of the surge tank, and upgrades and replacements of the electrical and mechanical systems in the plant. At that time no work was completed on the upstream control systems that supply water to the plant.

Based on the findings of the civil infrastructure assessment, the following work is necessary for the Rattling Brook hydro plant system in 2011:

- Replacement of Rattling Lake spillway;
- Upgrades to Amy's Lake dam and Amy's Lake freeboard dam; and
- Upgrades to Rattling Lake dam.

Details on the proposed expenditures are included in ***1.3** Rattling Brook Dam Refurbishment*.

Justification

Replacement of the Rattling Lake spillway and upgrades to the dams and dykes will allow Newfoundland Power to continue to operate this facility over the long term, maximizing the benefits of this renewable resource for its customers.

This project is necessary at this time due to the age and physical condition of the plant assets.

A present worth feasibility analysis of projected capital and operating expenditures for the Rattling Brook Plant has determined the levelized cost of energy from the plant over the next 50 years to be 1.52¢ per kWh, which is significantly less than the cost of replacement energy at Holyrood.[2]

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[2] The cost of electricity from the Holyrood thermal generating station is estimated at 11.63¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $73.30 per barrel for 2010 as per Newfoundland Hydro 2010 Capital Budget Application, Generation Planning Issues 2009 Mid Year Report dated July 2009.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2011 to 2015.

Table 1
Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$2,110	-	-	-
Labour – Internal	95	-	-	-
Labour – Contract	-	-	-	-
Engineering	350	-	-	-
Other	45	-	-	-
Total	**$2,600**	**-**	**-**	**$2,600**

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

Project Cost: **$650,000**

Project Description

In 2008, Newfoundland Power conducted a study into alternative ways to improve the efficiency and energy production of existing hydroelectric plants.[3] 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 generation hydro project undertakes work coming out of the 2008 study.

Two items are included in this project:

1. *Raise Sandy Lake Spillway to Increase Production ($575,000).* This project was approved in Order No. P. U. 41 (2009) as part of the 2010 Capital Budget Application. Delays in obtaining the necessary permits and completing consultation with other stakeholders have necessitated postponing construction to the summer of 2011.

   Average annual water spill at the Sandy Brook hydroelectric generating plant is estimated to be 5.65 GWh. Increasing the amount of storage at Sandy Lake will reduce the amount of spilled water at this location and result in an estimated increased energy production of 0.86 GWh.

   Details on the proposed expenditures are included in the 2010 Capital Budget Application in section ***1.4*** *Raise Sandy Lake Spillway to Increase Production*.

2. *Complete Engineering Horse Chops/Cape Broyle Development ($75,000).* The Horsechops/Cape Broyle development is composed of two generating plants, Horse Chops and Cape Broyle, both located on the southern shore of the Avalon Peninsula.

   Horsechops hydroelectric generating plant was placed into service in 1953 and has normal annual production of approximately 41.8 GWh or 9.7% of the total hydroelectric production of Newfoundland Power. The drainage area above the intake to Horsechops plant is approximately 155 km^2.

   Cape Broyle plant was also placed into service in 1953 and has normal annual production of approximately 32.8 GWh or 7.6 % of the total hydroelectric production of Newfoundland Power. The drainage area above the intake to Cape Broyle plant is approximately 191 km^2.

[3] A copy of this study was filed as Attachment A to the 2010 Capital Budget Application response to Request for Information PUB-NP-09.

The 2008 study identified two potential projects to increase production, raise Blackwood's Ponds spillway elevations (2.29 ¢ per kWh) and replace Cape Broyle runner (6.90 ¢ per kWh) that require engineering work to be completed in 2011 for these projects to proceed in 2012.

Justification

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

The estimated levelized cost of the additional energy resulting from raising the spillway at Sandy Lake by 1.0 metre is 6.64 ¢ per kWh, which is significantly less than the cost of replacement energy at Holyrood[4]. Similarly, the Horse Chops/Cape Broyle Development has potential to increase production at a levelized cost less than the cost of replacement energy at Holyrood.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2011 and a projection of expenditures through 2015.

Table 1
Projected Expenditures
(000s)

Cost Category	**2011**	**2012**	**2013 - 2015**	**Total**
Material	$535	-	-	-
Labour – Internal	10	-	-	-
Labour – Contract		-	-	-
Engineering	95	-	-	-
Other	10	-	-	-
Total	**$650**	**650**	**3,280**	**$4,580**

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 future years will be presented in future Capital Budget Applications.

4 The cost of electricity from the Holyrood thermal generating station is estimated at 11.63¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $73.30 per barrel for 2010 as per Newfoundland Hydro 2010 Capital Budget Application, Generation Planning Issues 2009 Mid Year Report dated July 2009.

Project Title: **Sandy Brook Plant Refurbishment (Other)**

Project Cost: **$1,560,000**

Project Description

This generation hydro project involves a major refurbishment of electrical systems at Sandy Brook Plant. The components requiring replacement or refurbishment include the plant controls, governor controls, electrical protection, power cables and switchgear. The project also includes the implementation of a water management algorithm in the plant control system.

Details on the proposed expenditures are included in ***1.4*** *Sandy Brook Hydro Plant Refurbishment*.

Justification

The Sandy Brook hydroelectric generating plant located in central Newfoundland near the town of Grand Falls-Windsor, was commissioned in 1963 with a capacity of 6.4 MW.

Engineering assessments of the electrical systems have revealed a number of deficiencies. In particular, the assessment has identified that some key components have deteriorated and are in need of replacement.

A present worth feasibility analysis of projected capital and operating expenditures for the Sandy Brook Plant has determined the levelized cost of energy from the plant over the next 50 years to be 2.37¢ per kWh, which is significantly less than the cost of replacement energy at Holyrood.[5]

[5] The cost of electricity from the Holyrood thermal generating station is estimated at 11.63¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $73.30 per barrel for 2010 as per Newfoundland Hydro 2010 Capital Budget Application, Generation Planning Issues 2009 Mid Year Report dated July 2009.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2011 to 2015.

Table 1
Projected Expenditures
(000s)

Cost Category	**2011**	**2012**	**2013 - 2015**	**Total**
Material	$779	-	-	-
Labour – Internal	122	-	-	-
Labour – Contract	438	-	-	-
Engineering	133	-	-	-
Other	88	-	-	-
Total	**$1,560**	**-**	**-**	**$1,560**

Costing Methodology

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

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

Future Commitments

This is not a multi-year project.

GENERATION - THERMAL

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

Project Cost: **$268,000**

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 2011 project consists of:

1. 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 recent historical information $168,000 is required for 2011.

2. The refurbishment of the Wesleyville Gas Turbine exhaust stack at an estimated cost of $100,000. The exhaust stack was originally included with the gas turbine in 1969 when the unit was installed at the Company's facility in Salt Pond. In 1993 the exhaust stack was refurbished, including the replacement of the exhaust silencers internal to the stack. In 2003 when the gas turbine was relocated to Wesleyville, the external carbon steel surfaces were sandblasted and painted with high temperature rated paint for corrosion protection and aesthetic purposes.[1] Since the relocation to Wesleyville the 41 year old exhaust stack has undergone considerable deterioration. Much of the internal support structure for the exhaust silencers, installed in 1993, has corroded to the point of failure. To ensure the continued reliable operation of the gas turbine the internal support structure for the exhaust silencers will be replaced.

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 43.5 MW of thermal generation consisting of gas turbine and diesel units. These units are generally used to provide emergency generation, both locally and for the Island interconnected system, and to facilitate scheduled maintenance. Replacement and rehabilitation projects are identified during ongoing inspections and maintenance activities. These projects are necessary for the continued operation of thermal generation facilities in a safe, reliable and environmentally compliant manner.

[1] The exhaust stack is exposed to exhaust gases that exceed 750° Fahrenheit.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures (000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$ 149	-	-	-
Labour – Internal	30	-	-	-
Labour – Contract	15	-	-	-
Engineering	42	-	-	-
Other	32	-	-	-
Total	**$ 268**	**$302**	**$758**	**$1,328**

Costing Methodology

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

Table 2

Expenditure History (000s)

Year	2006	2007	2008	2009	2010F
Total	**-**	**$37**	**$301**	**$202**	**$150**

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.

SUBSTATIONS

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

Project Cost: **$3,074,000**

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** 2011 Substation Refurbishment and Modernization*.

The Company has 130 substations varying in age from 8 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 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures (000s)

Cost Category	2011	2012	2013 – 2015	Total
Material	$1,989	-	-	-
Labour – Internal	410	-	-	-
Labour – Contract	-	-	-	-
Engineering	593	-	-	-
Other	82	-	-	-
Total	**$3,074**	**$2,365**	**$11,116**	**$16,555**

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	**2006**	**2007**	**2008**	**2009**	**2010F**
Total	**$2,107**	**$2,364**	**$2,508**	**$4,153**	**$3,643**

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: **$2,221,000**

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 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$1,441	-	-	-
Labour – Internal	470	-	-	-
Labour – Contract	-	-	-	-
Engineering	216	-	-	-
Other	94	-	-	-
Total	**$2,221**	**$2,276**	**$7,168**	**$11,665**

Costing Methodology

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

Table 2

Expenditure History
(000s)

Year	2006	2007	2008	2009	2010F
Total	**$1,273**	**$2,134**	**$2,357**	**$2,329**	**$2,052**

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: **$4,852,000**

Project Description

This substations project includes:

1. The installation of a new 66/12.5 kV 25 MVA substation transformer at Kelligrews substation to replace the existing 15 MVA substation transformer to accommodate load growth in the Conception Bay South area. This area includes customers serviced from Kelligrews, Chamberlains and Seal Cove substations.[1] ($2,147,000)

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2. The installation of a new 66/12.5 kV 25 MVA substation transformer at Pulpit Rock substation to accommodate load growth in the Northeast St. John's area. The Northeast St. John's area includes customers serviced from Pulpit Rock (PUL), Broad Cove (BCV) and Hardwoods (HWD) substations. ($2,705,000)

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.

Details on 2011 proposed expenditures are included in ***2.2*** *2011 Additions Due to Load Growth*.

Justification

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

The least cost alternative that meets all of the technical criteria requires the installation of new 25 MVA power transformers at Kelligrews and Pulpit Rock substations.

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.

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[1] Hardwoods 25kV distribution system, which supplies the Town of Paradise, is also included in the Conception Bay South area due to its interconnection to the Chamberlains distribution system.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2011 and a projection of expenditures through 2015.

Table 1
Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$4,031	-	-	-
Labour – Internal	307	-	-	-
Labour – Contract	-	-	-	-
Engineering	430	-	-	-
Other	84	-	-	-
Total	**$4,852**	**$6,097**	**$9,405**	**$20,354**

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

This is not a multi-year project.

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

Project Cost: **$1,500,000**

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.

Details on the proposed expenditures are included in ***2.3*** *2011 PCB Removal Strategy*.

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 in accordance with subsection 17(2) of the *PCB Regulations*.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2011 and a projection of expenditures through 2015.

Table 1
Projected Cost
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$1,292	-	-	-
Labour – Internal	25	-	-	-
Labour – Contract		-	-	-
Engineering	174	-	-	-
Other	9	-	-	-
Total	**$1,500**	**3,000**	**12,000**	**$16,500**

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.

TRANSMISSION

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

Project Cost: **$4,745,000**

Project Description

This Transmission project involves:

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

   Proposed 2011 transmission line rebuilding work will take place on transmission lines 16L, 21L and 25L. Transmission line 16L operates between Kingsbridge Substation and Pepperrell Substation in the east end of the City of St. John's. Transmission line 21L is a 66 kV transmission line connecting Horsechops Plant to the Island interconnected system. Transmission line 25L operates between St. John's Main Substation and Goulds Substation in the City of St. John's.

   Details on the 2011 rebuilds are included in ***3.1** Transmission Line Rebuild* ($2,995,000).

2. The replacement of poles, crossarms, conductors, insulators and miscellaneous hardware due to deficiencies identified during inspections and engineering reviews or due to in-service and imminent failures ($1,750,000).

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

Thirty percent of the Company's 104 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 2011 and a projection of expenditures through 2011. Appendix A of ***3.1*** *Transmission Line Rebuild* details the transmission line rebuilds planned for each year.

Table 1
Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$1,674	-	-	-
Labour – Internal	457	-	-	-
Labour – Contract	2,130	-	-	-
Engineering	171	-	-	-
Other	313	-	-	-
Total	**$4,745**	**$5,150**	**$14,199**	**$24,094**

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	2006	2007	2008	2009	2010F
Total	**$4,456**	**$4,440**	**$5,236**	**$4,520**	**$9,053**[1]

1 Includes $3,138,000 approved under P.U. No. 17 (2010) for work associated with the March 2010 ice storm.

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

This is not a multi-year project.

DISTRIBUTION

Project Title: **Extensions (Pooled)**

Project Cost: **$11,568,000**

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 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures (000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$3,732	-	-	-
Labour – Internal	2,766	-	-	-
Labour – Contract	3,580	-	-	-
Engineering	1,187	-	-	-
Other	303	-	-	-
Total	**$11,568**	**$12,024**	**$39,943**	**$63,535**

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 2011.

Table 2
Expenditure History and Unit Cost Projection

Year	2006	2007	2008	2009	2010F	2011B
Total (000s)	**$11,136**	**$ 9,285**	**$10,592**	**$12,892**	**$12,251**	**$11,568**
Adjusted Cost (000s)[1]	$ 9,175[2]	$ 9,095	$11,281	$13,345	$12,251	-
New Customers	3,952	4,038	4,625	5,051	4,916	4,625
Unit Cost ($/customer)[1]	$ 2,322	$ 2,252	$ 2,439	$ 2,642	$ 2,492	$ 2,501

[1] 2010 Dollars.
[2] Excludes expenditure for extensions to cottage areas.

The project cost for the connection of new customers is calculated on the basis of historical data. Historical annual expenditures over the most recent five-year period, including the current year, are expressed in current-year dollars (“Adjusted 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: **$1,810,000**

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 2011.

Table 1
2011 Proposed Meter Acquisition

Program	Number of Meters
Energy Only Domestic Meters	16,900
Other Energy Only and Demand Meters	3,103

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.

Included in the overall meter budget is an allocation for the installation of automated meter reading ("AMR") technology. AMR meters will be installed where it is determined that the higher cost is justified by the savings provided in the *Metering Strategy* filed with the 2006 Capital Budget Application.

Included in the 2011 meter budget is a specific AMR project for the Conception Bay South, Paradise and Southlands area. This project involves the installation of approximately 2,900 new AMR meters to complete 10 meter reading routes with all AMR meters. Details on the proposed expenditure and project justification are included in ***4.3*** *2011 AMR Project*.

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 on an economic basis.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2011 and a projection of expenditures through 2015

Table 2
Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$1,551	-	-	-
Labour – Internal	167	-	-	-
Labour – Contract	92	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$1,810**	**$1,627**	**$5,107**	**$8,544**

Costing Methodology

Table 3 shows the annual expenditures for the most recent five-year period, as well as a projection for 2010.

Table 3
Expenditure History and Unit Cost Projection

Year	2006	2007	2008	2009	2010F	Avg	2011B
Meter Requirements							
New Connections	3,952	4,038	4,625	5,051	4,916		4,625
GROs/CSOs	13,371	3,546	13,691	14,188	9,730		10,906
Other	1,677	1,667	2,156	1,097	2,265		4,472
Total	19,000	9,251	20,472	20,336	16,911		20,003
Meter Costs							
Actual (000s)	$ 1,463	$ 1,154	$ 1,474	$ 1,962	$ 1,279		$ 1,810
Adjusted[1] (000s)	$ 1,711[2]	$ 1,271	$ 1,556	$ 2,016	$ 1,279		
Unit Cost[1]	$ 90[2]	$ 137	$ 76	$ 99	$ 76	$ 96	$ 90

1 2010 dollars.

2 Excludes two groups of meters which failed compliance sampling testing as required by Measurement Canada in 2006.

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 determined using historical data for retired meters and sampling results from previous years. 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: **$3,073,000**

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 2011 and a projection of expenditures through 2015.

Table 1
Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$925	-	-	-
Labour – Internal	1,705	-	-	-
Labour – Contract	149	-	-	-
Engineering	257	-	-	-
Other	37	-	-	-
Total	**$3,073**	**$3,172**	**$10,497**	**$16,742**

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 2011.

Table 2

Expenditure History and Unit Cost Projection
New Services

Year	2006	2007	2008	2009	2010F	2011B
Total (000s)	**$ 1,863**	**$ 1,949**	**$ 2,111**	**$ 2,828**	**$ 2,711**	**$ 2,595**
Adjusted Cost (000s)[1]	$ 2,139	$ 2,149	$ 2,249	$ 2,928	$ 2,711	-
New Customers	3,952	4,038	4,625	5,051	4,916	4,625
Unit Cost ($/customer)[1]	$ 541	$ 532	$ 486	$ 580	$ 551	$ 561

[1] 2010 dollars

The project cost for the connection of new customers is calculated on the basis of historical data. For *new* services, historical annual expenditures over the most recent five-year period, including the current year, are converted to current-year dollars ("Adjusted 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 2011.

Table 3

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

Year	2006	2007	2008	2009	2010F	2011B
Total	**$399**	**$472**	**$427**	**$410**	**$447**	**$478**
Adjusted Cost[1]	$458	$520	$455	$425	$447	$461

[1] 2010 dollars.

The process of estimating the budget requirement for *replacement* services is similar to that for *new* services, except the budget estimate is based on the historical average of the total cost of replacement services, as opposed to a unit cost. To ensure consistency from year to year, expenditures related to planned service replacement programs are excluded from the calculation of the historical average.

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

Future Commitments

This is not a multi-year project.

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

Project Cost: **$2,195,000**

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 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$1,189	-	-	-
Labour – Internal	782	-	-	-
Labour – Contract	169	-	-	-
Engineering	32	-	-	-
Other	23	-	-	-
Total	**$2,195**	**$2,267**	**$7,380**	**$11,842**

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 2010.

Table 2

**Expenditure History and Unit Cost Projection
New Street Lights**

Year	2006	2007	2008	2009	2010F	2011B
Total (000s)	**$ 1,131**	**$ 977**	**$ 1,315**	**$ 1,805**	**$ 1,651**	**$ 1,428**
Adjusted Cost (000s)[1]	$ 869	$ 1,077	$ 1,396	$1,863	$ 1,651	
New Customers	3,952	4,038	4,625	5,051	4,916	4,625
Unit Cost ($/cust.)[1]	$ 220	$ 267	$ 302	$ 369	$ 343	$ 309

[1] 2010 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 2011.

Table 3

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

Year	2006	2007	2008	2009	2010F	2011B
Total	**$ 451**	**$ 1,112**	**$ 692**	**$ 683**	**$ 677**	**$ 767**
Exclusions[1]	-	140	-	-	-	-
Adjusted Cost[2]	$ 523	$ 1,071	$ 735	$ 705	$ 677	$ 742

[1] Exclusions in 2007 reflect the Company's replacement of underground wiring for streetlights in the St. John's area at a cost of $140,000.

[2] 2010 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: **Replace Mercury Vapour Street Lights (Pooled)**

Project Cost: **$581,000**

Project Description

In 2011 this Distribution project will be in the third year of a 3 year project to replace existing Mercury Vapour ("MV") street light fixtures with the more energy efficient High Pressure Sodium ("HPS") fixtures.

At the beginning of 2009 there were approximately 7,000 MV street lights in service. Work completed in 2009 and year to date 2010 has resulted in 37% of the MV street lights being replaced. By the end of 2010 it is forecast that 59% of MV street lights will have been replaced, leaving 41% to be replaced in the final year of the project.

This project proposes to replace the remaining 41% of MV street lights in 2011. The project is principally driven by the energy savings realized by the replacement of the MV street lights with a HPS street light. Collectively, replacing the original 7,000 MV street lights have the potential to reduce the energy consumption attributable to street lighting by 2,184 MWh on an annual basis

Details on the proposed expenditures were included in the 2009 Capital Budget Application in report ***4.2*** *Energy Efficient Street Lights*.

Justification

Replacing the 7,000 MV street lights over the 3 year period as proposed will reduce both power purchase and maintenance cost associated with these street lights. The economic analysis completed in report ***4.2*** *Energy Efficient Street Lights* included with the 2009 Capital Budget Application indicates that the project as proposed provides approximately $626,000 in net benefit over the next 20 years when compared to the current practice of replacing street lights through normal attrition. The levelized cost of energy for this project is 5.65¢ per kWh. [1]

[1] In the 2009 Capital Budget the cost of electricity from the Holyrood thermal generating station is estimated at 10.63¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $67.00 per barrel as of March 31, 2008.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures (000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$290	-	-	-
Labour – Internal	233	-	-	-
Labour – Contract		-	-	-
Engineering	29	-	-	-
Other	29	-	-	-
Total	**$581**	**-**	**-**	**$581**

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: **Transformers (Pooled)**

Project Cost: **$7,999,000**

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 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures (000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$7,999	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$7,999**	**$7,783**	**$24,318**	**$40,100**

Costing Methodology

Table 2 shows the annual expenditures for the most recent five-year period, as well as an estimate for 2011.

Table 2

Expenditure History and Budget Estimate (000s)

Year	**2006**	**2007**	**2008**	**2009**	**2010F**	**2011B**
Total	**$5,643**	**$6,992**	**$8,545**	**$6,909**	**$7,668**	**$7,999**
Adjusted Cost[1]	$6,624	$7,699	$9,004	$7,089	$7,668	

[1] 2010 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: **$3,609,000**

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 be deferred 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 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures (000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$854	-	-	-
Labour – Internal	1,453	-	-	-
Labour – Contract	814	-	-	-
Engineering	365	-	-	-
Other	123	-	-	-
Total	**$3,609**	**$3,729**	**$11,950**	**$19,288**

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 2010.

Table 2
Expenditure History and Budget Estimate
(000s)

Year	**2006**	**2007**	**2008**	**2009**	**2010F**	**2011B**
Total	**$2,989**	**$3,563**	**$3,193**	**$4,123**	**$4,421**[2]	**$3,609**
Adjusted Cost[1]	$3,273	$3,243	$3,275	$4,268	4,421	

1 2010 dollars.
2 Includes $1,062,000 for the March storm on the East coast.

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

Project Cost: **$3,088,000**

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.

The work for 2011 includes 43 of the Company's 303 feeders. A listing of the feeders upon which work is proposed for 2011 follows:

GAL-04	SCR-02	HWD-06	MOL-08	CAR-02	GOU-03
GAL-05	WAL-04	HWD-07	MOL-09	SCT-02	MOL-06
HAR-02	WAL-05	KBR-04	OXP-01	SPF-02	LET-01
LEW-01	GAN-01	MOL-01	SLA-02	SPF-03	TRP-01
LEW-03	GAN-02	MOL-02	SLA-03	GAR-01	HGR-01
LEW-04	GBY-03	MOL-04	TWG-02	GRH-01	CAT-03
MMT-01	GLV-01	MOL-05	CLV-03	GRH-03	MSY-02
SCR-01					

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

Justification

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

The Company has over 8,800 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 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures (000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$1,491	-	-	-
Labour – Internal	1,251	-	-	-
Labour – Contract	177	-	-	-
Engineering	23	-	-	-
Other	146	-	-	-
Total	**$3,088**	**$3,182**	**$10,127**	**$16,397**

Costing Methodology

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

Table 2

Expenditure History (000s)

Year	2006	2007	2008	2009	2010F
Total	**$2,811**	**$3,249**	**$3,566**	**$1,608**	**$3,632**

Distribution feeders are inspected in accordance with Newfoundland Power's distribution inspection standards to identify deficiencies that are a risk to public or employee safety, or that are likely to result in imminent failure of a structure or hardware. This includes primary components such as poles, crossarms and conductor and specific items such as the following:

a) Deficiencies that are a risk to public or employee safety, or that are likely to result in imminent failure of a structure or hardware;
b) Locations where lightning arrestors are required as observed in the *2003 Lightning Arrestor Review*;[1]

[1] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment B for further details on lightning arrestor requirements.

c) Locations where CP8080 and 2-piece insulators still exist. These insulators have a history of failure;[2]
d) Locations where current limiting fuses are required in accordance with the internal memo dated January 11, 2000;[3] and
e) Hardware for which a high risk of failure has been identified, such as automatic sleeves and porcelain cutouts.[4]

The budget estimate is based on engineering estimates of individual rebuild 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.

2 See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment C for further details on problem insulators.
3 See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment D for further detail on current limiting fuse requirements.
4 See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment E and Attachment F for further detail on automatic sleeves and porcelain cutouts.

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

Project Cost: **$782,000**

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 Aliant, Persona 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 2011 and a projection of expenditures through 2015.

Table 1
Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$274	-	-	-
Labour – Internal	250	-	-	-
Labour – Contract	164	-	-	-
Engineering	80	-	-	-
Other	14	-	-	-
Total	**$782**	**$809**	**$2,600**	**$4,191**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	**2006**	**2007**	**2008**	**2009**	**2010F**
Total	**$1,801**	**$1,604**	**$1,585**	**$2,077**	**$1,785**
Adjusted Cost[1]	$802[2]	$570[3]	$591[4]	$877[5]	$685[6]

[1] 2010 dollars.
[2] Excludes $999,000 for Eastlink cross island project.
[3] Excludes $1,034,000 for Eastlink cross island project.
[4] Excludes $994,000 for Eastlink cross island project.
[5] Excludes $600,000 for Eastlink cross island project.
[6] Excludes $1,100,000 for Eastlink local phone service.

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.

To ensure consistency from year to year, expenditures related to past extraordinary requirements are excluded from the calculation. For example, four exclusions for work completed for Eastlink are identified in the notes to Table 2. For these projects, costs less betterment were recovered from Eastlink.

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: **Distribution Reliability Initiative (Other)**

Project Cost: **$521,000**

Project Description

This Distribution project involves the replacement of deteriorated poles, conductor and hardware to reduce both the frequency and duration of power interruptions to the customers served by specific distribution lines. The nature of the upgrading work follows from a detailed assessment of past service problems, knowledge of local environmental conditions (such as salt contamination and wind and ice loading), and engineering knowledge to apply location specific design and construction standards. Options are evaluated to improve reliability performance and project plans are subsequently developed from an engineering analysis.

The 2011 project involves continuation of work on feeder NWB-02 included in the Distribution Reliability Initiative ("DRI") from 2009.

Table 1 shows, for this feeder, the number of customers affected and the average unscheduled distribution interruption statistics for the five-year period ending December 31, 2009. These SAIFI[6] and SAIDI[7] statistics exclude planned power interruptions and interruptions due to all causes other than distribution system failure. An analysis of this feeder is contained in report ***4.1*** *Distribution Reliability Initiative*.

Table 1

Distribution Interruption Statistics
5-Years to December 31, 2009

Feeder	Number of Customers	Distribution SAIFI	Distribution SAIDI
North West Brook (NWB-02)	1,041	2.72	4.80
Company Average	**-**	**1.18**	**2.18**

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6 System Average Interruption Frequency Index (SAIFI) calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area. Distribution SAIFI records the average number of outages related to distribution system failure.

7 System Average Interruption Duration Index (SAIDI) is calculated by dividing the number of customer-outage-hours (e.g., a two hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area. Distribution SAIDI records the average hours of outage related to distribution system failure.

Justification

This project is justified on the basis of the obligation to provide reliable electrical service. Customers supplied by this feeder experience power interruptions more often, or of longer duration, than the Company average.

The distribution reliability initiative project has had a positive impact on the reliability performance of the feeders that have been upgraded.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2011 and a projection of expenditures through 2015.

Table 2
Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$251	-	-	-
Labour – Internal	211	-	-	-
Labour – Contract	30	-	-	-
Engineering	4	-	-	-
Other	25	-	-	-
Total	**$521**	**$500**	**$1,589**	**$2,610**

Costing Methodology

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

Table 3
Expenditure History
(000s)

Year	2006	2007[1]	2008	2009	2010F
Total	**$3,365**	**-**	**$1,411**	**$455**	**$447**

[1] The Distribution Reliability Initiative was suspended in 2007 in light of the Rattling Brook project.

The budget estimate is based on detailed engineering estimates of individual feeder upgrade 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: **St. John's Trunk Feeders (Clustered)**

Project Cost: **$160,000**

Project Description

This Distribution project consists of the relocation of a section of St. John's feeder PEP-01 from structures on transmission line 16L. 16L is a 66 kV transmission line running between King's Bridge Substation on King's Bridge Road and Pepperell Substation. Constructed in 1950, it is located in St. John's near Quidi Vidi Lake and runs alongside the Boulevard and King's Bridge Road.

The line is 1.98 kilometres in length and is single pole construction. The transmission line consists of 50 structures, 43 of which have distribution sharing the same poles, and many of which provide street lighting to the Boulevard.

The rebuild of transmission line 16L is planned for completion in 2011 with the distribution feeder rebuild completed at the same time.

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 (60 years old) and have surpassed their normal life expectancy. As well, much of the structure guying on 16L 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.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures (000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$44	-	-	-
Labour – Internal	86	-	-	-
Engineering	15	-	-	-
Other	15	-	-	-
Total	**$160**	**-**	**-**	**$160**

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: **$1,281,000**

Project Description

This Distribution project consists of the following 3 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 a new feeder originating at Pulpit Rock substation.

2. The increase in capacity of existing feeders for future growth in the St. John's downtown.

3. The upgrading of sections of single-phase distribution lines to three phase distribution lines to allow for balanced load growth on selected feeders

The increase in commercial and residential customer growth on the Northeast Avalon Peninsula has resulted in the need for a new feeder, and additional capacity in downtown St. John's. Also, as new subdivisions grow the original single phase distribution lines need to be upgraded to three phase distribution lines to ensure the customer load can be restored reliably under winter conditions

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.

Forecast and 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 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$499	-	-	-
Labour – Internal	209	-	-	-
Labour – Contract	377	-	-	-
Engineering	91	-	-	-
Other	105	-	-	-
Total	**$1,281**	**$1,030**	**$3,373**	**$5,684**

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: **$175,000**

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 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	-	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering		-	-	-
Other	175	-	-	-
Total	**$175**	**$179**	**$559**	**$913**

Costing Methodology

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

Table 2
Expenditure History and Budget Estimate
(000s)

Year	2006	2007	2008	2009	2010F
Total	$78	$77	$176	$172	$153

The increase in AFUDC since 2008 reflects methodological changes resulting from adoption of the asset rate base method for calculating rate base. This methodology was accepted in Order No. P.U. 32 (2007).

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: **$508,000**

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 ($125,000)*: 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 productivity and working conditions.

2. *Engineering Tools and Equipment ($200,000)*: This item includes engineering test equipment, tools and substation portable grounds 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 ($83,000)*: 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 ($100,000):* This item involves the purchase of grounding sticks for approximately 30 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]

[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 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures (000s)

Cost Category	**2011**	**2012**	**2013 – 2015**	**Total**
Material	$508	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$508**	**$517**	**$1,452**	**$2,477**

Costing Methodology

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

Table 2

Expenditure History (000s)

Year	**2006**	**2007**	**2008**	**2009**	**2010F**
Total	**$659**	**$617**	**$673**	**$384**	**$389**

The project cost is based on an assessment of historical expenditures for the replacement of tools and equipment that become broken or worn out, and is adjusted for anticipated expenditure requirements for extraordinary items. Historical expenditures in recent years have included items such as thermo scan cameras and arc flash equipment. A recent review of tool and equipment inventories indicates that future expenditures will be in line with the 2 most recent years expenditures which is less than the 5 year historical average.

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: **$224,000**

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 2011 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 $224,000 is required for 2011. 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 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$179	-	-	-
Labour – Internal	11	-	-	-
Labour – Contract	11	-	-	-
Engineering	12	-	-	-
Other	11	-	-	-
Total	**$224**	**$229**	**$715**	**$1,168**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2006	2007	2008	2009	2010F
Total	$150	$165	$244	$244	$225

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: **Kenmount Road Building 2nd Floor HVAC (Other)**

Project Cost: **$435,000**

Project Description

The Kenmount Road office building was built in 1968 as a two storey structure. The original building consisted of what are now the basement and first floor of the existing building. In 1979 two additional floors were added to the building with each floor having its own air-handling system.

This General Property project includes the replacement of the 2nd floor heating, ventilating and air conditioning ("HVAC") equipment. The HVAC system servicing the 2nd floor was installed during the 1979 construction and is 31 years old.

In April 2006 Newton Engineering completed an analysis of the HVAC systems at Kenmount Road building. This analysis was filed as part of the 2007 Capital Budget Application in support of a project to replace the HVAC systems in the basement and first floor. In the 2010 Capital Budget Application the Company included a project to replace the 3rd floor HVAC system.[2]

This 2011 project will complete the replacement of the HVACs systems for all floors of the Kenmount Road building.

Justification

The project is justified on the age and the deterioration of the existing HVAC equipment.

The condition of the HVAC equipment is such that repairs will not extend the life of the systems any further.

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[2] The April 2006 Newton Engineering report pertaining to the HVAC systems at the Kenmount Road building was originally submitted as Appendix A of report *4.1 HVAC System Replacement* included with the 2007 Capital Budget Application. In the response to CA-NP-43 of the 2010 Capital Budget Application the original April 2006 report was included as Attachment A. Attachment B of the same RFI included a June 2009 review of the 2nd and 3rd floor HVAC systems completed by the same engineer that authored the 2006 report.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$390	-	-	-
Labour – Internal	15	-	-	-
Labour – Contract	-	-	-	-
Engineering	30	-	-	-
Other	-	-	-	-
Total	**$435**	**-**	**-**	**$435**

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: **Kenmount Road Building Flooring Replacement (Other)**

Project Cost: **$150,000**

Project Description

The Kenmount Road office building was built in 1968 as a two storey structure. An additional two floors were added in 1979. At the present time the Kenmount Road building accommodates approximately 175 employees.

The majority of the building is used for general office space. The basement floor has an area of approximately 1,348 square metres while the remaining floors have an area of 1,172 square metres. Most of the floors are covered with carpet tiles.

The replacement of the approximately 2,300 square metres of carpet tiles on the 1st and 3rd floors is required. The carpet has deteriorated as a result of normal wear and tear, with traffic patterns and staining clearly visible. Carpet on the 1st floor is 16 years old while carpet on the 3rd floor is 22 years old.

Justification

The replacement of the existing carpet is justified on the basis of its age and deterioration.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2011 and a projection of expenditures through 2015.

Table 1
Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$80	-	-	-
Labour – Internal	5	-	-	-
Labour – Contract	60	-	-	-
Engineering	5	-	-	-
Other	-	-	-	-
Total	**$150**	**-**	**-**	**$150**

Costing Methodology

The budget estimate for this project is comprised of engineering estimates for material at \$35 m^2 and installation at \$25 m^2. Included in the installation cost is the work involved in disassembly and reassembly of office cubicles to accommodate the installation of the carpet tiles.

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: **Kenmount Road Building Entrance Renovation (Other)**

Project Cost: **$125,000**

Project Description

The Kenmount Road office building was built in 1968 as a two storey structure. The main entrance and lobby facing Kenmount Road provides access to the building for employees, contractors and customers. The entrance, lobby and underlying concrete of the front step are original to the 1968 construction and are in need of refurbishment.

The current sliding entrance doors were installed in 1968 and require replacement. The door frames and tracks are corroded causing the doors to frequently malfunction and often remain partially open during windy conditions. A filling compound has been used to patch severely corroded areas. During the winter months, considerable heat loss occurs as a result of the doors remaining partially open as well as through the normal operation of the doors. A weather tight seal is no longer present between the doors and their frames as there is a visible air gap between them on the sides and bottom. Water ingress has required the walls in the area of the entrance to be repaired.

Leading up to the building entrance is the original large concrete exterior step and landing with an integrated ramp to allow wheelchair and freight access to the building. The steps and landing were refurbished most recently in 2004 with a polymer coating. This coating requires annual maintenance to repair cracks and chips that are caused by deterioration from de-icing materials as well as the movement and deterioration of the underlying original concrete. The project involves the removal of the existing landing and steps and replacement with a smaller set of steps.

The hand railing was installed in the early 1980's and is heavily corroded, particularly around the mounting plates that secure the railing to the concrete step. Annual painting is required to keep the railing in a presentable condition. The railing is becoming a hazard as several rail posts are corroded through. The railing needs to be replaced at the same time as the concrete exterior step.

Replacement of the entrance door system will necessitate minor renovations to the ceiling, walls and flooring of the building lobby.

See Attachment A for photographs of deteriorated areas.

Justification

The renovation of the Kenmount Road building entrance is justified on the basis of its age and level of deterioration. Recent inspections have concluded that the building's main entrance, including the entrance door system, concrete step and hand railings have reached the point where continued maintenance is no longer feasible.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures (000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$80	-	-	-
Labour – Internal	15	-	-	-
Labour – Contract	20	-	-	-
Engineering	10	-	-	-
Other	-	-	-	-
Total	**$125**	-	-	**$125**

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.

Attachment A – Photographs

Figure 1 – Repairs to corroded door frame.

Figure 2 – Air gap between door and frame.

Figure 3 – Annual chipping and cracks from deteriorated underlying concrete.

Figure 4 – Completely corroded railing support post.

Figure 5 – Deteriorated concrete step.

Figure 6 – Damaged handrail.

Project Title: **Bill Inserter for Production Centre (Other)**

Project Cost: **$350,000**

Project Description

This General Property project is required for the replacement of the bill inserter in the production centre that has reached the end of its useful life.

An inserter is a device that assembles documents for insertion into envelopes. The production centre uses the inserter to assemble customers' monthly bills, other correspondence and return envelopes, and to insert the documents into an envelope for mail out. The bill inserter determines which documents are required for insertion in each customer envelope based upon a coded strip printed on the edge of the customer bill. Envelopes are then sorted according to Canada Post specifications for mailing.

The bill inserter is an essential piece of equipment for the timely delivery of customers' monthly bills and other correspondence.

Justification

This project is justified on the basis of the existing equipment's age and the discontinuation of vendor support.

The existing inserter was installed in 1999 and has been in use for 11 years.[3] The vendor no longer provides software support for this equipment and has discontinued manufacturing replacement parts. This unit has required service to repair or replace parts several times per month in the past year. Supply of replacement parts is expected to cease in 2011.

On a monthly basis, the inserter in the Company's production centre typically inserts over 750,000 pieces of print material to produce approximately 250,000 mailings. This project is necessary to ensure this material is processed on a timely basis and delivered to Canada Post in a manner suitable for distribution to customers.

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[3] The bill inserter purchased in 1999 was a refurbished unit supplied by the original equipment manufacturer.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures (000s)

Cost Category	2011	2012	2013 – 2015	Total
Material	$350	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$350**	-	-	**$350**

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: **$2,254,000**

Project Description

This Transportation project involves the 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 lists the units to be acquired in 2011.

Table 1
2011 Proposed Vehicle Replacements

Category	No. of Units
Heavy fleet vehicles[1]	6
Passenger vehicles[2]	26
Off-road vehicles[3]	6
Total	**38**

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

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 2011 and a projection of expenditures through 2015.

Table 2

Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$2,254	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$2,254**	**$2,374**	**$7,426**	**$12,054**

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

Table 3

Expenditure History
(000s)

Year	2006	2007	2008	2009	2010F
Total	**$2,751**	**$2,231**	**$2,384**	**$2,087**	**$2,352**

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: **$146,000**

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 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$139	-	-	-
Labour – Internal	7	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$146**	**$149**	**$468**	**$763**

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	**2006**	**2007**	**2008**	**2009**	**2010F**
Total	**$173**	**$110**	**$96**	**$105**	**$135**
Adjusted Cost[1]	$203	$121	$101	$108	$135

[1] 2010 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 planned projects are excluded from the calculation of the historical average.

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

Future Commitments

This is not a multi-year project.

Project Title: **Fibre Optic Circuit Replacement (Other)**

Project Cost: **$426,000**

Project Description

This Telecommunications project involves the replacement of leased and rented fibre optic communication circuits with fibre optic cables owned and maintained by Newfoundland Power.

The Company has 32 fibre optic systems in service which are a mix of owned, leased and rented facilities.

Newfoundland Power completed an engineering review of these fibre optic communication circuits for the 2008 Capital Budget Application. Over the period from 2008 to 2011, third party lease and rental agreements were expiring on 16 fibre optic cables and new agreements for ten year terms would otherwise need to be established. Details of the engineering review are found in report ***5.1*** *Fibre Optic Circuit Replacement* included in the 2008 Capital Budget Application.

2011 will be the final year of the 4 year program to replaced leased fibre optic circuits. In 2008 and 2009 the Company replaced 6 leased fibre optic circuits. In 2010 there are 5 leased fibre optic circuits identified for replacement, leaving 5 leased fibre optic circuits for replacement in 2011.

Justification

Reliable communications equipment is essential to the provision of safe, reliable electrical service. Replacement of rented facilities with Newfoundland Power owned fibre optic cables is justified by the positive Net Present Value analysis provided in ***5.1*** *Fibre Optic Circuit Replacement* included in the 2008 Capital Budget Application.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2011 and a projection of expenditures through 2015.

Table 1
Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	$376	-	-	-
Labour – Internal	3	-	-	-
Labour – Contract	-	-	-	-
Engineering	40	-	-	-
Other	7	-	-	-
Total	**$426**	**-**	**-**	**$426**

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: **$983,000**

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 reliability of the electrical system and compliance with regulatory and financial reporting requirements.

The application enhancements proposed in 2011 include Meter Reading Improvements, Electrical Engineering Software enhancements, Work Dispatch Improvements, Customer Service Internet and Energy Conservation Website enhancements.

The application enhancements proposed for 2011 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 ***5.1*** *2011 Application Enhancements*.

Justification

Some of the proposed enhancements included in this project are justified on the basis of improving customer service. Some will result in increased operational efficiencies. Some projects will have a positive impact on both customer service and operational efficiency.

Cost benefit analyses, where appropriate, are provided in ***5.1*** *2011 Application Enhancements*.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures (000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	60	-	-	-
Labour – Internal	674	-	-	-
Labour – Contract	-	-	-	-
Engineering	44	-	-	-
Other	205	-	-	-
Total	**$983**	**$1,000**	**$3,575**	**$5,558**

Costing Methodology

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

Table 2

Expenditure History (000s)

Year	2006	2007	2008	2009	2010F
Total	**$1,540**	**$1,353**	**$1,485**	**$1,444**	**$937**

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: **$808,000**

Project Description

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

For 2011, the project includes upgrades to the Customer Service System, Meter Equipment System and Transmission and Distribution Mobile Application.

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 D* of the 2009 Capital Budget.

Details on proposed expenditures are included in ***5.2*** *2011 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 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures (000s)

Cost Category	2011	2012	2013 – 2015	Total
Material	$200	-	-	-
Labour – Internal	508	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	100	-	-	-
Total	**$808**	**$1,425**	**$3,425**	**$5,658**

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	2006	2007	2008	2009	2010F
Total	**$1,017**	**$679**	**$668**	**$630**	**$1,038**

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 2009 through 2011 inclusive, which was approved as part of the 2009 Capital Budget application.

This is not otherwise a multi-year project.

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

Project Cost: **$390,000**

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 2011, a total of 118 PCs will be purchased, consisting of 76 desktop computers and 42 laptop computers. Twenty of these laptops are required for the Vehicle Mobile Computing Infrastructure project in 2011, and their cost is included in that project. 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 2009 and 2010, as well as the proposed additions and retirements for 2011.

Table 1
PC Additions and Retirements
2009 – 2011

	2009			**2010F**			**2011B**		
	Add	**Retire**	**Total**	**Add**	**Retire**	**Total**	**Add**	**Retire**	**Total**
Desktop	91	96	466	94	102	458	76	76	458
Laptop	82[1]	28	221	61[1]	26	256	42[1]	22	276
Total	**173**	**124**	**687**	**155**	**128**	**714**	**118**	**98**	**734**

[1] In 2009, 25 ruggedized laptop computers were added related to the Vehicle Mobile Computing Infrastructure project. In 2010, an additional 35 ruggedized laptop computers are forecast for that project. In 2011, an additional 20 ruggedized laptop computers are budgeted.

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 2011 and a projection of expenditures through 2015.

Table 2
Projected Expenditures
(000s)

Cost Category	2011	2012	2013 – 2015	Total
Material	$223	-	-	-
Labour – Internal	67	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	100	-	-	-
Total	**$390**	**$410**	**$1,325**	**$2,125**

Costing Methodology

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

Table 3
Expenditure History
(000s)

Year	2006	2007	2008	2009	2010F
Total	**$380**	**$409**	**$415**	**$459**	**$430**

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: **$1,092,000**

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 2011, the project includes the replacement of servers that are at end of their useful lives, as well as server infrastructure required to ensure the security of customer and corporate information. This project also includes the purchase of the replacement of the disk storage used to manage the Customer Service System databases and other corporate information.

The shared server infrastructure requirements for 2011 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 ***5.3*** *2011 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 2011 and a projection of expenditures through 2015.

Table 1

Projected Expenditures
(000s)

Cost Category	2011	2012	2013 – 2015	Total
Material	$705	-	-	-
Labour – Internal	272	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	115	-	-	-
Total	**$1,092**	**$800**	**$2,600**	**$4,492**

Costing Methodology

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

Table 2

Expenditure History
(000s)

Year	2006	2007	2008	2009	2010F
Total	**$493**	**$883**	**$903**	**$632**	**$660**

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: **$152,000**

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 2011, this project includes the purchase and implementation of network equipment to replace components that have reached the end of useful life and to provide additional network redundancy.

The individual network infrastructure requirements for 2011 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 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 2011 and a projection of expenditures through 2015.

Table 1
Projected Expenditures
(000s)

Cost Category	2011	2012	2013 – 2015	Total
Material	$103	-	-	-
Labour – Internal	49	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$152**	**$180**	**$545**	**$877**

Costing Methodology

Table 2 shows the annual expenditures for this project for the most recent five-year period. No Network Infrastructure expenditures were required in 2006 and 2007.

Table 2
Expenditure History
(000s)

Year	2006	2007	2008	2009	2010F
Total	**-**	**-**	**$162**	**$115**	**$153**

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

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

Future Commitments

This is not a multi-year project.

Project Title: **Vehicle Mobile Computing Infrastructure (Pooled)**

Project Cost: **$178,000**

Project Description

This Information Systems project is necessary to provide mobile computing infrastructure in Company vehicles. 2011 is the third year of a 3 year project to install mobile computers in 80 Company vehicles.[2]

In 2011, 20 ruggedized laptop computers will be purchased and deployed in Company vehicles used by field staff. This project also covers the supporting equipment required to properly install the computers in the vehicles such as ergonomic mounting hardware, and communications equipment.

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

The report ***5.4*** *Vehicle Mobile Computing* has been prepared updating the status of the Vehicle Mobile Computing Infrastructure project.

Justification

This project will improve customer service and operational effectiveness. As well, this project is justified on the basis of ensuring compliance and ongoing adherence to safety and environmental standards and processes in use by the Company.

[2] Board Order P.U. 27 (2008) approved the installation of 25 mobile computers in Company vehicles as part of the 2009 Capital Budget Application. Board Order P.U. 41 (2009) approved the installation of 35 mobile computers in Company vehicles as part of the 2010 Capital Budget Application.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2011 and a projection of expenditures through 2015.

Table 1
Projected Expenditures (000s)

Cost Category	2011	2012	2013 – 2015	Total
Material	$110	-	-	-
Labour – Internal	58	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	10	-	-	-
Total	**$178**	**-**	**-**	**$178**

Costing Methodology

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

Table 2
Expenditure History (000s)

Year	2006	2007	2008	2009	2010F
Total	**-**	**-**	**-**	**$289**	**$272**

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.

UNFORESEEN ALLOWANCE

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

Project Cost: **$750,000**

Project Description

This Unforeseen Allowance 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.

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.

To ensure the projects to which the proposed expenditures are applied are completed at the lowest possible cost consistent with safe and reliable service, all material and contract labour will be obtained through competitive tendering.

Future Commitment

This is not a multi-year project.

GENERAL EXPENSES CAPITALIZED

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

Project Cost: **$2,800,000**

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.
2011 Capital Budget
Future Required Expenditures

Improvement to Property	Estimated Annual Expenditure	Timing
Microsoft Enterprise Agreement[1]	$200,000	3 Years: 2009 through 2011

1 This is a multi-year project approved in Order No. P.U. 27(2008)

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

	2009	2008
Net Plant Investment		
Plant Investment	1,338,408	1,286,039
Accumulated Amortization	(562,009)	(539,654)
Contributions in Aid of Construction	(29,017)	(25,884)
	747,382	720,501
Additions to Rate Base		
Deferred Charges	103,761	100,321
Deferred Energy Replacement Costs	383	766
Cost Recovery Deferral – Hearing Costs	201	402
Cost Recovery Deferral - Depreciation	3,862	7,724
Cost Recovery Deferral - Conservation	948	-
Customer Finance Programs	1,679	1,776
Weather Normalization Reserve	3,919	5,910
	114,753	116,899
Deductions from Rate Base		
Municipal Tax Liability	1,363	2,727
Unrecognized 2005 Unbilled Revenue	4,618	9,236
Customer Security Deposits	581	785
Accrued Pension Obligation	3,379	3,142
Future Income Taxes	2,297	1,184
Demand Management Incentive Account	-	426
Purchased Power Unit Cost Variance Reserve	447	895
	12,685	18,395
Year End Rate Base	849,450	819,005
Average Rate Base Before Allowances	834,228	806,833
Rate Base Allowances		
Materials and Supplies Allowance	4,366	4,327
Cash Working Capital Allowance	9,899	9,716
Average Rate Base at Year End	848,493	820,876

2011 Capital Plan

June 2010

Table of Contents

1.0 Introduction

Newfoundland Power's 2011 Capital Plan provides an overview of the Company's 2011 Capital Budget together with an outlook for capital expenditure through 2015.

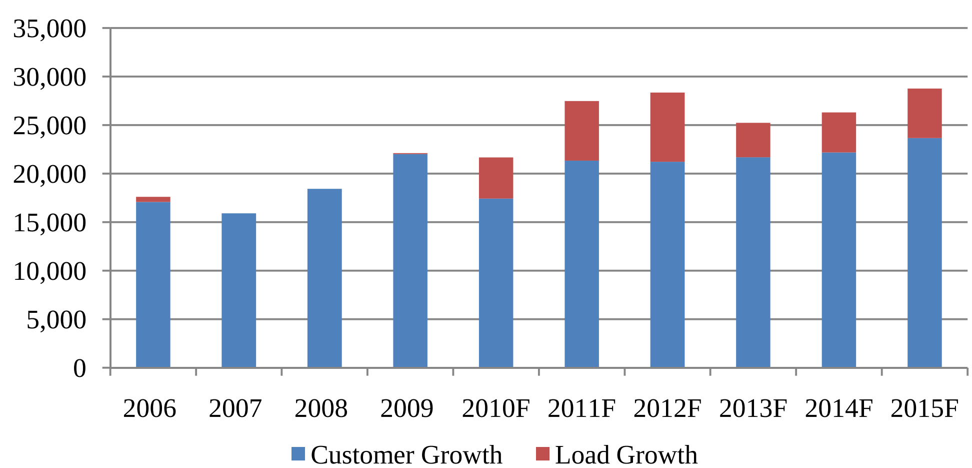
Newfoundland Power's 2011 Capital Budget totals $72,969,000.

Over the next five years, the Company plans to invest approximately $396 million in plant and equipment. The need for greater system capacity over the next 5 years in addition to federal regulatory changes and a directive from the Government of Canada will increase forecast capital expenditures through 2015.

Approximately 51% of planned expenditures through 2015 focus on the replacement of deteriorated or defective generation, transmission, substation and distribution electrical equipment. Capital expenditures related to customer and sales growth ("Customer Growth Capital") are forecast to comprise approximately 34% of capital expenditures through 2015, compared to an average of 30% in the previous 5 years.

Chart 1 shows Newfoundland Power's Customer Growth Capital[1] for the years 2006 to 2015F.

Chart 1
Customer Growth Capital[2]
2006 to 2015F
($000)



[1] Customer Growth Capital is the portion of Newfoundland Power's annual capital investment related to customer and sales growth. The level of Customer Growth Capital reflects a number of factors. One is an increase in the number of customers that Newfoundland Power serves. Another is an increase in the amount of electricity delivered by Newfoundland Power to its customers.

[2] Customer Growth includes those expenditures necessary to provide service to new customers connecting to the electricity system. Load Growth includes those expenditures necessary to expand the capacity of the electricity system to accommodate the additional load required for the new customers.

Over the next 5 years, Customer Growth Capital is forecast to include necessary investment to increase system capacity to serve increasing customer electricity requirements.

Compliance with federal regulation governing a number of aspects of Newfoundland Power's operations has influence on the Capital Plan. This includes regulation of PCBs, fisheries, and, likely, electricity metering.

The Capital Plan includes two specific projects that are required to ensure compliance with federal regulation. They are the $16.5 million PCB Bushing Phase Out project and a $4.5 million expenditure to provide for fish passage at Rattling Brook.

In September 2008, new *PCB Regulations* came into effect accelerating the elimination of PCBs from electrical equipment in Canada. Newfoundland Power has developed a plan to ensure compliance with the *PCB Regulations* by December 31, 2014.[3] A detailed description of the 2011 project to ensure compliance with the *PCB Regulations* can be found in ***2.3** PCB Removal Strategy*.

Since 2005, Newfoundland Power has been engaged in ongoing discussions with the Department of Fisheries and Oceans ("DFO") on the requirement to provide fish passage for atlantic salmon at the Rattling Brook hydroelectric facility. Based on studies completed with DFO, the Company has included a $4.5 million project in 2012 to design and construct facilities to allow atlantic salmon to access the Rattling Lake watershed.

Measurement Canada intends to introduce new compliance sampling regulations for electricity meters. The new compliance sampling requirements are anticipated to be significantly different from those currently in place. For example, the test sample sizes and meter seal extension periods are changing. Measurement Canada's consultation period for the regulation changes closed on March 31, 2010. It is anticipated that the new regulations will come into effect within the next year. New compliance sampling regulations for electricity meters could significantly impact the cost of managing meter replacement in the years immediately following the adoption of any new regulations.

As the extent and timing of any changes are currently uncertain, Newfoundland Power has not included any amount in this Capital Plan in respect of possible changes in federal regulation of electricity metering.

Federal regulatory requirements will have the effect of increasing capital budgets in the forecast period. The Company is working with the respective government departments, other utilities and

[3] The Company sought and was granted an end-of-use extension to December 31, 2014 for all bushings and instrument transformers where the PCB concentrations are unknown or at 500 mg/kg or more as allowed under Section 17(2) of the *PCB Regulations*. One of the conditions for granting the end-of-use extension was that Newfoundland Power undertake a plan to address all outstanding equipment that did not meet the *PCB Regulations*. Newfoundland Power, with other utilities and the Canadian Electricity Association, has been working with Environment Canada for a more gradual phase out of PCBs in electrical equipment.

the Canadian Electricity Association to minimize the impacts of these proposed changes on our customers.[4]

2.0 2011 Capital Budget

Newfoundland Power's 2011 capital budget is $72,969,000.

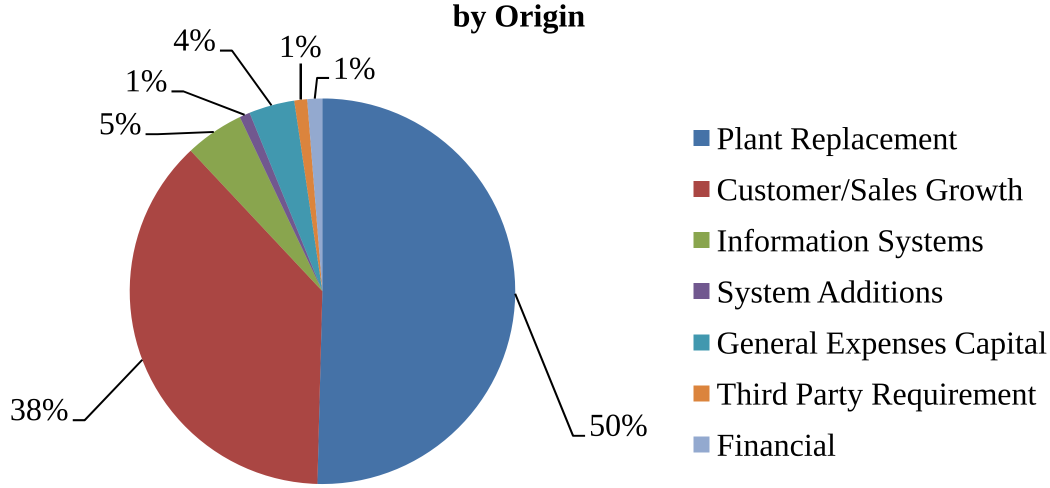
This section of the 2011 Capital Plan provides an overview of the 2011 capital budget by origin (root cause) and asset class. In addition, this section summarizes 2011 capital projects by the various categories set out in the Board's October 2007 Capital Budget Application Guidelines.

2.1 2011 Capital Budget Overview

Newfoundland Power's 2011 capital budget contains 41 projects totalling $73.0 million. From 2006 to 2010, the Company's annual capital program averaged $66.9 million in a range of $58.6 million to $74.3 million.

Chart 2 shows the 2011 capital budget by origin, or root cause.

Chart 2
2011 Capital Expenditures
by Origin



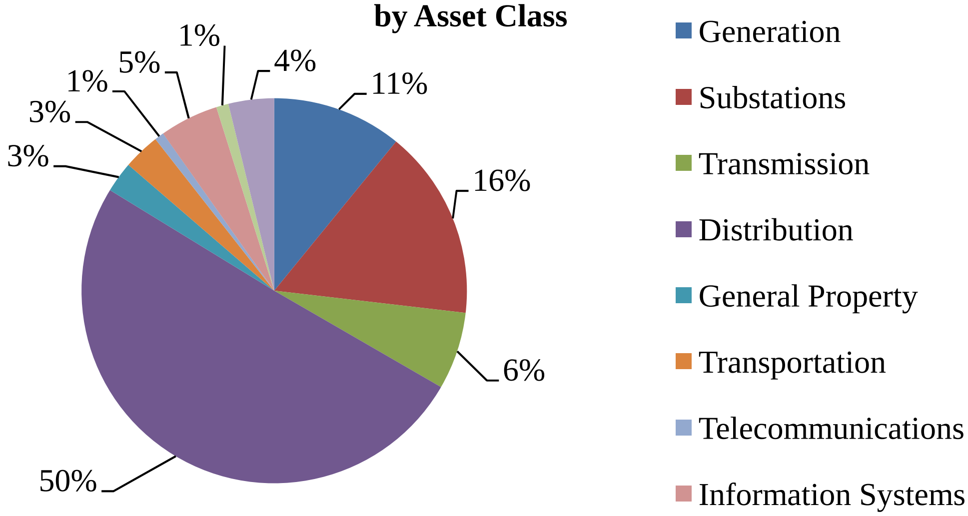
Approximately 50% of proposed 2011 capital expenditure is related to the replacement of plant. A further 38% of proposed 2011 capital expenditure is required to meet the Company's obligation to provide service to new customers and meet the requirement for increased system capacity. The remaining 12% of forecast capital expenditures for 2011 relate to information systems, system additions, capitalized general expenses, third party requirements and financial

4 The impacts of these planned changes upon customers extend beyond the Company's capital budget expenditures. Customers may be impacted by extended electricity outages to complete work associated with PCB removal and will experience the inconvenience of meter change outs.

carrying costs (allowance for funds used during construction). 2011 capital expenditures are broadly consistent with the allocation of the capital budget in the past five years.

Chart 3 shows the 2011 capital budget by asset class.

Chart 3
2011 Capital Expenditures by Asset Class



As in past years, Distribution capital expenditure accounts for the greatest percentage of overall expenditure at $36.8 million, or 50% of the 2011 capital budget. Substations capital expenditure accounts for $11.6 million, or 16% of the 2011 capital budget. Transmission capital expenditure accounts for $4.7 million, or 6% of the 2011 capital budget. Generation capital expenditure accounts for $8.0 million, or 11% of the 2011 capital budget. Together, expenditure for these four asset classes comprises 83% of the Company's 2011 capital budget.

Distribution capital expenditure is primarily driven by customer requests for new connections to the electrical system. Expenditures in 2011 are expected to be slightly below that of recent years. This reflects a slight decline in the forecast number of new customer connections, somewhat offset by inflationary increases and work to address the impact of sustained growth in recent years.

In 2011, the Company plans to install new power transformers at Kelligrews and Pulpit Rock substations to address load growth on the Northeast Avalon Peninsula.

Two St. John's transmission lines, 16L (built in 1950) and 25L (built in 1954) and one Southern Shore transmission line, 21L (built in 1952), are proposed for rebuild in 2011. The transmission system in the City of St. John's will be the focus of rebuild efforts over the next 5 years.

In 2011, the Company plans to upgrade the governor, switchgear, protection and control systems at the Sandy Brook hydroelectric plant. The generator windings at Horse Chops hydroelectric plant will also be replaced.

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 capital expenditure of $1,500,000 in 2011, and an additional $15 million in expenditures in the 5 year forecast period.

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 2011 Capital Budget Application complies with the CBA Guidelines.

The 2011 Capital Budget Application includes 41 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 2011 Capital Budget.

2011 Capital Projects by Definition

Table 1 summarizes Newfoundland Power's proposed 2011 capital projects by definition as set out in the CBA Guidelines.

Table 1
2011 Capital Projects
By Definition

Definition	**Number of Projects**	**Budget ($000s)**
Pooled	27	56,421
Clustered	2	4,905
Other	12	11,643
Total	**41**	**72,969**

There are a total of 29 *pooled* or *clustered* projects accounting for 84% of total expenditures.

2011 Capital Projects by Classification

Table 2 summarizes Newfoundland Power's proposed 2011 capital projects by classification as set out in the CBA Guidelines.

Table 2
2011 Capital Projects
By Classification

Classification	**Number of Projects**	**Budget ($000s)**
Mandatory	1	1,500
Normal	35	68,651
Justifiable	5	2,818
Total	**41**	**72,969**

There are 35 *normal* projects accounting for 94% of total expenditures.

2011 Capital Projects Costing

Table 3 summarizes Newfoundland Power's proposed 2011 capital projects by costing method (i.e., identified need vs. historical pattern) as set out in the CBA Guidelines.

Table 3
2011 Capital Projects
By Costing Method

Method	**Number of Projects**	**Budget ($000s)**
Identified Need	25	34,320
Historical Pattern	16	38,649
Total	**41**	**72,969**

Projects with costing method based on *identified need* account for 47% of total expenditures, while those based on *historical pattern* account for 53% of total expenditures.

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2011 Capital Projects Materiality
Table 4 segments Newfoundland Power's proposed 2011 capital projects by materiality as set out in the CBA Guidelines.

Table 4
2011 Capital Projects
Segmentation by Materiality

Segment	Number of Projects	Budget ($000s)
Under $200,000	7	1,086
$200,000 - $500,000	6	2,093
Over $500,000	28	69,790
Total	**41**	**72,969**

There are 28 projects budgeted at over $500,000 accounting for 96% of total expenditures.

3.0 5-Year Outlook

Newfoundland Power's 5-year capital outlook for 2011 through 2015 includes forecast average annual capital expenditure of $79.1 million. Over the five year period 2006 through 2010, the average annual capital expenditure is expected to be $66.9 million.

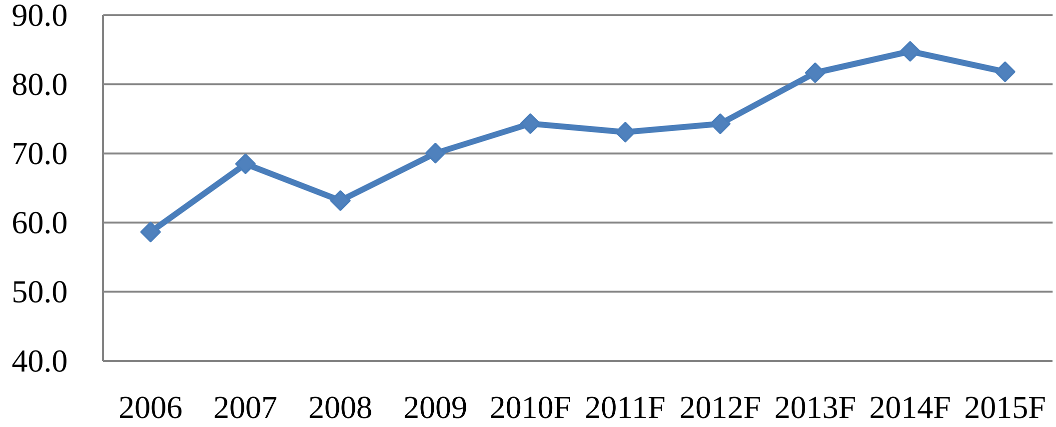
The increase in forecast annual capital expenditure reflects requirements for specific projects, such as additional power transformers for load growth, the phase out of PCB equipment, the requirement for a fish pass at Rattling Brook and the requirement for additional portable generation and substations.

3.1 Capital Expenditures: 2006 - 2015

The Company plans to invest $396 million in plant and equipment during the 2011 through 2015 period. On an annual basis, capital expenditures are expected to average approximately $79.1 million and range from a low of $73.0 million in 2011 to a high of $84.8 million in 2014.

Chart 4 shows actual capital expenditures for the period 2006 through 2009 and forecast capital expenditures for the period 2010 through 2015.

Chart 4
Capital Expenditures
2006 to 2015F
($000,000)



Overall planned capital expenditures for the 5-year period from 2011 through 2015 are expected to be greater than those in the 5-year period from 2006 through 2010. This is principally the result of inflation and forecast requirements for additional power transformers due to load growth, the phase out of PCB equipment, a fish pass at Rattling Brook, the replacement penstock for Pierre's Brook plant, and a portable substation and mobile generation.

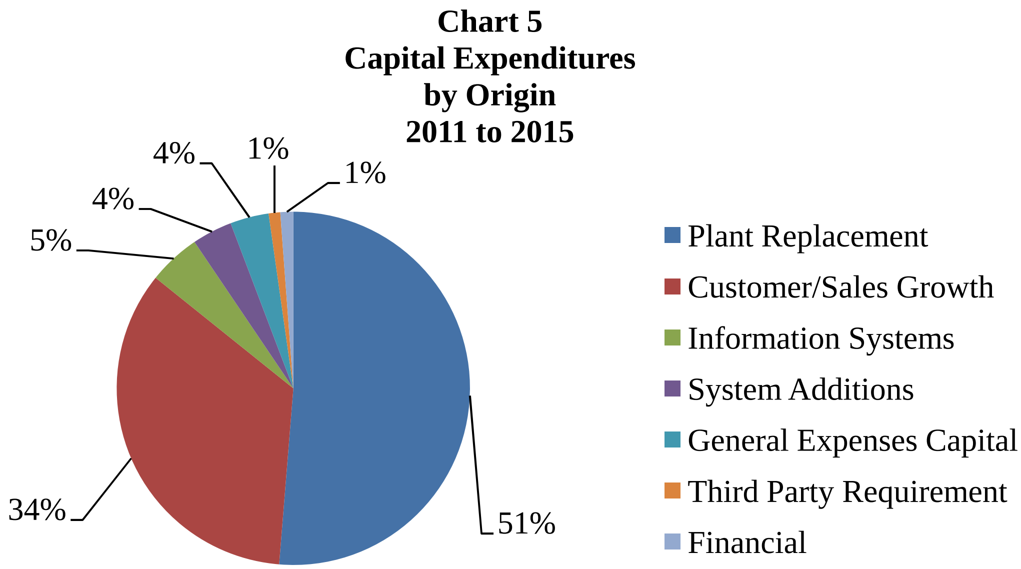
The replacement of plant has been, and will continue to be, the dominant driver of Newfoundland Power's capital budget, accounting for approximately 54% of total expenditure for the 10-year period from 2006 through 2015.

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

3.2 2011 – 2015 Capital Expenditures

3.2.1 Overview

Chart 5 shows aggregate forecast capital expenditures by origin for the period 2011 through 2015.

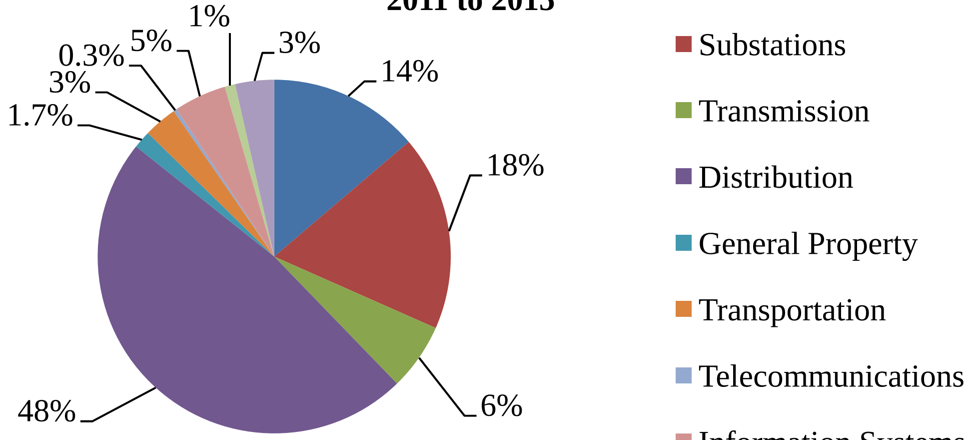


Plant replacement accounts for 51% of all planned expenditures over the 5-year period from 2011 through 2015. Capital expenditure related to customer and sales growth accounts for 34% of planned expenditures for this period. This is an increase from the average of 30% in the previous 5-year period from 2006 through 2010.

The remaining 15% of total capital expenditures for the 2011 through 2015 period relate to a variety of origins including information systems, system additions, third party requirements and financial costs.

Chart 6 shows aggregate forecast capital expenditures for the period 2011 through 2015 by asset class.

Chart 6
Capital Expenditures by Asset Class 2011 to 2015



The Distribution asset class accounts for 48% of all planned expenditures over the next five years, followed by Substations (18%), Generation (14%) and Transmission (6%). The remaining six asset classes account for 14% of total capital expenditures for the 2011 through 2015 period.

Overall, planned expenditures for the period 2011 through 2015 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.

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

3.2.2 Generation

Generation capital expenditures will average approximately $10.8 million per year from 2011 through 2015, which is comparable to the annual average of $8.1 million from 2006 through 2010.

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 2011 the Company plans to upgrade the 47 year old governors, switchgear, protection and control systems at the Sandy Brook hydroelectric plant at an estimated cost of $1.6 million as described in *1.4 Sandy Brook Hydro Plant Refurbishment*.

- In 2011, the Company plans to replace the 56 year old generator windings at the Horse Chops hydroelectric plant at an estimated cost of $1.3 million as described in *1.2 Horse Chops Rewind and Rotor Re-insulation*.

- In 2011, the Company plans to refurbish the 52 year old Rattling Brook spillway and associated dam structures at an estimated cost of $2.6 million as described in *1.3 Rattling Brook Dam Refurbishment*.

- In 2012, the Company plans to construct fish pass structures downstream from the Rattling Brook spillway at an estimated cost of $4.5 million. This project is required to satisfy a directive from the Government of Canada.

- In 2012 and 2013, the Company plans to refurbish the 54 year old Lockston hydroelectric plant at an estimated cost of $4.3 million.

- In 2013 and 2014, the Company plans to replace the Pierre's Brook hydroelectric plant penstock at an estimated cost of $11.5 million. The existing penstock was installed in 1965.

- In 2014 the Company plans refurbish the 60 year old Mobile hydroelectric plant at an estimated cost of $3.0 million.[5]

- In 2015 and 2016, the Company plans to purchase a 5 MW mobile generator at an estimated cost of $7.0 million. The mobile generator will be used for both emergency generation and to minimize customer outages during planned work.

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.

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

3.2.3 Transmission

Transmission capital expenditures are expected to average $4.8 million annually from 2011 through 2015 compared with $5.6 million annually from 2006 through 2010. The 2006-2010 average includes $3.1 million in 2010 storm damages.[6]

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 a 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 and is the principal reason for the increase in capital expenditures in transmission. An update of the strategic plan is included in report *3.1 Transmission Line Rebuild Strategy*.

Starting in 2011 the Company will be rebuilding a number of short transmission lines in the Metropolitan St. John's area. These lines were typically built in the 1950s and recent inspections have determined the transmission lines have reached a point where continued maintenance is no longer feasible and the lines have to be rebuilt to continue safe and reliable operations.

3.2.4 Substations

Substations capital expenditures are expected to average $14.0 million annually from 2011 through 2015, a material increase from the average of $6.8 million annually from 2006 through 2010. The increase in expenditure is largely attributable to the requirement for additional system capacity to serve increased customer load.

In addition, regulatory changes by the Government of Canada with respect to the phase out of bushings and instrument transformers containing polychlorinated biphenyls ("PCB"), has increased capital expenditures by approximately $16,500,000 over the next 5 years.[7] A detailed report on the impact of the change in PCB Regulations is included as ***2.3*** *PCB Removal Strategy.*

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6 Excluding the 2010 storm damage from the 2006 through 2010 historical cost reduces the average annual transmission capital expenditures to $4.9 million, which is consistent with the 2011 through 2015 forecast expenditures.

7 The industry is in discussions with Environment Canada to return the action plan for the gradual phase out to its original time line that would extend the end-of-use date for equipment to 2025.

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

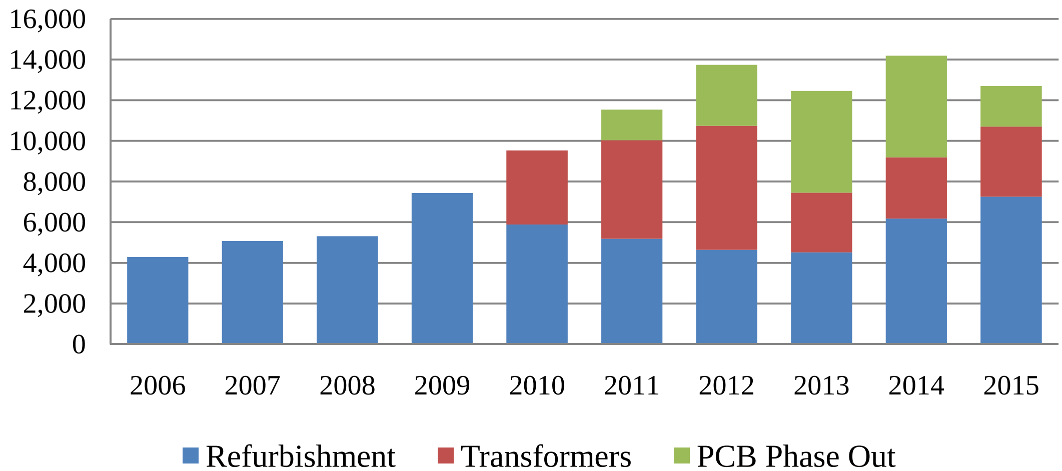
- breakdown capital maintenance;
- substation preventive capital maintenance; and
- system load growth.

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 level of failures and overall reliability of substation assets remains stable.

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, particular power transformation capacity. In addition, the Company is introducing a PCB phase out program over the planning period. Internal Company resources will be required to engineer and project manage the addition of power transformer capacity, and to manage the PCB phase out program. As a result the Company will reduce the scope of the Substation Refurbishment and Modernization project in the years where this additional work will require engineering resources.

Chart 7 shows the impact of the required new transformers and the PCB phase out program on the substations capital plan for the 2011 to 2015 period.

Chart 7
Substation Capital Plan
($000)



Over the 2011 to 2015 forecast period there is a requirement to purchase 9 large power transformers to accommodate load growth.[8] In 2011, new power transformers are required at Pulpit Rock and Kelligrews substations to provide capacity lost due to the customer and load growth experienced on the Northeast Avalon Peninsula over the past decade.[9]

Commencing in 2012 and continuing through 2015 new substation transformers are required for the Mount Pearl, Paradise, Grand Falls and Gander areas. In recent years, at some of these locations, customer load growth has been addressed through load transfers between adjacent substations. Eventually, as customer load continues to grow, options with respect to load transfers become exhausted and additional transformer capacity will be required.

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.

The Company's fleet of portable substations is aging and will require refurbishment over the 5 year period. Refurbishment of portable substation P3 is scheduled for 2011 while portable substation P4 is scheduled for refurbishment in 2012.

In 2013 and 2014, there is an additional portable substation planned increasing the fleet from 3 units to 4 units. The additional portable substation will increase the number of units available in the event of an in-service transformer failure and will provide greater flexibility in scheduling major planned substation projects.[10] This additional portable substation will cost approximately $5.0 million.

In its 2007 Capital Budget Application, the Company submitted its 10-year substation strategy in a report titled *Substation Strategic Plan*. The Company intends to follow this approach of preventive capital maintenance that involves the refurbishment and modernization of substation plant and equipment. An update of the strategic plan is included in report *2.1 2011 Substation Refurbishment and Modernization*.

3.2.5 Distribution

Distribution capital expenditures from 2011 through 2015 are expected to increase to an average of approximately $38.2 million annually, compared to an average of $35.4 million annually from 2006 through 2010.

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

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8 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.

9 Planning studies for the Conception Bay South and Northeast St. John's areas are included in *2.2 Additions Due To Load Growth* report.

10 The Company has 197 substation power transformers in service, a large number of which were installed in the 1970s. As these transformers age, it can be expected that some will experience an in-service failure. 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.

new customers to the electricity system are included in several distribution projects including *Extensions*, *Transformers*, *Services*, *Meters* and *Street Lighting*.

The Company operates approximately 8,800 km of distribution lines serving over 239,000 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.

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

	2011	**2012**	**2013**	**2014**	**2015**
New Customer Connections	4,625	4,652	4,740	4,755	4,970
Average Cost/Connection	$4,542	$4,563	$4,576	$4,666	$4,763
Capital Expenditure (000s)	$21,009	$21,227	$21,689	$22,187	$23,673

Over the period 2011 to 2015, the number of new customer connections is forecast to gradually increase. The impact of inflation over the same period increases the average cost per customer connection by 5%. These combined effects result in an increase to total capital expenditures to connect new customers over the period.

Distribution capital expenditures are required to relocate or replace distribution lines to meet third party requests from governments, telecommunications companies and individual customers. Over the next five years, these expenditures are forecast to remain stable and approximate the historical average.

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. These expenditures 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.

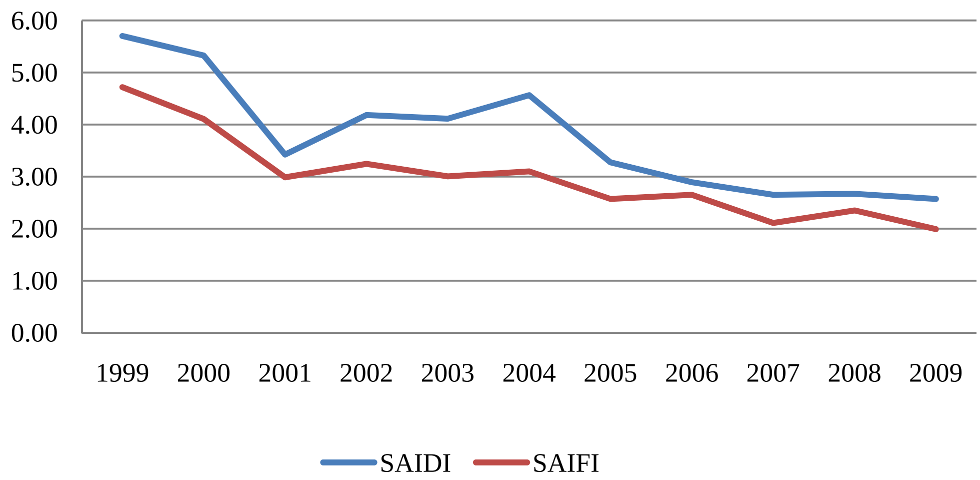
The Company anticipates annual capital expenditures related to St. John's Underground Distribution over the next five years. These expenditures will be driven by the need to replace deteriorated infrastructure, meet future load growth and reduce the risk of prolonged outage in the downtown commercial core. In 2011 *Feeder Additions for Load Growth* project, the Company plans to reduce the number of active power cables in the duct bank leading from St. John's Main Substation on Southside Road to Water Street. This will reduce the risk associated with catastrophic failure in the duct bank, and increase the capacity of the feeders serving the core of the downtown. This work is necessary to ensure adequate capacity exists to meet future load growth.

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 2011 through 2015 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*. The project planned for 2011 involves the completion of reliability upgrades to a feeder in the Northwest Brook area, which were started in 2009.

Chart 9 shows SAIDI, or system average interruption duration index, and SAIFI, or system average interruption frequency index, for the years 1999 through 2009. Chart 9 has been adjusted to remove the effects of severe weather events.[11]

Chart 9
SAIDI and SAIFI
1999 - 2009



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 will be reduced compared to previous years.

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.

The 2011 capital budget includes renovations to the Company's Kenmount Road office building including replacement of the 2nd floor HVAC system, replacement of flooring on the 2nd and 3rd floors and replacement of the building entrance.

General Property capital expenditures are expected to average $1.2 million annually from 2011 through 2015 which is less than the average of $1.5 million annually from 2006 through 2010.

[11] Adjustments exclude 1999 Burin and 2007 Bonavista severe weather events. If these were included, 1999 SAIDI and SAIFI would be 9.37 and 5.28, respectively; and 2007 SAIDI and SAIFI would be 5.94 and 2.46, respectively.

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 are expected to remain stable at an average of approximately $2.4 million annually from 2011 through 2015 which is the same as the annual average from 2006 through 2010.

3.2.8 Telecommunications

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

Telecommunications capital expenditures are expected to remain relatively stable at an average of approximately $0.24 million annually from 2011 through 2015 which is the similar to the annual average of $0.27 million annually from 2006 through 2010.

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 are expected to remain relatively stable at an average of approximately $3.8 million annually from 2011 through 2015 compared to an average of $3.5 million annually from 2006 through 2010.

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 2011 through 2015

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 $2.8 million is reflected in each year's capital budget from 2011 through 2015.

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 2011 through 2015.

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.[12]

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.

The current 5 year forecast for meter replacements is based upon historical average costs. These estimates may not be appropriate if compliance testing standards change significantly, resulting in an accelerated replacement of in service meter stock. While there have been no changes approved to the current meter regulation, it is anticipated that compliance testing standards will change during the forecast period. When these proposed regulations become law the Company will revise its meter budget estimates to reflect the new standards.

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 well into the next decade. The Company has continued to make modest enhancements to CSS where investments could be justified. However, significant business changes such as rate design changes, or the introduction of advanced metering infrastructure (smart meters) would have an impact on CSS. The scale and complexity of these factors or changing technology and vendor

[12] 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.

support could require the Company to consider a full replacement of CSS. The cost of this replacement could exceed $10 million.

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

Appendix A

2011 – 2015 Capital Plan

Newfoundland Power Inc.
2011-2015 Capital Plan
(000s)

Asset Class	**2011**	**2012**	**2013**	**2014**	**2015**
Generation	$7,964	$7,897	$13,045	$13,104	$12,105
Substations	11,647	13,738	15,145	16,813	12,731
Transmission	4,745	5,150	5,255	4,488	4,456
Distribution	36,842	36,302	37,265	39,352	41,312
General Property	1,792	1,306	995	993	1,155
Transportation	2,254	2,374	2,427	2,475	2,524
Telecommunications	572	149	153	156	159
Information Systems	3,603	3,815	3,820	3,840	3,810
Unforeseen Allowance	750	750	750	750	750
General Expenses Capitalized	2,800	2,800	2,800	2,800	2,800
Total	**$72,969**	**$74,281**	**$81,655**	**$84,771**	**$81,802**

Newfoundland Power Inc.
2011-2015 Capital Plan
(000s)

GENERATION

Project	2011	2012	2013	2014	2015
Facility Rehabilitation – Hydro	$1,610	$1,175	$1,175	$1,225	$1,225
Facility Rehabilitation - Thermal	268	302	282	311	165
Horse Chops Generator Rewind	1,276	-	-	-	-
Rattling Brook Plant – Dam Refurbishment	2,600	-	-	-	-
Sandy Brook Governors P&C	1,560	-	-	-	-
Hydro Plant Production Increase	650	650	1,355	525	1,400
Lockston Plant Refurbishment	-	1,250	3,010	-	-
New Chelsea Turbine Overhaul & Rewind	-	10	1,700	-	-
Pitman's Pond Runner Replacement	-	10	515	-	-
Rattling Brook – Fish Passage	-	4,500	-	-	-
Seal Cove Penstock Coating	-	-	-	420	-
Pierre's Brook Penstock	-	-	5,000	6,500	-
Tors Cove Runners and Wicket Gates	-	-	8	573	565
Mobile Plant Refurbishment	-	-	-	3,000	-
Morris Plant Refurbishment	-	-	-	550	-
Purchase Portable Generation	-	-	-	-	5,000
Hearts Content Plant Refurbishment	-	-	-	-	3,750
Total - Generation	**$7,964**	**$7,897**	**$13,045**	**$13,104**	**$12,105**

Newfoundland Power Inc.
2011-2015 Capital Plan
(000s)

SUBSTATIONS

Project	2011	2012	2013	2014	2015
Substations Refurbishment & Modernization	$3,074	$2,365	$2,370	$3,909	$4,837
Replacements Due to In-Service Failure	2,221	2,276	2,333	2,391	2,444
Additions Due to Load Growth	4,852	6,097	2,942	3,013	3,450
PCB Bushing Phase Out	1,500	3,000	5,000	5,000	2,000
Purchase portable Substation P5	-	-	2,500	2,500	
Total – Substations	**$11,647**	**$13,738**	**$15,145**	**$16,813**	**$12,731**

Newfoundland Power Inc.
2011-2015 Capital Plan
(000s)

TRANSMISSION

Project	**2011**	**2012**	**2013**	**2014**	**2015**
Rebuild Transmission Lines	$2,995	$3,050	$3,105	$2,288	$3,006
Transmission Line Reconstruction	1,750	2,100	2,150	2,200	1,450
Total – Transmission	**$4,745**	**$5,150**	**$5,255**	**$4,488**	**$4,456**

Newfoundland Power Inc.
2011-2015 Capital Plan
(000s)

DISTRIBUTION

Project	2011	2012	2013	2014	2015
Extensions	$11,568	$12,024	$12,664	$13,119	$14,160
Meters	1,810	1,627	1,666	1,702	1,739
Services	3,073	3,172	3,334	3,455	3,708
Street Lighting	2,776	2,267	2,364	2,436	2,580
Transformers	7,999	7,783	7,954	8,105	8,259
Reconstruction	3,609	3,729	3,855	3,982	4,113
Rebuild Distribution Lines	3,088	3,182	3,279	3,375	3,473
Relocations For Third Parties	782	809	838	866	896
Distribution Reliability Initiative	521	500	515	530	544
Feeder Additions for Load Growth	1,281	1,030	613	1,110	1,650
Trunk Feeders	160	-	-	486	-
Allowance for Funds Used During Construction	175	179	183	186	190
Total – Distribution	**$36,842**	**$36,302**	**$37,265**	**$39,352**	**$41,312**

Newfoundland Power Inc.
2011-2015 Capital Plan
(000s)

GENERAL PROPERTY

Project	2011	2012	2013	2014	2015
Tools and Equipment	$858	$517	$476	$484	$492
Additions to Real Property	224	229	234	238	243
Renovations Company Buildings	710	285	285	271	420
Stand-By Generators – SCC	-	275	-	-	-
Total – General Property	**$1,792**	**$1,306**	**$995**	**$993**	**$1,155**

Newfoundland Power Inc.
2011-2015 Capital Plan
(000s)

TRANSPORTATION

Project	2011	2012	2013	2014	2015
Purchase Vehicles and Aerial Devices	$2,254	$2,374	$2,427	$2,475	$2,524
Total – Transportation	**$2,254**	**$2,374**	**$2,427**	**$2,475**	**$2,524**

Newfoundland Power Inc.
2011-2015 Capital Plan
(000s)

TELECOMMUNICATIONS

Project	**2011**	**2012**	**2013**	**2014**	**2015**
Replace/Upgrade Communications Equipment	$146	$149	$153	$156	$159
Fibre Optic Cable	426	-	-	-	-
Total – Telecommunications	**$572**	**$149**	**$153**	**$156**	**$159**

Newfoundland Power Inc.
2011-2015 Capital Plan
(000s)

INFORMATION SYSTEMS

Project	2011	2012	2013	2014	2015
Application Enhancements	$983	$1,000	$1,100	$1,200	$1,275
System Upgrades	808	1,425	1,225	1,125	1,075
Personal Computer Infrastructure	390	410	420	430	475
Shared Server Infrastructure	1,092	800	900	900	800
Vehicle Mobile Computing	178	-	-	-	-
Network Infrastructure	152	180	175	185	185
Total – Information Systems	**$3,603**	**$3,815**	**$3,820**	**$3,840**	**$3,810**

Newfoundland Power Inc.
2011-2015 Capital Plan
(000s)

UNFORESEEN ALLOWANCE

Project	2011	2012	2013	2014	2015
Allowance for Unforeseen	$750	$750	$750	$750	$750
Total – Unforeseen Allowance	**$750**	**$750**	**$750**	**$750**	**$750**

Newfoundland Power Inc.
2011-2015 Capital Plan
(000s)

GENERAL EXPENSES CAPITALIZED

Project	2011	2012	2013	2014	2015
General Expenses Capitalized	$2,800	$2,800	$2,800	$2,800	$2,800
Total – General Expenses Capitalized	**$2,800**	**$2,800**	**$2,800**	**$2,800**	**$2,800**

2010 Capital Expenditure Status Report

June 2010

NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

**2010 Capital Expenditure
Status Report**

Explanatory Note

This report is presented in compliance with the directive of the Board of Commissioners of Public Utilities (the "Board") contained in paragraph 5 of Order No. P.U. 41 (2009).

Page 1 of the 2010 Capital Expenditure Status Report outlines the forecast variances from budget of the capital expenditures approved by the Board in Order Nos. P.U. 41 (2009) and P.U. 17 (2010). The detailed tables on pages 2 to 13 provide additional detail on capital expenditures in 2010, and also include information on those capital projects approved for 2008 and 2009 that were not completed prior to 2010.

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 2010 Capital Expenditure Status Report.

Newfoundland Power Inc.

2010 Capital Budget Variances
(000s)

	Approved by Order Nos. P.U. 41 (2009), P.U.17 (2010)	Forecast	Variance
Generation - Hydro	$5,279	$4,744	($ 535)
Generation - Thermal	150	150	-
Substations	10,218	9,818	(400)
Transmission[1]	9,053	9,053	-
Distribution[2]	33,027	38,818	5,791
General Property	1,381	1,381	-
Transportation	2,352	2,352	-
Telecommunications	379	379	-
Information Systems	3,490	3,490	0
Unforeseen Items	750	750	-
General Expenses Capitalized	2,800	2,800	-
Total	$68,879	$73,735	$4,856
Projects carried forward from 2009		$297	
Projects carried forward from 2008		$275	

Notes:

1 Includes $3,138,000 in estimated cost associated with the March 2010 ice storm approved in Order P.U. 17 (2010).

2 Includes $1,062,000 in estimated cost associated with the March 2010 ice storm approved in Order P.U. 17 (2010).

2010 Capital Expenditure Status Report
(000s)

	Capital Budget				Actual Expenditures				Forecast			
	2008	2009	2010	Total	2008	2009	2010	Total To Date	Remainder 2010	Total 2010	Overall Total	Variance
	A	B	C	D	E	F	G	H	I	J	K	L
2010 Projects	-	$ -	$ 68,879	$ 68,879	-	$ -	$ 21,646	$ 21,646	$ 52,089	$ 73,735	$ 73,735	$ 4,856
2009 Projects	-	297	-	$ 297	-	-	222	222	75	297	297	-
2008 Projects	1,930	-	-	$ 1,930	363	853	48	1,264	227	275	1,491	(439)
Grand Total	**$ 1,930**	**$ 297**	**$ 68,879**	**$ 71,106**	**$ 363**	**$ 853**	**$ 21,916**	**$ 23,132**	**$ 52,391**	**$ 74,307**	**$ 75,523**	**$ 4,417**

Column A	Approved Capital Budget for 2008
Column B	Approved Capital Budget for 2009
Column C	Approved Capital Budget for 2010
Column D	Total of Columns A,B and C
Column E	Actual Capital Expenditures for 2008
Column F	Actual Capital Expenditures for 2009
Column G	Actual Capital Expenditures for 2010
Column H	Total of Columns E,F and G
Column I	Forecast for Remainder of 2010
Column J	Total of Columns H and I
Column K	Total of Column J
Column L	Column K less Column D

2010 Capital Expenditure Status Report
(000s)

Category: Generation - Hydro

Project	Capital Budget 2010 (A)	Capital Budget Total (B)	Actual Expenditures 2010 (C)	Actual Expenditures Total To Date (D)	Forecast Remainder 2010 (E)	Forecast Total 2010 (F)	Forecast Overall Total (G)	Variance (H)	Notes*
2010 Projects									
Hydro Plants - Facility Rehabilitation	$ 1,340	$ 1,340	$ 287	$ 287	$ 1,053	$ 1,340	$ 1,340	$ -	
Lookout Brook Hydro Plant Refurbishment	2,155	2,155	378	378	1,777	2,155	2,155	-	
Petty Harbour Surge Tank and Unit No. 1 Main Valve	632	632	6	6	626	632	632	-	
Raise Sandy Lake Spillway to Increase Production	612	612	19	19	58	77	77	(535)	1
Seal Cove Hydro Plant Runner Replacement	540	540	152	152	388	540	540	-	
Total - Generation Hydro	**$ 5,279**	**$ 5,279**	**$ 842**	**$ 842**	**$ 3,902**	**$ 4,744**	**$ 4,744**	**$ (535)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2010
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2010
Column D	Total of Column C
Column E	Forecast for Remainder of 2010
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2010 Capital Expenditure Status Report
(000s)

Category: Generation - Thermal

Project	Capital Budget 2010	Capital Budget Total	Actual Expenditures 2010	Actual Expenditures Total To Date	Forecast Remainder 2010	Forecast Total 2010	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2010 Projects									
Thermal Plants - Facility Rehabilitation	$ 150	$ 150	$ 11	$ 11	$ 139	$ 150	$ 150	$ -	
Total - Generation Thermal	**$ 150**	**$ 150**	**$ 11**	**$ 11**	**$ 139**	**$ 150**	**$ 150**	$ -	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2010
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2010
Column D	Total of Column C
Column E	Forecast for Remainder of 2010
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2010 Capital Expenditure Status Report
(000s)

Category: Substations

Project	Capital Budget 2009	Capital Budget 2010	Capital Budget Total	Actual Expenditures 2009	Actual Expenditures 2010	Actual Expenditures Total To Date	Forecast Remainder 2010	Forecast Total 2010	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	
2010 Projects											
Substation Refurbishment and Modernization	$ -	$ 4,043	$ 4,043	$ -	$ 505	$ 505	$ 3,138	$ 3,643	$ 3,643	$ (400)	2
Replacement Due to In-Service Failures	-	2,052	2,052	-	865	865	1,187	2,052	$ 2,052	-	
Additions Due to Load Growth	-	3,650	3,650	-	356	356	3,294	3,650	$ 3,650	-	
Convert 23L to 66KV	-	286	286	-	85	85	201	286	$ 286	-	
Lookout Brook Substation Upgrades	-	187	187	-	47	47	140	187	$ 187	-	
Total 2009 Substations	-	10,218	10,218	-	1,858	1,858	7,960	9,818	9,818	(400)	
2009 Projects											
WAV Feeder Termination - Vale Inco	$ 297	$ -	$ 297	$ -	$ 222	$ 222	75	$ 297	$ 297	$ -	
Total - Substations	**$ 297**	**$ 10,218**	**$ 10,515**	**$ -**	**$ 2,080**	**$ 2,080**	**$ 8,035**	**$ 10,115**	**$ 10,115**	**$ (400)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2009
Column B	Approved Capital Budget for 2010
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2009
Column E	Actual Capital Expenditures for 2010
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2010
Column H	Total of Columns E and G
Column I	Total of Columns D and H
Column J	Column I less Column C

2010 Capital Expenditure Status Report
(000s)

Category: Transmission

Project	Capital Budget 2010	Capital Budget Total	Actual Expenditures 2010	Actual Expenditures Total To Date	Forecast Remainder 2010	Forecast Total 2010	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2010 Projects									
Transmission Line Rebuild	$ 5,915	$ 5,915	$ 342	$ 342	$ 5,573	$ 5,915	$ 5,915	$ -	
March 2010 Storm Repairs	$ 3,138	$ 3,138	$ 1,678	$ 1,678	$ 1,460	$ 3,138	$ 3,138	$ -	
Total - Transmission	**$ 9,053**	**$ 9,053**	**$ 2,020**	**$ 2,020**	**$ 7,033**	**$ 9,053**	**$ 9,053**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2010
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2010
Column D	Total of Column C
Column E	Forecast for Remainder of 2010
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2010 Capital Expenditure Status Report
(000s)

Category: Distribution

Project	Capital Budget 2008	Capital Budget 2009	Capital Budget 2010	Capital Budget Total	Actual Expenditures 2008	Actual Expenditures 2009	Actual Expenditures 2010	Actual Expenditures Total To Date	Forecast Remainder 2010	Forecast Total 2010	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	I	J	K	L	
2010 Projects													
Extensions	$ -	$ -	$ 8,856	$ 8,856	$ -	$ -	$ 3,477	$ 3,477	$ 8,774	$ 12,251	$ 12,251	$ 3,395	3
Meters	-	-	1,239	1,239	-	-	448	448	831	1,279	1,279	40	
Services	-	-	2,447	2,447	-	-	1,210	1,210	1,948	3,158	3,158	711	4
Street Lighting	-	-	1,783	1,783	-	-	810	810	1,518	2,328	2,328	545	5
Transformers	-	-	7,668	7,668	-	-	3,088	3,088	4,580	7,668	7,668	-	
Reconstruction	-	-	3,359	3,359	-	-	1,112	1,112	2,247	3,359	3,359	-	
Rebuild Distribution Lines	-	-	3,632	3,632	-	-	546	546	3,086	3,632	3,632	-	
Relocate/Replace Distribution Lines For Third Parties	-	-	685	685	-	-	337	337	1,448	1,785	1,785	1,100	6
Distribution Reliability Initiative	-	-	447	447	-	-	8	8	439	447	447	-	
St. John's Underground Distribution	-	-	550	550	-	-	-	-	550	550	550	-	
Feeder Additions for Growth	-	-	465	465	-	-	416	416	49	465	465	-	
Replace Mercury Vapour Street Lights	-	-	681	681	-	-	439	439	242	681	681	-	
AFUDC	-	-	153	153	-	-	56	56	97	153	153	-	
2010 March Storm Repairs	-	-	1,062	1,062	-	-	855	855	207	1,062	1,062	-	
Total 2010 Distribution	-	-	33,027	33,027	-	-	12,802	12,802	26,016	38,818	38,818	5,791	
2008 Projects													
Replace Water Street Underground	$ 1,930	$ -	$ -	$ 1,930	$ 363	$ 853	$ 48	$ 1,264	$ 227	$ 1,491	$ 1,491	$ (439)	7
Total - Distribution	**$ 1,930**	**$ -**	**$ 33,027**	**$ 34,957**	**$ 363**	**$ 853**	**$ 12,850**	**$ 14,066**	**$ 26,243**	**$ 40,309**	**$ 40,309**	**$ 5,352**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2008
Column B	Approved Capital Budget for 2009
Column C	Approved Capital Budget for 2010
Column D	Total of Columns A,B and C
Column E	Actual Capital Expenditures for 2008
Column F	Actual Capital Expenditures for 2009
Column G	Actual Capital Expenditures for 2010
Column H	Total of Columns E,F and G
Column I	Forecast for Remainder of 2010
Column J	Total of Columns H and I

2010 Capital Expenditure Status Report
(000s)

Category: General Property

Project	Capital Budget 2010 A	Capital Budget Total B	Actual Expenditures 2010 C	Actual Expenditures Total To Date D	Forecast Remainder 2010 E	Forecast Total 2010 F	Forecast Overall Total G	Variance H	Notes*
2010 Projects									
Tools and Equipment	$ 389	$ 389	$ 110	110	$ 279	$ 389	$ 389	$ -	
Additions to Real Property	225	225	15	15	210	225	225	-	
Kenmount Road Building Roof and HVAC	542	542	26	26	516	542	542	-	
System Control Centre UPS	225	225	8	8	217	225	225	-	
Total - General Property	**$ 1,381**	**$ 1,381**	**$ 159**	**$ 159**	**$ 1,222**	**$ 1,381**	**$ 1,381**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2010
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2010
Column D	Total of Column C
Column E	Forecast for Remainder of 2010
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2010 Capital Expenditure Status Report
(000s)

Category: Transportation

Project	Capital Budget 2010	Capital Budget Total	Actual Expenditures 2010	Actual Expenditures Total To Date	Forecast Remainder 2010	Forecast Total 2010	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2010 Projects									
Purchase Vehicles and Aerial Devices	$ 2,352	$ 2,352	$ 1,889	$ 1,889	$ 463	$ 2,352	$ 2,352	$ -	
Total - Transportation	**$ 2,352**	**$ 2,352**	**$ 1,889**	**$ 1,889**	**$ 463**	**$ 2,352**	**$ 2,352**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2010
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2010
Column D	Total of Column C
Column E	Forecast for Remainder of 2010
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2010 Capital Expenditure Status Report
(000s)

Category: Telecommunications

Project	Capital Budget 2010	Capital Budget Total	Actual Expenditures 2010	Actual Expenditures Total To Date	Forecast Remainder 2010	Forecast Total 2010	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2010 Projects									
Replace/Upgrade Communications Equipment	$ 135	$ 135	$ -	$ -	$ 135	$ 135	$ 135	$ -	
Fibre Optic Circuit Replacement	244	244	38	38	206	244	244	-	
Total - Telecommunications	**$ 379**	**$ 379**	**$ 38**	**$ 38**	**$ 341**	**$ 379**	**$ 379**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2010
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2010
Column D	Total of Column C
Column E	Forecast for Remainder of 2010
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2010 Capital Expenditure Status Report
(000s)

Category: Information Systems

	Capital Budget		Actual Expenditures		Forecast				
Project	**2010**	**Total**	**2010**	**Total To Date**	**Remainder 2010**	**Total 2010**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2010 Projects									
Application Enhancements	$ 937	$ 937	$ 534	$ 534	$ 403	$ 937	$ 937	$ -	
System Upgrades	1,038	1,038	58	58	980	1,038	1,038	-	
Personal Computer Infrastructure	430	430	264	264	166	430	430	-	
Shared Server Infrastructure	660	660	302	302	358	660	660	-	
Network Infrastructure	153	153	123	123	30	153	153	-	
Vehicle Mobile Computing Infrastructure	272	272	73	73	199	272	272	-	
Total - Information Systems	**$ 3,490**	**$ 3,490**	**$ 1,354**	**$ 1,354**	**$ 2,136**	**$ 3,490**	**$ 3,490**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2010
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2010
Column D	Total of Column C
Column E	Forecast for Remainder of 2010
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2010 Capital Expenditure Status Report
(000s)

Category: Unforeseen Items

Project	Capital Budget 2010	Capital Budget Total	Actual Expenditures 2010	Actual Expenditures Total To Date	Forecast Remainder 2010	Forecast Total 2010	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2010 Projects									
Allowance for Unforeseen Items	$ 750	$ 750	$ -	$ -	$ 750	$ 750	$ 750	$ -	
Total - Unforeseen Items	**$ 750**	**$ 750**	**$ -**	**$ -**	**$ 750**	**$ 750**	**$ 750**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2010
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2010
Column D	Total of Column C
Column E	Forecast for Remainder of 2010
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2010 Capital Expenditure Status Report
(000s)

Category: General Expenses Capitalized

	Capital Budget		Actual Expenditures		Forecast				
Project	**2010**	**Total**	**2010**	**Total To Date**	**Remainder 2010**	**Total 2010**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2010 Projects									
Allowance for General Expenses Capitalized	$ 2,800	$ 2,800	$ 673	$ 673	$ 2,127	$ 2,800	$ 2,800	$ -	
Total - General Expenses Capitalized	**$ 2,800**	**$ 2,800**	**$ 673**	**$ 673**	**$ 2,127**	**$ 2,800**	**$ 2,800**	**$ -**	

* See Appendix A for notes containing variance explanations.

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Column A	Approved Capital Budget for 2010
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2010
Column D	Total of Column C
Column E	Forecast for Remainder of 2010
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

Generation - Hydro

1. *Raise Sandy Lake Spillway to Increase Production:*
Budget: $612,000 Forecast: 77,000 Variance: ($535,000)

The Sandy Brook Spillway project is being deferred to 2011 due to delays incurred in obtaining permits from government and completing consultation with other stakeholders resident on the Sandy Lake watershed. The engineering will be completed in 2010.

Substations

2. Substation Refurbishment and Modernization:

Budget: $4,043,000 Forecast: $3,643,000 Variance: ($400,000)

Work associated with upgrading portable substation P3 is being deferred to 2011 because of the requirement to have the unit available for service during the time when the planned work was to proceed. The engineering will be completed in 2010, and the portable substation will be refurbished during the winter of 2010/2011.

Distribution

3. *Extensions :*
Budget: $8,856,000 Forecast: $12,251,000 Variance: $3,395,000

The original 2010 Capital budget estimate for extensions was based on 3,864 new customer connections. Revised data from the Canada Mortgage and Housing Corporation and the Conference Board of Canada now places the estimate for new customer connections at 4,916, a 27% increase. The additional $3,395,000 is required to build the infrastructure required to connect the additional customers. The additional expenditure represents a 38% increase over budget. The increase is due to the additional customers and increased pole setting costs resulting from a revised pole contract in late 2009

4. *Services :*
Budget: $2,447,000 Forecast: $3,158,000 Variance: $711,000

The original 2010 Capital budget estimate for services was based on 3,864 new customer connections. Revised data from the Canada Mortgage and Housing Corporation and the Conference Board of Canada now places the estimate for new customer connections at 4,916. It is estimated that an additional $711,000 is required to provide service to the 1,052 additional customers.

5. *Street Lights :*
Budget: $1,783,000 Forecast: $2,328,000 Variance: $545,000

The original 2010 Capital budget estimate for services was based on 3,864 new customer connections. Revised data from the Canada Mortgage and Housing Corporation and the Conference Board of Canada now places the estimate for new customer connections at 4,916. It is estimated that an additional $545,000 is required to provide service to the 1,052 additional customers.

Distribution

6. *Relocate/Replace Distribution Lines for Third Parties :*
Budget: $685,000 Forecast: $1,785,000 Variance: $1,100,000

The capital expenditure associated with Relocate/Replace Distribution Lines for Third Parties is required to either upgrade distribution lines to accommodate the placement of additional telecommunications attachments or to relocate lines at the request of a customer. A Contribution in Aid of Construction is a consideration in all cases.

The increase in 2010 expenditure is driven by continued higher than normal activity associated with upgrades to the various telecommunications companies systems. The total cost is now estimated to be $1,785,000. Contributions in Aid of Construction are expected to recover approximately 66% of the total capital cost of this project.

7. *Replace Water Street Underground (2008 Project) :*
Budget: $1,930,000 Forecast: $1,491,000 Variance: ($439,000)

The budget was based on prices obtained through a tender issued by the City of St. John's. The City was not satisfied with the prices received in the initial tender, and issued a second tender subsequent to the Board's approval of the expenditure. The prices obtained in the second tender were lower. There was no change in the scope of the project.

2011 Facility Rehabilitation

June 2010

Prepared by:

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1.0 Introduction

The 2011 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 428.8 GWh[1]. The alternative to maintaining these facilities is to retire them.

The 2011 Facility Rehabilitation project totalling $1,610,000 is comprised of Hydro Dam Rehabilitation; Generation Equipment Replacements Due to In-Service Failures, Main Valve Replacement at West Brook and Engineering for Lockston Plant Refurbishment.

2.0 Hydro Dam Rehabilitation

Cost: $780,000

The Company has over 150 dam structures throughout its 23 hydroelectric facilities. Based on the average age of structures in the Newfoundland Power system, deterioration of embankment 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 2011 includes:

1. *Heart's Content Seal Cove Pond Dam Improvements. ($350,000)*
   This project involves construction of an earth dam with metal cut-off wall. Dam safety inspections indicate the existing rock filled timber crib dam has deteriorated with water infiltrating through the structure. Remedial work was completed during 2006 as a temporary measure to stabilize the structure. Timbers have since

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[1] Normal annual production was established as 419.6 GWh in the Water Management Study – Hydrology Update prepared by SGE Acres dated August 1, 2005. Normal production was increased as a result of capacity increases at Rattling Brook and Rose Blanche to make the revised base normal hydroelectric production to 428.8 GWh.

deteriorated to the point that additional rehabilitation is now required to maintain the integrity of the structure.

2. *Petty Harbour Gatehouse Rehabilitation ($100,000)*
This project involves replacement of the wooden gatehouse, which houses control equipment for the intake gate and water level monitoring equipment. Inspections have determined that the roof and building exterior has deteriorated. The handrail, perimeter platform and security fence at the forebay dam and along the penstock are also a public safety concern and require improvements to meet safety standards.

3. *Rocky Pond: Cluney's Dam and Spillway Rehabilitation ($125,000)*
This project involves replacement of the existing rock filled timber crib spillway and rip rap improvements on the existing dam. Inspections have determined that the timbers are in poor condition, sections of the spillway crest are rotted and broken, and rip rap on the dam face is sparse and undersized.

4. *Tors Cove: Frank's Pond Spillway Improvements ($75,000)*
This project involves replacement of the wooden spillway crest, the addition of rip rap and drainage improvements. Inspections indicate rip rap is sparse on abutments, wooden sill rotted with significant leakage, and ponded water at the downstream toe of the spillway.

5. *Sandy Brook: Forebay Spillway Rehabilitation ($130,000)*
This project involves rehabilitation of the concrete abutments and piers, and refurbishment of the lift mechanism and monorail hoist on the spillway structure. Inspections have indicated concrete deterioration on the abutments, and structural concerns with the gate lift mechanism under certain loading conditions.

The physical condition and observed deterioration of these structures has been assessed within the scope of regularly scheduled dam safety inspections. These inspections are the primary means of identifying deficiencies and establishing capital improvement plans on a priority basis.

3.0 Generation Equipment Replacements Due to In-Service Failures

Cost: $535,000

Equipment and infrastructure at generating facilities, such as turbines and generators, 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 2006.

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

Year	**2006**	**2007**	**2008**	**2009**	**2010F**
Total	$591[1]	$409	$679	$475	$520

[1] Excludes Rocky Pond rebuild.

Based upon this recent historical information and engineering judgement, $535,000 is estimated to be required in 2011 for replacement of equipment due to in-service failures or equipment at risk of imminent failure.

Generation equipment, buildings, intakes, dams and control structures are critical components in the safe and reliable operation of generating facilities. This item is required to enable the timely refurbishment or replacement of equipment to facilitate the continued operation of generating facilities in a safe and reliable manner.

4.0 Main Valve Replacement - West Brook Plant

Cost: $275,000

West Brook Plant is located on the southern part of the Burin Peninsula near the community of St Lawrence. It was commissioned in 1942 and has an installed capacity of 680 KW. The unit consists of one Francis turbine manufactured by Leffel, and a Westinghouse generator. The original 1942 main valve at West Brook was replaced in 1967 by a 24 inch butterfly valve.[2]

The 43 year old valve experiences leaks and control problems. This type of butterfly valve has an expected service life of approximately 40 years. Erosion of the valve disc and seat has rendered the valve ineffective in providing the positive water shut off required to perform maintenance on the turbine, runner and wicket gates. It is impossible to seal off the turbine for maintenance because of the leakage. As a result the penstock has to be drained each time

[2] The main valve is water actuated with a water actuated bypass valve. The valve does not have a dismantling joint making its removal for servicing difficult.

maintenance is required on the turbine. This situation limits the Company's ability to maintain and service other equipment in the plant. Typically the main valve assembly includes a bypass valve and drain valve.[3] The existing main valve does not include either a drain valve or bypass valve. The lack of a bypass valve appears to be a contributing factor in the excessive leakage around the valve disc when in the closed position.

Figure 1 - West Brook Main Valve

In its current condition the valve is prone to sticking in the open position. In 2009 the valve actuator failed in the open position. This presents a risk of equipment damage if the wicket gates fail to close on unit shut down.

The closure of both the main valve and wicket gates is typically necessary to stop the flow of water from entering the turbine. If the wicket gates failed to stop the flow of water in this situation, a catastrophic failure of the turbine and generator would be very likely.

The battery bank and charger were installed in 1991 and having met their useful life expectancy will be replaced during the plant outage to install the new main valve.

The thrust bearing is oil cooled. In recent years the oil cooling system has not been able to sufficiently cool the bearing during the summer months when the ambient air temperature is higher. As a result there have been a number of incidents where the generator has tripped off line due to high bearing temperature. The oil cooling system will be redesigned with a larger heat exchanger and greater capacity for oil flow to address the inability of the current system to cool the bearing.

Due to age and condition, the main valve, the battery bank, battery charger, and cooling water system will be replaced as part of this project.

The continued operation of West Brook Plant is economical over the long term. Investing in the life extension of the plant ensures the continued availability of 2.9 GWh of energy to the Island Interconnected electrical system. The estimated levelized cost of energy from the plant over the next 50 years, including the capital expenditure of $275,000 in 2011, is 5.38 cents per kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation[4].

3 The drain valve is a manually operated valve that is used to drain the penstock for maintenance. The bypass valve is used to direct water past the main valve prior to opening, thereby equalizing the pressure on both sides of the main valve to reduce the strain on the valve disc when opening.

4 The cost of electricity from the Holyrood thermal generating plant is estimated at 11.63 ¢/kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $73.30/barrel for 2010 as per Newfoundland Hydro 2010 Capital Budget Application, Generating Planning Issues 2009 Mid Year Report dated July 2009.

5.0 Engineering for Lockston Plant Refurbishment

Cost: $20,000

Newfoundland Power's Lockston hydroelectric generating plant is located on the Bonavista Peninsula near the community of Port Rexton. The plant was commissioned in 1956 and has an installed capacity of 3,375 KW. The normal annual production at Lockston plant is approximately 8.4 GWh or 2.0% of the total hydroelectric production of Newfoundland Power.

The plant has 2 units each consisting of a horizontal Francis turbine manufactured by Gilkes and a generator manufactured by General Electric. Selected pieces of plant equipment are 54 years old and the Company intends to undertake a refurbishment of the civil, electrical, and mechanical systems at Lockston plant starting in 2012.

Figures 2 and 3 are photographs of the turbine runner on Generator No. 2 taken during a 2007 inspection. This runner was refurbished in 2001, with extensive repairs to the runner blades. Holes in the buckets were welded with aluminum bronze rods. The entire runner was coated with a Belzona Super Glide ceramic coating. Two new 660 bronze rotating seals were installed and machined to give proper clearance. The stationary seal was repaired and reinstalled in the turbine. Subsequent inspections have revealed additional cavitation and 50% of the Belzona coating has since eroded.

Figure 2-Low pressure side showing loss of belzona coating

Figure 3-Cavitation

As part of the overall plant refurbishment the Company currently plans to bring forward a capital budget project proposal for the replacement of the turbine runners at Lockston Plant in the 2012 Capital Budget Application. This capital budget project proposal will require detailed engineering design work be completed. Completing the detailed engineering design work in advance will allow Newfoundland Power to prepare engineering specifications and tender documents in 2011 to ensure the project can be completed during the 2012 construction season.[5]

5 Turbine runners typically have long delivery periods after the engineering design has been approved.

6.0 Concluding

This project, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable plant operations. A 2011 budget of $1,610,000 for Facility Rehabilitation is recommended as follows:

- $780,000 for Hydro Dam Rehabilitation;
- $535,000 for Generation Equipment Replacements Due to In-Service Failures;
- $275,000 for West Brook Plant Main Valve Replacement
- $20,000 for Engineering for Lockston Plant Refurbishment

Horse Chops Rewind and Rotor Re-insulation

June 2010

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1.0 Introduction

The Horse Chops hydroelectric generating plant ("the Plant") was commissioned in 1954 and has a nameplate rating of 8.3 MW. The normal annual production from the plant is 41.8 GWh or approximately 9.7% of Newfoundland Power's ("the Company's") annual hydroelectric production.

The Plant contains a vertical 10,000 hp Francis turbine manufactured by Dominion Engineering and a Canadian General Electric generator. The unit is automated and controlled remotely through the SCADA system. The plant is connected to the Island Interconnected System via Newfoundland Power's transmission line 21L.

Major work completed at this facility in recent years includes the installation of a steel surge tank, steel penstock, intake structure and new main inlet valve. The protection and control systems, including the governor controls, generator protection, voltage regulation and plant control system were upgraded in 2009.

2.0 Stator Rewind

A typical alternating current ("AC") generator consists of a stationary stator winding and a rotor mounted within the stator, as shown in Figure 1. The stator contains a specific number of coils, each with a specific number of windings. Coils are the main current carrying components in the generator. The core provides slots to secure the coils in place and concentrate the magnetic field produced by the rotor.

The coils in the Horse Chops generator are original to the unit. Generator coil insulation has a design life estimated at 40 years in service. The actual life is dependent on several factors including quality control during manufacture, quality control during installation and operating conditions.

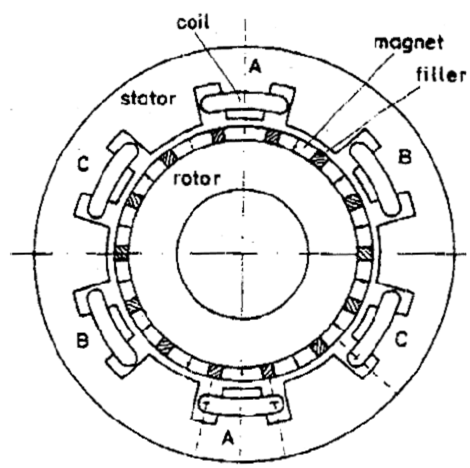

Figure 1 - Stator and Rotor Cross Section

Coils in the stator are subjected to thermal and mechanical stresses during normal operation. These stresses are generated from a number of sources which include:

- expansion and contraction of the coils caused by the heating and cooling cycle during operation
- introduction of magnetic forces to coils when the field voltage is applied
- vibration produced while the unit is operating
- voltage stresses experienced while the unit is operating
- system fault currents experienced by the unit while operating

Stresses cause movement of the coils in the stator slots. This movement, as well as electrical stresses during normal operation, leads to degradation of the insulating material on the coils.

Failure of the insulating material will result in failure of the generator. In 2002, such a failure occurred at the Rattling Brook hydroelectric generating plant, resulting in downtime and lost production while the stator coils were being manufactured and installed.

Newfoundland Power uses industry standard tests to monitor the condition of stator coil insulation. These include polarization index testing and partial discharge testing. They are completed as part of the Company's ongoing asset management program. Results are compared to minimum acceptable results or to a statically significant sample of similar generators.

The polarization index test is used to measure insulation integrity in electrical equipment. It compares the insulation resistance readings taken after one minute and ten minutes. This ratio is the polarization index. Test results for this unit are below the standard recommended value. [1] These poor test results can be attributed to thermal degradation of the insulating material.

The partial discharge test is accomplished by connecting specialized test equipment to sensors permanently attached to the generator winding. Test results indicate an upward trend in partial discharge activity in the stator coils. This increase in discharge activity is interpreted as degradation in coil insulation.

In addition, the coil insulation level at Horse Chops has been compared to other generators of similar size and age. Generators with acceptable insulation levels have resistance values that are on average 12 times higher than this unit. With such low resistance values, there are concerns the Horse Chops generator is a candidate for winding failure in the event it were to experience an abnormal system condition, when operating or on unit start-up or shut down.

Based on test results, operating experience and the typical design life of the stator coils, the Horse Chops generator stator windings will be replaced to ensure continued safe and reliable operation of the generator.

3.0 Rotor Re-insulation

The rotor contains magnetic fields which are established and fed by the exciter. When the rotor is rotated AC current is induced in the stator windings.

Rotor insulation is subjected to thermal stresses during normal operation of the unit. Mechanical stresses experienced by rotor poles are high due to centrifugal forces during normal operation. During an abnormal shutdown, over speed of the rotor occurs significantly increasing the magnitude of centrifugal forces.

Figure 2 - End of Coils and Two Rotor Poles

[1] IEEE Recommended Practice for Testing Insulation Resistance of Rotating Machinery, Standard 43-2000(R2006) indicates that the polarization index for this type of unit should be 2.0 or above. Polarization index test results from this generator over the past 3 years have ranged from a low of 1.47 to a high of 1.79.

Newfoundland Power also uses polarization index testing to monitor the integrity of the insulation on rotor poles. Test results for the unit are below the standard recommended value, and can be attributed to thermal degradation of the insulating material.[2]

Based on test results, operating experience and the design life of the rotor pole insulation, the poles will be reinsulated to ensure continued safe and reliable operation of the generator. Re-insulating the rotor poles at the same time as the stator coils are replaced will reduce the overall cost of both projects as the generator will only need to be disassembled once.

4.0 Project Cost

The total project cost is estimated at $1,276,000. Table 1 below provides the cost breakdown by cost category.

Table 1
Projected Expenditures

Cost Category	Estimated Cost
Material	$1,050,000
Labour - Internal	30,000
Labour - Contract	23,000
Engineering	90,000
Other	83,000
Total	**$1,276,000**

5.0 Economic Feasibility

Appendix A provides an economic feasibility analysis for the continued operation of the Plant. It is based on the latest forecast of total capital expenditure of $1,276,000. 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 continued availability of 41.8 GWh of annual energy to the Island interconnected system.

The estimated levelized cost of energy from the Plant over the next 50 years, including the capital expenditure of $1,276,000, is 1.015 ¢/kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation[3].

[2] See footnote 1, page 2.

[3] The cost of electricity from the Holyrood thermal generating plant is estimated at 11.63 ¢/kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $73.30/barrel for 2010 as per Newfoundland Hydro 2010 Capital Budget Application, Generating Planning Issues 2009 Mid Year Report dated July 2009.

6.0 Concluding

Coils installed in the stator core and individual poles attached to the rotor are fundamental current carrying components of the generator. There are no alternatives to rewinding the stator coils and re-insulating the rotor poles to ensure the continued reliability of the generator. It must be completed in its entirety.

The following work is to be completed during the 2011 Capital Project:

1. Replace original stator coils;
2. Re-insulate rotor poles

Appendix A
Feasibility Analysis

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Page

1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Horse Chops hydroelectric plant (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2011.

With investment required in 2011 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
Horse Chops
Hydroelectric Plant
Capital Expenditures

Year	**(000s)**
2011	$1,275
2016	683
2021	45
2022	1,000
2026	35
2034	1,007
2036	69
Total	**$4,114**

The total capital expenditure for the Plant until 2036 is $4,114,000 in 2011 dollars. 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 $161,066[4] 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.

4.0 Benefits

The maximum output from the Plant is 8.3 MW. The Plant normally operates at an efficient load of 7.2 MW to maximize the energy from the water.

The estimated long-term normal production at the Plant under present operating conditions is 41.8 GWh per year. This estimate is based on the results of the Water Management Study completed by SGE Acres in 2005.

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 1.015 ¢/kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Horse Chops can be produced at a significantly lower price than the cost of electricity currently supplied from Newfoundland and Labrador Hydro's Holyrood thermal generating station at 11.63 ¢/kWh[5].

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 Recommendation

The results of this feasibility analysis show that the continued operation of the Plant is economically viable. Investing in the current upgrades of the facilities at Horse Chops ensures the availability of low cost energy to the Province. Otherwise, the annual production of 41.8 GWh would be replaced by more expensive energy sources 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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[4] 2011 dollars.
[5] See footnote 3, page 3.

Attachment A
Summary of Capital Costs

Horse Chops Feasibility Analysis Summary of Capital Costs ($000s)							
Description	**2011**	**2016**	**2021**	**2022**	**2026**	**2034**	**2036**
Civil							
Control Structures				1,000			
Penstock		683					
Powerhouse							
Plant Access							
Mechanical							
Mechanical Refurbishment							
Turbine Upgrades							
Governor Upgrades							
Electrical							
Controls Upgrade						1,007	
Generator Rewind	1,275						
Exciter							
DC Systems			45		35		69
Switchgear							
Forebay Cable							
Substation							
Annual Totals	**1,275**	**683**	**45**	**1,000**	**35**	**1,007**	**69**

Attachment B
Summary of Operating Costs

Horse Chops Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs

Year	**Amount**
2005	$ 176,987
2006	186,096
2007	160,025
2008	145,565
2009	136,656
Average	**$ 161,066**

5 -Year Average Operating Cost	$161,066[6]

[6] 2011 Dollars.

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis[7]

Weighted average Incremental Cost of Capital 7.68%
Present Worth Year 2010

Year	Generation Hydro 64.4yrs 8% CCA	Capital Revenue Costs	Operating Costs	Net Benefit	Present Worth Benefit	Cumulative Present Worth (¢/kWhr)	Rev Rqmt 50 years	Levelized Rev Rqmt (¢/kWhr)
2011	1,275,000	114,712	161,066	-275,778	-256,108	-256,108	0.660	1.015
2012	-	110,243	164,477	-274,721	-236,931	-493,039	0.657	1.015
2013	-	111,225	168,122	-279,347	-223,738	-716,777	0.668	1.015
2014	-	111,952	171,295	-283,247	-210,681	-927,458	0.678	1.015
2015	-	112,443	174,622	-287,065	-198,292	-1,125,750	0.687	1.015
2016	753,622	180,520	177,720	-358,240	-229,808	-1,355,557	0.857	1.015
2017	-	177,954	180,960	-358,913	-213,818	-1,569,375	0.859	1.015
2018	-	178,426	184,277	-362,703	-200,665	-1,770,040	0.868	1.015
2019	-	178,578	187,734	-366,312	-188,207	-1,958,247	0.876	1.015
2020	-	178,436	191,216	-369,652	-176,377	-2,134,624	0.884	1.015
2021	54,428	182,920	194,810	-377,730	-167,377	-2,302,001	0.904	1.015
2022	1,231,983	292,908	198,431	-491,339	-202,190	-2,504,192	1.175	1.015
2023	-	287,741	202,125	-489,866	-187,207	-2,691,398	1.172	1.015
2024	-	287,619	205,791	-493,410	-175,113	-2,866,511	1.180	1.015
2025	-	287,045	209,690	-496,735	-163,719	-3,030,230	1.188	1.015
2026	46,417	290,232	213,607	-503,839	-154,217	-3,184,447	1.205	1.015
2027	-	288,699	217,559	-506,258	-143,905	-3,328,352	1.211	1.015
2028	-	287,012	221,620	-508,632	-134,268	-3,462,620	1.217	1.015
2029	-	284,992	225,814	-510,806	-125,225	-3,587,845	1.222	1.015
2030	-	282,667	230,138	-512,805	-116,748	-3,704,593	1.227	1.015
2031	-	280,060	234,545	-514,605	-108,802	-3,813,395	1.231	1.015
2032	-	277,193	239,037	-516,230	-101,361	-3,914,757	1.235	1.015
2033	-	274,089	243,615	-517,704	-94,401	-4,009,157	1.239	1.015
2034	1,552,272	410,422	248,280	-658,703	-111,545	-4,120,702	1.576	1.015
2035	-	401,456	253,035	-654,492	-102,927	-4,223,629	1.566	1.015
2036	110,475	408,881	257,881	-666,762	-97,378	-4,321,006	1.595	1.015
2037	-	405,496	262,819	-668,315	-90,643	-4,411,649	1.599	1.015
2038	-	402,139	267,853	-669,992	-84,389	-4,496,039	1.603	1.015
2039	-	398,353	272,982	-671,335	-78,528	-4,574,567	1.606	1.015
2040	-	394,170	278,210	-672,380	-73,040	-4,647,607	1.609	1.015
2041	-	389,623	283,538	-673,161	-67,910	-4,715,517	1.610	1.015
2042	-	384,740	288,968	-673,708	-63,118	-4,778,634	1.612	1.015
2043	-	379,549	294,502	-674,051	-58,646	-4,837,280	1.613	1.015
2044	-	374,075	300,142	-674,217	-54,476	-4,891,756	1.613	1.015
2045	-	368,339	305,890	-674,229	-50,592	-4,942,348	1.613	1.015
2046	-	362,363	311,748	-674,111	-46,975	-4,989,324	1.613	1.015
2047	-	356,167	317,718	-673,885	-43,610	-5,032,934	1.612	1.015
2048	-	349,767	323,803	-673,570	-40,481	-5,073,415	1.611	1.015
2049	120,883	354,056	330,004	-684,060	-38,179	-5,111,594	1.637	1.015
2050	-	346,873	336,323	-683,197	-35,411	-5,147,006	1.634	1.015
2051	-	340,049	342,764	-682,814	-32,867	-5,179,873	1.634	1.015
2052	-	333,055	349,328	-682,384	-30,504	-5,210,377	1.632	1.015
2053	-	325,905	356,018	-681,924	-28,309	-5,238,686	1.631	1.015
2054	-	318,611	362,836	-681,448	-26,272	-5,264,958	1.630	1.015
2055	-	311,185	369,785	-680,970	-24,381	-5,289,339	1.629	1.015
2056	-	303,637	376,867	-680,504	-22,627	-5,311,966	1.628	1.015
2057	-	295,977	384,084	-680,061	-20,999	-5,332,965	1.627	1.015
2058	-	288,214	391,439	-679,653	-19,490	-5,352,454	1.626	1.015
2059	-	280,356	398,936	-679,292	-18,090	-5,370,544	1.625	1.015
2060	-	272,411	406,576	-678,987	-16,792	-5,387,337	1.624	1.015
2061	-	264,386	414,362	-678,748	-15,589	-5,402,926	1.624	1.015

[7] 2012 energy increase project not included in the levelized cost calculation.

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects a statutory income tax rate of 32%.

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%	6.61%	3.63%
Common Equity	45.00%	9.0%	4.05%
Total	**100.00%**		**7.68%**

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 16, 2010.

Rattling Brook Dam Refurbishment

Rattling Lake Spillway Replacement and Dam Upgrades

June 2010

Prepared by:

Gary K. Humby, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
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June/29/2010
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PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

The Rattling Brook hydroelectric development is the largest generating station operated by Newfoundland Power. It is located approximately 50 kilometres west of Gander near the Notre Dame Bay community of Norris Arm South. The development was placed into service in December 1958 and has provided 52 years of reliable energy production. The normal annual plant production is approximately 78.1 GWh of energy, or about 18.2% of Newfoundland Power's total hydroelectric production.

In 2007, upgrades were completed at Rattling Brook, which included the replacement of the woodstave penstock, refurbishment of the surge tank, and upgrades and replacements of the electrical and mechanical systems in the plant. In the 2007 Capital Budget Application for this project, Newfoundland Power also identified future replacement and refurbishment work to be completed on the dams and spillways.

Since 2005, Newfoundland Power has been engaged in ongoing discussions with the Department of Fisheries and Oceans ("DFO") on the requirement to provide fish passage at Rattling Brook. The uncertainty around the requirements for passage has delayed necessary work on the Rattling Brook spillway identified in the Hatch report of April 23, 2007.[1]

Studies completed with DFO have since determined that fish passage utilizing the spillway at Rattling Lake is not required. This result now makes it possible to proceed with the project to replace the Rattling Lake spillway. There is however a future requirement to provide another means of fish passage at Rattling Lake at another location.[2]

A complete inspection of the civil infrastructure of the Rattling Brook facility including dams, dykes, tunnels, control gates and roads was completed in 2005. Volume 2, Appendix D *"Civil Infrastructure Assessment"* of the 2007 Capital Budget Application documents the condition of the existing infrastructure of the system. In summary several items require attention to ensure the continued safe and reliable operation of the Rattling Brook development.

Based on the findings of the civil infrastructure assessment, the following work is necessary for the Rattling Brook hydroelectric development in 2011:

- Replacement of Rattling Lake spillway;
- Upgrades to Amy's Lake dam and Amy's Lake freeboard dam; and
- Upgrades to Rattling Lake Dam.

---

1 The detailed conditional assessment of Rattling Lake spillway completed by Hatch was submitted with Newfoundland Power's 2007 Capital Budget Application.

2 The Company has included a $4.5 million project in its capital plan for 2012 to design and construct facilities at Rattling Brook to allow salmon to access the Rattling Lake watershed.

Figure 1 is a map of the lower section of the Rattling Brook hydroelectric development showing the locations of Rattling Lake spillway, Amy's Lake dam and Rattling Lake dam.

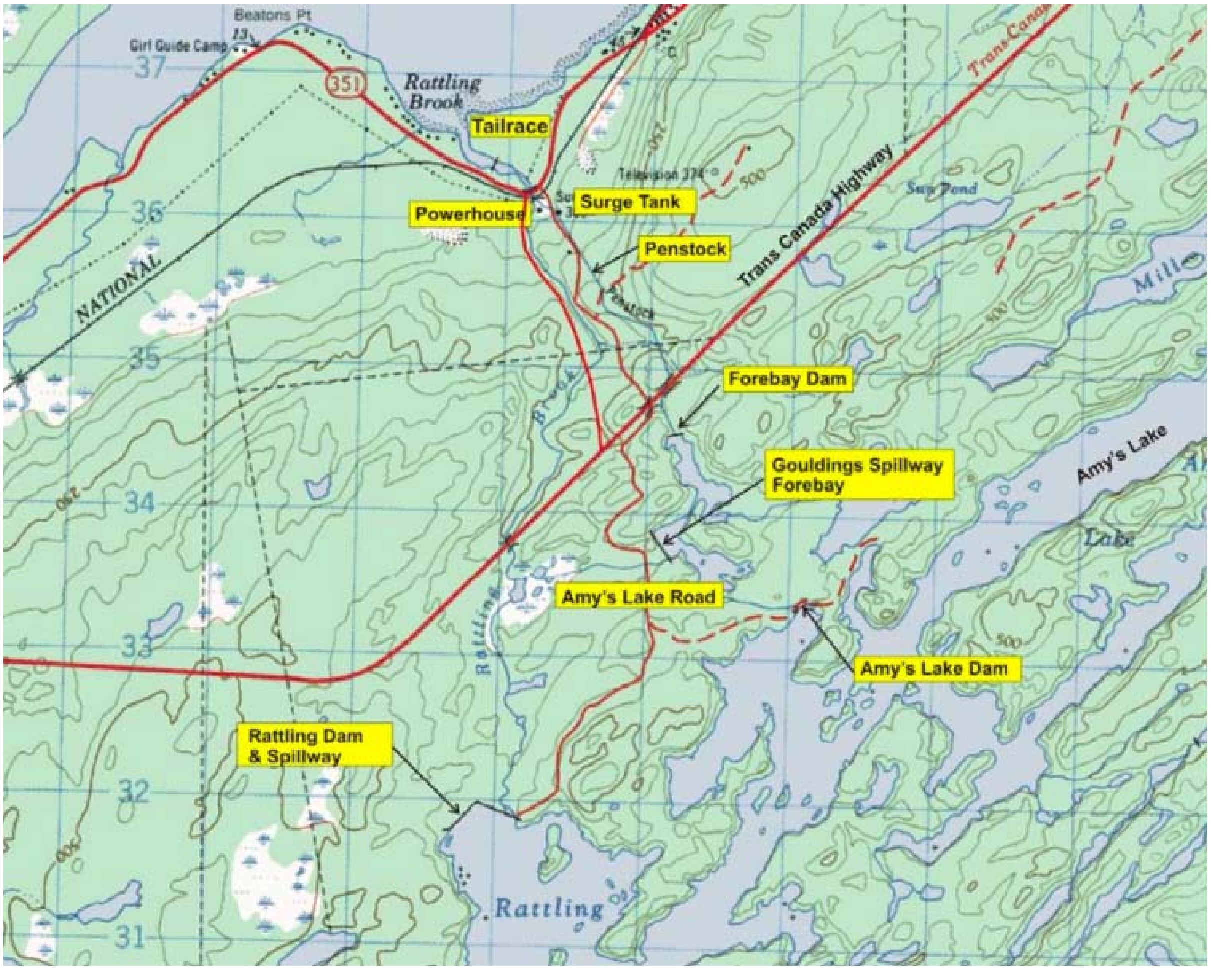

Figure 1 – Rattling Brook Hydroelectric Development

Replacement of Rattling Lake spillway and upgrades to the dams and dykes will allow Newfoundland Power to continue to operate this facility over the long term, maximizing the benefits of this renewable resource for its customers.

2.0 Civil Infrastructure Upgrades

2.1 Rattling Lake

2.1.1 Rattling Spillway

Rattling Lake Spillway is the main spillway in the Rattling Brook development and is a high consequence structure according to the Canadian Dam Association ("CDA") classification system.[3] Since it's commissioning in 1958, with the exception of the replacement of the deteriorated stoplogs[4] and other minor upgrades, the spillway is in its original condition. As part of Newfoundland Power's Dam Safety Program, engineering inspections of the Rattling Lake spillway are conducted every 2 years to assess and document the current condition of the structure.

Figure 2 - Aerial Shot of Rattling Lake

Additional input to the assessment includes previous dam safety inspection reports, and dam safety reviews and flood and dam break studies completed by AMEC E&C Services Limited ("the Consultants").[5] The most resent assessment was completed in 2009.

Due to the importance of the spillway in the Rattling Brook development and the condition and age of the structure, a stability evaluation was also performed by Newfoundland Power in 2005 to assess the structural integrity of the structure.[6] Stability of the structure is dependent on bracing and anchoring systems, which provide some measure of resistance, but should not be relied upon for ongoing stability under long term service conditions.

The spillway design flood cannot be safely passed with stoplogs in place. Provision for adequate discharge capacity and freeboard requirements at Rattling Lake is largely dependent on stoplog removal operations. The process of removing stoplogs during adverse weather conditions poses an increased risk of workplace hazard to Company employees. Extreme flood conditions and the inability to access the site may prevent the execution of stoplog removal operations, thus jeopardizing dam safety. For these reasons, the Rattling Lake spillway will be replaced in 2011.

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3 CDA classifies dams in terms of consequences of failure. A structure is classified as a high consequence structure if, in the event of a failure, there is potential for fatalities and a large amount of socioeconomic, financial and environmental damages.

4 A stoplog is a hydraulic control element that is used to control the elevation of a reservoir by adjusting the elevation of the spillway crest. Stoplogs are typically long rectangular timber beams or boards that are placed on top of each other and dropped into premade slots inside a spillway structure.

5 Reports utilized to assess Rattling Lake spillway include: 1) *Dam Safety Review Rattling Brook Development,* (Prepared by AMEC E&C Services Limited), 2) *Rattling Brook Hydro System Flood and Dam Break Study*,(Prepared by AMEC E&C Services Limited), 3) *1999, 2003, 2005and 2007 Dam Safety Inspection Reports Rattling Brook Development* (Prepared by Newfoundland Power), 4) Canadian Dam Association (1999) *Dam Safety Guidelines, 5)Dam Safety Review Rattling Brook Development, (Prepared by Mitchelmore Engineering, 2009).*

6 The detailed conditional assessment of Rattling Lake spillway was submitted with Newfoundland Power's 2007 Capital Budget Application.

A detailed assessment of replacement alternatives was conducted by Hatch[7] in March of 2007 to determine the most feasible, least cost option for the replacement of Rattling Lake spillway. The detailed assessment report "*Main Spillway Replacement Assessment*" is included in Appendix A of this report. This detailed assessment included a review of the hydrology, freeboard requirements and discharge capacity as well as an evaluation of several viable options that could be utilized for the proposed spillway replacement.

Canadian Dam Safety Guidelines recommend that the freeboard[8] requirement for an earth embankment dam, such as Rattling Lake dam and Amy's Lake dam, should be sufficient to avoid dam overtopping for 95 percent of the waves created under specific wind conditions. Based on this condition, an Inflow Design Flood[9] ("IDF") of 416 m^3/s and an Annual Exceedance Probability[10] ("AEP") of 1/10,000 is necessary. The required freeboard allowance for the replacement of Rattling Lake spillway is 1.2 metres. These values were used to evaluate replacement alternatives for the Rattling Lake spillway.

Three options considered as part of the assessment include:

- Option A: Overflow spillway (i.e. labyrinth[11] or straight overflow spillway);
- Option B: Combination of overflow spillway sill elevation 114.9 m / automated section; and
- Option C: Combination of overflow spillway sill elevation 113.7 m / automated section.

There are a number of water release devices that were considered based on the above three options, including:

- Gravity overflow spillway (labyrinth or straight overflow spillway);
- Quick release stoplogs;
- Vertical gates;
- Timber crest stoplogs; and
- Rubber dams or gates.

Based on Option A, B and C and the water release devices listed, a total of 9 unique combinations were evaluated as replacement options for Rattling Lake spillway. A cost estimate was completed for each option. Appendix A, "*Main Spillway Assessment Report*" contains the list of options and cost estimates associated with each option.

---

7 On August 1, 2006 SGE Acres integrated more closely with parent company, Hatch. Therefore, SGE Acres now offers services under the name Hatch.

8 Freeboard is the vertical distance between the still water reservoir surface elevation and the top of the dam.

9 The Inflow Design Flood is the flood flow above which the incremental increase in water surface elevation due to failure of a dam or other water impounding structure is no longer considered to present an unacceptable threat to downstream life or property.

10 The chance of a flood of a given size (or larger) occurring in any one year, usually expressed as a percentage. For example, if a peak flood discharge of 500 m^3/s has an AEP of 5%, it means that there is a 5% chance (i.e. a 1/20 chance) of a peak discharge of 500 m^3/s (or larger) occurring in any one year.

11 A labyrinth overflow spillway is a series of interconnected v-shaped weirs. It creates a greater length of crest compared to a conventional spillway crest occupying the same lateral space.

Based on the detailed assessment it was determined that the most feasible and least cost option to replace Rattling Lake spillway is a labyrinth overflow spillway. A labyrinth shaped overflow spillway offers improved hydraulic efficiency and enables a longer crest length and the ability to increase spill capacity. It requires no user intervention during a flood, no power requirements and, since there are no moving parts, minimal maintenance will be required.

Compared to other operated water release devices that were assessed, a gravity overflow labyrinth spillway will require a higher flood water level and hence higher dam heights to provide the recommended freeboard of 1.2 metres. The crest of Rattling Lake dam, Amy's Lake dam, and Amy's freeboard dykes will require a minimal crest raising of 1.0 metre to maintain a freeboard of 1.2 metres during a design flood occurrence.

Replacing Rattling Lake spillway with a labyrinth overflow spillway will provide adequate discharge capacity under extreme flood conditions, satisfy freeboard requirements and will require no user intervention, thus eliminating the increased risk of workplace hazard to employees. The total estimated cost for the replacement of Rattling Lake spillway with a gravity overflow labyrinth spillway is $1,800,000.

2.1.2 Rattling Lake Dam

Since the commissioning of the site in 1958, upgrades to Rattling Lake dam include the replacement of the riprap on the upstream face in 2000. No improvements are required on the upstream face of the dam at this time.

The crest of Rattling Lake Dam will be raised 1.0 metres to accommodate the design flood associated with the new labyrinth spillway. Raising the crest of the dam will require additional earth and rock fill on the downstream slope of the dam.

It is important to control vegetation growth on earth filled dams. Dam safety can be compromised if vegetation such as trees or other deep rooted plants become established. Decaying roots of dying vegetation can create a seepage path in the dam, leading to internal erosion, commonly referred to as piping.

Figure 3 - Rattling Lake Dam
(Note excessive vegetation on downstream face)

Prior to the placement of earth and rock fill on the downstream slope of the dam; the downstream face will be scarified by a mechanical means to remove the root system.

Furthermore ditching improvements along the downstream toe will be implemented to collect any seepage that may occur through the dam. This will allow engineering staff to monitor for seepage through the dam.

Implementing these upgrades will significantly reduce the extent of re-vegetation, reducing costs associated with future vegetation clearing efforts and ensuring that the integrity of the dam is maintained.

2.2 Amy's Lake

2.2.1 Amy's Lake Dam

Amy's Lake Dam is original to the 1958 construction. Other than the replacement of the trash racks in 2000, no major upgrades have been implemented to this structure. Upgrades to be completed in 2011 include:

- Riprap refurbishment on the upstream face of the dam;
- Re-grading of the downstream face and placement of additional rock fill along the entire length of the downstream face;
- Ditching improvements along the downstream toe of the dam;
- Placement of large boulders along the channels edge to prevent rock fill from sliding into the approach channel; and
- Removal of rock to widen the discharge channel.
- Raise crest 1.0 metres to accommodate the design flood associated with the new labyrinth spillway.

Figure 4 - Aerial Photograph of Amy's Lake Dam

The riprap on the upstream face of Amy's Lake Dam is sparse throughout the entire length of the structure and requires refurbishment. It is extremely important that earth embankment dams, such as Amy's Lake Dam, are adequately protected from erosion caused by wave action. Sparse sections in the riprap are potential areas where erosion of the dam may occur. Refurbishment of the riprap on the upstream face will ensure sufficient erosion protection of the dam.

Re-grading of the downstream slope of the dam and placement of additional rock fill along the entire length is required to raise the crest of the dam. Ditching improvements along the downstream toe of the dam will be implemented to collect any seepage that may occur through the dam. This will allow engineering staff to monitor seepage through the dam should any seepage occur.

Other upgrades include placement of large boulders along the approach channels edge to prevent rock fill from sliding into the approach channel and widening of the discharge channel. This will help minimize flow restriction into and out of the Amy's Lake concrete outlet tunnel.

2.2.2 Amy's Lake Freeboard Dykes

Overall Amy's Lake Freeboard Dykes are in good condition with the exception of some minor upgrades that have been identified through assessments. Upgrades that will be carried out on these structures include the re-grading of the riprap on Freeboard Dyke No.3. The crest of Amy's Lake Freeboard Dykes will be raised 1.0 metres to accommodate the design flood associated with the new labyrinth spillway.

3.0 Project Execution

The replacement of Rattling Lake Spillway and upgrades to Rattling Lake/Amy's Lake dams and Amy's Lake Freeboard Dykes is necessary for 2011 to ensure the continued safe and reliable operation of Rattling Brook Hydroelectric facility.

The replacement of Rattling Lake Spillway and all other dam upgrades will be completed from mid June to mid September 2011 when reservoir levels are low. During this construction period the plant will remain in operation.

The design for the replacement of the spillway will be completed by a consultant. This portion of the project will be tendered and awarded in the first quarter of 2011. The design for all other upgrades will be completed in-house and will commence in the first quarter of 2011.

4.0 Project Cost

The total project is estimated at $2.600 million. Table 1 provides a cost breakdown.

Table 1
Rattling Brook Civil Infrastructure Upgrades
($000s)

Description	**2011**
Rattling Spillway	1,800
Amy's Lake Dam Rehabilitation	400
Rattling Lake Dam Rehabilitation	400
Total	**2,600**

5.0 Feasibility Analysis

Appendix B provides a feasibility analysis for continued operation of the Rattling Brook hydroelectric development assuming that the planned capital upgrades for 2011 are undertaken. The results of the feasibility analysis show that the continued operation of the facility is economical over the long term.

The estimated levelized cost of energy from Rattling Brook over the next 50 years, including the proposed capital expenditures, is 1.52 cents per kWh. This energy is lower in cost than the replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation.[12]

[12] The cost of electricity from the Holyrood thermal generating station is estimated at 11.63¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $73.30 per barrel for 2010 as per Newfoundland Hydro 2010 Capital Budget Application, Generation Planning Issues 2009 Mid Year Report dated July 2009.

6.0 Concluding

Condition assessments have been completed on the civil infrastructure within the Rattling Brook hydroelectric development. The assessments have identified necessary work to be completed to ensure the continued safe and reliable operation of the facility.

In particular, Rattling Lake spillway is at the end of its useful life and must be replaced. Replacement of this structure with a labyrinth spillway will provide adequate discharge capacity in extreme flood conditions, while satisfying freeboard requirements. Furthermore the structure requires no user intervention during a flood, thus eliminating labour intensive efforts from plant operations staff.

Upgrades to Rattling and Amy's Lake Dams and Freeboard Dykes will ensure that the integrity of the dams are maintained and will extend the life of the structures.

The feasibility of the analysis included in Appendix B verifies the financial viability of completing this project. Based upon these considerations, and others outlined in this report and attached assessments, the project is recommended to proceed with design in the 1st Quarter of 2011, with execution of construction in the summer of 2011.

Appendix A

Rattling Brook Hydroelectric Development
Main Spillway Replacement Assessment

Prepared by:

Hatch

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P.O. Box 8910
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Rattling Brook Hydroelectric Development

Main Spillway Replacement Assessment Final Report

H-325359
0
April 23, 2007

Newfoundland Power
Rattling Brook Hydroelectric Development

Main Spillway Replacement Assessment

Final Report

Prepared by: Walter Smith — April 23, 2007
Walter Smith — Date

Distribution List

H-325359

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Executive Summary

The Rattling Brook main spillway requires replacement with a modern structure. Newfoundland Power plans to modernize this structure in 2008.

The present spillway has been deemed unstable and deteriorated.

Its operation requires extensive personnel attendance to remove the deep stoplog panels. This operation can be dangerous in winter. It is difficult to predict flood inflows and it has been determined that up to 50 continuous hours may be required to remove all log panels. There is no practical way to replace log panels until flow succession and excess power flows are lost during major spill events.

This study has outlined several water release device combinations which are superior to the existing structure. This study has determined that a labyrinth shaped spillway, which requires no moving or mechanized parts, and operates automatically without operator attention, is the best and most cost effective solution. Its estimated cost including contingencies is $1.8 million.

1. Introduction

Newfoundland Power (NP) have determined that the existing spillway at Rattling Brook is unstable and deteriorated to the extent requiring replacement. The present plan is to have it budgeted for replacement in 2008 construction season.

1.1 Object of the Study

The study would review previous inspection reports and studies available, identify suitable conventional systems of gates, inflatable rubber dams, stoplogs, quick release stoplogs and the like to replace the existing stoplog structure. The study would determine the best solution from economical and practical considerations.

1.2 Background

The Rattling Brook hydroelectric development is located about 10 km southeast of Botwood, in central Newfoundland. Its main storage reservoir is impounded on the former Rattling and Amy's Lakes. Water releases for the Hydro plant are released at Amy's dam and the main spillway outlet is at Rattling Lake which discharges to Rattling Brook. The combined drainage area at Rattling Spillway, including Frozen Ocean Pond upstream storage, is 381 km^2.

Prior studies have concluded that the design flood required for the structures is 1:10,000 return period which has a peak flow or 416 m^3 per second (m^3/s) at the spillway.

The spillway, except for repair and maintenance, is largely as it was constructed in 1958 when the project was commissioned. It consists of 35 stoplog bays 2.4 m high by 2.44 m wide and 7 bays 3.0 m high by 1.83 m wide. The full supply level is 114.91 m, the top of stoplogs elevation 115.06 m and the top of deck is 115.22 m elevation. The logs are manually removed using lifting hooks and pins through the end of each log from the walkway above. The logs can be stored on a central widened timber platform. It has been estimated that as much as 50 continuous hours of manual labour crews may be required to pull all the logs.

The present system of manually removable timber stoplogs is not adequate. The structure has been determined to be unstable using recommended safety criteria and is suffering from deterioration, particularly the concrete base and strut supports. The removal of stoplogs is difficult and sometimes dangerous to personnel depending on the time of year removal is necessary. Prediction of flood flows is necessary to determine the number of logs to remove for a given flood event and it may not be possible to remove many of the deeper logs when spilling a large event. Replacement of logs during flow is difficult, necessitating more spillage, and the reservoir is lowered from full supply level when there is concern of excessive ice load on the spillway structure. Hence there are power generation losses associated with the inability to consistently maintain full supply level during ice and spill events.

1.3 Information Available

The following data and information has been provided by NP.

- Dam Safety Review 2001, Rattling Brook Development
- 2003 and 2005 Dam Safety Inspection Reports
- 2002 Flood and Dam Break Study, Rattling Brook Hydro System

- Spill records for the last 20 years
- Reservoir elevation versus time curves
- Field survey of the site
- Construction drawings

1.4 Salient Data

The following pertinent data has been obtained from the reference material.

Spillway Configuration

Spillway Length	107.35 m (excluding abutments)
Net Spillway Length	98.15 m
Dam Crest Elevation	116.13 m
Dam Crest Length	1200 m (includes Rattling/Amy's Dams and Freeboard Dykes)
Dam Crest Width	5.7 m
Maximum Stoplog Elevation	115.12 m
FSL Current	114.91 m
FSL Original Drawings	114.30 m
Concrete Sill Elevation	112.78 m
Top of Deck	115.22
Bedrock Foundation Elevation (nominal)	111.86 m

42 stoplog bays

35 have net length percent of 2.44 m

7 have net length percent of 1.83 m

Storage = 69.2 x 10^6 m^3 at FSL

Present winter level =112.2 to prevent ice rafting

2. Requirements for the Spillway

NP requires that the new spillway be capable of handling significant flood events without personnel travelling to site. Thus the new spillway must be either statically capable of handling floods, such as an overflow spillway, or partially or fully mechanized and automated for remote operation. The latter requirement necessitates extending the existing 12.5 kV transmission line to the site. The present line is terminated near the Amy's Outlet structure and will have to be extended a distance of approximately 2 km. It is anticipated that 600V, 3 phase motors will be used to operate gate hoists or rubber bladder blowers. A backup diesel generated power supply will be required to operate the facilities when power is not available from the transmission line.

There is an access road to the site which will need to be upgraded for operation of manually operated stoplogs and gates and to maintain the structures.

3. Hydraulics

This section presents the review of hydrology, freeboard requirements, and hydraulic assessment of potential alternatives for the Rattling Lake proposed spillway improvement.

3.1 Hydrology

As noted in Section 1, the Inflow Design Flood (IDF) was determined during previous work for Newfoundland Power as the event with an Annual Exceedance Probability (AEP) of 1/10,000. The peak flow during this event was determined as 416 m^3/s and is based on the report "Flood Hydrology Review Bonavista, Central and West Coast Regions, Newfoundland" prepared by Acres International Limited, May 1999. Since that study was conducted 8 years ago, the hydrometric stations used were reviewed for this study to ensure no significant flood events have occurred recently that could alter the flood estimates presented in the 1999 report. The review indicated that the 1999 results, as estimated for the Rattling Brook Hydroelectric System, would not be significantly different with the recent data included. Therefore, the 1999 study results were considered appropriate to use for this study. Along with estimating the flow for the IDF, it is also important to determine flows with higher AEP's. This will allow an assessment of flood capacity for portions of the spillway that may be automated. Table 3.1 provides the peak flows for AEP's ranging from 1/20 to 1/10,000.

Table 3.1
Flood Estimates

Annual Exceedance Probability	[1]Peak Flow (m^3/s)
1/20	195
1/100	255
1/500	310
1/1,000	335
1/10,000	416

[1]Based on the methodology presented in "Flood Hydrology Review Bonavista, Central and West Coast Regions, Newfoundland"

3.2 Freeboard Requirements

The Rattling Lake dam is an earth embankment dam and the Canadian Dam Association Dam Safety Guidelines recommend that for embankment dams the freeboard should generally be sufficient to avoid dam overtopping for 95 percent of the waves created under specified wind conditions. The guidelines note that the dam crest is normally set at the level which satisfies all of the following conditions.

- Wave conditions and set-up due to wind with a 1/1,000 AEP with the reservoir at its maximum normal level.
- Wave conditions and set-up due to the most severe reasonable wind conditions for the reservoir at its maximum extreme level based on the selected IDF.

Determining the required freeboard is necessary not only to assess the current spillway capacity, but to assess any proposed spillway improvement. Based on the conditions noted above and assuming a side slope of 2H:1V the required freeboard allowance would be 1.2 m. Therefore, for any proposed spillway improvement the difference between the dam crest elevation and IDF water surface elevation would be 1.2 m.

3.3 Hydraulic Assessment of Alternatives

The following alternatives were selected for hydraulic review.

- Option A: Overflow Weir
- Option B: Combination overflow weir sill el. 114.9 m/ automated section sill el. 112.5 m
- Option C: Combination overflow weir sill el. 113.7 m/ automated section sill el. 112.5 m

Although there are a number of structural options among each of these three options (rubber dam, gates, stop logs, quick release gates), for the purposes of ranking options it was assumed that regardless of the structural option, the hydraulics (i.e., spill capacity) would be the same. Therefore, nominal values of spillway length and discharge coefficient were selected for the analysis.

The overall length of the spillway was taken as 100 m. It could be expected that the net effective length would be higher for a rubber dam option compared with a gate/ stop log option, since the latter options would have intermediate piers that would decrease net effective spillway length. It was felt, however, for ranking purposes that this difference would be insignificant. This is the same assumption for the comparison of a rubber dam and gates related to the coefficient of discharge. Since information for the river channel below is not available, it has been assumed that there would be no backwater effects from the channel and that spill would be free flowing over the spillway for the weir/ rubber gate options. It has also been assumed that if mechanical gates are used (or quick release gates), the existing concrete sill would be in place such that if the gates are full open and are above the design water level, weir flow (as opposed to orifice flow) would govern. During final ranking or final design of the selected alternative, a detailed review of spillway capacity should be assessed and modifications to the configuration made, as required.

To assess the spill capacity of the three options noted and to determine the split in spillway length for Option B and Option C, the maximum allowable level was assumed to be 115.1 m. This level was determined as the difference between the existing dam crest elevation (el. 116.3 m) and the required freeboard allowance of 1.2 m. Therefore, for improvement, the maximum reservoir elevation during the IDF would be 115.1 m. Based on this, a hydraulic analysis was conducted and the results follow.

- Option A: Overflow Weir sill el. 113.5 m (Length 100 m)
- Option B: Automated Section sill el. 112.5 m (Length 50 m); Overflow Weir sill el. 114.9 m (Length 50 m)
- Option C: Automated Section sill el. 112.5 m (Length 20 m); Overflow Weir sill el. 113.7 m (Length 80 m)

Based on the sill elevations and lengths noted, and the assumptions noted above, each of the three options would have the required spillway capacity to pass the IDF with an AEP of 1/10,000 without exceeding the maximum allowable level of 115.1 m; therefore, providing the required freeboard allowance. For Option B and Option C, the automated sections would be able to pass a flood with an AEP of 1/1,000 and less than 1/20 up to an elevation of 114.9 m, respectively, before the overflow weir spillway capacity was used. This illustrates the flexibility Newfoundland Power would have in passing events with only the automated sections, and the frequency it could be expected the overflow sections would be used.

Since Rattling Lake attenuates the flood using available surface area and storage, the actual spillway capacity is less then the peak of the flood. As an example, the peak flow for the IDF with an AEP of 1/10,000 is 416 m^3/s; however, the peak flow at the spillway for each of the options noted above is approximately 380 m^3/s. This value can be used to help evaluate spillway alternatives, since it takes into account the reservoir attenuation.

4. Options Considered

4.1 Water Release Options Considered

The following water release structures or device options have been considered.

1. Gravity Overflow Structure

A fixed gravity overflow structure consists of a concrete or rock filled timber crib structure constructed to full supply level height. The overflow structure is overtopped during floods and the water freely spills. The capacity for spill is dependent on the water level above the height of the structure; for a given length of overflow spillway the flood water level will rise until the spill capacity is equal to the reservoir inflows.

A gravity overflow structure can be straight or labyrinth in plan view. The labyrinth shaped overflow spillway enables a longer crest length and hence the ability to increase spill capacity without increasing flood water level. Labyrinth spillways can offer improved hydraulic efficiency and have operated in northern climates but require more careful design. Also the labyrinth spillway can use less concrete than a straight spillway because the base is wider and the shape provides buttressing; however formwork is complicated.

Gravity overflow spillways are cost effective and require no user intervention during a flood. Since there are no moving parts, there is minimal maintenance and no power requirements. Compared with operated spillways, a gravity overflow spillway will require a higher flood water level and hence higher dam heights to provide necessary freeboard above flood water level.

2. Quick Release Stoplogs

Quick release stoplogs consist of timber stoplogs supported by abutments and a central vertical column which can be released by removing a pin or other such fixing mechanism at the top. The central column collapses and the logs, which are half the width of the spillway, are discharged downstream. For this project only timber logs were considered. The timber is sacrificed during the flood and must be retrieved or usually replaced after loss in the flood discharge. The vertical column is usually a steel structural section which can be retrieved and reset after flood succession.

Quick release stoplogs are not used for normal spill, but instead are installed as inexpensive last-resort spillways meant to augment other spillways. Typically, quick release stoplogs cannot be reinstated after release under flow and the bay must be dewatered to re-install the central beam and timber logs. Quick release stoplogs are typically manually actuated with a hydraulic jack, so personnel must travel to site during the flood event and a crest walkway above the stoplogs is required.

3. Vertical Gates

Vertical gates consist of fabricated steel gates set in reinforced concrete abutments with side and bottom seals. The gates are raised and lowered by screw stem operators or cable hoists. For this project only fully automated screw stem hoists were considered.

Vertical crest gates are commonly used operable spillway devices that have proven to be durable, relatively vandal-resistant and can provide 50 years of service with routine maintenance such as greasing and painting. The gates do not have to be fully open, so outflow can be calibrated to the particular flood event. The gate hoists can be manually operated or motorized and automated.

Steel gates are rigid and hence subject to the full load of an ice cover pressing against the gate. The abutments must also be capable of withstanding ice loading. A bubbler system can be used to prevent ice formation near the gates and hence mitigate the ice loads on the gates. For this project it is assumed that a bubbler system is installed and the gates and abutments are not designed to withstand ice loads. Ice can also form on the upstream face of the gate and hinder opening and closing of the gate. Heaters can be installed in the abutments and within the gates (if necessary) to ensure the gates can operate year-round.

Gates require an access walkway across the spillway to permit inspection and maintenance. Spillway gates typically have upstream stoplog slots in the abutments to permit removing the gate periodically for inspection and maintenance.

4. Timber Crest Stoplogs

Timber crest stoplogs consist of individual timber pieces set in concrete abutments guides. For this project, a 1.2 m high panel of timber for each bay was considered. Log panels higher than 1.2 m tend to be difficult to remove manually, which is the usual method used. A walking deck over the log panels is provided for manual removal with special hooks and for log storage.

The main advantages of timber stoplogs is that they are inexpensive and the system is easy to repair – simply replace any damaged logs. The primary disadvantages are the labour involved, the associated personnel safety concerns, and difficulty closing the openings under flow. NP estimates that it takes about 50 continuous hours to fully open the existing stoplog structure. Crest stoplogs which are only 1.2 m high would be easier to open and close than the existing 2.4 and 3.0 m high logs. Flood monitoring and watershed management are more important when relying on stoplogs because of the slow response time to open or close.

5. Rubber Dams or Gates

Rubber dams or gates consist of a rubber bladder which is inflated by air blowers or compressors. Two general types have been considered; a simple rubber bladder and steel panels supported by rubber bladder such as manufactured by Obermeyer Hydro, Inc. For the purposes of this study, it is assumed that the rubber dam or gate will be 2.4 m high.

The simple rubber bladder dam is common in Canada for the past twenty years. It is manufactured by Bridgestone, Sumimoto Electric, and Qingdao Huaxia Rubber Belt Co. Research for this project revealed that Bridgestone cannot supply any product until 2010 due to full manufacturing capacity and the latter two manufacturers are represented by Dyrhoff in Norway.

The Obermeyer Water Control Gate features inclined steel panels which are supported by and raised/lowered by a rubber bladder which is under the panels and anchored to a concrete base. The steel panels are hinged to the base. At the ends are concrete abutments with UHMW polyethylene panels against which the steel panels provide a water seal.

Both types of air bladder controlled spillway offer several advantages which have contributed to their popularity.

- Normally there is no bridge across the top of the bladder because there is no need for personnel access.
- The bladders can be partially inflated to control upstream water level and the rate of spill.
- Both have measures to resists the pressures of ice sheets. The simple rubber bladder is flexible and moves readily with ice expansion and contraction. The Obermeyer gate will automatically lower the panels when pressure inside the bladder exceeds a set value and thereby sluice the ice sheet The side panels can be heated if there is a need to operate the gate when ice is present.
- These types of spillways require little maintenance and are very suitable for remote automation. The rubber bladders can be easily repaired and would not fail except in the case of very large cuts or tears.

Air bladder controlled spillways generally have a shorter service life (about 30 years) than steel gates or gravity overflow spillway. The rubber bladder can be vandalized but is repairable. The air compressor or blower starts as needed to maintain set pressure in the bladder. The simple bladder gate will concentrate flows in the centre of the gate when partially deflated. Each manufacturer has unique design details to address concerns with noise while spilling and debris passing when fully deflated.

4.2 Combinations

Combinations of water release options were evaluated for cost. Combinations were created based on meeting the following criteria.

1. Some form of automatic operation is desirable in order to avoid personal attendance during routine flooding. As an objective, one half of the design spillway capacity of 380 m^3/sec or 190 m^3/sec is a desirable minimum to achieve where practical.
2. The crest of the earth dams may require raising to ensure adequate freeboard in combination with the alternatives and water release options in order to maintain the minimum freeboard of 1.2 m. The recommended maximum flood water level without crest raising is 115.1 m.

   Existing Freeboard:

Top of Dam Elevation	=	116.3 m
Full Supply Level (FSL)	=	114.9 m
Existing Freeboard at FSL	=	1.5 m
Required Freeboard	=	1.2 m

3. Some alternatives require power supply to the spillway. We have assumed that a diesel powered backup generator will be installed with those combinations requiring power to ensure uninterrupted operation and control.

The following hydraulically equivalent combination options were selected for costing.

Option 1 – 100 m long gravity overflow with 1.5 m high freeboard added.

Option 2 – 60 m long gravity overflow with 40 m gated section (steel vertical lift gates). No freeboard adjustment.

Option 2.1 – 60 m long gravity overflow with 40 m rubber dam/gate. No freeboard adjustment.

Option 2.2 – 60 m long gravity overflow section 20 m long rubber gate and 20 m long quick release stoplogs. No freeboard adjustment.

Option 2.3 – 80 m long gravity overflow with 1.2 m high stoplogs and a 20 m long rubber gate/dam and no freeboard adjustment.

Option 3 – 100 m long overflow with 1.3 m high timber stoplogs and no freeboard adjustment.

Option 4 – 2 vertical steel crest gates by 5 m width, 30 m long section of quick release stoplogs with 60 m long overflow section with no freeboard adjustment.

Option 4.1 – 2 vertical steel crest gates, 90 m long gravity overflow section including 76 m with 1.2 m high stoplogs with no freeboard adjustment.

Option 5 – 250 m long labyrinth shaped overflow in the 100 m wide opening with 1 m of freeboard added.

4.3 Manual Operation, Automation and Power Supply

- **Manual Operation**

  Crest stoplog panels or quick release facilities will require access for manual operation.

- **Automation**

  Where rubber or steel gates are used, automation for control open or closed from a remote station through the Rattling Brook powerhouse control room will be required. An enclosure to house control and equipment such as compressors blowers and PLC will be required near the spillway.

- **Power Supply**

  Where electric power is required for facilities, the power supply will be an overhead line taken off the 12.5 KV , 3 phase line to the Amy's outlet gate. The line will be transformed at the site to 600 volt and other voltages required at the control enclosure.

  A back-up power supply consisting of a diesel generator with automatic stop start and transfer switch will be provided.

- **Winter Heating**

  Where heating devices for sealing faces are required, suitable devices such as strip heaters will be included.

5. Cost Evaluation and Ranking

Estimates were made with limited quantity take-offs combined with unit prices from previous and current projects. Unit prices include all contractors' overhead and profit. Gate and quick release and crest stoplogs were assessed on a per bay basis and rubber dams and overflow weirs on a per lineal metre basis with fixed costs added in each case.

5.1 Data

Rubber dam costs were made from data bases in our files including the quotes made to NP for rubber dams at this site in 2005 along with current budget prices provided by Obermeyer Inc. and Qingdao Huaxia. It should be noted that Bridgestone Inc. were unable to quote for deliver in 2008 because of production backlogs. Hatch has included crest gate options incorporating only the Armtec gate prices because the Fontaine slide gates were deemed to be less robust and more troublesome from an operating perspective especially in winter. Note that neither steel crest gate is designed for ice pressures and heat and or/ air bubbler systems have been incorporated in estimates.

Budget pricing was provided by Armtec for gates and screw stems and by Fontaine International Corporation.

Timber stoplogs with an in house quick release design were used to cover the quick release option.

Reinforced concrete structures were used for gravity overflow options.

5.2 Contingency and Indirect Costs

The estimates are considered to be in the plus 20 percent minus 10 percent range.

An allowance of 10 percent is included to cover engineering, design, project management and owner's costs.

A contingency of 20 percent has been included to account for changes and other fluctuations up to the tendering time.

Cost estimates for each option is shown in Figures 5.1 and 5.2.

Rattling Brook Hydroelectric Development

Main Spillway Replacement Assessment
Cost Estimates
Prices for Unit Lengths of Structure

Estimating Prices			2.4 m of Quick Release Stoplogs		2.4 m Section 1.2 m Crest Stoplogs Gravity Dam		5 m Wide Gates Each Steel Crest Gate		Lineal Metre Rubber Dam		1.5 m on Crest Lineal Metre Concrete Overflow		1.0 m on Crest Lineal Metre Labyrinth Overflow	
	Unit	Unit Price	Qty	Total	Qty	Total	Qty	Total	Qty	Total	Qty	Total	Qty	Total
Mobilization, Demobilization and Access	LS	$100,000	1	$100,000	1	$100,000	1	$100,000	1	$100,000	1	$100,000	1	$100,000
Demolition	LS	$50,000	1	$50,000	1	$50,000	1	$50,000	1	$50,000	1	$50,000	1	$50,000
Clearing and Grubbing	m^2	$2		$0		$0		$0		$0		$0		$0
Prepare Dam Crest	m^2	$2		$0		$0		$0		$0	6050	$12,100	6050	$12,100
Load, Haul and Place Impervious	m^3	$25		$0		$0		$0		$0	15730	$393,250	8470	$211,750
Load, Haul and Place Filter and Drain	m^3	$20		$0		$0		$0		$0	330	$6,600	330	$6,600
Load, Haul and Place Gravel	m^3	$15		$0		$0		$0		$0	1089	$16,335	1089	$16,335
Load, Haul and Place Rip Rap	m^3	$45		$0		$0		$0		$0	3630	$163,350	3630	$163,350
Rock Excavation	m^3	$30	4.8	$144	4.8	$144	2	$60	2	$60	2	$60	2	$60
Foundation Preparation	m^2	$2		$0		$0		$0		$0	4	$8	4	$8
Concrete incl. Formwork, Rebar,etc	m^3	$980											8	$7,840
Concrete incl. Formwork, Rebar,etc	m^3	$700	18	$12,600	18	$12,600	20	$14,000	4	$2,800	12	$8,400		
Embedded Parts	kg	$8	90	$720	40	$320		$0		$0		$0		$0
Miscellaneous Steel	kg	$6	180	$1,080		$0		$0		$0		$0		$0
Handrailings, Fences and Barriers	kg	$6	75	$450	75	$450	75	$450	75	$450		$0		$0
Timber Stoplogs	m^2	$130	5.76	$749	2.88	$374		$0		$0		$0		$0
Quick Release Mechanism	LS	$10,000	1	$10,000		$0		$0		$0		$0		$0
Crest Gate Embeds	Each	$35,000		$0		$0	1	$35,000		$0		$0		$0
Crest Gate	Each	$124,800		$0		$0	1	$124,800		$0		$0		$0
Gate Installation	LS	$35,000		$0		$0	1	$35,000		$0		$0		$0
Hoist	Each	$71,000		$0		$0	1	$71,000		$0		$0		$0
Gate Limit Switches and Protection	LS	$15,000		$0		$0	1	$15,000		$0		$0		$0
Hoist Remote Control	Each	$10,000		$0		$0	1	$10,000		$0		$0		$0
Basic Remote Automation	LS	$30,000		$0		$0		$0		$0		$0		$0
Rubber Dam	m	$14,000		$0		$0		$0	1	$14,000		$0		$0
Rubber Dam Embeds	LS	$300		$0		$0		$0	1	$300		$0		$0
Rubber Dam Ancilliary	LS	$100,000		$0		$0		$0		$0		$0		$0
Rubber Dam Installation	m	$1,500		$0		$0		$0	1	$1,500		$0		$0
Equipment Enclosure	LS	$30,000		$0		$0		$0				$0		$0
Back-up Power Supply	LS	$50,000		$0		$0		$0		$0		$0		$0
Power Supply	LS	$80,000		$0		$0		$0		$0		$0		$0
Sum of Unit Costs				$25,743		$13,888		$305,310		$19,110		$8,400		$7,908
Sum of Fixed Cost				$150,000		$150,000		$340,100		$450,000		$741,635		$560,135
			2.4 m of Quick Release Stoplogs		2.4 m Section 1.2 m Crest Stoplogs Gravity Dam		5 m Wide Gates Each Steel Crest Gate		Lineal Metre Rubber Dam		1.5 m on Crest Lineal Metre Concrete Overflow		1.0 m on Crest Lineal Metre Labyrinth Overflow	
														Figure 5.1

Rattling Brook Hydroelectric Development

4/23/2007

Main Spillway Replacement Assessment
Cost Estimates
Total Structure Cost By Option

	Total Construction Cost	Indirect Cost 30%	Total Project Cost	Cost Ranking	Percent Automatic Regulation	Frequency Flood Handled Automatically	Spillway Flood Flow Handled m^3/s		Rubber Dam H X Length	Steel Crest Gate No. X H	Overall Lm	Quick Release Stoplogs No. X H	Overall Lm	Crest Stoplogs No. X H	Overall Lm	Straight Overflow Overall Lm	Labyrinth Overall Lm	Freeboard Adjustment m
Option 1	$1,581,635	$474,491	$2,056,126	6	100	10000	360	Option 1								100		1.5
Option 2	$3,286,580	$985,974	$4,272,554	9	100	10000	360	Option 2		8 X 2.7	40					60		0
Option 2.1	$1,718,400	$515,520	$2,233,920	8	100	10000	360	Option 2.1	2.4 X 40							60		0
Option 2.2	$1,548,864	$464,659	$2,013,523	5	100	10000	360	Option 2.2	2.4 X 20			8 X 2.7	19.2			60.8		0
Option 2.3	$1,366,225	$409,867	$1,776,092	2	100	10000	360	Option 2.3	2.4 X 20					22 X 1.2	52.8	27.2		0
Option 3.0	$1,538,840	$461,652	$2,000,492	4	100	10000	360	Option 3.0						42 X 1.3	100			0
Option 4.0	$1,625,189	$487,557	$2,112,746	7	100	10000	360	Option 4.0		2 X 2.7	10	13 X 2.7	31.2			58.8		0
Option 4.1	$1,506,029	$451,809	$1,957,837	3	100	10000	360	Option 4.1		2 X 2.7	10			32 X 1.2	76.8	13.2		0
Option 5	$1,350,935	$405,281	$1,756,216	1	100	10000	360	Option 5									250	1

Notes:

Indirects cost includes contingency of 20% and Engineering and Owner's cost of 10%
HST is not included
There are no environmental impact costs included
All structures are assumed to be built along existing structure centrelines

Option 1 gravity concrete overflow weir and add 1.5 m of freeboard
Option 2 2.4 m high by 5 m wide by 8 no. vertical steel gates by 60 m long gravity overflow-no freeboard adjustment
Option 2.1 2.4 m rubber dam by 40 m long with 60 m long gravity overflow-no freeboard adjustment
Option 2.2 20 m long rubber dam, 20 m long quick release stoplogs with 60 m long overflow section with no freeboard adjustment
Option 2.3 80 m long gravity overflow with 53 m long section of 1.2 m high timber stoplogs and 20 m long rubber dam
Option 3.0 100 m long overflow with 1.3 m high stoplogs and no free board adjustment
Option 4.0 2 vertical steel gates by 5 m wide, 30 m long quick release stoplogs with 60 m long overflow section with no freeboard adjustment
Option 4.1 2 vertical steel crest gates, 90 m long gravity overflow with 76 m long section of 1.2 m high timber stoplogs
Option 5 250 m long labyrinth-shaped spillway and add 1 m of freeboard

Figure 5.2

6. Summary of Findings and Recommendations

The preferred option is a labyrinth shaped reinforced concrete overflow spillway combined with a crest raising of 1.0 m for the Rattling/Amy's Lake dams. It is the least cost solution, is fully automatic being an overflow weir. The crest of the dams and dykes require a minimal raising by 1 m to maintain a freeboard of 1.2 m during design flood occurrence. The Rattling/Amy's dams and dykes can be raised by 1 m and no major technical problems are anticipated in completing this work. Anticipated construction would consist of an extension of the central glacial till core, filters, rockfill shoulders and riprap.

It is recommended that the spillway be replaced with the labyrinth spillway in 2008. Estimated total costs including indirect costs is $1.8 million.

Appendix A

Background Article

- Labyrinth Spillway Article, "Power to the People", International Water Power & Dam Construction, December 1996

A unique partnership in the Northwest Territories in Canada between indigenous people, private and public initiatives, has led to the first Canadian hydro project of its kind to be 100% owned by local communities. Part of the Dogrib Power Project, the latest phase of development of the Snare River system was completed earlier this year, but had many obstacles to overcome - not least the climate and isolation of the area.

Power to the People

By Richard Slopek, George Leseberg** and Al-Nashir Jamal†*

The Snare Cascades Hydro Project is located on the Snare River in the Northwest Territories, Canada, approximately 200km north of Yellowknife. Here winter temperatures reach 45°C and the long winter season creates problems in gaining access to remote communities. It is costly to provide all-weather roads over permafrost so access to the site is only available over winter roads from late January to mid-March and by air the rest of the year.

The contract for the 4.3MW project was awarded to PCL-Monenco AGRA, a joint venture, in autumn 1994, following a proposal in December 1993. Nishi-Khon/SNC Lavalin Ltd, a member of the Dogrib Nation Group of Companies, was appointed as the owner's representative.

Design of the labyrinth spillway across the Snare River, the power canal and the powerhouse progressed rapidly to meet the construction constraints set by climatic conditions - that included 35km of ice roads over lakes. By early 1995, movement of equipment, materials and camp construction had commenced. About 200 truck loads brought in materials and equipment. The main items included 1260 bags of cement each weighing 1.5t, 300t of reinforcement, a rock crusher, concrete batching plant, intake and draft tube gates, trash racks, the main power transformer, the overhead crane and the draft tube liner. By the end of March 1995, excavation had begun and work was underway.

The civil work was almost completed by December 1995, including the construction of the eleven cycle labyrinth spillway across the Snare River. The labyrinth walls are 1.88m high and the weir crest elevation is set at 182.88m, the full supply level. The spillway is designed to pass the one in 1000 year design flood of 500m^3/sec at a high water elevation of 184.5m. The 230m long power canal and power house were also completed during this time while the major turbine and electrical components were delivered to site over the 1996 winter roads. Sulzer Hydro supplied the 'S' type turbine designed to generate 4.3MW with a rated gross head of 9.15m.

Aboriginal owned

The Dogrib First Nation people are the owners of the power plant through the Dogrib Power Corporation (DPC). The company was set up under the Dogrib Treaty 11 Council, following the council's 1992 decision to promote sustainable development in the region. The council approached the Northwest Territories Power Corporation (NWTPC) that year to explore potential initiatives. The corporation was evaluating the Cascades site as a potential fourth hydro development on the Snare River system.

In March 1993, during the United Nation's Year of Indigenous People, an agreement in principle was signed between the two parties, so creating a partnership for the development and operation of the project. The benefit to the community included workforce targets of up to 60%, Dogrib hiring on site at peak construction and training for a number of positions. This training included a classroom programme carried out by a local community college augmented with formal training from the partners in the construction joint venture.

Cascades project

Plans for a fourth hydro scheme had existed since 1977. In fact, the main equipment for the project, including turbines and generators, had been purchased at the time but the project was subsequently cancelled and the equipment eventually sold. After two subsequent reviews during 1981 and 1992 the plans were revitalised in a formal agreement with the Dogrib Power Corporation in 1993.

Prospective bidders were asked to tender on the arrangement shown in figure 1. The head available was restricted by the tailwater level from the upstream Snare Falls plant and the forebay level of the downstream Snare Forks station. The new plant was designed for an

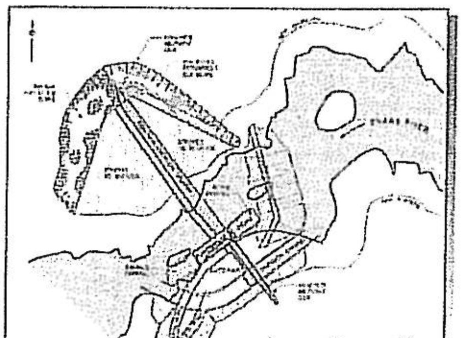

Fig.1: Original layout plan of Snare Cascades project, showing straight spillway.

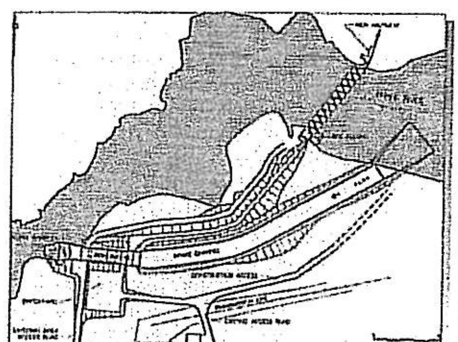

Fig 2. Proposed alternative arrangement plan

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average forebay level of 182.88m and an average tailwater level of 173.52m. The spillway was to be designed to discharge a design flood of 500m^3/sec at a high water elevation of 184.5m.

An alternative arrangement was developed by PCL/Monenco AGRA and this concept won the approval of the Dogrib Power Corporation. The main changes consisted of deleting the concrete straight overflow spillway and constructing a labyrinth spillway further upstream. The powerhouse was also relocated which reduced its height from 6.88m to 2.88m (see figure 2).

Power canal

The power canal was designed to maintain flow velocities of less than 0.6m/sec in order to minimise head losses and allow for the formation of a stable ice cover at the onset of winter.

The powerhouse contains a single 4.3MW double regulated horizontal shaft 'S' turbine direct-coupled to a synchronous generator. The intake portion consisted of a reinforced concrete structure complete with trash racks and a 'wheeled' head gate. The contract called for the trash racks to be designed for full headwater pressure. This was needed because no facilities were to be provided for installing stoplogs upstream of the head gate for maintenance purposes. Instead, the dewatering procedure required that sheets of plywood be installed over the trash racks to dewater the intake section.

The substructure for the powerhouse consisted of mass concrete with reinforced concrete walls, and the superstructure above ground level comprised metal cladding and insulation. The roof was made of standing seam decking. The draft tube 'slide' gate was located within the powerhouse, and was designed to be lifted in still water using the powerhouse crane. The 45t powerhouse crane, which was designed to lift the heaviest component, provided adequate capacity for lifting the draft tube gate. Both the draft tube gate and the head gate are located within the powerhouse. This is to provide heat to the slots and prevent freezing in the gates during the cold winter months.

Fig.3: Project location map.

Spillway

The original layout was based on a straight overflow spillway. It would have needed to be about 115m long in order to discharge the peak river conditions. The full supply level of 182.88m provided the required sill elevation for the spillway. In order to provide sufficient overflow spillway length, it would have required a 45m excavation into the right abutment (see figure 1). This posed some concerns because of the presence of permafrost in this area. The alternative proposal of a labyrinth spillway minimises the excavation required. Also, by moving the spillway upstream of the cascades, the overall height of the structure was reduced.

The use of labyrinth spillways is not uncommon when there are constraints with the amount of frontage available to pass flows. Numerous studies have been carried out involving model and prototype tests. The hydraulic design of the spillway was based on parameters obtained from the Navet Pumped Storage Spillway in Trinidad which was of similar size. Table 1 compares the size and capacity of the two spillways.

Due to the similarity of the two structures, it was decided that hydraulic model testing would not be carried out. Instead the design would be based on designed curves developed for similar structures with a degree of conservatism thrown in. Figure 5 shows the discharge magnification curves presented by Phelps (1974) and the curves

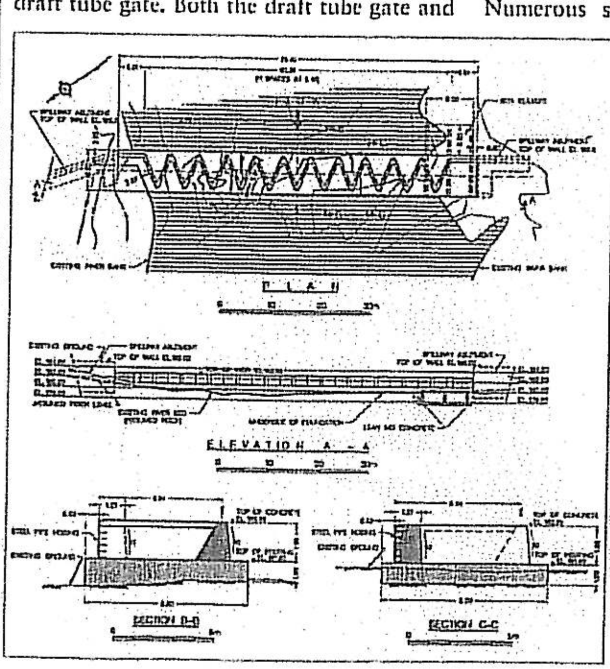


Fig.4: Plan of revised labyrinth spillway, showing sawtooth design.

References

1) Hinchliff, D.L. and Houston, K.L., January 1984. Hydraulic Design and Application of Labyrinth Spillways. US Bureau of Reclamation,Denver, Co, USA.

2) Phelps, H.O., March 1974. Model Study of Labyrinth Weir - Navet Pumped Storage Project. University of the West Indies, Faculty of Engineering, Department of Civil Engineering, Series No.6.

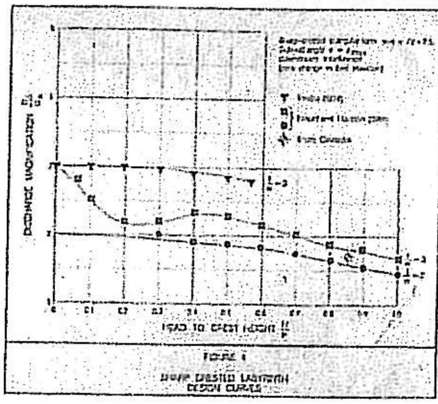


Fig.5: Sharp-crested labyrinth spillway design curves.

by Hinchcliff and Houston (1984) used to size the Snare Cascades structure. The lower value of 1.7, highlighted in figure 5, was selected as the basis for sizing the spillway. Essentially, this meant that the spillway frontage could be reduced by about 40% resulting in the entire spillway being located in the existing river channel. A discharge curve for the spillway was developed based on this value (see figure 7). To date the spillway has only seen nominal flows, however, when runoff starts, the head required to pass the flows will be measured to confirm the capacity of the spillway.

Table 1.

Description	Navet	Snare Cascades
Width of structure	54.86m (180ft)	60.39m
Developed weir length	137.16m (450ft)	150.98m
Developed crest length/cycle	13.72m (45ft)	13.72m
Width/cycle	5.49m (18ft)	5.49m
Length magnification	2.5	2.5
Number of cycles	10	11
Head for maximum discharge	1.52m (5ft)	1.62m
Height of weir above apron	3.05m (10ft)	1.88m
Ratio h/p	0.5	0.86
Ratio w/h	3.6	3.39
Design discharge	480m³/sec (17 000cfs)	500m³/sec

The climate is the main differentiating factor between the two spillways and the temperature extremes provided the key parameters for the Cascades design. The geometry of the labyrinth spillway wall system (figure 6) was such as stiff boundary conditions enhanced the potential for cracking due to internal forces caused by shrinkage and temperature changes. As a result, pour sequences isolating the stiffer end nodal points from the straight infill walls between the nodes, were used to lessen shrinkage stress. These pour sequences can be identified by the construction joints located on the labyrinth walls at the centre of the straight walls. The upstream sections were poured first, followed by the downstream ones.

Temperature forces were modelled using a finite element program. This assumed both a uniform temperature change from the pouring and setting temperature as well as a temperature gradient between the upstream submerged wall and the down walls that were exposed to cold air. Additional horizontal reinforcement was added to the downstream face to account for the stress due to the thermal gradient.

The upstream pier noses are protected from ice and debris with a steep pipe nosing. The inner portion of the saw tooth spillway arrangement was given a sloped face. This reduces the loads on the spillway when the ice is sluiced over the spillway. During the first winter after the spillway was completed, it was necessary to divert flows over the spillway while construction inside the powerhouse and installation of the mechanical and electrical equipment continued. Figure 6 shows the ice cover that built up in front of the spillway, as well as the open water surface immediately at the labyrinth spillway walls. The spillway discharges approximately 40m^3/sec during summer.

Construction constraints

Under the contract terms, there were only two winter seasons allowing vehicle access available during the construction period to meet the planned commissioning date of 1 July 1996.

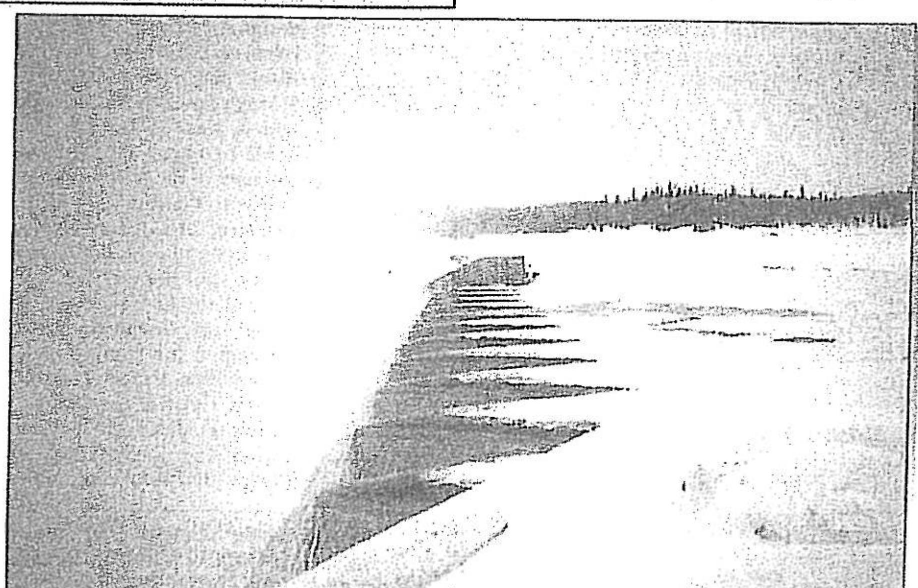


Fig.6: Sawtooth spillway reduces build up of snow and ice during winter operation.

Aerial view of the Snare Cascades project.

The first summer period was dedicated to civil engineering work, while the second summer would be used to complete the mechanical and electrical installations.

A camp to accommodate a peak work force of 70 and materials moved in. The turnaround period established for construction staff was a four week in and one week out period. Experience with similar projects indicated that these were the optimum periods to maximise productivity without jeopardising safety. A safety initiative programme was established which rewarded staff for a good safety record. This proved very effective as the project was completed with only a few, very minor injuries. Work scheduling was based on the assumption that productivity in extreme temperatures would be about 60% of that carried out in more moderate conditions.

Clearing and site excavation began in March 1995. Excavated materials were crushed to produce concrete aggregate and local sand processed and stockpiled for future use. By June, concrete was poured in the powerhouse foundations with construction of the labyrinth spillway initiated in August after a diversion conduit was constructed at the left bank of the Snare river beneath the first cycle of the spillway.

On September 22, 1995, a topping-off ceremony was held for the placement of the last bucket of concrete. Erection of the structural steel and cladding to the powerhouse followed in October with work carrying through until Christmas 1995. After a brief pause, work resumed in January to meet the arrival of the turbine and generator components delivered along the winter roads. Any unwanted equipment and materials were also removed at this time to avoid additional costs in having such equipment idle for a further year. The number of people working at the site was also halved.

Equipment commissioning commenced in April 1996 and on May 27 the unit was synchronised with the NWTPC grid for the first time. Plant commissioning was completed on June 29, 1996 when the station was formally handed over to DPC and NWTPC, joint operators of the power station.

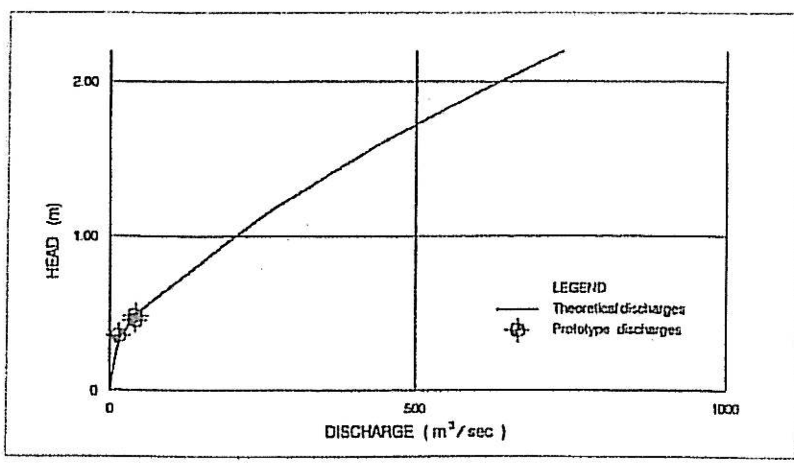
Working together

The Snares Cascade hydroelectric project is an example of how aboriginal-public-private partnership can work together to have a responsible, people-centred, sustainable development. It demonstrates, too, how climate and locale can be overcome to build a state of the art development. The labyrinth spillway was selected because of concerns of excavating into the river banks and exposing permafrost and the problems associated with working in this type of material. While adopting this type of spillway for restricted space reasons is fairly common, the climatic conditions made this approach unique. In the end, the extreme temperature differentials did not present any problems that could not be overcome in the design.

Acknowledgments

The authors would like to thank the Dogrib Power Corporation, PCL Civil Construction (Canada) Inc. and Monenco AGRA Inc. for their permission and support in the preparation of this article.

Fig.7: Spillway discharge curve for Snare Cascades.



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Appendix B

Feasibility Analysis

Table of Contents

1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Rattling Brook hydroelectric development. The continued long-term operation of the Rattling Brook hydroelectric development is reliant on the completion of capital improvements in 2011. Planned improvements include replacement of Rattling Lake Spillway and upgrades to Rattling Lake and Amy's Lake Dams and Freeboard Dykes.

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 capital expenditures required to maintain the safe and reliable operation of the facilities are summarized in Table 1.

Table 1
Hydroelectric Development
Capital Expenditures

Year	(000s)
2011	2,600
2012	4,500
2016	850
2017	1,050
2025	1,800
2030	1,500
2032	1,500
Total	**$13,800**

The total capital expenditure of all of the projects listed above is $13,800,000. 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 in the order of $318,432 per year. This estimate is based primarily 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 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 (Water Resources Management Division) based on yearly hydro plant production. Such a charge is not reflected in the historical annual operating costs for the Rattling Brook development. Therefore, an adjustment is applied to account for the associated increased operating expenses on a go-forward basis.

4.0 Benefits

The estimated long-term normal production at this plant under present operating conditions is 78.1 GWh per year. This estimate is based on the results of the Water Management Study completed by SGE Acres in 2005 and adjusted for the increase in production associated with the 2007 plant upgrades.

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 Rattling Brook plant over the next 50 years is 1.52 cents per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Rattling Brook can be produced at a significantly lower price than the cost of replacement energy, assumed to come from Newfoundland and Labrador Hydro's Holyrood thermal generating station.[1]

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

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[1] The cost of electricity from the Holyrood thermal generating station is estimated at 11.63¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $73.30 per barrel for 2010 as per Newfoundland Hydro 2010 Capital Budget Application, Generation Planning Issues 2009 Mid Year Report dated July 2009.

6.0 Recommendation

The results of this feasibility analysis show that the continued operation of the Rattling Brook hydroelectric development is economically viable. Investing in the life extension of facilities at Rattling Brook guarantees the availability of low cost energy to the Province. Otherwise the annual production of 78.1 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 2011. 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

Description	2011	2012	2016	2017	2025	2030	2032
Civil							
Dams, spillways	$2,600						
Amy's Tunnel Upgrade						$1,500	$500
Fish Passage Structure		$4,500					
Forebay Intake					$1,500		
Amy's Gate				$200			
Frozen Ocean Dam/Outlet					$300		
Mechanical							
Unit No. 1 Turbine Overhaul			$850				
Unit No. 2 Turbine Overhaul				$850			
Unit No. 1 Replacement Runner							
Unit No. 2 Replacement Runner							
Governor Upgrades							$500
Electrical							
Controls Upgrade							$500
Annual Totals ($2011)	**$2,600**	**$4500**	**$850**	**$1050**	**$1,800**	**$1,500**	**$1,500**

Attachment B

Summary of Operating Costs

Rattling Brook Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs	
Year	**Amount**
2005	$ 233,081
2006	265,216
2007[1]	134,254
2008	247,334
2009	284,895
Average	**$ 257,631**

5-Year Average Operating Cost	$257,632
Water Power Rental Rate[2]	60,800
Total Forecast Annual Operating Cost	$318,432

[1] In 2007 operating costs were lower due to plant being out of service for an extended period for penstock replacement and other upgrades. Hence 2007 costs were not included in 5 year average.
[2] ($0.80/MWh * 76,000 MWh/yr)

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted average Incremental Cost of Capital 7.68%
Present Worth Year 2010

YEAR	Generation Hydro 64.4yrs 8% CCA	Generation Hydro 64.4yrs 50% CCA	Capital Revenue Rqmt	Operating Costs	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2011	-	2,600,000	(5,690)	318,432	(312,742)	(290,437)	(290,437)	0.40	1.52
2012	4,595,313	-	321,569	325,177	(646,746)	(557,781)	(848,217)	0.83	1.52
2013	-	-	500,062	332,382	(832,444)	(666,730)	(1,514,947)	1.07	1.52
2014	-	-	598,641	338,655	(937,296)	(697,167)	(2,212,114)	1.20	1.52
2015	-	-	646,517	345,233	(991,751)	(685,058)	(2,897,172)	1.27	1.52
2016	-	937,890	666,602	351,358	(1,017,960)	(653,011)	(3,550,183)	1.30	1.52
2017	224,702	954,985	662,553	357,762	(1,020,315)	(607,840)	(4,158,022)	1.31	1.52
2018	-	-	702,279	364,321	(1,066,600)	(590,094)	(4,748,116)	1.37	1.52
2019	-	-	806,410	371,156	(1,177,566)	(605,020)	(5,353,136)	1.51	1.52
2020	-	-	853,807	378,039	(1,231,846)	(587,768)	(5,940,904)	1.58	1.52
2021	-	-	872,562	385,144	(1,257,707)	(557,306)	(6,498,210)	1.61	1.52
2022	-	-	876,745	392,303	(1,269,048)	(522,225)	(7,020,435)	1.62	1.52
2023	-	-	873,408	399,607	(1,273,015)	(486,495)	(7,506,930)	1.63	1.52
2024	-	-	866,099	406,855	(1,272,954)	(451,775)	(7,958,705)	1.63	1.52
2025	1,952,836	390,567	1,031,448	414,564	(1,446,012)	(476,591)	(8,435,296)	1.85	1.52
2026	-	-	1,000,893	422,307	(1,423,200)	(435,618)	(8,870,913)	1.82	1.52
2027	-	-	1,020,063	430,121	(1,450,183)	(412,218)	(9,283,132)	1.86	1.52
2028	-	-	1,023,330	438,150	(1,461,480)	(385,800)	(9,668,931)	1.87	1.52
2029	-	-	1,018,341	446,440	(1,464,781)	(359,093)	(10,028,024)	1.88	1.52
2030	2,143,265	-	1,201,772	454,990	(1,656,762)	(377,189)	(10,405,214)	2.12	1.52
2031	-	-	1,182,399	463,703	(1,646,102)	(348,033)	(10,753,247)	2.11	1.52
2032	2,226,142	-	1,371,006	472,583	(1,843,589)	(361,987)	(11,115,234)	2.36	1.52
2033	-	-	1,350,140	481,633	(1,831,774)	(334,015)	(11,449,249)	2.35	1.52
2034	-	-	1,337,718	490,857	(1,828,575)	(309,650)	(11,758,899)	2.34	1.52
2035	-	-	1,323,961	500,257	(1,824,218)	(286,880)	(12,045,780)	2.34	1.52
2036	-	-	1,309,025	509,838	(1,818,862)	(265,637)	(12,311,417)	2.33	1.52
2037	-	-	1,293,029	519,601	(1,812,630)	(245,846)	(12,557,262)	2.32	1.52
2038	-	-	1,276,071	529,552	(1,805,623)	(227,429)	(12,784,691)	2.31	1.52
2039	-	-	1,258,234	539,694	(1,797,927)	(210,308)	(12,994,999)	2.30	1.52
2040	-	-	1,239,591	550,029	(1,789,620)	(194,406)	(13,189,405)	2.29	1.52
2041	-	-	1,220,208	560,563	(1,780,771)	(179,648)	(13,369,053)	2.28	1.52
2042	-	-	1,200,146	571,298	(1,771,444)	(165,961)	(13,535,014)	2.27	1.52
2043	-	-	1,179,459	582,239	(1,761,697)	(153,276)	(13,688,290)	2.26	1.52
2044	-	-	1,158,197	593,389	(1,751,585)	(141,527)	(13,829,817)	2.24	1.52
2045	-	-	1,136,406	604,753	(1,741,159)	(130,651)	(13,960,468)	2.23	1.52
2046	-	-	1,114,129	616,334	(1,730,463)	(120,587)	(14,081,055)	2.22	1.52
2047	-	-	1,091,404	628,137	(1,719,542)	(111,280)	(14,192,335)	2.20	1.52
2048	-	-	1,068,268	640,167	(1,708,435)	(102,675)	(14,295,010)	2.19	1.52
2049	-	-	1,044,754	652,426	(1,697,180)	(94,724)	(14,389,734)	2.17	1.52
2050	-	-	1,020,890	664,921	(1,685,811)	(87,379)	(14,477,113)	2.16	1.52
2051	-	-	996,707	677,655	(1,674,361)	(80,596)	(14,557,709)	2.14	1.52
2052	-	-	972,228	690,632	(1,662,860)	(74,333)	(14,632,042)	2.13	1.52
2053	-	-	947,478	703,858	(1,651,337)	(68,553)	(14,700,596)	2.11	1.52
2054	-	-	922,479	717,338	(1,639,817)	(63,220)	(14,763,816)	2.10	1.52
2055	-	-	897,250	731,075	(1,628,325)	(58,299)	(14,822,115)	2.08	1.52
2056	-	-	871,810	745,076	(1,616,886)	(53,761)	(14,875,876)	2.07	1.52
2057	-	-	846,175	759,345	(1,605,520)	(49,576)	(14,925,452)	2.06	1.52
2058	-	-	820,362	773,887	(1,594,249)	(45,717)	(14,971,168)	2.04	1.52
2059	-	-	794,384	788,707	(1,583,092)	(42,159)	(15,013,327)	2.03	1.52
2060	-	-	768,255	803,812	(1,572,067)	(38,879)	(15,052,206)	2.01	1.52
2061	-	-	741,987	819,205	(1,561,192)	(35,857)	(15,088,063)	2.00	1.52

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects a statutory income tax rate of 32%.

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%	6.61%	3.63%
Common Equity	45.00%	9.0%	4.05%
Total	**100.00%**		**7.68%**

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 16, 2010.

Sandy Brook Hydro Plant

Refurbishment

June 2010

Prepared by:

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1.0 Introduction

The Sandy Brook hydroelectric generating plant (the "Plant"), located in central Newfoundland near the town of Grand Falls-Windsor, was commissioned in 1963 with a capacity of 6.4 MW. The plant contains a single vertical 8,000 hp Francis turbine manufactured by Dominion Engineering and a Canadian Westinghouse generator. The unit is automated and controlled remotely through the SCADA system. The Plant is connected to the Island interconnected electrical system at Grand Falls substation via Newfoundland Power's transmission line 105L.

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:

1986 – Capacitors replaced
1997 – Brush temperature sensors, and vibration sensors added
1999 – Cooling water system upgraded
2000 – Station service transfer switch installed
2001 – Instrumentation and Programmable Logic Controller ("PLC") installed
2001 – Power cables, runner and wicket gates replaced
2004 – Bearing oil level sensors added
2007 – Battery bank and charger replaced

This assessment is based upon a site inspection completed on March 4, 2010.

2.0 Governor

The governor is a Woodward Model HR size 10 x 14 gate shaft hydraulic unit. It has a rated torque of 16,300 ft-lbs and pressure supplied by a size 27 gear pump. The unit was reconditioned in 2001. The original equipment manufacturer discontinued supplying replacement parts for these units as of July 1, 2008. Due to its robust design with no parts exposed to excessive wear, the hydraulic power portion of the governor will remain serviceable for many years.[1]

Figure 1 - Woodward Governor

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

[1] Recent plant refurbishment projects have replaced the hydraulic control portion of these governors with digital systems that provide enhanced control and feedback capabilities.

The governor consists of two sections, the power piston and the control head. The power piston provides the force necessary to operate the wicket gates under load. The control head adjusts the position of the power piston to maintain system frequency through varying load conditions.

Figure 2 - Governor Control

The control head will be replaced as far as the relay valve, which initiates the movement of the power piston, with a PLC based digital control system. The fly ball governor head, pilot valve assembly, mechanical restoring linkages and permanent magnet generator, used for speed sensing, will be removed. The new governor control system will facilitate the implementation of a water management system.

The existing hydraulic power piston assembly will be retained, along with the relay valve, hand wheel, and gate operating linkages. Reconditioning of all seals, bushings and other components, that have deteriorated over the past 48 years, will be required. This will eliminate leakage and extend the life of the power piston and relay valve assemblies.

3.0 Generator

Upgrading the electrical and mechanical protection of the 47 year old generator will extend the remaining life of the asset. The generator windings are original to the 1963 installation but there is no evidence that they require upgrading at this time. Temperature signals from the resistance temperature detectors ("RTDs") installed in the stator windings will be 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 as it permits large ground fault currents to flow. To minimize the magnitude of fault currents, high impedance grounding is the preferred method of generator neutral connection. A neutral grounding transformer with secondary resistor will be installed to provide this protection.

Generators are shut down when there is inadequate water available for production. This usually occurs during the summer and early fall when humidity in the plants 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. It will also prevent re-energization of the generator should the insulation value fall 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. Since the generator is grounded, a neutral contactor is required. The contactor will automatically disconnect the windings from ground to facilitate insulation testing. It will also reconnect the neutral to ground before the unit is re-energized. The neutral contactor will replace the existing neutral disconnect switch referred to above.

The surge protection is located in the termination cabinet attached to the generator. The surge capacitors, which were installed in 1986, will be replaced with two-bushing units to facilitate the operation of the MegAlert® insulation tester. To ensure the surge protection system continues to protect the generator windings from electric system surges, the lightning arresters, which are original, will be replaced with intermediate class MOV type surge arrestors.

The installation of new switchgear will necessitate reconfiguration of the power cables to the generator. Because the cables between the generator and switchgear are not long enough to be re-terminated in the new switchgear and the cables and terminations are over 40 years old, they will be replaced. The power cables between the switchgear and power transformer, which were installed in 2001, will be re-terminated in the new switchgear cubicle.

4.0 Excitation System

The exciter was originally supplied with the Westinghouse generator in 1963. Infrared brush temperature sensors were added in 1997. The exciter is regularly maintained and will not be considered for rewinding or replacement until the generator stator requires rewinding at some point in the future.

The voltage regulator is the original Brown Boveri Model AB2/1 with mechanical operating mechanisms. It has been discontinued for many years. It cannot be integrated into the upgraded control system to accomplish the required automated control. It will be replaced with a digital voltage regulator incorporated into the Combination Generator Control Module (“CGCM”) located in the unit control panel. The CGCM is designed to be easily integrated into the control system and provide improved voltage regulation under varying system conditions.

The field breaker is the original Westinghouse Model DBF-6 and is beyond its expected service life. It is no longer supported by the original manufacturer, making it very expensive to overhaul and maintain. A new field breaker will be installed in a cabinet located near the generator. The power cables from the exciter to the rotor via the field breaker were installed in 2001 and will be reused.

5.0 Switchgear

The generator breaker, emergency station service transformer, potential transformers (PTs) and current transformers (CTs) are integral to the switchgear and are original units installed in 1963. Concerns of failure exist because of the condition and age of this equipment. The existing Westinghouse Type DH generator breaker is at the end of its service life and must be replaced. The PTs and CTs must also be replaced. They are all critical to electrical protection of the generator. The emergency station service transformer bank consists of two single phase 120/240 V transformers connected in an open delta configuration. This is no longer standard. It will be replaced with a three phase 120/208 V wye connect unit.

Figure 3 - Switchgear and Control Panels

The protective relays and control switches are incorporated into the switchgear doors, which greatly increases arc flash hazards for personnel operating these control switches. A path is provided for an electric arc and hot gases to exit the switchgear directly towards personnel who may be standing in front of the door operating the control switches.

The existing switchgear will be replaced with an arc flash rated cubicle with breakers that require minimum maintenance. Higher accuracy instrument transformers for improved protection and metering will be supplied with the switchgear. The control switches and associated wiring will be relocated to a new unit control panel remote from the switchgear and outside the arc flash zone of influence, providing increased employee safety. A 120/208 V three phase emergency station service transformer will be incorporated into the new switchgear.

As a result of the fault levels and clearing times at this location there is a high arc flash hazard associated with this switchgear. It requires an arc flash boundary of 2.1 m. To provide protection from this hazard, walls will be constructed to separate the switchgear from the control room and the generator gallery.

6.0 AC Distribution System

The main AC service entrance from the substation, the essential services panel and transfer switch were installed in 2000 and do not require any modification. The main service is supplied from the original 120/240 V closed delta transformer bank located in the substation, which will be replaced with a standard 120/208 V transformer bank.

The non-essential services panel is the original AC panel located in the switchgear and replacement breakers are not readily available. It will be replaced with a standard 60-circuit 120/208V AC panel located on the switchgear room wall near the AC service entrance.

Figure 4 - Station Service Transformers

Under normal conditions service to all AC loads will be supplied from the normal station service transformers located in the substation.

7.0 DC System

The existing GNB Exide gel-cell battery bank and C-Can battery charger were installed in 2007 and do not require any modifications.

The 8-circuit DC distribution panel with separate main breaker is original. Currently, there are not enough circuits to accommodate each device in the protection and control system. Items have been paralleled together which is not normal practice. A new 60-circuit panel will be installed to provide adequate capacity, improved circuit isolation and ensure the availability of replacement circuit breakers.

Figure 5 - DC Panel

8.0 Protective Relaying

The generator electrical protection is provided by CGE/GEC electromechanical relays. The following protective elements are in service:

40	Loss of Field
49	Thermal Protection
51N	Overcurrent
51V	Backup Protection – Voltage Controlled Overcurrent
59	Overvoltage
64F	Voltage Relay for Rotor Ground Fault
87	Differential

The existing protective relays at Sandy Brook plant lack three elements[2] of the minimum protection set. In addition to not meeting the minimum recommended protection level, the existing electromechanical relays are corroded and no longer satisfactory.

The existing generator protective relays will be replaced with modern digital relays to provide the minimum protection set. Improved generator protection reduces stresses due to electrical faults and in turn extends the life of the generator.

In addition to the enhanced generator protection, bus differential and arc flash protection will be added with the new switchgear to provide improved equipment protection and reduce the arc flash hazard to employees working in the vicinity of the switchgear.

9.0 Plant Control

The existing Allan-Bradley SLC 5/03 programmable logic controller (PLC) was installed in 1997. It monitors vibration and bearing temperatures, controls the cooling water system and provides annunciation of a number of trip and alarm conditions. The PLC is not capable of complete unit control. This is done through various electromagnetic relays and switches from the original installation. An Allan-Bradley ControlLogix® programmable logic controller will be installed to replace this unit.[3] It will provide local and remote control of the generator and plant functions. The SLC 5/03 will be utilized to provide spares for other in-service units.

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 a PLC with increased processing power will greatly improve the local and remote monitoring and control functionality. It will facilitate the implementation of

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2 The existing generator protection does not include Stator Unbalance 46, Frequency 81 and sensitive Ground Fault 87GN elements which are recommended by the IEEE for these generators.

3 The Allan-Bradley ControlLogix® programmable logic controller will provide functionality similar to that provided at Rattling Brook plant when it was upgraded in 2007. Both Sandy Brook plant and Rattling Brook plant are operated and maintained by Company staff stationed in Norris Arm South in Central Newfoundland.

a variety of control modes to ensure the efficient operation of the plant and utilization of available water.

The new unit control panel will contain the processor, associated monitoring and control equipment and control switches. The following equipment will be located there:

a) AB ControlLogix® PLC
b) Industrial Computer HMI with keyboard
c) Ethernet Switch
d) Combination Generator Control Module (CGCM)
e) Synchro Check Relay
f) MegAlert® remote LED display and switch board meter
g) Synchroscope
h) Emergency stop pushbutton (latching)
i) Start pushbutton
j) Stop pushbutton
k) Alarm reset pushbutton
l) Generator breaker control switch (ANSI device No. 52CS)
m) Field breaker control switch (ANSI device No. 41CS; LBK-G3 only)
n) Speed raise/lower control switch (ANSI device No. 15CS)
o) Gate limit control switch (ANSI device No. 65CS)
p) Voltage raise/lower control switch (ANSI device No. 70CS)
q) Automatic/manual synchronizing control switch (ANSI device No. 25CS)
r) Generator lock out relay (ANSI Device No. 86G)
s) Three position local/remote control switch (ANSI Device No. 43CS)

A new Gateway data concentrator will be installed to replace the existing RTU, improving communications to the SCADA system. This communications system in conjunction with the upgraded processor will enhance 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 time consuming and costly site visit.

The Westinghouse XT7 auto-synchronizer is an electromechanical relay utilizing vacuum tube technology included with the original installation. It is no longer supported by the manufacturer and will be replaced. A synchrocheck relay will be installed to supervise both automatic and manual synchronizing. It will ensure unit speed and voltage are within acceptable limits before the generator breaker closure is permitted. The synchronizing function will be incorporated in CGCM Module located in the unit control panel.

Figure 6 - XT7 Auto-synchronizer

10.0 Instrumentation

The instrumentation has been upgraded over the past number of years with brush temperature and vibration monitoring installed in 1997, the cooling water system upgraded in 1999, bearing temperature sensors installed in 2001 and bearing oil level sensors installed in 2004.

Except for the speed switch and vibration monitor, all instrumentation will be maintained and integrated into the new control system. The speed switch will be removed and dual speed sensors installed on the existing PMG toothgear to provide analogue speed signals to the governor and unit control PLCs. The unit control PLC will perform the speed processing functions previously performed by the speed switch. The vibration sensors will be reused but the monitor will be replaced with a Rockwell Entek system, designed to be seamlessly integrated into the Allan-Bradley ControlLogix PLC.

11.0 Heating and Ventilation

There are no infrared heaters installed over the unit. The anti-condensation blower type heaters in the turbine pit are located in the air intake plenum and controlled by a humidistat located in the generator room. There are two exhaust fans located in the building that are in good condition.

Figure 7 - Anti-condensation Heaters

The heat and ventilation controls will be consolidated into one plant control panel and integrated with the plant control PLC. Temperature and humidity sensors will be installed in the generator room and turbine pit. Infrared heaters will be installed and new blower heaters will be mounted under the generator windings. This will help prevent condensation on the generator windings when the unit is not operating.

12.0 Cooling Water

The cooling water system was upgraded and PLC control added in 1999. A duplex strainer was installed in 2001. Except for the replacement of a small amount of piping no further upgrading is required. The control of the cooling water system will be integrated into the new ControLogix PLC but no other modifications are required.

13.0 Air Compressor

The air compressor used to operate the generator braking system is original and will be replaced.

14.0 Water Level Monitoring and Control

Figure 8 - Forebay Water Level System

The forebay water level system is critical to the implementation of the Water Management System in the PLC. The water level probe was replaced in 2006 and does not require any work. The water level and trash rack signals are transmitted to the plant utilizing pulse modulated and hard wired signals over a 25 year old copper communications cable which is susceptible to lightning damage. The communications cable has 3 of its 11 pairs made unusable by lightning. To improve reliability, eliminate legacy equipment with its inherent maintenance problems and to facilitate the use of more reliable technology, the copper cable will be replaced with a fibre optic cable. The existing communications system will be upgraded to technology compatible with the new control system.

The plant PLC will use the water level signals to control the Water Management System. High level (spill) and low level alarms will also be initiated when specified levels are reached.

The Water Management System will optimize the 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:

a) Peak Water Level
b) Low Inflow Peak Water Level
c) Efficient Water Level
d) Low Inflow Efficient Water Level
e) Partial Water Level
f) Low Inflow Partial Water Level
g) Shutdown Water Level
h) Low Inflow Shutdown Water Level
i) Water Level Deadband
j) Start-up Water Level
k) Peak Gate Position
l) Efficient Gate Position
m) Partial Gate Position
n) Gate Position Deadband
o) Rate of Rise (Bump)
p) Water Elevation Mode Water Level
q) Water Elevation Mode Gate Shutdown Level
r) Load Control Mode Voltage Level
s) Load Control Mode Kilowatt Level
t) Load Control Mode Kilowatt Deadband

15.0 Project Cost

The total project cost is estimated at $1,560,000. Table 1 below provides the cost breakdown by cost category.

Table 1
Projected Expenditures

Cost Category	Estimated Cost
Material	$779,000
Labour - Internal	122,000
Labour - Contract	438,000
Engineering	133,000
Other	88,000
Total	**$1,560,000**

16.0 Summary of Work

The following is a summary of the work proposed to be completed during the 2011 refurbishment project:

a) Install programmable logic controller based digital control systems to replace the hydraulic control portion of the governors.
b) Complete mechanical modifications to governor.
c) Install neutral grounding transformer and resistor.
d) Install automatic stator insulation testing system.
e) Replace surge protection.
f) Replace power cables between the generator and switchgear as required.
g) Replace the automatic voltage regulator.
h) Replace the field breaker and power cables between switchgear and generator.
i) Replace the switchgear complete with breaker, potential transformers and current transformers and emergency service transformer.
j) Modify the control room to provide a switchgear room.
k) Replace the non-essential AC distribution panel.
l) Replace station service transformer bank in substation.
m) Replace the DC distribution panel.
n) Replace generator protective relaying.
o) Add bus differential and arc flash relaying.
p) Replace the existing programmable logic controller with a programmable logic controller system that will monitor and control plant functions and the unit.
q) Install a Gateway data concentrator to communicate with SCADA and provide remote administration of the new equipment.
r) Replace the auto-synchronizer.
s) Upgrade speed sensing and bearing vibration system.

t) Modify the plant heating and ventilation system and upgraded controls.
u) Upgrade cooling water piping.
v) Replace air compressor.
w) Replace forebay communications cable and communications equipment.
x) Implement a water management system in the Plant programmable logic controller including upgraded communications to the forebay.

17.0 Economic Feasibility

Appendix A provides an economic feasibility analysis for the continued operation of the Plant. It is based on the latest forecast of total capital expenditure of $10,964,000. 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 continued availability of 30.2 GWh of energy to the Island Interconnected electrical system.

The estimated levelized cost of energy from the Plant over the next 50 years, including the capital expenditure of $10,964,000, is 2.37 cents per kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation[4].

[4] The cost of electricity from the Holyrood thermal generating plant is estimated at 11.63 ¢/kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $73.30/barrel for 2010 as per Newfoundland Hydro 2010 Capital Budget Application, Generating Planning Issues 2009 Mid Year Report dated July 2009.

Appendix A
Feasibility Analysis

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1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Sandy Brook hydroelectric plant (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2011.

With investment required in 2011 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
Sandy Brook Hydroelectric Plant
Capital Expenditures

Year	($000s)
2011	2,234
2017	700
2020	4,387
2023	1,608
2026	227
2036	1,808
Total	**10,964**

The estimated capital expenditure for the Plant over the next 25 years is $10,964,000 in 2011 dollars. 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 $141,261[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 an estimated water use licence fee of $24,160[2] applicable to the licence being applied for in 2010. This fee is paid annually to the Provincial Department of

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1 2011 dollars.
2 Newfoundland Power is anticipating receiving a new water use licence for Sandy Brook in 2010.

Environment and Conservation (Water Resources Management Division). This charge is not reflected in the historical annual operating costs for the Plant. An adjustment beyond lease expiry will have to be applied to account for the associated increased operating expenses on a go-forward basis.

4.0 Benefits

The maximum output from the Plant is 6.4 MW. The Plant normally operates at an efficient load of 5.7 MW to maximize the energy from the water.

The estimated long-term normal production at the Plant under present operating conditions is 30.2 GWh per year. This estimate is based on the average production for the past five years.

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 25 years is 2.37 cents per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Sandy Brook can be produced at a significantly lower price than the cost of replacement energy, assumed to come from Newfoundland and Labrador Hydro's Holyrood thermal generating station.[3]

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

6.0 Concluding

The results indicate that continued operation of the Plant is economically viable. Investing in the current upgrades of the facilities at Sandy Brook guarantees the availability of low cost energy to the Province. Otherwise, the annual production of 30.2 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.

[3] The cost of electricity from the Holyrood thermal generating station is estimated at 11.63¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $73.30 per barrel for 2010 as per Newfoundland Hydro 2010 Capital Budget Application, Generation Planning Issues 2009 Mid Year Report dated July 2009.

Attachment A
Summary of Capital Costs

Sandy Brook Feasibility Analysis
Summary of Capital Costs
($000s)

Description	2011	2017	2020	2023	2026	2036
Civil						
Dam, Spillways and Control Structures	100	700				100
Penstock			3,749			
Surge Tank			638			
Powerhouse					79	
Increase Storage	575					
Mechanical						
Mechanical	42					
Turbine Upgrades						1,651
Governor Upgrades	126				30	
Electrical						
Controls Upgrade	933			29	118	57
Generator Rewind				1,497		
Exciter				82		
Switchgear	458					
Annual Totals	**2,234**	**700**	**4,387**	**1,608**	**227**	**1,808**

Attachment B
Summary of Operating Costs

Sandy Brook Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs

Year	**Amount**
2005	$ 98,499
2006	$ 92,014
2007	$ 118,221
2008	$ 147,150
2009	$ 129,622
Average	**$** 117,101

5 -Year Average Operating Cost	$117,101[1]
Water Use Rental Fee	$ 24,160[2]
Total Forecast Annual Operating Cost	$ 141,261

[1] 2011 dollars.
[2] Estimated fee for licence being applied for in 2010.

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted Average Incremental Cost of Capital - 7.68%
Present Worth Year - 2010

Year	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2011	134,086	141,261	0	-275,347	-255,708	-255,708	0.912	2.368
2012	104,736	144,253	0	-248,989	-214,739	-470,447	0.824	2.368
2013	160,236	147,449	0	-307,685	-246,435	-716,882	1.019	2.368
2014	187,633	150,232	0	-337,865	-251,306	-968,188	1.119	2.368
2015	200,851	153,151	0	-354,001	-244,529	-1,212,717	1.172	2.368
2016	206,863	155,867	0	-362,730	-232,688	-1,445,404	1.201	2.368
2017	207,443	158,708	0	-366,151	-218,130	-1,663,534	1.212	2.368
2018	181,721	161,618	0	-343,339	-189,951	-1,853,486	1.137	2.368
2019	239,862	164,650	0	-404,512	-207,834	-2,061,320	1.339	2.368
2020	666,048	167,703	0	-833,752	-397,820	-2,459,139	2.761	2.368
2021	637,308	170,856	0	-808,163	-358,108	-2,817,247	2.676	2.368
2022	701,598	174,031	0	-875,630	-360,330	-3,177,576	2.899	2.368
2023	904,098	177,271	0	-1,081,370	-413,255	-3,590,832	3.581	2.368
2024	907,043	180,487	0	-1,087,530	-385,967	-3,976,799	3.601	2.368
2025	920,205	183,906	0	-1,104,111	-363,904	-4,340,703	3.656	2.368
2026	923,473	187,342	0	-1,110,814	-340,001	-4,680,705	3.678	2.368
2027	912,303	190,808	0	-1,103,111	-313,562	-4,994,267	3.653	2.368
2028	930,625	194,370	0	-1,124,995	-296,975	-5,291,241	3.725	2.368
2029	935,486	198,047	0	-1,133,533	-277,887	-5,569,128	3.753	2.368
2030	933,226	201,840	0	-1,135,066	-258,417	-5,827,545	3.758	2.368
2031	927,048	205,705	0	-1,132,754	-239,497	-6,067,042	3.751	2.368
2032	918,581	209,645	0	-1,128,226	-221,526	-6,288,568	3.736	2.368
2033	908,666	213,660	0	-1,122,325	-204,650	-6,493,218	3.716	2.368
2034	897,747	217,751	0	-1,115,499	-188,898	-6,682,116	3.694	2.368
2035	886,070	221,921	0	-1,107,992	-174,245	-6,856,362	3.669	2.368
2036	1,134,220	226,171	0	-1,360,391	-198,679	-7,055,041	4.505	2.368
2037	1,111,257	230,503	0	-1,341,759	-181,982	-7,237,023	4.443	2.368
2038	1,100,207	234,917	0	-1,335,124	-168,167	-7,405,190	4.421	2.368
2039	1,088,161	239,416	0	-1,327,576	-155,290	-7,560,479	4.396	2.368
2040	1,075,203	244,001	0	-1,319,204	-143,305	-7,703,784	4.368	2.368
2041	1,060,708	248,674	0	-1,309,381	-132,093	-7,835,877	4.336	2.368
2042	1,035,526	253,436	0	-1,288,962	-120,759	-7,956,636	4.268	2.368
2043	1,044,238	258,289	0	-1,302,527	-113,326	-8,069,962	4.313	2.368
2044	1,040,032	263,236	0	-1,303,268	-105,303	-8,175,265	4.315	2.368
2045	1,029,096	268,277	0	-1,297,373	-97,350	-8,272,616	4.296	2.368
2046	1,014,543	273,415	0	-1,287,957	-89,751	-8,362,367	4.265	2.368
2047	997,632	278,651	0	-1,276,282	-82,594	-8,444,961	4.226	2.368
2048	974,970	283,987	0	-1,258,957	-75,662	-8,520,623	4.169	2.368
2049	967,261	289,426	0	-1,256,687	-70,139	-8,590,763	4.161	2.368
2050	953,378	294,968	0	-1,248,346	-64,704	-8,655,467	4.134	2.368
2051	936,242	300,617	0	-1,236,859	-59,537	-8,715,003	4.096	2.368
2052	917,328	306,374	0	-1,223,702	-54,702	-8,769,705	4.052	2.368
2053	897,385	312,242	0	-1,209,626	-50,216	-8,819,922	4.005	2.368
2054	876,799	318,221	0	-1,195,020	-46,072	-8,865,993	3.957	2.368
2055	855,772	324,315	0	-1,180,088	-42,251	-8,908,244	3.908	2.368
2056	834,418	330,526	0	-1,164,944	-38,734	-8,946,978	3.857	2.368
2057	803,379	336,856	0	-1,140,235	-35,208	-8,982,187	3.776	2.368
2058	638,863	343,307	0	-982,171	-28,165	-9,010,352	3.252	2.368
2059	938,977	349,882	0	-1,288,859	-34,323	-9,044,675	4.268	2.368
2060	1,074,095	356,582	0	-1,430,677	-35,383	-9,080,057	4.737	2.368
2061	1,126,642	363,411	0	-1,490,053	-34,223	-9,114,280	4.934	2.368

Feasibility Analysis
Major Inputs and Assumptions

Specific assumptions include:

Income Tax: Income tax expense reflects a statutory income tax rate of 32%.

Operating Costs: Operating costs were assumed to be in 2010 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%	9.00%	4.05%
Total	**100.00%**		**7.68%**

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 16, 2010.

Appendix B
Sandy Brook Switchgear Arc Flash Study

ELECTRICAL ENGINEERING

ARC FLASH HAZARD STUDY

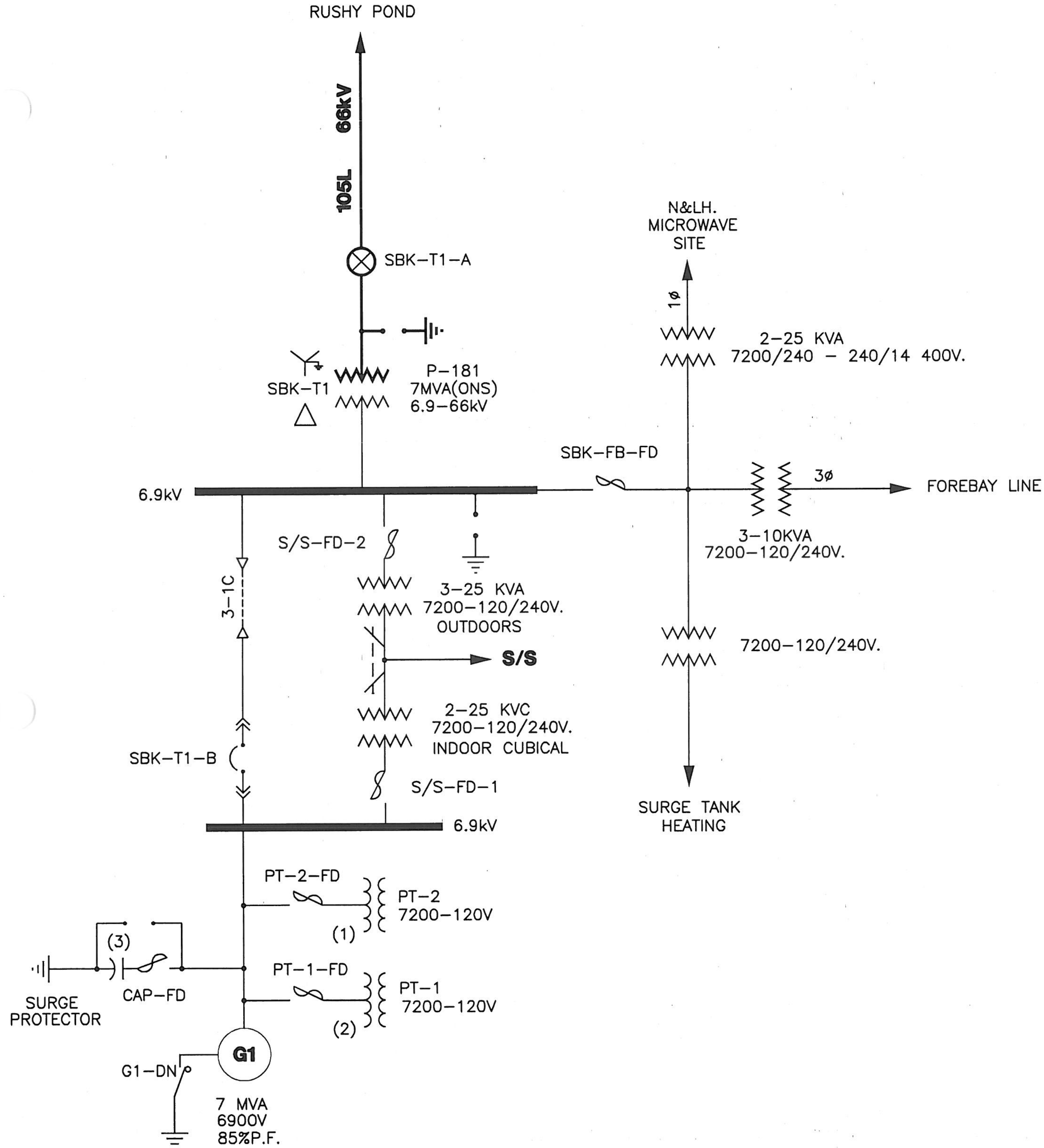
Company Area:	Grand Falls		
Switchgear Included:	SBK 07		
Prepared by:	D. Hopkins	**Date:**	3/8/2006

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



REGISTERED PROFESSIONAL ENGINEER
G. Richard Spurrell
SIGNATURE
2002-06-12
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 R0140 which is valid for the year 2002.

SANDY BROOK (SBK)

Date: 2002-06-12	Page 1 Of 1
App:	SLD No. **6-910**

NF POWER- RELAY REPORT 1

Wednesday, March 08, 20

Region: 6

Eqpt code: -GFS-105L-

Setting group:

		kV						Date	PT	CT	Remarks	Range	Power Supply
67	JBC51H	66	MVA= 10.3	P/U= 1.5	TD= 1.0	Pri amps= 90	TCC=	3/20/85		60	DIR PHASE O/C	1.5-6	
67/50	JBC51H	66	MVA= 54.9	P/U= 8	TD=	Pri amps= 480	TCC=	3/20/85		60	DIR PH INST O/C	2-8	
67N	IBCG51	66	MVA= 3.4	P/U= 0.5	TD= 1.5	Pri amps= 30	TCC=	3/20/85		60	DIR GND O/C	0.5-2	

Eqpt code: -SBK-6.9B-

Setting group:

		kV						Date	PT	CT	Remarks	Range	Power Supply
27L-1	SV-1	6.9	MVA=	P/U= 100	TD=	Pri amps=	TCC=	8/24/87				70-160	

Eqpt code: -SBK-G1 -

Setting group:

		kV						Date	PT	CT	Remarks	Range	Power Supply
40X	CV-2	6.9	MVA=	P/U= 93.0	TD= 2.0	Pri amps=	TCC=	8/26/87				55-140	
49	CT	6.9									SETTING= 100DGC TD=5		
64GF	DGF	6.9									(-75)-(+75) SETTING= (-0.3)-		
25L	CV-7	6.9	MVA=	P/U= 105	TD= 1.0	Pri amps=	TCC=	8/24/87			OVER/UNDER VOLTAGE	55-140	
40	D-3	6.9									(-5)-(+5)MV SETTING= (-3)-(		
27L-1	SV-7	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	8/24/87		100		70-160	
51GG	CO-8	6.9	MVA=	P/U= 1.0	TD= 1.0	Pri amps=	TCC=	8/24/87				0.5-2.5	
51N	CO-8	6.9	MVA= 1.4	P/U= 1.0	TD= 1.0	Pri amps= 120	TCC=	8/24/87		120	GEN GND O/C	4-12	
51V	COR	6.9	MVA= 14.3	P/U= 10	TD= 8.0	Pri amps= 1200	TCC=	8/24/87		120	PH O/C VOLT REST	4-12	
59	ROV	6.9	MVA=	P/U= 134	TD=	Pri amps=	TCC=	8/24/87			OVERVOLTAGE	120-160	
87	CA	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	8/24/87			FACTORY ADJUSTED	10% REST	
87S	CO-2	6.9	MVA= 0.12	P/U= 0.5	TD= 0.5	Pri amps= 10	TCC=	8/24/87		20	SPLIT PHASE O/C	0.5-2.5	
87S/50	CO-2	6.9	MVA= 0.96	P/U= 4	TD=	Pri amps= 80	TCC=	8/24/87		20	SPLIT PHASE O/C	4-16	
25Z	CV-7	6.9	MVA=	P/U= 105	TD= 2.0	Pri amps=	TCC=	8/24/87			OVER/UNDER VOLTAGE	55-140	

Eqpt code: -SBK-T1 -

Setting group:

		kV						Date	PT	CT	Remarks	Range	Power Supply
51TN	CO-8	66	MVA= 5.7	P/U= 2.5	TD= 6.0	Pri amps= 50	TCC=	8/24/87		20	GEN XFMR GND O/C	0.5-2.5	

Maximum Generation Fault SBK 6.9kV

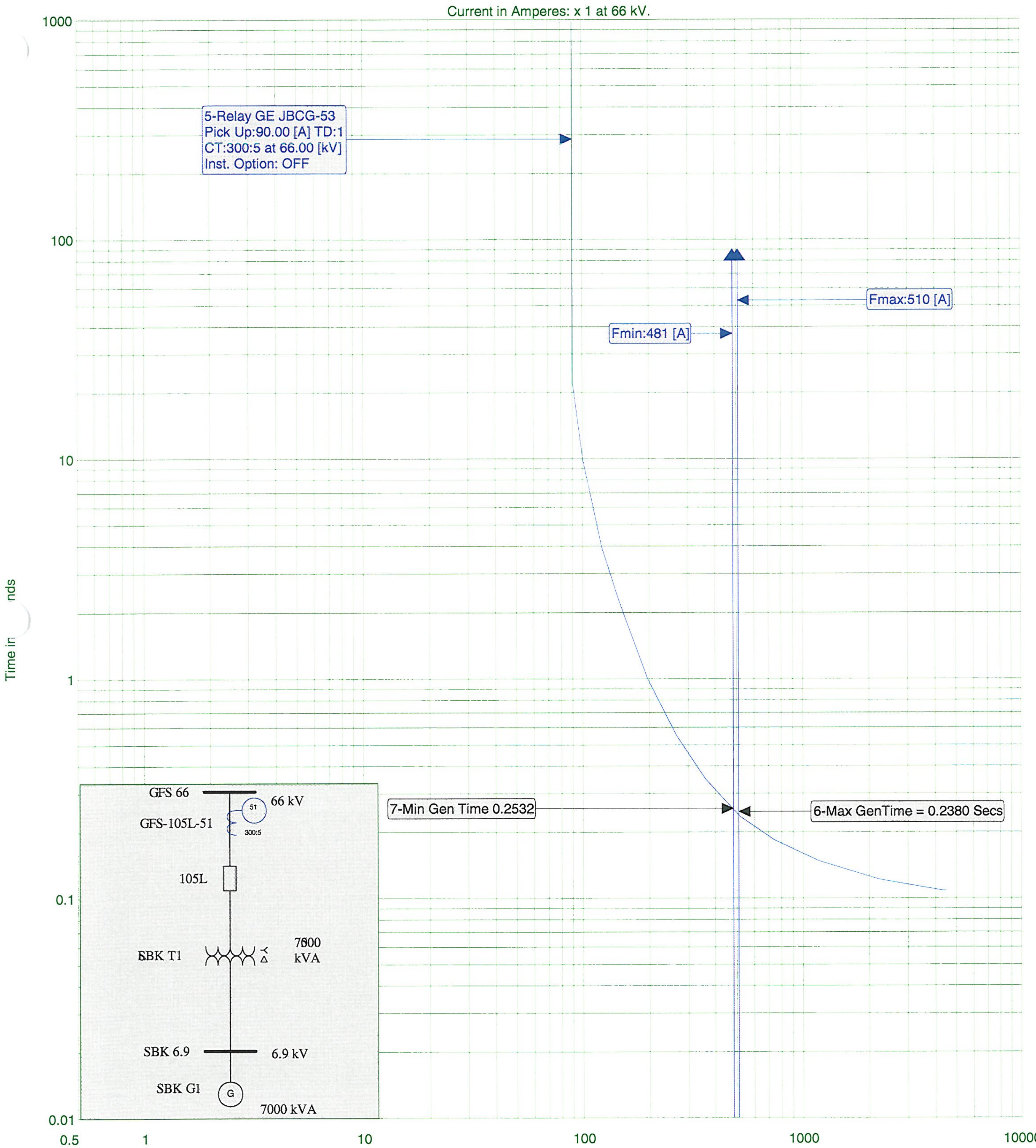
ID	Type	Prefault kV	Angle	Fault type	Fault S [MVA]	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
Faulted Bus ->													
SBK 07		6.9	0	LLL	83	6960.7527	-83.4695	6960.7527	156.5305	6960.7527	36.5305	0	0
First Ring Contributions													
SBK G1	Generator	6.9	0	LLL	25	2091.8489	-90	2091.8489	150	2091.8489	30	0	0
SBK T1	Fixed-Tap Xmer	6.9	0	LLL	58	4888.2476	-80.68	4888.2476	159.32	4888.2476	39.32	0	0

Faulted Bus	Branch id	Type	ault typ	Branch Sid	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
SBK 07	105L	Line	LLL	GFS 66	510.6	129.3203	510.6	9.3203	510.6	-110.6797	0	0
SBK 07	105L	Line	LLL	SBK 66	512	-50.6967	512	-170.6967	512	69.3033	0	0

Minimum Generation Fault SBK 6.9kV

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 ->													
SBK 07		6.9	0	LLL	80	6676.5957	-83.9024	6676.5957	156.0976	6676.5957	36.0976	0	0
First Ring Contributions													
SBK T1	Fixed-Tap Xmer	6.9	0	LLL	55	4601.9882	-81.1347	4601.9882	158.8653	4601.9882	38.8653	0	0
SBK G1	Generator	6.9	0	LLL	25	2091.8489	-90	2091.8489	150	2091.8489	30	0	0

Faulted Bus	Branch id	Type	ault typ	Branch Sid	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
SBK 07	105L	Line	LLL	GFS 66	480.8	128.8656	480.8	8.8656	480.8	-111.1344	0	0
SBK 07	105L	Line	LLL	SBK 66	482.1	-51.1522	482.1	-171.1522	482.1	68.8478	0	0



For LLL SBK 6.9 kV fault at Maximun Generation CT = 0.2380

For LLL SBK 6.9 kV fault at Minimum Generation CT = 0.2532

PLOTTING VOLTAGE:66 kV

BY: D. Hopkins

NO:

DATE: 3-8-2006

Study: H:\COMM\Arc Flash\Plants\SBK\SBK 6.9 kV fault Max and Min Gen.tcc

Arc Flash Hazard SBK 6.9 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.
SBK 6.9	Max	LLL	6961	0.2380	0.2380	16"	56	4.0	2	60"	26"	7"
SBK 6.9	Min	LLL	6677	0.2532	0.2532	16"	82	5.9	2	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.
SBK 6.9	Max	LLL	6961	0.2380	0.2380	36"	56	1.8	1	60"	26"	7"
SBK 6.9	Min	LLL	6677	0.2532	0.2532	36"	82	2.7	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

82 inches	Flash Hazard Boundary
2.7	cal / cm2 Flash Hazard at 36 inches
class 1	PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

82 inches	Flash Hazard Boundary
2.7	cal / cm2 Flash Hazard at 36 inches
class 1	PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard
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82 inches	Flash Hazard Boundary
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60 inches	Limited Approach
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7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

82 inches	Flash Hazard Boundary
2.7	cal / cm2 Flash Hazard at 36 inches
class 1	PPE Level, FR shirt and FR pants or FR coverall (1 layer). Hard hat and safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

56 inches	Flash Hazard Boundary
1.8	cal / cm2 Flash Hazard at 36 inches
class Ø 1	PPE Level, Non-melting, flammable materials (i.e., untreated cotton, wool, rayon or blends of these materials) with a fabric weight at least 4.5 oz/yd2 Safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

56 inches	Flash Hazard Boundary
1.8	cal / cm2 Flash Hazard at 36 inches
class Ø 1	PPE Level, Non-melting, flammable materials (i.e., untreated cotton, wool, rayon or blends of these materials) with a fabric weight at least 4.5 oz/yd2 Safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

56 inches	Flash Hazard Boundary
1.8	cal / cm2 Flash Hazard at 36 inches
class Ø 1	PPE Level, Non-melting, flammable materials (i.e., untreated cotton, wool, rayon or blends of these materials) with a fabric weight at least 4.5 oz/yd2 Safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

56 inches	Flash Hazard Boundary
1.8	cal / cm2 Flash Hazard at 36 inches
class Ø 1	PPE Level, Non-melting, flammable materials (i.e., untreated cotton, wool, rayon or blends of these materials) with a fabric weight at least 4.5 oz/yd2 Safety glasses.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

56 inches	Flash Hazard Boundary	
4.0	cal / cm2 Flash Hazard at 16 inches	
class 2	PPE Level,	Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard	
60 inches	Limited Approach	
26 inches	Restricted Approach	
7 inches	Prohibited Approach	

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

56 inches	Flash Hazard Boundary	
4.0	cal / cm2 Flash Hazard at 16 inches	
class 2	PPE Level,	Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard	
60 inches	Limited Approach	
26 inches	Restricted Approach	
7 inches	Prohibited Approach	

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

56 inches	Flash Hazard Boundary	
4.0	cal / cm2 Flash Hazard at 16 inches	
class 2	PPE Level,	Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard	
60 inches	Limited Approach	
26 inches	Restricted Approach	
7 inches	Prohibited Approach	

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

56 inches	Flash Hazard Boundary	
4.0	cal / cm2 Flash Hazard at 16 inches	
class 2	PPE Level,	Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard	
60 inches	Limited Approach	
26 inches	Restricted Approach	
7 inches	Prohibited Approach	

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

82 inches	Flash Hazard Boundary
5.9	cal / cm2 Flash Hazard at 16 inches
class 2	PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

82 inches	Flash Hazard Boundary
5.9	cal / cm2 Flash Hazard at 16 inches
class 2	PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

82 inches	Flash Hazard Boundary
5.9	cal / cm2 Flash Hazard at 16 inches
class 2	PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

WARNING

Arc Flash and Shock Hazard Appropriate PPE Required

82 inches	Flash Hazard Boundary
5.9	cal / cm2 Flash Hazard at 16 inches
class 2	PPE Level, Cotton underwear - conventional short sleeve and brief/sh plus FR shirt and FR pants (1 or 2 layers). Hard hat, arc rated face shield, ear, hand and foot protecti
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:SBK 07

2011 Substation Refurbishment and Modernization

June 2010

Prepared by:

Peter Feehan, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
PETER J. FEEHAN
SIGNATURE
June 29, 10
DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Substation Refurbishment and Modernization Strategy

Newfoundland Power's (the "Company") substations connect the high voltage transmission system to the low voltage distribution system. The Company's substation maintenance program and the Substation Refurbishment and Modernization project ensure the delivery of reliable least cost electricity to customers in a safe and environmentally responsible manner.

The Substation Refurbishment and Modernization project provides a structured approach for the overall refurbishment and modernization of substations and coordinates major equipment maintenance and replacement activities. 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.

In preparation of annual capital budgets, 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 establish the priority for 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 light.

In the *Substation Strategic Plan* filed with the Company's 2007 Capital Budget Application, it was indicated that expenditures under the Substation Refurbishment and Modernization project were expected to average approximately $4 million per year. Expenditure is currently expected to reach this level in 2010. In 2011, the budget estimate is materially below this level due to a requirement to address government regulations concerning polychlorinated biphenyls ("PCB").[1] Such developments highlight the practical requirement for flexibility in execution of the Substation Refurbishment and Modernization project over time.

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

2.0 Substation Refurbishment and Modernization 2011 Projects

The 2011 Substation Refurbishment and Modernization Project includes planned refurbishment and modernization work on 4 substations and one of the Company's portable substations. This work is estimated to cost a total of $2,753,000, which comprises approximately 90% of total 2011 project costs. Silicon carbide lightning arrestors are planned to be replaced in an additional 2 substations on a priority basis. Petro plug devices are planned to be installed in 8 substations to permit continuous draining of water from spill containment pans. Protection improvements are planned for 2 substations. These improvements are estimated to cost a total of $171,000, which comprises approximately 6% of total 2011 project costs. Finally, system monitoring and

[1] A description of the work required to meet the new PCB regulations established by Environment Canada can be found in ***2.3** 2011 PCB Removal Strategy*.

operations technology upgrades are planned at $150,000. This comprises approximately 5% of total 2011 project costs.

The refurbishment of Portable Substation P3, with the exception of the engineering work which is being completed in 2010, is included with the 2011 Refurbishment and Modernization project. The reason for not completing the refurbishment of P3 in 2010 is that the scheduled use of the portable substation in 2010 did not allow sufficient time to complete the refurbishment. A similar project to upgrade Portable Substation P4 was scheduled for 2011 and has been re-scheduled to 2012. Delaying the refurbishment of P4 to 2012 is required since it is not possible to upgrade both portable substations in 2011 and still complete the planned substation capital and maintenance programs.

Table 1
2011 Substation Projects
(000s)

Substation	**Budget**
Heart's Content (HCT)	$1,007
Portable Substation 3 (P3)	440
Port aux Basques (PAB)	440
New Grand Falls (NGF)	707
Stamps Lane (SLA)	159
Items Under $50,000	171
Substation Monitoring	150
Total	**$3,074**

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

2.1 Heart's Content Substation ($1,007,000)

Heart's Content substation was built in 1956 as a generation substation and over the years has developed into a distribution substation. The substation contains one 66 kV to 12.5 kV distribution power transformer T3 with a capacity of 2.3 MVA and one 66kV to 2.4 kV generation power transformer T1 with a capacity of 3 MVA.

The substation directly serves approximately 450 customers in the Heart's Content area through one 12.5 kV feeder. In the substation there are three 66 kV transmission lines terminated on the high voltage bus, transmission lines 41L to Carbonear substation, 43L to New Chelsea substation and 80L to Islington substation.

Heart's Content Substation Location

Maintenance records and on-site engineering assessments show that the 66 kV steel structures and bus are in good condition. Some of the structure foundations are in poor condition as anchor bolts have rusted off. These foundations will be replaced.

The 66 kV potential transformers will be replaced as their enclosures have deteriorated significantly over their 39 years of service. The 66 kV power fuse holders for T1 have experienced arcing and require replacement.

The power cables for both T1 and T3 are 1966 and 1971 vintage, are deteriorated and will be replaced.[2] The lightning arrestors on the 66 kV side of T1 are gap type and will be replaced with new metal oxide arrestors.[3]

The protection relays for the transmission lines and 66 kV bus protection are 1972 vintage electro mechanical type and will be replaced with new micro processor based relays[4].

The fence is showing significant deterioration and sections will be refurbished or replaced. There have been issues with flooding in the station and drainage improvements will be made to prevent re-occurrence. The ground grid for the substation will be extended to improve safety for personnel inside the substation

2 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that power cable failures begin to occur when cables are about 35 years old. The Heart's Content power cables are 39 and 44 years of age and will be replaced during the 2011 refurbishment and modernization of the substation.

3 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.

4 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.

Severe Rusting On Anchor Bolt

39 Year Old Potential Transformers

1966 Vintage Power Cables

Damage Due To Flooding

.

2.2 Portable Substation P3 ($440,000)

Portable substation P3 was purchased in 1977. It is used to respond to power transformer failures and for carrying out planned transformer and substation maintenance. Of the approximate 190 power transformers in service on Newfoundland Power's system, P3 can provide backup for 68% of them.

Portable Substation P3

This is the first comprehensive refurbishment of this portable substation since its purchase over thirty years ago. Purchase of a comparable new portable substation would cost approximately $5 million. Refurbishment of portable substation P3 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. The manual hydraulic jacks on the unit have deteriorated and they will be replaced with a motorized system. A fall arrest system and work platforms will be installed in areas when employees have to work aloft. External lighting will be provided at locations around the trailer.

The alarm annunciation panel has had several failures and will be replaced. The protection relays are 32 year old electro mechanical type and will be replaced with new electronic digital protection relays.[5] A digital metering system for power, voltage and current will be provided.

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

[5] 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.

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.

2.3 Port aux Basques Substation ($440,000)

Port aux Basques substation was built in 1946. Today it is a distribution substation and a generation substation. The distribution substation contains one power transformer T5 with a capacity of 13.3 MVA at 12.5 kV. The station also contains one 4.16 kV to 12.5 kV generation transformer T3 with a capacity of 3 MVA connecting a 2.5 MW diesel generator to the electricity system. The substation directly services approximately 1,400 customers in the Port aux Basques area through four 12.5 kV outdoor feeders. There is one 66 kV radial transmission line 417L terminated in the substation.

Port aux Basques Substation Location

The power transformers T3 and T5 are in good condition. The lightning arrestors on the transformers are silicon carbide and require replacement with metal oxide arrestors[6].

Maintenance records and on-site engineering assessments show the 66 kV wood pole structure and 12.5 kV steel structures are in good condition. The concrete foundations, buses and insulators are in good condition. However, the retaining wall for the substation is deteriorated and will be replaced.

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6 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.

Deteriorated Retaining Wall

The new retaining wall will enclose a larger area than is currently enclosed and new fencing will be installed along the top of the retaining wall to replace the existing deteriorated fencing.

Fencing Along Retaining Wall Side

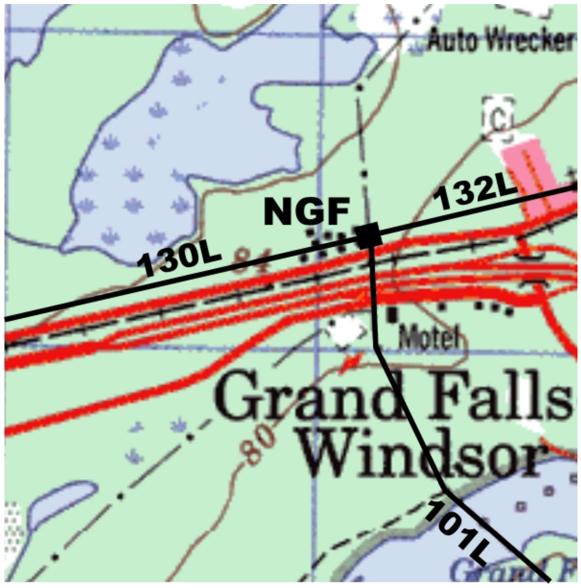
The 12.5 kV metering tank will be replaced with a dry type unit. The feeders have Nulec reclosers installed and these will be automated for control from the System Control Centre[7].

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

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

2.4 New Grand Falls Substation ($707,000)

New Grand Falls substation was built in 1976 as both a transmission and distribution substation. The transmission portion of the substation contains one 138 kV to 66 kV, 30 MVA power transformer T1. There are two 138 kV transmission lines terminated in the substation, 130L to Newfoundland & Labrador Hydro's substation at Stoney Brook and 136L to Bishop Falls substation. There are two 66 kV transmission lines terminated in the substation, 101L to Rattling Brook substation and a 66 kV tie to Grand Falls substation. There are two distribution power transformers T2 and T3. Each distribution transformer has a capacity of 20 MVA at 25 kV. The substation directly serves approximately 5,800 customers in the Grand Falls area through five 25 kV feeders.



New Grand Falls Substation Location

Maintenance records and on-site engineering assessments show that the 138 kV, 66 kV and 25 kV steel structures, foundations, buses and insulators are in good condition.

138kV & 25 kV Steel Structures & Bus

The three power transformers T1, T2 and T3 are in good condition. The lightning arrestors on the transformers are silicon carbide and will be replaced with metal oxide arrestors.[8]

The power cable and terminations for T2 are thirty four years old, are approaching the end of their anticipated useful life and will be replaced.[9] The 138 kV air-break switch for transformer T2 no longer operates reliably and will be replaced.

The 25 kV potential transformers and 66 kV potential transformers on 101L show significant deterioration and will be replaced. A new set of 25 kV potential transformers will be installed on the 25 kV bus of transformer T3 for protection and monitoring when T2 & T3 transformers are not operating in parallel.

8 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.

9 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that power cable failures begin to occur when cables are about 35 years old. The Grand Fall's power cables are 34 years of age and will be replaced during the 2011 refurbishment and modernization of the substation.

66 kV potential Transformers

The relays for the transmission lines are 1976 vintage electro mechanical type and will be replaced with new micro processor based relays[10].

Transmission Line Electro Mechanical Relays

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.

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

2.5 Stamps Lane Substation ($159,000)

Stamp's Lane substation was built in 1963 as a 66 kV transmission switching substation and as a 4.16 kV and a 12.5 kV distribution substation. The distribution substation contains four power transformers (T1, T2, T3 & T4) with a combined capacity of 50 MVA at 12.5 kV and 21 MVA at 4.16 kV. The substation directly services approximately 9,400 customers in the central area of St. John's through five 4.16 kV metal clad switchgear feeders and six 12.5 kV outdoor feeders. There are six 66 kV transmission lines terminated in the substation. These are transmission lines 13L to St. John's Main substation, 14L to Memorial substation, 15L to Molloy's Lane substation, 69L to Kenmount substation and 31L and 70L to Oxen Pond substation.

Stamps Lane Substation Location

In 2007 Stamp's Lane substation underwent a refurbishment and modernization project that addressed deterioration of concrete foundations and power cables, along with protective relay upgrades on 11 distribution feeders. Recent engineering assessments have determined that the 66 kV and 12.5 kV steel structures and 4.16 kV metal clad switchgear remain in good condition. Concrete foundations remain in good condition.

The five transmission line relays are an older vintage micro processor based relay and the manufacturer has identified a deficiency with these relays. New relays will replace the defective relaying on the five transmission lines.[11]

[11] 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.

The radiators on transformer T2 are corroded in several locations. Temporary repairs were completed in 2007 to prevent oil leaks. Due to the advanced level of corrosion the radiators on transformer T2 will be replaced in 2011.

Patched Radiator on SLA-T2

2.6 Items Under $50,000 ($171,000)

The 2011 Substation Refurbishment and Modernization project includes a number of smaller items that must be addressed in the near future, and cannot wait for a more comprehensive refurbishment of the substation. The replacement of lightning arrestors in two locations receives priority because of the risk of customer outages related to existing lightning arrestor failure. Petro plug devices are to be installed in eight locations to allow continuous draining of water from spill containment pans without endangering the environment. Protection upgrades are planned in two substations.

2.7 Substation Monitoring and Operations ($150,000)

Over the past decade, there has been substantial increased use 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 2011, upgrades to the communications hubs that connect multiple devices in substations to the SCADA system are planned. Effective management of increased volumes of electrical system data requires the upgrading of the hubs. This requires both hardware and software upgrades.

In 2011, the required work will incorporate manufacturers' upgrades to communications and other computer-based equipment located in Company substations. These upgrades typically increase functionality of the equipment and software and remedy known deficiencies.

Appendix A

Substation Refurbishment and Modernization Plan
Five-Year Forecast 2011 to 2015

Substation Refurbishment and Modernization Plan
Five-Year Forecast
2011 to 2015
(000s)

2011		2012		2013		2014		2015	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
HCT	1,007	SPO	823	NCH	1,016	CAT	1,672	BRB	1,205
PAB	440	P4	610	CAR	698	VIC	1,058	FRN	1,016
P3	440	SCT	197	MAS	506	GLN	394	GBE	107
NGF	707	STV	495	SMU	150	TWG	248	GBS	1.074
SLA	159	Misc	90			SPR	397	STX	230
Misc	171	SMU	150			ILC	90	WAL	945
SMU	150					SMU	50	Misc	210
								SMU	50
	$3,074		**$2,365**		**$2,370**		**$3,909**		**$4,837**

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.

2011 Additions Due to Load Growth

June 2010

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A FORTIS COMPANY

Table of Contents

1.0 Introduction

As load increases on an electrical system, individual components can become overloaded. The focus of Newfoundland Power's system planning is to avoid or minimize component overloading through cost effective upgrades to the system. In the case of substation power transformers, an engineering study is completed to identify and evaluate technical alternatives in advance of the overload. These technical alternatives are fully examined, cost estimates are prepared and an economic analysis is performed to identify the least cost alternative.

In urban settings load can be transferred between adjacent substations. For this reason, engineering studies of alternatives to address load growth commonly identify an area with multiple substations as the scope of the system planning study.

In this case, two studies were undertaken to address the impact on the Company's substations of load growth on the Northeast Avalon Peninsula. The scope of the studies included six substations serving customers in Conception Bay South and in the areas northeast of the city of St. John's. A review of the peak loads experienced in the most recent winter season was used to identify actual and forecast overload conditions on power transformers in these substations.

This report identifies two items to be included in the Additions Due to Load Growth Project in the 2011 Capital Budget. The first item is the replacement of a 15 MVA power transformer with a new 25 MVA transformer at Kelligrews substation, addressing transformer capacity in Conception Bay South. The second item is to install a new 25 MVA transformer for Pulpit Rock substation, addressing transformer capacity in the areas north of the city of St. John's. These two items jointly provide the least cost expansion plan to address load growth on the Northeast Avalon Peninsula.

2.0 Conception Bay South Area

An engineering study has been completed on the distribution system upgrades to meet the electrical demands in the Conception Bay South area.[1] This area includes customers serviced from Kelligrews ("KEL"), Chamberlains ("CHA") and Seal Cove ("SCV") substations. Hardwoods ("HWD") 25kV distribution system, which supplies the Town of Paradise, is also included in this report due to its interconnection to the CHA distribution system.

The study examines 3 alternatives to determine the least cost approach to dealing with the forecast overload conditions in the Conception Bay South area. Each alternative was evaluated using a 20 year load forecast. Based on net present value calculations the least cost alternative was selected.

The proposed project involves installing a new 25 MVA power transformer at KEL substation to replace the existing 15 MVA unit.

[1] The engineering study titled "Additions Due to Load Growth, Conception Bay South Study" is included as Attachment A.

3.0 Northeast St. John's Area

An engineering study has been completed on the distribution system upgrades to meet the electrical demands in the Northeast St. John's area.[2] The Northeast St. John's area includes customers serviced from Pulpit Rock ("PUL"), Broad Cove ("BCV") and Hardwoods ("HWD") substations.

The study examines 3 alternatives to determine the least cost approach to dealing with the forecast overload conditions in the Northeast St. John's area. Each alternative was evaluated using a 20 year load forecast. Based on net present value calculations the least cost alternative was selected.

The proposed project involves installing an additional 25 MVA power transformer at PUL substation, as well as additional trunk feeder capacity from PUL substation.[3]

4.0 Project Cost

Table 1 shows the total 2011 capital costs for each project.

Table 1
2011 Project Costs
($000)

Cost Category	Kelligrews Transformer	Pulpit Rock Transformer
Material	1,797	2,234
Labour – Internal	132	175
Labour – Contract		
Engineering	182	248
Other	36	48
Total	**2,147**	**2,705**

5.0 Concluding

Both the Conception Bay South and Northeast St. John's areas have experienced customer and load growth in recent years. As a result the available transformer capacity has diminished and equipment overloads are forecast to occur.

[2] The engineering study titled "Additions Due to Load Growth, Northeast St. John's Study" is included as Attachment B.

[3] The additional trunk feeder capacity from PUL substation study is included in a separate project, described in report *4.2 Feeder Additions for Load Growth,* filed with Newfoundland Power's 2011 Capital Budget Application.

It is recommended that the projects identified as part of the least cost alternatives in the attached studies be undertaken in 2011 to address capacity issues in the Conception Bay South and Northeast St. John's areas.

The least cost alternatives proposed include installing a new 25 MVA power transformer at KEL substation to replace the existing 15 MVA unit and installing an additional 25MVA power transformer at PUL substation. The estimated cost to complete this work in 2011 is $4,852,000.

Attachment A

Conception Bay South Study

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Page

1.0 Introduction

The purpose of this study is to determine the distribution system alternative that best meets the electrical demands of the Town of Conception Bay South. This area includes customers serviced from Kelligrews ("KEL"), Chamberlains ("CHA") and Seal Cove ("SCV") substations. Hardwoods ("HWD") 25kV distribution system, which supplies the Town of Paradise, is also included in this report due to its interconnection to the CHA distribution system.

In 2009, the distribution power transformers supplying the area experienced a total peak load of 87.5 MVA compared to a total capacity of 101 MVA.[1] A transformer at KEL ("KEL-T1") is currently the closest to being overloaded, experiencing a peak of 14.5 MVA compared to a capacity of 15 MVA. The current forecast indicates that KEL-T1 will overload by 2011. Load growth on this transformer is primarily the result of an increase in residential development in the Town of Conception Bay South.

This report identifies the capital project(s) required to avoid the 2011 forecast overload at KEL by determining the least cost expansion plan required to meet a 20 year load forecast.

2.0 Description of Existing System

2.1 KEL Substation

KEL substation is located on Middle Bight Road in the community of Conception Bay South. The substation has one transformer, KEL-T1. This is a 15 MVA transformer used to convert the 66 kV transmission voltage to the 12.5 kV distribution voltage and supply customers through KEL substation feeders.

There are two 12.5 kV feeders supplied from KEL substation. KEL-01 feeder extends from the substation north along Middle Bight Road and then west along Route 60 supplying approximately 1,872 customers in the Kelligrews area of Conception Bay South. KEL-02 extends from the substation north along Middle Bight Road and then east along Route 60 supplying approximately 1,151 customers in the Foxtrap area of Conception Bay South.

2.2 CHA Substation

CHA substation is located on Fowlers Road in the community of Conception Bay South. There are two transformers located in the substation, CHA-T1 and CHA-T2. Both transformers are rated 25MVA and are used to convert 66 kV transmission voltage to 25 kV distribution voltage and supply customers through CHA substation feeders.

There are three 25 kV feeders originating from CHA substation. CHA-01 feeder supplies approximately 2,266 customers in the Chamberlains and Manuals areas of Conception Bay South. CHA-02 feeder supplies approximately 1,745 customers in the Topsail area of Conception Bay South as well as Paradise. CHA-03 feeder extends south along Fowlers Road

[1] A distribution power transformer converts electricity from transmission voltages (typically 66 kV) to distribution primary voltages (typically between 4kV and 25kV).

and then along the Conception Bay South Bypass Road supplying approximately 2,113 customers in the Chamberlains, Manuals and Foxtrap areas of Conception Bay South.

2.3 HWD Substation

HWD substation is located in the town of Paradise. There are three transformers located in the substation. HWD-T1 and HWD-T2 are both 20 MVA rated transformers used to convert 66kV transmission voltage to 12.5kV distribution voltage and supply customers on five distribution feeders through HWD substation.[2]

HWD-T3 is a 25 MVA transformer used to convert 66 kV transmission voltage to 25 kV distribution voltage and supply customers through two 25 kV feeders. HWD-07 extends along Karwood Drive onto Topsail Road and along Paradise Road to St. Thomas Line supplying approximately 2,508 customers. HWD-08 feeder extends along Karwood Drive onto Topsail Road and supplies approximately 1,685 customers in the Paradise area.

2.4 SCV Substation

SCV substation is located in Seal Cove in the community of Conception Bay South. There is one power transformer located in the substation, SCV-T2. This is a 11.2 MVA rated transformer used to convert 66kV transmission voltage to 12.5kV distribution voltage and supply customers through SCV substation feeders.

There are two 12.5 kV feeders originating from SCV substation. SCV-01 extends from the substation east along Route 60 supplying approximately 1,424 customers in the Seal Cove and Upper Gullies area of Conception Bay South. SCV-02 feeder extends from the substation west along Route 60 supplying 470 customers in the Seal Cove area of Conception Bay South and the community of Holyrood.

3.0 Load Forecast

The following are the peak substation transformer loads recorded this past winter for each of these substations.

- KEL-T1 is rated at 15 MVA. The load on this transformer peaked at 14.5 MVA in 2009.
- CHA-T1 and CHA-T2 are both rated at 25 MVA. The load on each transformer peaked at 19.9 MVA in 2009.
- HWD-T3 is rated at 25 MVA. The load on this transformer peaked at 23.9 MVA in 2009.
- SCV-T2 is rated at 11.2 MVA. The load on this transformer peaked at 9.3 MVA in 2009.

This study uses a 20 year load forecast for these power transformers. The base case 20 year substation forecast for KEL-T1, CHA-T1, CHA-T2, HWD-T3 and SCV-T2 is located in

[2] The five 12.5 kV feeders originating from HWD substation do not interconnect with CHA feeders and therefore HWD-T1 and HWD-T2 are not included in this report.

Appendix A. A high and low load growth forecast has also been created for each alternative for use in a sensitivity analysis. With the exception of the first year forecast, the sensitivities are based on increasing the load growth by a factor of 50% for the high forecast and decreasing by a factor of 50% for the low forecast.

4.0 Development of Alternatives

Three alternatives have been developed to eliminate the forecast overload conditions using a set of defined technical criteria.[3] These alternatives will provide sufficient capacity to meet forecast loads over the next 20 years.

Each alternative contains estimates for all costs involved, including transformers, new feeders and load transfers. The results of a net present value calculation are provided for each alternative.

4.1 Alternative 1

- New 25MVA, 66/12.5kV transformer at KEL substation to replace the existing 15 MVA rated transformer (KEL-T1) in 2011.
- New 25 MVA, 66/25kV transformer at HWD substation to increase the total 25kV transformer capacity to 50 MVA in 2014.[4]
- New distribution feeder from KEL to complete load transfer from SCV to KEL in 2018.
- New 25 MVA, 66/12.5kV transformer at CHA substation to increase the total transformer capacity to 75 MVA in 2026.

The resulting peak load forecasts for each transformer under Alternative 1 are shown in Appendix B.

4.2 Alternative 2

- New 25MVA power transformer at SCV substation to replace the existing 11.2 MVA rated transformer (SCV-T2) in 2011.
- New distribution feeder from SCV to complete load transfer from KEL to SCV in 2011.
- New 25 MVA, 66/25kV transformer at HWD substation to increase the total 25kV transformer capacity to 50 MVA in 2014.
- New 25 MVA, 66/12.5kV transformer at CHA substation to increase the total transformer capacity to 75 MVA in 2026.

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[3] The following technical criteria were applied:
- The steady state power transformer loading should not exceed the nameplate rating.
- The minimum steady state feeder voltage should not fall below 116 Volts (on a 120 Volt base).
- The feeder normal peak loading should be sufficient to permit cold load pickup.
- The conductor loading should not exceed the ampacity rating established in the distribution planning guidelines.

[4] The new transformer to be installed in 2014 at Hardwoods substation has been identified in both the Conception Bay South and the Northeast St. John’s engineering studies.

The resulting peak load forecasts for each transformer under Alternative 2 are shown in Appendix C.

4.3 Alternative 3

- Complete a voltage conversion of a portion of KEL-02 feeder in order to transfer 3MVA of load from KEL to the CHA 25kV system in 2011.
- New 25 MVA, 66/25kV transformer at HWD substation to increase the total 25kV transformer capacity at HWD to 50 MVA in 2012.
- New 25 MVA, 66/12.5kV transformer at KEL substation to replace the existing 15 MVA rated transformer (KEL-T1) in 2016.
- New distribution feeder from KEL to complete load transfer from SCV to KEL in 2016.
- New 25 MVA, 66/12.5kV transformer at CHA to increase the total transformer capacity to 75 MVA in 2024.

The resulting peak load forecasts for each transformer under Alternative 1 are shown in Appendix D.

5.0 Evaluation of Alternatives

5.1 Cost of Alternatives

Table 1 shows the capital costs estimated for Alternative 1.

Table 1
Alternative 1 Capital Costs

Year	Item	Cost
2011	Purchase and install new 25 MVA transformer at KEL substation to replace existing transformer.	$2,147,000
2014	Purchase and install new 25 MVA transformer at HWD substation.	$2,500,000
2018	Construct new KEL distribution feeder.	$234,000
2018	Complete substation modifications at KEL for new feeder.	$205,000
2026	Purchase and install new 25 MVA transformer at CHA substation.	$2,500,000
	Total	**$7,586,000**

Table 2 shows the capital costs estimated for Alternative 2.

Table 2
Alternative 2 Capital Costs

Year	Item	Cost
2011	Purchase and install new 25 MVA transformer at SCV substation to replace existing transformer and complete substation modifications for new feeder.	$2,705,000
2011	Construct new SCV distribution feeder.	$390,000
2014	Purchase and install new 25 MVA transformer at HWD substation.	$2,500,000
2026	Purchase and install new 25 MVA transformer at CHA substation.	$2,500,000
	Total	**$8,095,000**

Table 3 shows the capital costs estimated for Alternative 3.

Table 3
Alternative 3 Capital Costs

Year	Item	Cost
2011	Convert 3MVA of load from KEL-12.5kV to CHA-25kV.	$375,000
2012	Purchase and install new 25 MVA transformer at HWD substation.	$2,500,000
2016	Purchase and install new 25 MVA transformer at KEL substation to replace existing transformer and complete substation modifications for new feeder.	$2,352,000
2016	Construct new KEL distribution feeder.	$234,000
2024	Purchase and install new 25 MVA transformer at CHA substation.	$2,500,00
	Total	**$7,961,000**

5.2 Economic Analysis

In order to compare the economic impact of the alternatives, a net present value ("NPV") calculation of customer revenue requirement was completed for each alternative. Capital costs from 2011 to 2030 were converted to revenue requirement and the resulting customer revenue requirement from 2011 to 2057 was reduced to a net present value using the Company's weighted average incremental cost of capital.[5]

Table 4 shows the NPV of customer revenue requirement for each alternative under the base case load forecast.

Table 4
Net Present Value Analysis
($000)

Alternative	NPV
1	5,969
2	6,660
3	6,261

Alternative 1 has the lowest NPV of customer revenue requirement.

5.3 Sensitivity Analysis

To assess the sensitivity to load forecast error of each alternative, high and low load forecasts were developed. The peak load forecasts for the sensitivity analysis are shown in Appendix B, C and D for Alternatives 1, 2 and 3, respectively.

In general, the low load forecast results in delaying the required construction. Similarly, with a higher load forecast the timing of the projects is advanced.[6] Using these revised dates, the net present value of the customer revenue requirement was calculated.

5 The 2011 to 2057 time period captures the customer revenue requirement for the 46 year life of the new transformer asset in 2011.

6 The sensitivity analysis for each of the high level forecast alternatives include additional projects to add transformer capacity at the end of the 20 year period.

Table 5 shows the NPV of customer revenue requirement for each alternative under the high and low load forecasts.

Table 5
Sensitivity Analysis
($000)

Alternative	High Load Forecast NPV	Low Load Forecast NPV
1	7,789	4,528
2	8,170	5,246
3	7,839	4,517

Under the high load forecast scenario, Alternative 1 is still the least cost alternative. Under the low forecast scenario, Alternative 3 is the least cost alternative. However, the difference between Alternative 1 and Alternative 3 is not material and therefore does not have an effect on the recommendations of this report.

The recommendation to implement Alternative 1 is still appropriate given the results of the sensitivity analysis.

6.0 Project Cost

Table 6 shows the estimated project costs for 2011.

Table 6
Project Costs

Description	Cost Estimate
Purchase and install new 25 MVA transformer at KEL substation to replace existing 15MVA transformer (KEL-T1).	$2,147,000
Total	**$2,147,000**

7.0 Conclusion and Recommendation

A 20-year load forecast has projected the electrical demands for the towns of Conception Bay South and Paradise. This area includes customers serviced from KEL, CHA, SCV and HWD substations. The development and analysis of alternatives has established a preferred expansion plan to meet the forecast needs.

The least cost alternative that meets all technical criteria is the expansion plan described in Alternative 1.

Further, a sensitivity analysis has confirmed the recommended alternative is appropriate under varying load growth forecasts.

The 2011 project that is part of the least cost expansion plan is to replace the existing 15 MVA KEL-T1 power transformer with a 25 MVA transformer. This project is estimated to cost $2,147,000.

Appendix A

2010 Substation Load Forecast – Base Case

20 Year Substation Load Forecast – Base Case

Device	CHA-T1	CHA-T2	HWD-T3	KEL-T1	SCV-T2
Voltage (kV)	24.94	24.94	24.94	12.47	12.47
Rating (MVA)	25	25	25	14.95	11.2
2009 Peak (MVA)	19.9	19.9	23.9	14.5	9.3
Year	**Forecasted Undiversified Peak - MVA**				
2010	22.1	22.1	23.6	14.8	10.1
2011	22.7	22.7	24.2	15.1	10.3
2012	24.4	24.4	24.3	15.4	10.5
2013	24.9	24.9	24.9	15.7	10.7
2014	25.5	25.5	25.5	16.0	10.9
2015	26.1	26.1	26.1	16.3	11.1
2016	26.7	26.7	26.7	16.6	11.3
2017	27.3	27.3	27.3	16.9	11.6
2018	28.0	28.0	27.9	17.2	11.8
2019	28.6	28.6	28.6	17.5	12.0
2020	29.3	29.3	29.2	17.8	12.2
2021	30.0	30.0	29.9	18.2	12.4
2022	30.7	30.7	30.6	18.5	12.7
2023	31.4	31.4	31.3	18.9	12.9
2024	32.2	32.2	32.1	19.2	13.2
2025	32.9	32.9	32.8	19.6	13.4
2026	33.7	33.7	33.6	19.9	13.7
2027	34.5	34.5	34.4	20.3	13.9
2028	35.3	35.3	35.2	20.7	14.2
2029	36.1	36.1	36.0	21.1	14.4
2030	36.9	36.9	36.9	21.5	14.7

Appendix B

Alternative 1
20 Year Substation Load Forecasts

Alternative 1

20 Year Substation Base Case Load Forecasts - Base Case

Device	CHA-T1	CHA-T2	CHA-T3	HWD-T3	HWD-T4	KEL-T1	SCV-T2
Voltage (kV)	24.94	24.94	24.94	24.94	24.94	12.47	12.47
Rating (MVA)[7]	25	25	25	25	25	25	11.2
2009 Peak (MVA)	19.9	19.9	0.0	23.9	0.0	14.5	9.3
Year	**Forecasted Undiversified Peak - MVA**						
2010	22.1	22.1	0.0	23.6	0.0	14.8	10.1
2011	22.7	22.7	0.0	24.2	0.0	15.1	10.3
2012	24.4	24.4	0.0	24.3	0.0	15.4	10.5
2013	24.9	24.9	0.0	24.9	0.0	16.2	10.2
2014	23.0	23.0	0.0	15.2	15.2	16.5	10.4
2015	23.6	23.6	0.0	15.6	15.6	16.8	10.6
2016	24.1	24.1	0.0	15.9	15.9	17.1	10.8
2017	24.7	24.7	0.0	16.3	16.3	17.4	11.0
2018	22.7	22.7	0.0	19.2	19.2	20.0	8.9
2019	23.3	23.3	0.0	19.7	19.7	20.4	9.1
2020	23.8	23.8	0.0	20.1	20.1	20.8	9.3
2021	24.4	24.4	0.0	20.6	20.6	21.2	9.4
2022	24.9	24.9	0.0	21.1	21.1	21.6	9.6
2023	23.5	23.5	0.0	23.6	23.6	22.0	9.8
2024	24.1	24.1	0.0	24.1	24.1	22.4	10.0
2025	24.6	24.6	0.0	24.7	24.7	22.8	10.2
2026	10.1	10.1	10.1	22.8	22.8	23.2	10.3
2027	10.3	10.3	10.3	23.3	23.3	23.7	10.5
2028	10.6	10.6	10.6	23.8	23.8	24.1	10.7
2029	10.8	10.8	10.8	24.4	24.4	24.6	10.9
2030	11.1	11.1	11.1	25.0	25.0	25.0	11.1

7 Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

Alternative 1
20 Year Substation Load Forecast – High Growth

Device	CHA-T1	CHA-T2	CHA-T3	HWD-T3	HWD-T4	KEL-T1	SCV-T2
Voltage (kV)	24.94	24.94	24.94	24.94	24.94	12.47	12.47
Rating (MVA)[8]	25	25	25	25	25	25	11.2
2009 Peak (MVA)	19.9	19.9	0.0	23.9	0.0	14.5	9.3
Year	**Forecasted Undiversified Peak - MVA**						
2010	22.1	22.1	0.0	23.6	0.0	14.8	10.1
2011	23.0	23.0	0.0	24.5	0.0	15.2	10.4
2012	24.9	24.9	0.0	24.9	0.0	15.7	10.7
2013	23.3	23.3	0.0	15.4	15.4	16.6	10.6
2014	24.1	24.1	0.0	15.9	15.9	17.1	10.8
2015	25.0	25.0	0.0	16.5	16.5	17.6	11.1
2016	23.3	23.3	0.0	19.6	19.6	20.4	9.2
2017	24.2	24.2	0.0	20.3	20.3	20.9	9.4
2018	22.5	22.5	0.0	23.5	23.5	21.5	9.7
2019	23.3	23.3	0.0	24.3	24.3	22.1	9.9
2020	24.6	24.6	0.0	24.6	24.6	22.7	10.2
2021	10.2	10.2	10.2	23.0	23.0	23.4	10.5
2022	10.5	10.5	10.5	23.8	23.8	24.0	10.8
2023	10.9	10.9	10.9	24.6	24.6	24.7	11.1
2024	15.3	15.3	15.3	19.5	19.5	20.9	15.9
2025	15.8	15.8	15.8	20.2	20.2	21.5	16.4
2026	16.4	16.4	16.4	20.9	20.9	22.1	16.8
2027	16.9	16.9	16.9	21.6	21.6	22.7	17.3
2028	17.5	17.5	17.5	22.4	22.4	23.3	17.8
2029	18.1	18.1	18.1	23.2	23.2	24.0	18.3
2030	18.8	18.8	18.8	24.0	24.0	24.7	18.8

8 Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

Alternative 1
20 Year Substation Load Forecast – Low Growth

Device	CHA-T1	CHA-T2	CHA-T3	HWD-T3	HWD-T4	KEL-T1	SCV-T2
Voltage (kV)	24.94	24.94	24.94	24.94	24.94	12.47	12.47
Rating (MVA)[9]	25	25	25	25	25	25	11.2
2009 Peak (MVA)	19.9	19.9	0.0	23.9	0.0	14.5	9.3
Year	**Forecasted Undiversified Peak - MVA**						
2010	22.1	22.1	0.0	23.6	0.0	14.8	10.1
2011	22.5	22.5	0.0	24.0	0.0	15.0	10.3
2012	24.0	24.0	0.0	23.9	0.0	15.2	10.4
2013	24.4	24.4	0.0	24.3	0.0	15.4	10.5
2014	24.7	24.7	0.0	24.7	0.0	15.6	10.7
2015	22.6	22.6	0.0	15.0	15.0	15.8	10.8
2016	23.0	23.0	0.0	15.3	15.3	16.0	10.9
2017	23.3	23.3	0.0	15.5	15.5	16.6	10.6
2018	23.7	23.7	0.0	15.7	15.7	16.9	10.7
2019	24.1	24.1	0.0	16.0	16.0	17.1	10.8
2020	24.4	24.4	0.0	16.2	16.2	17.3	11.0
2021	24.8	24.8	0.0	16.5	16.5	17.5	11.1
2022	23.2	23.2	0.0	18.7	18.7	17.7	11.2
2023	23.6	23.6	0.0	19.0	19.0	20.2	9.1
2024	23.9	23.9	0.0	19.3	19.3	20.5	9.2
2025	24.3	24.3	0.0	19.6	19.6	20.7	9.3
2026	24.7	24.7	0.0	19.9	19.9	21.0	9.4
2027	22.6	22.6	0.0	22.8	22.8	21.3	9.5
2028	22.9	22.9	0.0	23.1	23.1	21.5	9.7
2029	23.3	23.3	0.0	23.5	23.5	21.8	9.8
2030	23.7	23.7	0.0	23.8	23.8	22.1	9.9

9 Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

Appendix C

Alternative 2

20 Year Substation Load Forecasts

Alternative 2

20 Year Substation Load Forecast – Base Case

Device	**CHA-T1**	**CHA-T2**	**CHA-T3**	**HWD-T3**	**HWD-T4**	KEL-T1	**SCV-T2**
Voltage (kV)	24.94	24.94	24.94	24.94	24.94	12.47	12.47
Rating (MVA)[10]	25	25	25	25	25	14.95	25
2009 Peak (MVA)	19.9	19.9	0.0	23.9	0.0	14.5	9.3
Year	Forecasted Undiversified Peak – MVA						
2010	22.1	22.1	0.0	23.6	0.0	14.8	10.1
2011	22.7	22.7	0.0	24.2	0.0	10.1	15.3
2012	24.4	24.4	0.0	24.3	0.0	10.3	15.6
2013	24.9	24.9	0.0	24.9	0.0	10.5	15.9
2014	23.0	23.0	0.0	15.2	15.2	10.7	16.2
2015	23.6	23.6	0.0	15.6	15.6	10.9	16.5
2016	24.1	24.1	0.0	15.9	15.9	11.1	16.8
2017	24.7	24.7	0.0	16.3	16.3	11.3	17.1
2018	22.7	22.7	0.0	19.2	19.2	11.5	17.5
2019	23.3	23.3	0.0	19.7	19.7	11.7	17.8
2020	23.8	23.8	0.0	20.1	20.1	11.9	18.1
2021	24.4	24.4	0.0	20.6	20.6	12.1	18.5
2022	24.9	24.9	0.0	21.1	21.1	12.4	18.8
2023	23.5	23.5	0.0	23.6	23.6	12.6	19.2
2024	24.1	24.1	0.0	24.1	24.1	12.8	19.5
2025	24.6	24.6	0.0	24.7	24.7	13.1	19.9
2026	10.1	10.1	10.1	22.8	22.8	13.3	20.3
2027	10.3	10.3	10.3	23.3	23.3	13.6	20.6
2028	10.6	10.6	10.6	23.8	23.8	13.8	21.0
2029	10.8	10.8	10.8	24.4	24.4	14.1	21.4
2030	11.1	11.1	11.1	25.0	25.0	14.4	21.8

10 Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

Alternative 2
20 Year Substation Load Forecast – High Growth

Device	CHA-T1	CHA-T2	CHA-T3	HWD-T3	HWD-T4	KEL-T1	SCV-T2
Voltage (kV)	24.94	24.94	24.94	24.94	24.94	12.47	12.47
Rating (MVA)[11]	25	25	25	25	25	14.95	25
2009 Peak (MVA)	19.9	19.9	0.0	23.9	0.0	14.5	9.3
Year	**Forecasted Undiversified Peak – MVA**						
2010	22.1	22.1	0.0	23.6	0.0	14.8	10.1
2011	23.0	23.0	0.0	24.5	0.0	10.2	15.4
2012	24.9	24.9	0.0	24.9	0.0	10.5	15.9
2013	23.3	23.3	0.0	15.4	15.4	10.8	16.3
2014	24.1	24.1	0.0	15.9	15.9	11.1	16.8
2015	25.0	25.0	0.0	16.5	16.5	11.4	17.3
2016	23.3	23.3	0.0	19.6	19.6	11.8	17.7
2017	24.2	24.2	0.0	20.3	20.3	12.1	18.2
2018	22.5	22.5	0.0	23.5	23.5	12.4	18.8
2019	23.3	23.3	0.0	24.3	24.3	12.8	19.3
2020	24.6	24.6	0.0	24.7	24.7	13.1	19.8
2021	10.2	10.2	10.2	23.0	23.0	13.5	20.4
2022	10.5	10.5	10.5	23.8	23.8	13.9	21.0
2023	10.9	10.9	10.9	24.7	24.7	14.3	21.5
2024	15.3	15.3	15.3	19.5	19.5	14.7	22.1
2025	15.8	15.8	15.8	20.2	20.2	14.2	23.7
2026	16.4	16.4	16.4	20.9	20.9	14.6	24.3
2027	16.9	16.9	16.9	21.7	21.7	15.0	25.0
2028	17.5	17.5	17.5	22.4	22.4	17.9	23.2
2029	18.2	18.2	18.2	23.2	23.2	18.4	23.9
2030	18.8	18.8	18.8	24.0	24.0	19.0	24.5

[11] Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

Alternative 2
20 Year Substation Load Forecast – Low Growth

Device	CHA-T1	CHA-T2	CHA-T3	HWD-T3	HWD-T4	KEL-T1	SCV-T2
Voltage (kV)	24.94	24.94	24.94	24.94	24.94	12.47	12.47
Rating (MVA)[12]	25	25	25	25	25	14.95	25
2009 Peak (MVA)	19.9	19.9	0.0	23.9	0.0	14.5	9.3
Year	**Forecasted Undiversified Peak – MVA**						
2010	22.1	22.1	0.0	23.6	0.0	14.8	10.1
2011	22.5	22.5	0.0	24.0	0.0	15.0	10.3
2012	24.0	24.0	0.0	23.9	0.0	10.1	15.5
2013	24.4	24.4	0.0	24.3	0.0	10.2	15.7
2014	24.7	24.7	0.0	24.7	0.0	10.4	15.8
2015	22.6	22.6	0.0	15.0	0.0	10.5	16.0
2016	23.0	23.0	0.0	15.3	0.0	10.6	16.2
2017	23.3	23.3	0.0	15.5	0.0	10.8	16.5
2018	23.7	23.7	0.0	15.7	2.5	10.9	16.7
2019	24.1	24.1	0.0	16.0	2.6	11.0	16.9
2020	24.4	24.4	0.0	16.2	2.6	11.2	17.1
2021	24.8	24.8	0.0	16.5	2.7	11.3	17.3
2022	23.2	23.2	0.0	18.7	2.7	11.5	17.5
2023	23.6	23.6	0.0	19.0	4.8	11.6	17.7
2024	23.9	23.9	0.0	19.3	4.9	11.7	17.9
2025	24.3	24.3	0.0	19.6	5.0	11.9	18.2
2026	24.7	24.7	0.0	19.9	2.7	12.0	18.4
2027	22.6	22.6	0.0	22.8	2.7	12.2	18.6
2028	22.9	22.9	0.0	23.1	2.8	12.3	18.9
2029	23.3	23.3	0.0	23.5	2.8	12.5	19.1
2030	23.7	23.7	0.0	23.8	2.9	12.6	19.3

[12] Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

Appendix D

Alternative 3
20 Year Substation Load Forecasts

Alternative 3
20 Year Substation Load Forecast – Base Case

Device	CHA-T1	CHA-T2	CHA-T3	HWD-T3	HWD-T4	KEL-T1	SCV-T2
Voltage (kV)	24.94	24.94	24.94	24.94	24.94	12.47	12.47
Rating (MVA)[13]	25	25	25	25	25	25	11.2
2009 Peak (MVA)	19.9	19.9	0.0	23.9	0.0	14.5	9.3
Year	**Forecasted Undiversified Peak – MVA**						
2010	22.1	22.1	0.0	23.6	0.0	14.8	10.6
2011	24.2	24.2	0.0	24.2	0.0	12.1	10.8
2012	22.9	22.9	0.0	15.2	15.2	12.3	11.1
2013	23.5	23.5	0.0	15.5	15.5	13.1	10.8
2014	24.0	24.0	0.0	15.9	15.9	13.3	11.0
2015	24.5	24.5	0.0	16.2	16.2	13.5	11.2
2016	22.6	22.6	0.0	19.1	19.1	16.1	9.1
2017	23.1	23.1	0.0	19.6	19.6	16.4	9.2
2018	23.7	23.7	0.0	20.0	20.0	16.7	9.4
2019	24.2	24.2	0.0	20.5	20.5	17.0	9.6
2020	24.8	24.8	0.0	21.0	21.0	17.3	9.8
2021	23.4	23.4	0.0	23.5	23.5	17.7	10.0
2022	23.9	23.9	0.0	24.0	24.0	18.0	10.1
2023	24.5	24.5	0.0	24.6	24.6	18.3	10.3
2024	10.7	10.7	10.7	21.7	21.7	18.7	10.5
2025	10.9	10.9	10.9	22.2	22.2	19.0	10.7
2026	11.2	11.2	11.2	22.7	22.7	19.4	10.9
2027	11.5	11.5	11.5	23.2	23.2	19.7	11.1
2028	11.7	11.7	11.7	23.7	23.7	20.6	10.8
2029	12.0	12.0	12.0	24.3	24.3	21.0	11.0
2030	12.3	12.3	12.3	24.9	24.9	21.4	11.2

[13] Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

Alternative 3
20 Year Substation Load Forecast – High Growth

Device	CHA-T1	CHA-T2	CHA-T3	HWD-T3	HWD-T4	KEL-T1	SCV-T2
Voltage (kV)	24.94	24.94	24.94	24.94	24.94	12.47	12.47
Rating (MVA)[14]	25	25	25	25	25	25	11.2
2009 Peak (MVA)	19.9	19.9	0.0	23.9	0.0	14.5	9.3
Year	**Forecasted Undiversified Peak – MVA**						
2010	22.1	22.1	0.0	23.6	0.0	14.8	10.1
2011	24.5	24.5	0.0	24.5	0.0	12.2	10.4
2012	23.5	23.5	0.0	15.5	15.5	12.6	10.7
2013	24.3	24.3	0.0	16.0	16.0	13.0	11.1
2014	22.7	22.7	0.0	19.1	19.1	15.6	9.0
2015	23.4	23.4	0.0	19.7	19.7	16.0	9.3
2016	24.3	24.3	0.0	20.4	20.4	16.5	9.6
2017	23.1	23.1	0.0	23.1	23.1	17.0	9.8
2018	23.9	23.9	0.0	24.0	24.0	17.4	10.1
2019	24.8	24.8	0.0	24.8	24.8	17.9	10.4
2020	10.9	10.9	10.9	22.2	22.2	18.4	10.7
2021	11.3	11.3	11.3	22.9	22.9	18.9	11.0
2022	11.7	11.7	11.7	23.8	23.8	21.3	9.5
2023	12.1	12.1	12.1	24.6	24.6	21.9	9.8
2024	16.5	16.5	16.5	19.5	19.5	22.5	10.0
2025	17.1	17.1	17.1	20.1	20.1	23.1	10.3
2026	17.7	17.7	17.7	20.9	20.9	23.8	10.6
2027	18.3	18.3	18.3	21.6	21.6	24.4	10.9
2028	19.0	19.0	19.0	22.3	22.3	23.6	12.7
2029	19.6	19.6	19.6	23.1	23.1	24.3	13.1
2030	20.3	20.3	20.3	23.9	23.9	25.0	13.4

[14] Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

Alternative 3
20 Year Substation Load Forecast – Low Growth

Device	**CHA-T1**	**CHA-T2**	**CHA-T3**	**HWD-T3**	**HWD-T4**	**KEL-T1**	**SCV-T2**
Voltage (kV)	24.94	24.94	24.94	24.94	24.94	12.47	12.47
Rating (MVA)[15]	25	25	25	25	25	25	11.2
2009 Peak (MVA)	19.9	19.9	0.0	23.9	0.0	14.5	9.3
Year	**Forecasted Undiversified Peak - MVA**						
2010	22.1	22.1	0.0	23.6	0.0	14.8	10.6
2011	22.5	22.5	0.0	24.0	0.0	15.0	10.8
2012	25.0	25.0	0.0	24.9	0.0	12.2	10.9
2013	22.4	22.4	0.0	15.7	15.7	12.3	11.1
2014	22.7	22.7	0.0	15.9	15.9	12.5	11.2
2015	23.1	23.1	0.0	16.1	16.1	13.1	10.8
2016	23.4	23.4	0.0	16.4	16.4	13.3	11.0
2017	23.8	23.8	0.0	16.6	16.6	13.5	11.1
2018	24.2	24.2	0.0	16.9	16.9	13.6	11.2
2019	24.6	24.6	0.0	17.2	17.2	16.1	9.1
2020	24.9	24.9	0.0	17.4	17.4	16.3	9.2
2021	23.3	23.3	0.0	19.7	19.7	16.5	9.3
2022	23.7	23.7	0.0	20.0	20.0	16.7	9.4
2023	24.1	24.1	0.0	20.3	20.3	16.9	9.5
2024	24.4	24.4	0.0	20.6	20.6	17.1	9.7
2025	24.8	24.8	0.0	21.0	21.0	17.4	9.8
2026	23.2	23.2	0.0	23.3	23.3	17.6	9.9
2027	23.6	23.6	0.0	23.7	23.7	17.8	10.0
2028	23.9	23.9	0.0	24.0	24.0	18.0	10.1
2029	24.3	24.3	0.0	24.4	24.4	18.2	10.3
2030	24.7	24.7	0.0	24.8	24.8	18.5	10.4

15 Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

Attachment B

Northeast St. John's Study

Table of Contents

1.0 Introduction

The purpose of this study is to determine the distribution system alternative that best meets the electrical demands in the area northeast of the city of St. John's. The Northeast St. John's Area includes customers serviced from Pulpit Rock ("PUL"), and Broad Cove ("BCV") substations. Hardwoods ("HWD") 25kV distribution system, which supplies the Town of Paradise, is also included in this report due to its interconnection to the BCV distribution system.

In 2009, the distribution power transformers supplying the area experienced a total peak load of 72.2 MVA compared to a total capacity of 75 MVA. A transformer at BCV ("BCV-T1") experienced a peak load of 25.6 MVA, exceeding its capacity rating of 25 MVA.[1] Load growth on this transformer is primarily the result of residential load growth.

This report identifies the capital project(s) required to address the overload on BCV-T1 by determining the least cost expansion plan required to meet a 20 year load forecast.

2.0 Description of Existing System

2.1 BCV Substation

BCV substation is located at Broad Cove in the community of Portugal Cove-St. Phillips. The substation has one transformer, BCV-T1.[2] This is a 25 MVA transformer used to convert the 66 kV transmission voltage to the 12.5 kV distribution voltage and supply customers through BCV substation feeders.

There are four 12.5 kV feeders supplied from BCV substation. BCV-01 feeder extends from the substation along Old Broad Cove Road and onto Portugal Cove Road supplying approximately 866 customers. BCV-02 extends to Bell Island via a submersible cable where it supplies approximately 1,529 customers. BCV-03 feeder extends west from the substation along Thorburn Road and onto St. Thomas Line supplying approximately 997 customers. BCV-04 feeder extends south from the substation along Tuckers Hill Road and into Portugal Cove supplying approximately 1,034 customers.

2.2 PUL Substation

PUL substation is located in the community of Torbay, located on the Northeast Avalon Peninsula. There is one transformer located in the substation, PUL-T1. This is a 25 MVA transformer used to convert 66 kV transmission voltage to 12.5 kV distribution voltage and supply customers through PUL substation feeders.

There are three 12.5 kV feeders originating from PUL substation. PUL-01 feeder supplies approximately 1,947 customers in the community of Torbay. PUL-02 feeder extends north from

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[1] This overload occurred despite a load transfer to HWD-T3 that was completed in 2009. This reflects higher than forecast load growth on BCV-T1.

[2] A distribution power transformer converts electricity from transmission voltages (typically 66 kV) to distribution primary voltages (typically between 4kV and 25kV).

the substation and supplies approximately 1,463 customers in the communities of Flatrock and Pouch Cove. PUL-03 feeder also extends north from the substation along the Bauline Line and supplies approximately 871 customers in Torbay and Bauline.

2.3 HWD Substation

HWD substation is located in the community of Paradise, on the Avalon Peninsula west of the City of St. John's. There are three transformers located in the substation. HWD-T1 and HWD-T2 are both 20 MVA rated transformers used to convert 66kV transmission voltage to 12.5kV distribution voltage and supply customers on five distribution feeders through HWD substation.[3]

HWD-T3 is a 25 MVA transformer used to convert 66 kV transmission voltage to 25 kV distribution voltage and supply customers through two HWD substation feeders. HWD-07 extends along Karwood Drive onto Topsail Road and along Paradise Road to St. Thomas Line, supplying approximately 2,508 customers. HWD-08 feeder extends along Karwood Drive onto Topsail Road and supplies approximately 1,685 customers in the Paradise Area.

3.0 Load Forecast

The following are the peak substation transformer loads recorded this past winter for each of these substations.

- BCV-T1 is rated at 25 MVA. The load on this transformer peaked at 25.6 MVA in 2009.
- PUL-T1 is rated at 25 MVA. The load on this transformer peaked at 22.7 MVA in 2009.
- HWD-T3 is rated at 25 MVA. The load on this transformer peaked at 23.9 MVA in 2009.

This study uses a 20-year load forecast for these power transformers. The base case 20 year forecasts for BCV-T1, PUL-T1 and HWD-T3 are located in Appendix A. A high and low load growth forecast has also been created for each of the alternatives for use in a sensitivity analysis. With the exception of the first year forecast, the sensitivities are based on increasing the load growth by a factor of 50% for the high forecast and decreasing it by 50% for the low forecast.

4.0 Development of Alternatives

Three alternatives have been developed to eliminate the existing and forecasted overload conditions using a set of defined technical criteria.[4] These alternatives will provide sufficient capacity to meet forecasted loads over the next 20 years.

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[3] The five 12.5 kV feeders originating from HWD substation do not service the Northeast Avalon area included in this study, and therefore HWD-T1 and HWD-T2 are not included in this report.

[4] The following technical criteria were applied.

- The steady state power transformer loading should not exceed the nameplate rating.
- The minimum steady state feeder voltage should not fall below 116 Volts (on a 120 Volt base).
- The feeder normal peak loading should be sufficient to permit cold load pickup.
- The conductor loading should not exceed the ampacity rating established in the distribution planning guidelines.

Each alternative contains estimates for all costs involved including transformers, new feeders and load transfers. The results of net present value calculations are provided for each alternative.

4.1 Alternative 1

- New 25 MVA, 66/12.5kV transformer at PUL substation to increase the total substation transformer capacity to 50 MVA in 2011.
- New distribution feeder from PUL to complete load transfer from BCV to PUL in 2011.
- New 25 MVA, 66/25kV transformer at HWD substation to increase the total 25kV transformer capacity to 50 MVA in 2014.[5]
- Upgrade and extend PUL-03 feeder to allow additional load transfers from BCV to PUL in 2016.
- New 25 MVA, 66/12.5kV transformer at BCV substation to increase the total transformer capacity to 50 MVA in 2023.

The resulting peak load forecasts for each transformer under Alternative 1 are shown in Appendix B.

4.2 Alternative 2

- New 25 MVA, 66/12.5kV transformer at BCV substation to increase the total transformer capacity to 50 MVA in 2011.
- New distribution feeder from BCV to complete load transfer from PUL to BCV in 2012.
- New 25 MVA, 66/25kV transformer at HWD substation to increase the total 25kV transformer capacity to 50 MVA in 2014.
- Upgrade and extend BCV-04 feeder to allow additional load transfers from PUL to BCV in 2021.
- New 25 MVA, 66/12.5kV transformer at PUL substation to increase the total transformer capacity to 50 MVA in 2027.
- New distribution feeder from PUL to complete load transfer from BCV to PUL in 2027.

The resulting peak load forecasts for each transformer under Alternative 2 are shown in Appendix C.

4.3 Alternative 3

- Complete a voltage conversion of a portion of BCV-03 feeder in order to transfer load from BCV to the HWD 25kV system in 2011.
- New 25 MVA, 66/25kV transformer at HWD substation to increase the total 25kV transformer capacity at HWD to 50 MVA in 2011, to support the voltage conversion and load transfer from BCV.
- New 25 MVA, 66/12.5kV transformer at PUL substation to increase the total transformer capacity at PUL to 50 MVA in 2012.

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5 The new transformer to be installed in 2014 at Hardwoods substation has been identified in both the Conception Bay South and the Northeast St. John's engineering studies.

- New distribution feeder from PUL to complete load transfer from BCV to PUL in 2012.
- Upgrade and extend PUL-03 feeder to allow additional load transfers from BCV to PUL in 2021.
- New 25 MVA, 66/12.5kV transformer at BCV substation to increase the total transformer capacity at BCV to 50 MVA in 2029.

The resulting peak load forecasts for each transformer under Alternative 2 are shown in Appendix D.

5.0 Evaluation of Alternatives

5.1 Cost of Alternatives

Table 1 shows the capital costs estimated for Alternative 1.

Table 1
Alternative 1 Capital Costs

Year	Item	Cost
2011	Purchase and install new 25 MVA transformer at PUL substation and complete substation modifications for new feeder.	$2,705,000
2011	Construct new PUL distribution feeder.	$638,000
2014	Purchase and install new 25 MVA transformer at HWD substation.	$2,500,000
2016	Extend and upgrade PUL-03 feeder.	$427,000
2023	Purchase and install new 25 MVA transformer at BCV substation.	$2,500,000
	Total	**$8,770,000**

Table 2 shows the capital costs estimated for Alternative 2.

Table 2
Alternative 2 Capital Costs

Year	Item	Cost
2011	Purchase and install new 25 MVA transformer at BCV substation and complete substation modifications for new feeder.	$2,705,000
2012	Construct new BCV distribution feeder.	$850,000
2014	Purchase and install new 25 MVA transformer at HWD substation.	$2,500,000
2021	Extend and upgrade BCV-04 feeder.	$427,000
2027	Purchase and install new 25 MVA transformer at PUL substation and complete substation modifications for new feeder.	$2,705,000
2027	Construct new PUL distribution feeder.	$290,000
	Total	**$9,477,000**

Table 3 shows the capital costs estimated for Alternative 3.

Table 3
Alternative 3 Capital Costs

Year	Item	Cost
2011	Convert 3MVA of load from BCV-12.5kV to HWD-25kV	$550,000
2011	Purchase and install a new 25 MVA transformer at HWD.	$2,500,000
2012	Purchase and install new 25 MVA transformer at PUL substation and complete substation modifications for new feeder.	$2,705,000
2012	Construct new PUL distribution feeder.	$638,000
2021	Extend and upgrade PUL-03 feeder.	$427,000
2029	Purchase and install new 25 MVA transformer at BCV substation.	$2,500,000
	Total	**$9,320,000**

5.2 Economic Analysis

In order to compare the economic impact of the alternatives, a net present value ("NPV") calculation of customer revenue requirement was completed for each alternative. Capital costs from 2011 to 2030 were converted to revenue requirement and the resulting customer revenue requirement from 2011 to 2057 was reduced to a net present value using the Company's weighted average incremental cost of capital.[6]

Table 4 shows the NPV of customer revenue requirement for each alternative under the base case load forecast.

Table 4
Net Present Value Analysis
($000)

Alternative	NPV
1	7,490
2	7,507
3	7,795

Alternative 1 has the lowest NPV of customer revenue requirement.

5.3 Sensitivity Analysis

To assess the sensitivity to load forecast error of each alternative, high and low load forecasts were developed. With exception of the first year forecast, the sensitivities were based on increasing the load growth by a factor of 50% for the high forecast and decreasing by a factor of 50% for the low forecast. The peak load forecasts for the sensitivity analysis are shown in Appendix B, C and D for Alternatives 1, 2 and 3, respectively.

In general, the low load forecast results in delaying the required construction. Similarly, with a higher load forecast the timing of the projects is advanced.[7] Using these revised dates, the net present value of the customer revenue requirement was calculated.

[6] The 2011 to 2057 time period captures the customer revenue requirement for the 46 year life of the new transformer asset in 2011.

[7] The sensitivity analysis for each of the high level forecast alternatives include additional projects to add transformer capacity at the end of the 20 year period.

Table 5 shows the NPV of customer revenue requirement for each alternative under the high and low load forecasts.

Table 5
Sensitivity Analysis
($000)

Alternative	High Load Forecast NPV	Low Load Forecast NPV
1	8,947	5,868
2	9,086	6,096
3	8,894	6,783

Under the low load forecast, Alternative 1 is still the least cost alternative. Under the high forecast, Alternative 3 is the least cost alternative. However, the difference between Alternative 1 and Alternative 3 is small. Further, in the case of high load growth, Alternative 3 results in lower aggregate capacity to meet future load growth beyond 2030, relative to Alternatives 1 and 2.[8] This will tend to increase costs beyond 2030.

The recommendation to implement Alternative 1 is still appropriate given the results of the sensitivity analysis.

6.0 Project Cost

Table 6 shows the estimated costs for the projects to be completed in 2011.

Table 6
Project Costs

Description	Cost Estimate
Purchase and install new 25 MVA transformer at PUL substation.	$2,500,00
Complete substation modifications at PUL for new distribution feeder.	$205,000
Construct new PUL distribution feeder.	$638,000
Total	**$3,343,000**

[8] In 2030, under the high forecast scenario, Alternative 3 has a total distribution transformer capacity of 150 MVA while Alternatives 1 and 2 have a total capacity of 175 MVA

7.0 Conclusion and Recommendation

A 20-year load forecast has projected the electrical demands for the areas of the Northeast Avalon supplied from BCV, PUL, and HWD (25kV) substations. The development and analysis of alternatives has established a preferred expansion plan to meet these needs.

The least cost alternative that meets all of the technical criteria is the expansion plan described in Alternative 1.

Further, a sensitivity analysis has confirmed the recommended alternative is appropriate under varying load growth forecasts.

The 2011 projects that are part of the least cost expansion plan include installing a new transformer at PUL substation, construction a new feeder termination point at the substation and the construction of a new PUL distribution feeder. The estimated cost to complete this work in 2011 is $3,343,000.[9]

[9] The $3,343,000 project cost is found in 2 different 2011 capital projects. The Substations *Additions Due to Load Growth* project includes $2,705,000 for the PUL transformer and the Distribution *Feeder Additions for Growth* project included $638,000 for the new PUL feeder.

Appendix A

2010 Substation Load Forecast – Base Case

20 Year Substation Load Forecast – Base Case

Device	BCV-T1	HWD-T3	PUL-T1
Voltage (kV)	12.47	24.94	12.47
Rating (MVA)	25	25	25
2009 Peak (MVA)	25.6	23.9	22.7
Year	**Forecasted Undiversified Peak - MVA**		
2010	27.3	23.6	24.2
2011	28.0	24.2	24.8
2012	28.7	24.3	25.4
2013	29.3	24.9	26.0
2014	30.0	25.5	26.6
2015	30.7	26.1	27.2
2016	31.4	26.7	27.9
2017	32.2	27.3	28.5
2018	32.9	27.9	29.2
2019	33.7	28.6	29.9
2020	34.5	29.2	30.6
2021	35.3	29.9	31.3
2022	36.1	30.6	32.0
2023	36.9	31.3	32.8
2024	37.8	32.1	33.5
2025	38.7	32.8	34.3
2026	39.6	33.6	35.1
2027	40.5	34.4	35.9
2028	41.5	35.2	36.8
2029	42.4	36.0	37.6
2030	43.4	36.9	38.5

Appendix B

Alternative 1
20 Year Substation Load Forecast

Alternative 1
20 Year Substation Load Forecasts – Base Case

Device	BCV-T1	BCV-T2	HWD-T3	HWD-T4	PUL-T1	PUL-T2
Voltage (kV)	12.47	12.47	24.94	24.94	12.47	12.47
Rating (MVA)[10]	25	25	25	25	25	25
2009 Peak (MVA)	25.6	0.0	23.9	0.0	22.7	0.0
Year	**Forecasted Undiversified Peak - MVA**					
2010	27.3	0.0	23.6	0.0	24.2	0.0
2011	22.8	0.0	24.2	0.0	13.7	13.7
2012	23.3	0.0	24.3	0.0	14.0	14.0
2013	23.9	0.0	24.9	0.0	14.4	14.4
2014	24.4	0.0	12.7	12.7	14.7	14.7
2015	25.0	0.0	13.0	13.0	15.0	15.0
2016	21.6	0.0	13.3	13.3	17.4	17.4
2017	22.1	0.0	13.6	13.6	17.8	17.8
2018	22.6	0.0	14.0	14.0	18.2	18.2
2019	23.1	0.0	14.3	14.3	18.6	18.6
2020	23.7	0.0	14.6	14.6	19.1	19.1
2021	24.2	0.0	15.0	15.0	19.5	19.5
2022	24.8	0.0	15.3	15.3	20.0	20.0
2023	12.7	12.7	15.7	15.7	20.4	20.4
2024	13.0	13.0	16.0	16.0	20.9	20.9
2025	13.3	13.3	16.4	16.4	21.4	21.4
2026	13.6	13.6	16.8	16.8	21.9	21.9
2027	13.9	13.9	17.2	17.2	22.4	22.4
2028	14.2	14.2	17.6	17.6	23.0	23.0
2029	14.6	14.6	18.0	18.0	23.5	23.5
2030	14.9	14.9	18.4	18.4	24.0	24.0

10 Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

Alternative 1
20 Year Substation Load Forecast – High Growth

Device	BCV-T1	BCV-T2	HWD-T3	HWD-T4	PUL-T1	PUL-T2	PUL-T3
Voltage (kV)	12.47	12.47	24.94	24.94	12.47	12.47	12.47
Rating (MVA)[11]	25	25	25	25	25	25	25
2009 Peak (MVA)	25.6	0.0	23.9	0.0	22.7	0.0	0.0
Year	**Forecasted Undiversified Peak - MVA**						
2010	27.3	0.0	23.6	0.0	24.2	0.0	0.0
2011	23.1	0.0	24.5	0.0	15.2	15.2	0.0
2012	24.0	0.0	24.9	0.0	15.7	15.7	0.0
2013	24.8	0.0	12.9	12.9	16.3	16.3	0.0
2014	21.7	0.0	13.3	13.3	18.8	18.8	0.0
2015	22.4	0.0	13.8	13.8	19.5	19.5	0.0
2016	23.2	0.0	14.3	14.3	20.2	20.2	0.0
2017	24.0	0.0	14.8	14.8	20.9	20.9	0.0
2018	24.9	0.0	15.3	15.3	21.6	21.6	0.0
2019	12.9	12.9	15.9	15.9	22.4	22.4	0.0
2020	13.3	13.3	16.4	16.4	23.2	23.2	0.0
2021	13.8	13.8	17.0	17.0	24.0	24.0	0.0
2022	14.3	14.3	17.6	17.6	24.8	24.8	0.0
2023	17.8	17.8	18.2	18.2	22.7	22.7	0.0
2024	18.4	18.4	18.9	18.9	23.5	23.5	0.0
2025	19.1	19.1	19.5	19.5	24.3	24.3	0.0
2026	21.7	21.7	20.2	20.2	23.2	23.2	0.0
2027	22.5	22.5	20.9	20.9	24.0	24.0	0.0
2028	23.3	23.3	21.7	21.7	24.8	24.8	0.0
2029	24.1	24.1	22.4	22.4	8.6	8.6	8.6
2030	25.0	25.0	23.2	23.2	8.9	8.9	8.9

11 Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

Alternative 1
20 Year Substation Load Forecast – Low Growth

Device	**BCV-T1**	**BCV-T2**	**HWD-T3**	**HWD-T4**	**PUL-T1**	**PUL-T2**
Voltage (kV)	12.47	12.47	24.94	24.94	12.47	12.47
Rating (MVA)[12]	25	25	25	25	25	25
2009 Peak (MVA)	25.6	0.0	23.9	0.0	22.7	0.0
Year	**Forecasted Undiversified Peak - MVA**					
2010	27.3	0.0	23.6	0.0	24.2	0.0
2011	22.5	0.0	24.0	0.0	13.6	13.6
2012	22.9	0.0	23.9	0.0	13.8	13.8
2013	23.3	0.0	24.3	0.0	14.0	14.0
2014	23.6	0.0	24.7	0.0	14.3	14.3
2015	24.0	0.0	25.0	0.0	14.5	14.5
2016	24.4	0.0	12.7	12.7	14.7	14.7
2017	24.7	0.0	12.9	12.9	14.9	14.9
2018	21.1	0.0	13.1	13.1	17.2	17.2
2019	21.5	0.0	13.3	13.3	17.4	17.4
2020	21.8	0.0	13.5	13.5	17.7	17.7
2021	22.1	0.0	13.7	13.7	18.0	18.0
2022	22.5	0.0	14.0	14.0	18.3	18.3
2023	22.8	0.0	14.2	14.2	18.5	18.5
2024	23.2	0.0	14.4	14.4	18.8	18.8
2025	23.5	0.0	14.6	14.6	19.1	19.1
2026	23.9	0.0	14.8	14.8	19.4	19.4
2027	24.3	0.0	15.1	15.1	19.7	19.7
2028	24.7	0.0	15.3	15.3	20.0	20.0
2029	24.1	0.0	15.6	15.6	20.8	20.8
2030	24.4	0.0	15.8	15.8	21.2	21.2

[12] Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

Appendix C

Alternative 2
20 Year Substation Load Forecasts

Alternative 2
20 Year Substation Load Forecasts – Base Case

Device	BCV-T1	BCV-T2	HWD-T3	HWD-T4	PUL-T1	PUL-T2
Voltage (kV)	12.47	12.47	24.94	24.94	12.47	12.47
Rating (MVA)[13]	25	25	25	25	25	25
2009 Peak (MVA)	25.6	0.0	23.9	0.0	22.7	0.0
Year	**Forecasted Undiversified Peak - MVA**					
2010	27.3	0.0	23.6	0.0	24.2	0.0
2011	14.0	14.0	24.2	0.0	24.8	0.0
2012	16.8	16.8	24.3	0.0	20.4	0.0
2013	17.2	17.2	24.9	0.0	20.9	0.0
2014	17.6	17.6	12.7	12.7	21.4	0.0
2015	18.0	18.0	13.0	13.0	21.9	0.0
2016	18.4	18.4	13.3	13.3	22.4	0.0
2017	18.9	18.9	13.6	13.6	22.9	0.0
2018	19.3	19.3	14.0	14.0	23.4	0.0
2019	19.8	19.8	14.3	14.3	24.0	0.0
2020	20.2	20.2	14.6	14.6	24.5	0.0
2021	22.2	22.2	15.0	15.0	22.1	0.0
2022	22.7	22.7	15.3	15.3	22.6	0.0
2023	23.3	23.3	15.7	15.7	23.2	0.0
2024	23.8	23.8	16.0	16.0	23.7	0.0
2025	24.4	24.4	16.4	16.4	24.3	0.0
2026	24.9	24.9	16.8	16.8	24.8	0.0
2027	22.5	22.5	17.2	17.2	15.7	15.7
2028	23.0	23.0	17.6	17.6	16.1	16.1
2029	23.6	23.6	18.0	18.0	16.5	16.5
2030	24.1	24.1	18.4	18.4	16.8	16.8

13 Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

Alternative 2
20 Year Substation Load Forecast – High Growth

Device	BCV-T1	BCV-T2	BCV-T3	HWD-T3	HWD-T4	PUL-T1	PUL-T2
Voltage (kV)	12.47	12.47	12.47	24.94	24.94	12.47	12.47
Rating (MVA)[14]	25	25	25	25	25	25	25
2009 Peak (MVA)	25.6	0.0	0.0	23.9	0.0	22.7	0.0
Year	**Forecasted Undiversified Peak - MVA**						
2010	27.3	0.0	0.0	23.6	0.0	24.2	0.0
2011	16.7	16.7	0.0	24.5	0.0	20.1	0.0
2012	17.3	17.3	0.0	24.9	0.0	20.9	0.0
2013	17.9	17.9	0.0	12.9	12.9	21.6	0.0
2014	18.5	18.5	0.0	13.3	13.3	22.3	0.0
2015	19.1	19.1	0.0	13.8	13.8	23.1	0.0
2016	19.8	19.8	0.0	14.3	14.3	23.9	0.0
2017	20.5	20.5	0.0	14.8	14.8	24.8	0.0
2018	22.7	22.7	0.0	15.3	15.3	22.6	0.0
2019	23.5	23.5	0.0	15.9	15.9	23.4	0.0
2020	24.4	24.4	0.0	16.4	16.4	24.3	0.0
2021	22.2	22.2	0.0	17.0	17.0	15.6	15.6
2022	23.0	23.0	0.0	17.6	17.6	16.1	16.1
2023	23.8	23.8	0.0	18.2	18.2	16.7	16.7
2024	24.6	24.6	0.0	18.9	18.9	17.3	17.3
2025	22.3	22.3	0.0	19.5	19.5	21.1	21.1
2026	23.1	23.1	0.0	20.2	20.2	21.8	21.8
2027	23.9	23.9	0.0	20.9	20.9	22.6	22.6
2028	24.8	24.8	0.0	21.7	21.7	23.4	23.4
2029	8.5	8.5	8.5	22.4	22.4	24.2	24.2
2030	8.8	8.8	8.8	23.2	23.2	25.0	25.0

[14] Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

Alternative 2
20 Year Substation Load Forecast – Low Growth

Device	**BCV-T1**	**BCV-T2**	**HWD-T3**	**HWD-T4**	**PUL-T1**	**PUL-T2**
Voltage (kV)	12.47	12.47	24.94	24.94	12.47	12.47
Rating (MVA)[15]	25	25	25	25	25	25
2009 Peak (MVA)	25.6	0.0	23.9	0.0	22.7	0.0
Year	**Forecasted Undiversified Peak - MVA**					
2010	27.3	0.0	23.6	0.0	24.2	0.0
2011	13.9	13.9	24.0	0.0	24.6	0.0
2012	14.1	14.1	23.9	0.0	25.0	0.0
2013	16.8	16.8	24.3	0.0	20.4	0.0
2014	17.1	17.1	24.7	0.0	20.7	0.0
2015	17.3	17.3	25.0	0.0	21.0	0.0
2016	17.6	17.6	12.7	12.7	21.4	0.0
2017	17.9	17.9	12.9	12.9	21.7	0.0
2018	18.2	18.2	13.1	13.1	22.0	0.0
2019	18.4	18.4	13.3	13.3	22.4	0.0
2020	18.7	18.7	13.5	13.5	22.7	0.0
2021	19.0	19.0	13.7	13.7	23.1	0.0
2022	19.3	19.3	14.0	14.0	23.4	0.0
2023	19.6	19.6	14.2	14.2	23.8	0.0
2024	19.9	19.9	14.4	14.4	24.2	0.0
2025	20.2	20.2	14.6	14.6	24.5	0.0
2026	20.6	20.6	14.8	14.8	24.9	0.0
2027	22.4	22.4	15.1	15.1	22.3	0.0
2028	22.7	22.7	15.3	15.3	22.7	0.0
2029	23.1	23.1	15.6	15.6	23.0	0.0
2030	23.4	23.4	15.8	15.8	23.4	0.0

15 Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

Appendix D

Alternative 3

20 Year Substation Load Forecasts

Alternative 3
20 Year Substation Load Forecasts – Base Case

Device	**BCV-T1**	**BCV-T2**	**HWD-T3**	**HWD-T4**	**PUL-T1**	**PUL-T2**
Voltage (kV)	12.47	12.47	24.94	24.94	12.47	12.47
Rating (MVA)[16]	25	25	25	25	25	25
2009 Peak (MVA)	25.6	0.0	23.9	0.0	22.7	0.0
Year	**Forecasted Undiversified Peak – MVA**					
2010	27.3	0.0	23.6	0.0	24.2	0.0
2011	25.0	0.0	13.4	13.4	24.8	0.0
2012	20.4	0.0	13.7	13.7	15.3	15.3
2013	20.9	0.0	14.0	14.0	15.7	15.7
2014	21.3	0.0	14.3	14.3	16.0	16.0
2015	21.8	0.0	14.7	14.7	16.4	16.4
2016	22.3	0.0	15.0	15.0	16.8	16.8
2017	22.9	0.0	15.4	15.4	17.2	17.2
2018	23.4	0.0	15.7	15.7	17.6	17.6
2019	24.0	0.0	16.1	16.1	18.0	18.0
2020	24.5	0.0	16.5	16.5	18.4	18.4
2021	21.1	0.0	16.8	16.8	20.8	20.8
2022	21.6	0.0	17.2	17.2	21.3	21.3
2023	22.1	0.0	17.6	17.6	21.8	21.8
2024	22.6	0.0	18.1	18.1	22.3	22.3
2025	23.1	0.0	18.5	18.5	22.9	22.9
2026	23.7	0.0	18.9	18.9	23.4	23.4
2027	24.2	0.0	19.4	19.4	23.9	23.9
2028	24.8	0.0	19.8	19.8	24.5	24.5
2029	12.7	12.7	20.3	20.3	23.1	23.1
2030	13.0	13.0	20.7	20.7	23.6	23.6

[16] Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

Alternative 3
20 Year Substation Load Forecast – High Growth

Device	BCV-T1	BCV-T2	HWD-T3	HWD-T4	PUL-T1	PUL-T2
Voltage (kV)	12.47	12.47	24.94	24.94	12.47	12.47
Rating (MVA)[17]	25	25	25	25	25	25
2009 Peak (MVA)	25.6	0.0	23.9	0.0	22.7	0.0
Year	**Forecasted Undiversified Peak - MVA**					
2010	27.3	0.0	23.6	0.0	24.2	0.0
2011	20.1	0.0	13.5	13.5	15.2	15.2
2012	20.9	0.0	14.0	14.0	15.7	15.7
2013	21.6	0.0	14.5	14.5	16.3	16.3
2014	22.3	0.0	15.0	15.0	16.8	16.8
2015	23.1	0.0	15.5	15.5	17.4	17.4
2016	23.9	0.0	16.1	16.1	18.0	18.0
2017	24.8	0.0	16.6	16.6	18.7	18.7
2018	21.6	0.0	17.2	17.2	21.3	21.3
2019	22.4	0.0	17.8	17.8	22.1	22.1
2020	23.2	0.0	18.5	18.5	22.8	22.8
2021	24.0	0.0	19.1	19.1	23.6	23.6
2022	24.9	0.0	19.8	19.8	24.5	24.5
2023	14.9	14.9	20.5	20.5	23.3	23.3
2024	15.4	15.4	21.2	21.2	24.2	24.2
2025	19.9	19.9	21.9	21.9	21.0	21.0
2026	20.6	20.6	22.7	22.7	21.8	21.8
2027	21.4	21.4	23.5	23.5	22.5	22.5
2028	22.1	22.1	24.3	24.3	23.3	23.3
2029	22.9	22.9	24.0	24.0	24.1	24.1
2030	23.7	23.7	24.8	24.8	25.0	25.0

[17] Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

Alternative 3
20 Year Substation Load Forecast – Low Growth

Device	BCV-T1	BCV-T2	HWD-T3	HWD-T4	PUL-T1	PUL-T2
Voltage (kV)	12.47	12.47	24.94	24.94	12.47	12.47
Rating (MVA)[18]	25	25	25	25	25	25
2009 Peak (MVA)	25.6	0.0	23.9	0.0	22.7	0.0
Year	**Forecasted Undiversified Peak - MVA**					
2010	27.3	0.0	23.6	0.0	24.2	0.0
2011	24.7	0.0	13.3	13.3	24.6	0.0
2012	19.9	0.0	13.5	13.5	15.1	15.1
2013	20.3	0.0	13.7	13.7	15.3	15.3
2014	20.6	0.0	13.9	13.9	15.6	15.6
2015	20.9	0.0	14.1	14.1	15.8	15.8
2016	21.2	0.0	14.3	14.3	16.1	16.1
2017	21.5	0.0	14.6	14.6	16.3	16.3
2018	21.9	0.0	14.8	14.8	16.6	16.6
2019	22.2	0.0	15.0	15.0	16.8	16.8
2020	22.6	0.0	15.3	15.3	17.1	17.1
2021	22.9	0.0	15.5	15.5	17.4	17.4
2022	23.3	0.0	15.7	15.7	17.6	17.6
2023	23.6	0.0	16.0	16.0	17.9	17.9
2024	24.0	0.0	16.2	16.2	18.2	18.2
2025	24.4	0.0	16.5	16.5	18.5	18.5
2026	24.8	0.0	16.7	16.7	18.7	18.7
2027	21.2	0.0	17.0	17.0	21.0	21.0
2028	21.5	0.0	17.3	17.3	21.4	21.4
2029	21.8	0.0	17.5	17.5	21.7	21.7
2030	22.2	0.0	17.8	17.8	22.0	22.0

18 Ratings reflect the transformer capacity rating in 2030 as per the expansion plan.

2011 PCB Removal Strategy

June 2010

Prepared by:

Peter Feehan, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
PETER J. FEEHAN
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DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

In September, 2008 the Canadian Environment Protection Act was amended by the Government of Canada with the *PCB Regulations* coming into effect and the repealing of *The Chlorobiphenyls Regulations* and the *Storage of PCB Material Regulations*. The PCB Regulations ("the Regulations") came into effect for the purpose of minimizing risks posed by polychlorinated biphenyls ("PCBs") and accelerating the elimination of PCBs from electrical equipment in Canada.[1]

Section 16 (1) of the Regulations establishes end-of–use dates for PCB contaminated equipment based on: PCB concentration, equipment type and location. Certain equipment such as power transformers, circuit breakers, reclosers, pad-mounted transformers, current transformers, potential transformers, and bushings with a PCB concentration of 500 mg/kg or more must be removed from service by December 31, 2009. The Regulations permit an extension to the deadline until December 31, 2014, based on approval from the Minister of Environment.[2]

The Company sought and was granted an end-of-use extension to December 31, 2014 for all bushings and instrument transformers where the PCB concentrations are unknown or at 500 mg/kg or more as allowed under Section 17(2) of the Regulations.[3]

Prior to the enactment of the new regulations, Canadian electric utilities were working towards removing from service equipment having a PCB concentration level of 500 mg/kg or more prior to December 31, 2025. This schedule was the result of the 2006 publication by Environment Canada in the Canada Gazette, Part 1, Section 18(c) which stated "A person may continue to use, until December 31, 2025……current transformers, potential transformers, circuit breakers, reclosers and bushings that are located at an electrical generation, transmission or distribution facility". Thus Newfoundland Power and other Canadian utilities planned to phase-out these types of PCB contaminated equipment by the 2025 deadline.

The schedule for testing and replacement of bushings and instrument transformers presented in this report was developed to meet the December 31, 2014 deadline. The Company considers this schedule to be very aggressive. In many instances testing and remedial work will require substation outages which will interrupt electricity service to customers, and will create resource challenges with respect to the Company's other capital work. In light of these issues Newfoundland Power and other utilities have expressed their concern over the 2014 deadline to Environment Canada and is working with the Canadian Electricity Association ("CEA") to reinstate the original 2025 date.

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[1] In the Canada Gazette, Part 1 published in November 2006, Environment Canada states that the purpose of the proposed regulations was to improve the protection of Canada's environment and the health of Canadians and as well, to implement Canada's national and international commitments on the use, storage and elimination of PCBs.

[2] The deadline and extension requirement also apply to the equipment listed above with a PCB concentration of 50 mg/kg or more that is located in sensitive locations. In addition, the above listed equipment with PCB concentrations of 50 mg/kg or more (including pole-top electrical transformers) must be removed from service by December 31, 2025.

[3] This is the only equipment for which Newfoundland Power requires the end-of-use date extension. All other equipment such as pole mounted transformers, power transformers and breakers have been confirmed to be less than 500 mg/kg or less than 50 mg/kg in sensitive locations. The end-of-use date extension is included in Appendix A.

2.0 PCB Equipment Remediation Strategy

Newfoundland Power's end-of-use date extension application ("the Extension Application"), as approved by Environment Canada, identified a total of 429 pieces of equipment which require PCB testing and possible remediation. This included 161 power transformers, 186 circuit breakers, 56 potential transformers, 12 current transformers, 6 metering tanks and 8 station service transformers. A total of 2,330 bushings are associated with this equipment. The PCB concentration of these items is unknown.[4]

Newfoundland Power will conduct PCB testing and, if required, replace any bushings and instrument transformers with a PCB concentration at 500 mg/kg or more to meet the December 31, 2014 deadline.

The strategy is comprised of two parts:

- Part 1 - Test all of the equipment identified to determine actual PCB concentration or to identify which pieces of equipment cannot be tested (for example hermetically sealed oil filled bushings).
- Part 2 - Replace all equipment that either cannot be tested or has a PCB concentration of 500 mg/kg or more. Equipment that cannot be tested will have to be replaced as the level of PCB contamination cannot be determined.

The remediation strategy for each equipment category is discussed in the sections to follow.

2.1 Power Transformers

The average age of the 161 power transformers identified in the Extension Application is approximately 40 years. Over 1,200 transformer bushings were listed in the Extension Application that was approved by Environment Canada.[5]

The remediation strategy for power transformers will require the replacement of the transformer bushings for units that test at 500 mg/kg or more. Replacement of the oil contained within the bushings is not an option as the majority of the PCB contaminated oil in a bushing is contained in the bushing's paper, which cannot be replaced on site. Due to the high replacement cost of power transformers and their relatively long life, the remediation strategy for power transformer bushings will be to test individual bushings and order replacements for units that test at 500 mg/kg or more.[6]

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[4] Equipment that was built since January 1st, 1986 was deemed to be free of PCB contamination based on a review of Newfoundland Power's records. Consequently all of the equipment in question is twenty-five years old or older.

[5] This list has been reduced to approximately 1,100 units by identifying specific types of bushings that are not oil filled and therefore are not subject to PCB contamination.

[6] There is a six month lead time required to procure new power transformer bushings.

Figure 1 shows the location of the bushings at the top of the power transformer tank.

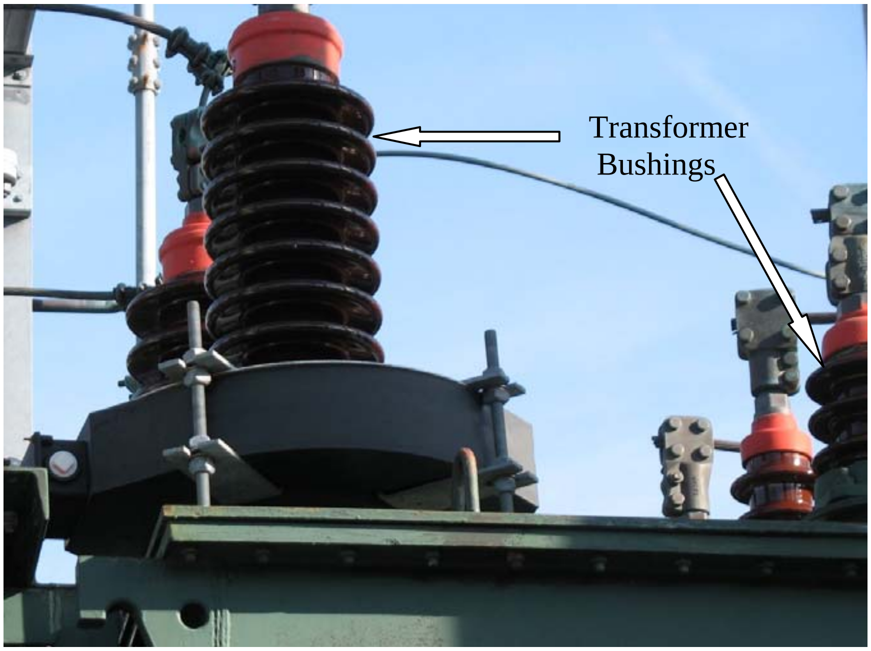

Figure 1 – Power Transformer Bushings

In situations with one or more of a transformer's bushings test at 500 mg/kg or more, all bushings that test above 50 mg/kg will also be replaced. While bushings that test between 50 mg/kg and 500 mg/kg can remain in service until 2025, it is cost effective to replace all bushings during the one power transformer outage, especially in situations where installing a portable substation is required.

Approximately half of the transformer bushings can be tested and remediated without incurring customer outages.[7] The other half will require customer outages to allow testing to be completed. It is estimated that there are 63 transformer locations where the portable substations will not be available to maintain electricity service to customers while testing of the transformer bushings is completed. Each of these 63 transformers will require a four hour customer outage to complete the testing.

Where practical, the Company will schedule bushing testing and remediation to the transformer's normal maintenance schedule. However, because of the requirement to complete all testing and remediation before the 2014 deadline, only one third of the transformer bushings will be tested during the normal maintenance cycle. All testing and remediation work required to meet the 2014 deadline that is completed outside of the normal maintenance schedule will be part of the PCB removal capital project.

To date, the Company has very few actual PCB test results for power transformer bushings. Until the Company accumulates a reasonable sample of its own test data a failure rate will have

7 In some locations customer load can be transferred to adjacent substations, or there are multiple transformers in the same substation servicing customers. In these situations the testing can be completed without incurring a customer outage.

to be assumed. The Company has assumed a 1% failure rate for transformer bushings.[8] If the actual failure rate turns out to be significantly different than the assumed failure rate then the scheduling of testing and remediation work will be adjusted accordingly. In addition, approximately 25% of Newfoundland Power's transformers have bushings that cannot be tested. These bushings will have to be replaced as their PCB concentration cannot be determined.

Table 1 provides the Company's schedule for testing and replacement of power transformer bushings.

Table 1
Power Transformer Bushing Testing & Replacement Schedule

Year	**Number of Transformers To Test**	**Estimated Number of Transformers Requiring Bushing Replacement[9]**	**Transformer Bushing Replacement Year**
2010	16	5	2 in 2010 3 in 2013
2011	45	13	5 in 2011 8 in 2013
2012	45	13	5 in 2012 8 in 2014
2013	45	13	5 in 2013 8 in 2014
2014	10	4	4 in 2014
Total	**161**	**48**	

2.2 *Bulk Oil Circuit Breakers*

Newfoundland Power has not purchased bulk oil circuit breakers since 1982[10]. The average age of the bulk oil circuit breakers in service is approximately 40 years. The life expectancy of an oil

[8] Newfoundland Power has tested bushings on thirteen different transformers to date. Two of the transformers have bushings that tested greater than 50 mg/kg while none have tested above 500 mg/kg. The CEA PCB Equipment Inventory from November 2009 indicates that 1% of tested oil filled bushings have PCB concentrations in excess of 500 mg/kg. Based upon the CEA results, although all transformer bushings must be tested, it is likely only 1% will prove to be greater than 500 mg/kg.

[9] Estimate based on a 1% failure rate (above 500 mg/kg) and on the fact that approximately 25% of Newfoundland Power's transformers have some bushings that cannot be tested.

[10] The Company has purchased mostly SF6 breakers since 1982. However some minimum oil (not PCB) and some vacuum breakers have also been purchased. Today the Company only purchases SF6 or vacuum breakers.

circuit breaker varies; however, based on experience an average life span of 38 years is reasonable.

Whenever one breaker bushing tests at 500 mg/kg or more then it is likely all 6 bushings on that breaker will have similar PCB content. Replacing all 6 bushings on these breakers would approach the cost of purchasing a new breaker. Therefore, due to their age and the cost of bushing replacement, the complete breaker will be replaced when 1 bushing tests greater than 500 mg/kg.[11]

Figure 2 shows the location of the bushings at the top of the bulk oil circuit breaker tank.

Breaker Bushings

Figure 2 - 66 kV Bulk Oil Breaker

Where practical, the Company will schedule bushing testing and remediation to the breaker's normal maintenance schedule. However, because of the requirement to complete testing and remediation before the 2014 deadline, only one third of the breaker bushings will be tested during the normal maintenance cycle. All testing and remediation work required to meet the 2014 deadline that is completed outside of the normal maintenance schedule will be part of the PCB removal capital project.

[11] The Company anticipates that the majority of breaker bushings can be tested. However, any breakers with bushings that cannot be tested will also be replaced as the PCB concentration cannot be determined.

Table 2 provides the Company's schedule for testing and replacement of circuit breaker bushings.

Table 2
Circuit Breaker Bushing Testing & Replacement Schedule

Testing Year	Number of Breakers To Test	Estimated Number of Breakers Requiring Replacement [12]	Breaker Bushing Replacement Year
2010	12	1	2012
2011	85	8	2012
2012	85	8	2013
2013	4	1	2014
2014	0	0	-
Total	186	18	

Approximately 95% of the breakers can be tested and remediated without incurring customer outages. The remaining 5% will require customer outages to allow testing to be completed. [13] To minimize the total number of customer outages required, remediation of the latter group of breakers will be completed at the same time as the testing for the transformer bushings is completed.

2.3 Potential and Current Transformers

Potential and current transformers are typically hermetically sealed therefore they cannot be tested for PCB concentrations. The units with sampling ports will be tested, and those that test at 500 mg/kg or more will be replaced. All units that cannot be tested will be replaced with new units.

Approximately 60% of the Company's potential transformers ("PTs") and 50% of the current transformers ("CTs") can be tested and remediated without a customer outage. The remainder of the units will require customer outages to test. Replacement of these units will also require outages or the installation of a portable substation if available in order to complete the replacements.

[12] Newfoundland Power has completed testing for the bushings on only 11 breakers. As a result there is little empirical data on which to base an estimated failure rate. For the purpose of preparing a budgetary estimate it is assumed that a minimum of 1 breaker will require replacement during a year when testing is undertaken. A maximum failure rate of 10% is assumed for any year in which testing is completed.

[13] Approximately 6 locations.

The plan is to test one third of these units in each of the three years starting in 2011. All required replacements will be done in 2013 and 2014.

Figure 3 shows the location of a set of three 66 kV PTs on a substation structure.

Figure 3 - 66 kV Potential Transformers

2.4 Metering Tanks

The 6 metering tanks identified in the Extension Application will be tested before the end of 2013. All required replacements will be completed prior to the end of 2014.

2.5 Station Service Transformers

These 8 units are low cost and are relatively easy to replace. They will be tested before the end of 2013 and replaced with new units as required before the end of 2014.

3.0 Project Cost

Table 3 identifies capital budget estimates for completing the above testing and expected remediation work prior to the 2014 deadline established by the Government of Canada.

Table 3
Project Cost 2011 to 2014

Year	Expenditure
2011	$1,500,000
2012	$3,000,000
2013	$5,000,000
2014	$5,000,000
2015	$2,000,000

The estimated expenditures include the work outlined in Tables 1 and 2 of section 2.0, including testing and replacement costs. Based on the limited data available from the manufacturers or testing programs completed by other utilities, several assumptions were made in developing the cost estimates for this strategy. As a result the actual expenditure in future years will vary depending upon the accuracy of the assumptions used to create the cost estimates. As more data is collected in 2010, 2011 and 2012 the full implications and cost of meeting the requirements of the Regulations will become better defined.

4.0 Concluding

Replacing equipment with a PCB concentration that is either unknown or at 500mg/kg or more, by the 2014 deadline will be extremely difficult for Newfoundland Power and other Canadian electric utilities. On May 11, 2010 the Canadian Electricity Association ("CEA") wrote to Environment Canada requesting that Canadian utilities be afforded the appropriate time to ensure proper management of PCB contaminated equipment in an economically feasible manner. The CEA has requested that the Regulations be amended to ascribe bushings and instrument transformers an end-of-use date of 2025.

If the CEA amendment is accepted, and the deadline for dealing with the equipment is extended until 2025, the PCB phase-out can be completed over a 15 year period (2011-2025) compared to a 4 year period (2011-2014). This longer timeframe would put the Company in a better position to meet Environment Canada's regulatory requirements without dramatically impacting the Company's annual capital budget expenditures.

The current legislation also requires other equipment such as pole-top transformers with a PCB concentration of 50 mg/kg or more be removed from the system by the end of 2025. The implication is that expenditures on PCB remediation will likely continue until 2025. The work completed over the next couple of years will allow clearer identification of the future remediation that will be required to meet the PCB Regulation.

This project as presented is required to allow Newfoundland Power to meet its obligations as stated in the Extension Application and subsequent approval by Environment Canada.

Appendix A

Extension of End-of-Use Date for Equipment and Liquids Containing PCBs

Environment Canada / Environnement Canada

Newfoundland Power
55 Kenmount Road, P.O. Box 8910,
St. John's, Newfoundland Canada A1B 3P6

05 February 2010 / 05 février 2010

EXTENSION OF DECEMBER 31, 2009 END-OF-USE DATE FOR EQUIPMENT AND LIQUIDS CONTAINING PCBs Granted Under Subsection 17(2) of the *PCB Regulations*

PROLONGATION DE LA DATE DE FIN D'UTILISATION DU 31 DÉCEMBRE 2009 POUR DES PIÈCES D'ÉQUIPEMENT ET DES LIQUIDES QUI CONTIENNENT DES BPC Accordée en vertu du paragraphe 17(2) du *Règlement sur les BPC*

File Number / No. de dossier : 09/109/EXT

The Department of the Environment grants Newfoundland Power, St. John's, the extension requested in its application. The end-of-use date of the equipment and liquids used for their servicing described below is extended from December 31, 2009 to the dates indicated in the table below.

This extension is granted in accordance with subsection 17(2) of the *PCB Regulations*. The condition specified in subparagraph 17(2)(*a*)(i) of the Regulations and referred to in the application is met.

Le ministère de l'Environnement accorde à Newfoundland Power, St. John's, la prolongation exigée dans sa demande. La date de fin d'utilisation des pièces d'équipement et des liquides nécessaires à leur entretien décrits ci-dessous est reportée du 31 décembre 2009 aux dates indiquées au tableau ci-dessous.

Cette prolongation est accordée en vertu du paragraphe 17(2) du *Règlement sur les BPC.* La condition énoncée au sous-alinéa 17(2)*a*)(i) du Règlement et invoquée dans la demande est remplie.

Number of bushings / Nombre de traversées isolées	Number of pieces of equipment/ Nombre de pièces d'équipement	Extension date/ Date de prolongation
6	1	30 October 2010
2,330	429	31 December 2014
Total : 2,336	Total : 430	

Canada

Environment Canada | Environnement Canada

Condition referred to in the application for an extension / Condition invoquée dans la demande de prolongation

The equipment is being replaced with equipment that is engineered to order, and it is not technically feasible to replace the equipment on or before December 31, 2009.

La pièce d'équipement doit être remplacée par une pièce d'équipement conçue et fabriquée sur mesure et il est techniquement impossible de le faire le 31 décembre 2009 ou avant cette date.

Applicant and person authorized to act on applicant's behalf Demandeur et personne autorisée à agir en son nom

Applicant/ Demandeur, 17(3)(a)
Newfoundland Power
55 Kenmount Road, P.O. Box 8910,
St. John's, Newfoundland Canada A1B 3P6

Person authorized to act on applicant's behalf/ Personne autorisée à agir au nom du demandeur, 17(3)(a)
Mr. Paul O'Leary
Director, Environment
Newfoundland Power
P.O. Box 8910
55 Kenmount Road
St. John's, Newfoundland A1B 3P6
Telephone: (709) 737-2868
Fax: (709) 737-2960
Email: poleary@newfoundlandpower.com

Owner of equipment containing PCBs/ Propriétaire des pièces d'équipement contenant des BPC, 17(1)
Same as applicant above.

Description and location of equipment and liquids needed for their servicing / Description et emplacement des pièces d'équipement et des liquides nécessaires à leur entretien

See attached list of equipment for details, this list is part of the authorization / Voir la liste des pièces d'équipements annexée pour le détail, cette liste fait partie intégrante de l'autorisation

Canada

Type and function of the equipment/ Type et fonction de l'équipement, 17(3)(b)(i): See Tables 1 and 2 below for details. Equipment covered by the application include:

- breaker,
- oil filled bushing,
- current transformer,
- metering tank,
- potential transformer,
- regulator,
- station service transformer,
- step up transformer,
- step down transformer,
- transformer, and
- load tap changer.

Quantity of liquid (litres) containing PCBs in the equipment/ Quantité de liquide (litres) contenant des BPC dans la pièce d'équipement, 17(3)(b)(ii): Estimated total of 15,250 L of liquid containing PCBs for all known and unknown equipment.

See Tables 1 and 2 below for details. Quantity per equipment is 4L for known PCB containing equipment and varies from 1L to 240 L for equipment with unknown PCB concentration.

Total Table 1- Equipment with known PCB concentration – 1 piece of equipment containing 6 bushings = 24 L.
Total Table 2- Equipment potentially containing PCBs in a concentration of 500 mg/kg or more – 429 pieces of equipment containing 2,330 bushings = 15,226 L

Quantity of liquid (litres) containing PCBs needed for its servicing/ Quantité de liquide (litres) contenant des BPC nécessaire à son entretien, 17(3)(b)(ii): No additional liquids are kept for the purpose of servicing the working equipment.

Concentration of PCBs (mg/kg) in the liquid/ Concentration de BPC (mg/kg) dans le liquide, 17(3)(b)(iii): Known concentrations in Table 1 vary from 570 mg/kg to 700 mg/kg. An average PCB concentration of 638 mg/kg is used as an estimate for all pieces of equipment with "unknown" concentrations in Table 2. See Tables 1 and 2 below for details.

Quantity of PCBs (kg) in the liquid/ Quantité de BPC (kg) dans le liquide/, 17(3)(b)(iv): Estimated total of 8.57 kg of PCBs in the liquid for all known and unknown equipment.

See Tables 1 and 2 below for details. Quantity of PCBs for known equipment varies from 0.0020 to 0.0025 kg and for unknown equipment from 0.0006 kg to 0.0450 kg.
Total for known equipment in Table 1 = 0.0134 kg
Total for unknown equipment in Table 2 = 8.56 kg
Total quantity of PCBs (kg) in all liquids = Table 1 + Table 2 = 0.0134 kg + 8.56 kg = 8.57 kg.

Name-plate description, manufacturer's serial number/ Plaque d'identification et numéro de série , 17(3)(b)(v) : See Tables 1 and 2 below for details. Manufacturer nameplate information and serial numbers are not readily available for the unknown equipment.

Unique identification number on the label required under section 29/ Numéro d'identification unique sur l'étiquette conformément à l'article 29, 17(3)(c): See Tables 1 and 2 below for details. All equipment noted in Table 1 has been labeled in accordance with Section 29 of the PCB Regulations. Each label contains a unique identification number. For the unknown equipment, the equipment will be labeled in accordance with Section 29 of the PCB Regulations once testing has confirmed that the PCB level of concentration is 500 mg/kg or more. Each label will contain a unique identification number (i.e. manufacturer's serial number).

Place where the equipment is located/ Endroit où se trouve la pièce d'équipement, 17(3)(d):

Equipment Known to contain PCBs in a concentration of 500 mg/kg or more: The six electrical bushings on the breaker are located at the Kelligrews Substation. The Kelligrews Substation, with designation KEL, is an entirely fenced facility located on Middle Bight Road in the Town of Conception Bay South, Newfoundland and Labrador. The substation steps down voltage from 66KV to 12.5KV. All equipment is enclosed in a locked fenced area outdoors at all locations.

Equipment with Unknown PCB concentration: See Table 2 below for details on each of the unknown bushings. All equipment is enclosed in a locked fenced area outdoors at all locations, potential of 116 Substations.

Information demonstrating that it is not technically feasible to replace the equipment with equipment that is engineered to order on or before December 31, 2009/ Renseignements qui établissent qu'il est techniquement impossible de remplacer la pièce d'équipement conçue et fabriquée sur mesure le 31 décembre 2009 ou avant cette date, 17(3)(e): The information provided in the application for an extension in accordance with this section indicate that the applicant is meeting the condition specified in subparagraph 17(2)*a*)(i).

Necessary measures taken to minimize or eliminate any harmful effect of the PCBs that are contained in the equipment on the environment and human health/ Mesures nécessaires prises pour éliminer ou atténuer tout effet nocif des BPC contenus dans la pièce d'équipement sur l'environnement et la santé humaine, 17(3)(f): The measures are indicated in the application for an extension.

Plan for ending the use of equipment by the end of the extension along with timelines/ Plan et échéancier mis en oeuvre afin que l'utilisation de la pièce d'équipement cesse à la fin de la prolongation, 17(3)(g): Provided in the application for an extension. The known piece of equipment with 6 bushings containing PCBs as components will be removed from use by October 30, 2010 and the 429 pieces of equipment with 2,330 bushings as components and potentially containing PCBs will be removed from use by December 31, 2014 in accordance with the application.

Plan for inspecting equipment/ Plan d'inspection de la pièce d'équipement, 17(3)(h): Monthly inspections will be conducted for the period of the extension for damage that could lead to the release of PCBs.

Please take note that it is your responsibility as the owner or the person who controls or possesses the equipment and liquids containing PCBs to ensure that the requirements set out in the *PCB Regulations* made pursuant to CEPA 1999 are complied with at all time.

Veuillez noter qu'en tant que propriétaire ou personne qui contrôle ou possède les pièces d'équipement et des liquides contenant des BPC il vous incombe de veiller à ce que les exigences établies dans le *Règlement sur les BPC* et dans la LCPE (1999) soient remplies en tout temps.

Signed for and on behalf of the Minister of the Environment /
Signé au nom du ministre de l'Environnement

CBlain

Carolyne Blain
Director / Directrice
Waste Reduction & Management / Réduction et gestion des déchets
Public and Resources Sectors / Secteurs publics et des ressources
Environment Canada / Environnement Canada

Transmission Line Rebuild

June 2010

Prepared by:

M. R. Murphy, B.Sc, E.I.T.

Approved by:

Michael Comerford, P. Eng.

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
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July 7, 2010
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NEWFOUNDLAND POWER
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1.0 Transmission Line Rebuild Strategy

Transmission lines are the bulk transmitter of electricity providing service to customers. Transmission lines operate at higher voltages, either 66 kV or 138 kV and are often located across country away from road rights 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 Transmission Line Rebuild Projects Planned for 2011

In 2011, the Company plans to rebuild transmission lines 16L, 21L and 25L. Appendix B contains topographic views of each of the lines to be rebuilt. Appendix C contains photographs of the existing lines.

These lines are each more than 55 years old; and there is deterioration of the 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.

2.1 Transmission Line 16L ($730,000)

16L is a 66 kV transmission line running between King's Bridge Substation and Pepperell Substation. The line is 1.98 kilometres in length and is single pole construction with 1/0 Copper conductor. Constructed in 1950, it is located near Quidi Vidi Lake and runs alongside the Boulevard and King's Bridge Rd.

The line consists of 50 structures, 43 of which have distribution underbuilt on the poles, and many of which provide street lighting to the Boulevard. Most of these structures are directly adjacent to the road in the face of the curb and are prone to damage by passing snowploughs and other vehicles.

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. Much of the structure guying on 16L 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 most recent 2010 inspection of 16L noted the following deficiencies:

Table 1
16L Deficiencies

Deficiency Category	Number of Structures[1]
Insulators	4
Deteriorated/Damaged Crossarms	28
Grounding	6
Pole Leaning	5
Pole Deteriorated/Damaged	21

Based on the overall deteriorated condition of the line, it is recommended the line be rebuilt in 2011 at an estimated cost of $730,000.

2.2 Transmission Line 21L ($822,000)

21L is a 66 kV H-Frame transmission line running between the Horse Chops Hydroelectric Plant and transmission line 20L.[2] 21L connects the Horse Chops plant to the main electricity grid.[3] It is 5.73 kilometres in length and was originally constructed in 1952. The line consists of 36 two and three-pole H-Frame structures using non-standard 266.8 ACSR conductors with a number of road crossing spans along the route.

Inspections have identified substantial deterioration due to decay, woodpecker holes, and splits and checks in the poles, crossarms and crossbraces. Many of these wooden components are in advanced stages of deterioration and require replacement. Transmission line 25L also contains insulators manufactured by Canadian Ohio Brass (COB). These insulators are identified as deficiencies due to a history of premature failure caused by cement growth. As the cement in these insulators expands, cracks in the porcelain insulators occur making the insulators more susceptible to flashovers.

The poles, crossarms and crossbraces have had their strength compromised due to the extent of deterioration. Long span lengths combined with the physical condition, make the line susceptible to damage should it become exposed to wind, ice or snow loading.

---

1 16L has a total of 50 structures.

2 21L terminates at the intersection of Horse Chops Road and the Southern Shore Highway near Cape Broyle. At its termination, 21L connects with transmission line 20L.

3 Horse Chops plant produces 43 GWH of electricity annually, or 10.1% of Newfoundland Power’s annual hydroelectric production.

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 most recent 2010 inspection of 21L noted the following deficiencies:

Table 2
21L Deficiencies

Deficiency Category	Number of Structures[4]
Insulators	25
Crossarms Deteriorated/Damaged	7
Crossbraces Deteriorated/Damaged	17
Pole Deteriorated/Damaged	11

Based on the advanced age and overall deteriorated condition of the line, it is recommended the line be rebuilt in 2011 at an estimated cost of $822,000.

2.3 Transmission Line 25L ($1,443,000)

25L is a 66 kV H-Frame transmission line running between the Goulds substation on Main Road in the Goulds and St. John's Main substation on Southside Rd. This line is 9.25 kilometres in length and was originally constructed in 1954.

The line consists of 51 two and three-pole H-Frame structures and two steel towers using non-standard 477 ACSR conductor. Inspections have identified substantial deterioration including numerous instances of rot in the poles and timbers, as well as rusting guys and worn hardware. Corrosion is evident on the steel towers and the line contains insulators manufactured by Canadian Ohio Brass (COB) which have been identified as deficiencies due to a history of premature failure caused by cement growth.

The poles and timbers, in many cases, are now moss-covered which indicates advanced decay and, therefore, have compromised strength. In a number of instances, temporary bracing has been used in cases where the poles are visibly unable to support the line.[5]

4 21L has a total of 36 structures.
5 Photographs of some temporary braces are included in figure 14 of Appendix C.

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 most recent 2010 inspection of 25L noted the following deficiencies:

Table 3
25L Deficiencies

Deficiency Category	**Number of Structures**[6]
Insulators	43
Crossarms Deteriorated/Damaged	15
Crossbraces Deteriorated/Damaged	27
Pole Deteriorated/Damaged	30

Based on the advanced age and overall deteriorated condition of the line, it is recommended the line be rebuilt in 2011 at an estimated cost of $1,443,000.

3.0 Concluding

In 2011, the Company will rebuild transmission lines 16L, 21L and 25L. Each of these transmission lines is more than 55 years old; with structures experiencing deterioration of the poles, crossarms, hardware, and conductor. Recent inspections have determined the transmission lines have reached a point where continued maintenance is no longer feasible and they have to be rebuilt to continue providing safe, reliable electrical service.

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

[6] 25L has a total of 51 structures.

Appendix A

Transmission Line Rebuild Strategy Schedule

Transmission Line Rebuilds 2011-2015 ($000)

Line	Year	2011	2012	2013	2014	2015
012L KBR-MUN	1950		595			
013L SJM-SLA	1962				605	
014L SLA-MUN	1950			237		
015L SLA-MOL	1958					133
016L PEP-KBR	1950	730				
018L GOU-GDL	1951					766
021L 20L-HCP	1952	822				
025L GOU-SJM	1954	1,443				
030L RRD-KBR	1959					825
032L OXP-RRD	1959					353
035L OXP-KEN	1963					929
068L HGR-CAR	1951				881	
069L KEN-SLA	1951				802	
110L CLV-LOK	1958		1,653	2,868		
124L CLV-GAM	1964		802			
	Total	**$2,995**	**$3,050**	**$3,105**	**$2,288**	**$3,006**

Transmission Line Rebuilds 2016-2022 ($000)

Line	Year	2016	2017	2018	2019	2020	2021	2022
041L CAR-HCT	1958	695	2,830					
049L HWD-CHA	1966						595	
057L BRB-HGR	1958	3,228						
100L SUN-CLV	1964						2,203	2,978
101L GFS-RBK	1957			1,863	4,076			
102L GAN-RBK	1958				2,038	6,568	4,406	
124L CLV-GAM	1964							3,750
301L SPO-GRH	1959		208					
302L SPO-LAU	1959		1,509	3,627				
403L TAP-ROB	1960							919
	Total	**$3,923**	**$4,547**	**5,490**	**$6,114**	**$6,568**	**$7,204**	**$7,647**

Appendix B

Topographic Maps of
Transmission Lines 16L, 21L, and 25L

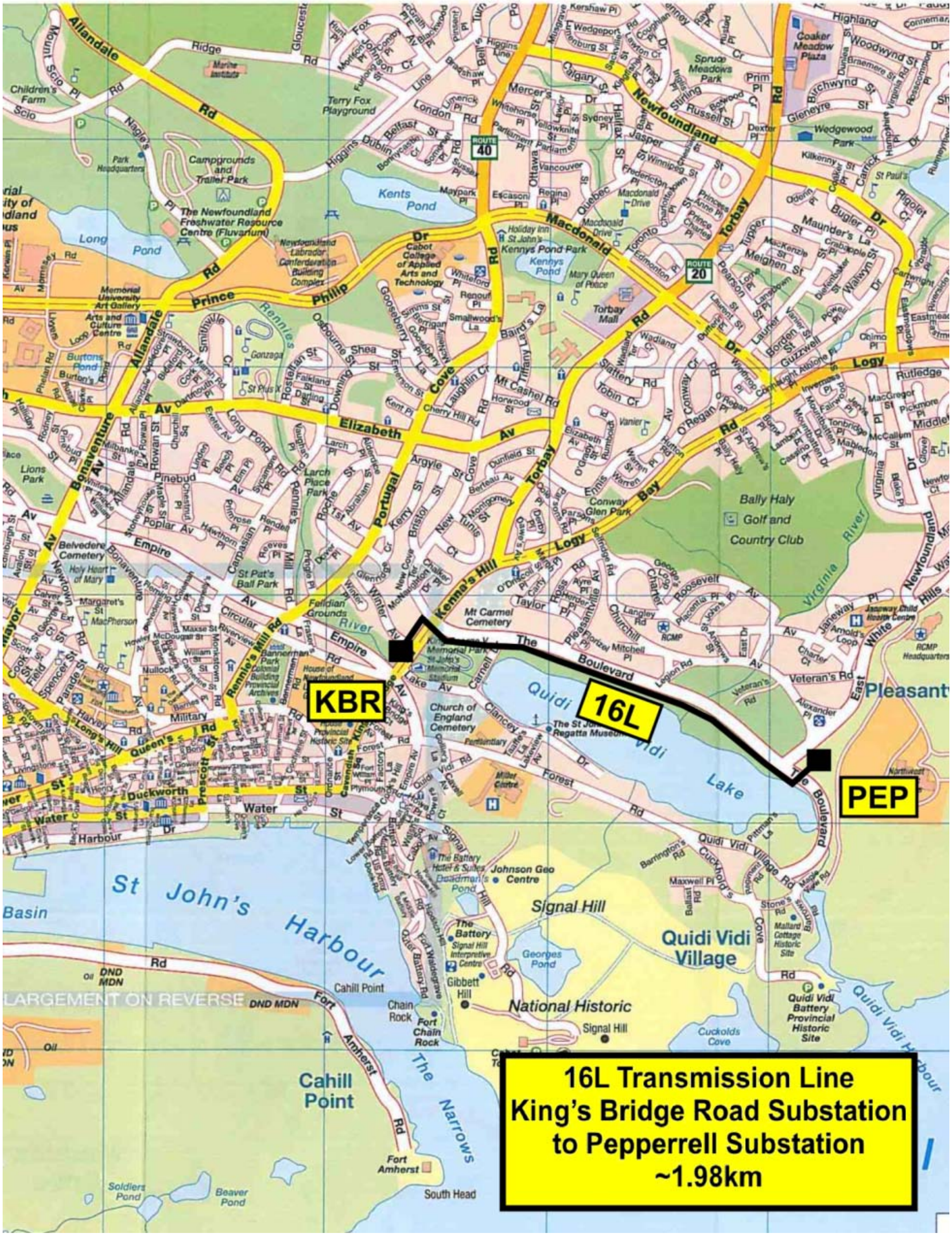

Figure 1 – Road Map 16L

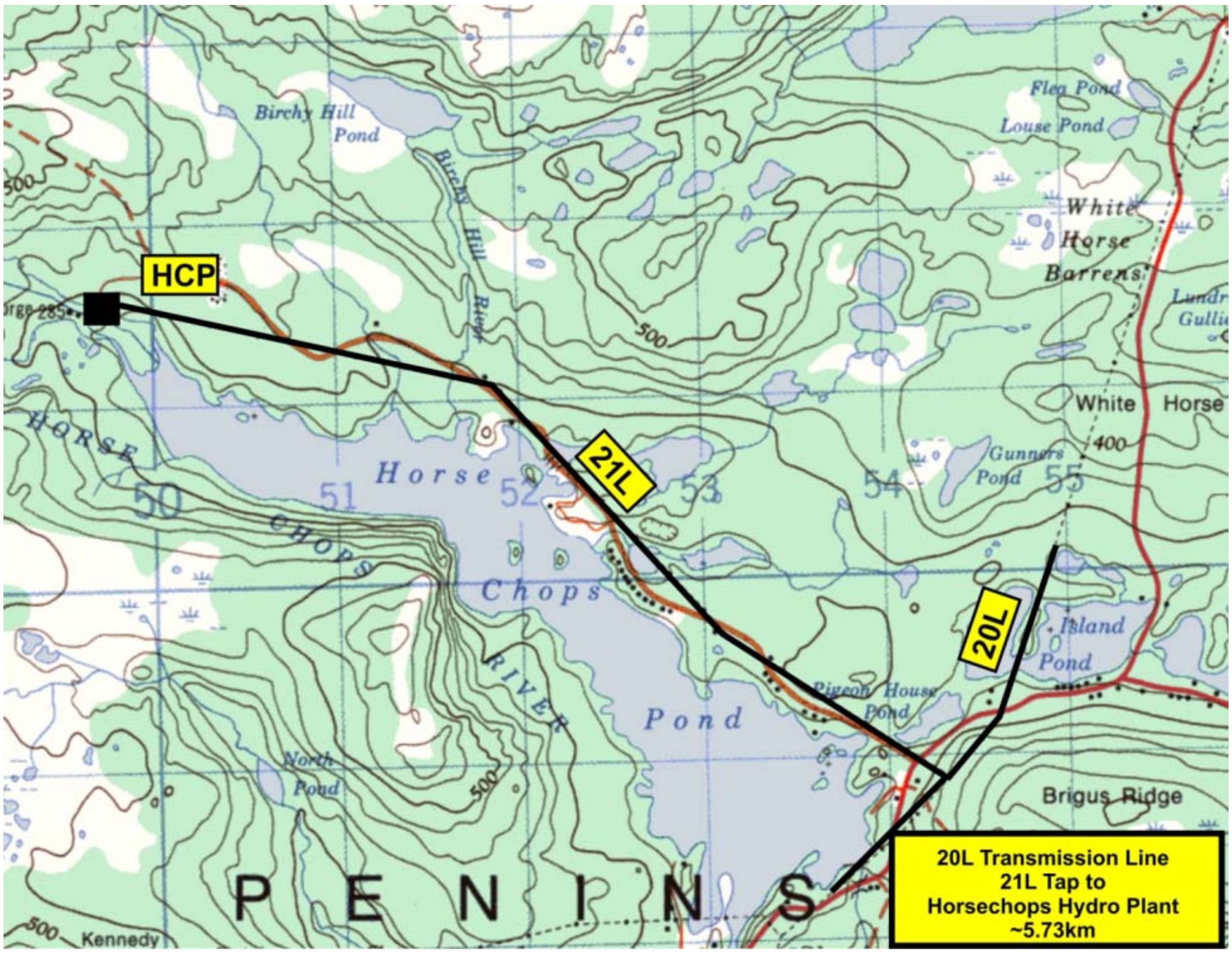

Figure 2 – Topographic Map 21L

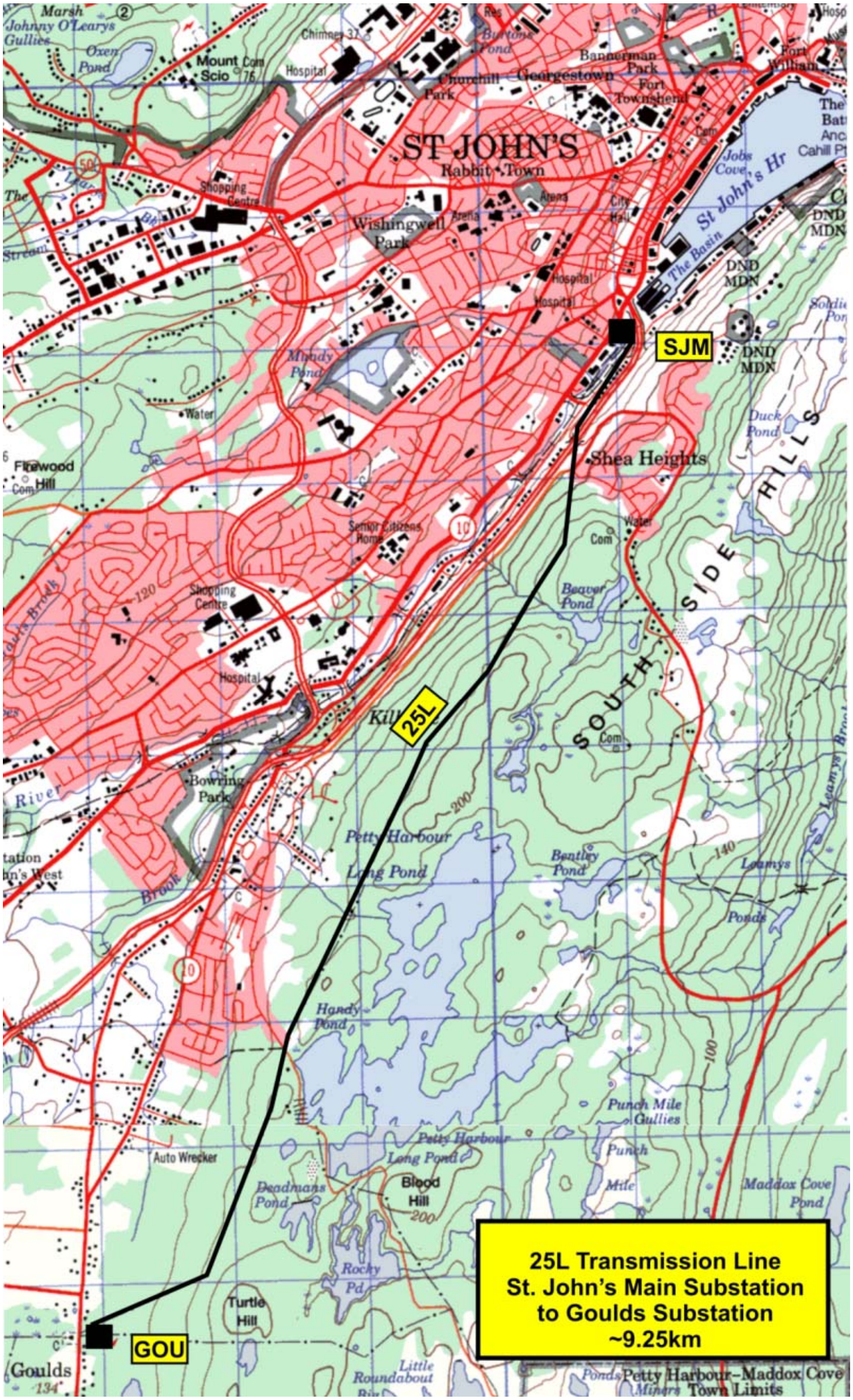

Figure 3 – Topographic Map 25L

Appendix C

Photographs of Transmission Lines 16L, 21L, and 25L

<u>Transmission Line 16L</u>

Figure 1 – Pole damaged by vehicle 16L

Figure 2 – Poles leaning along the Boulevard 16L

Figure 3 – Deteriorated poles 16L

Figure 4 – Split Crossarm 16L

Transmission Line 21L

Figure 5 – Split crossbrace 21L

Figure 6 – Pole requiring temporary support 21L

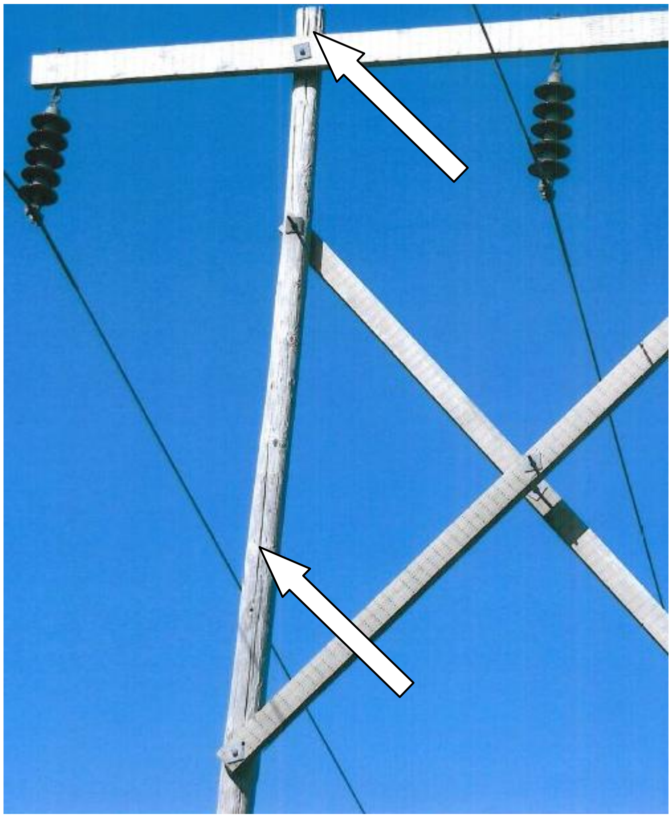

Figure 7 – Badly deteriorated pole 21L

Figure 8 – Woodpecker hole 21L

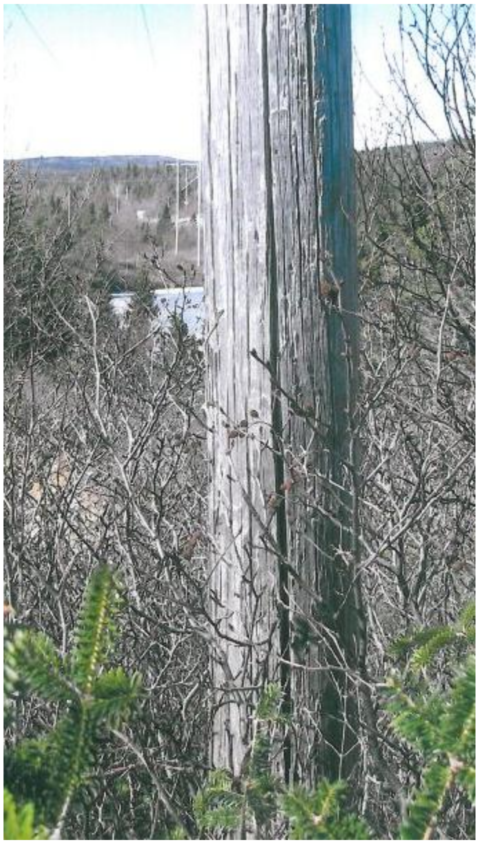

Figure 9 – Deteriorated pole 21L

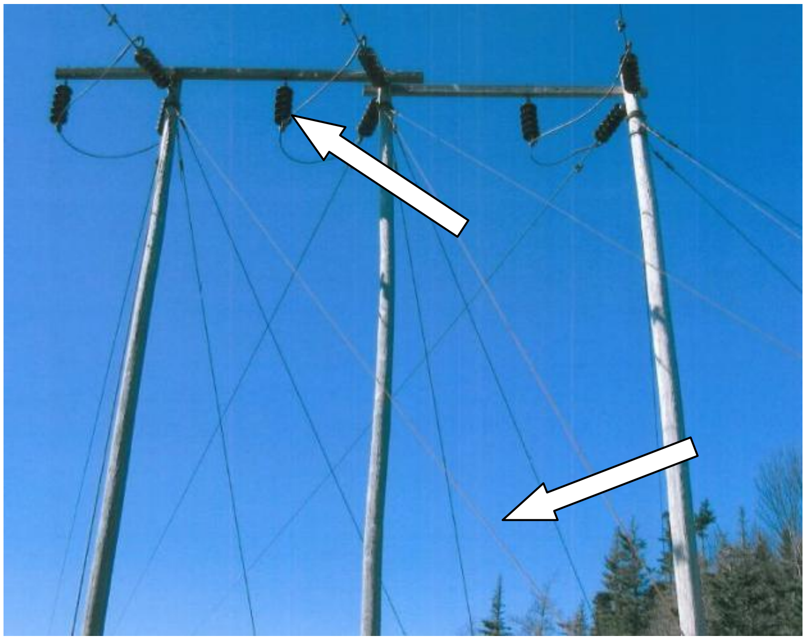

Figure 10 – Rusted guys and old vintage COB insulators 21L

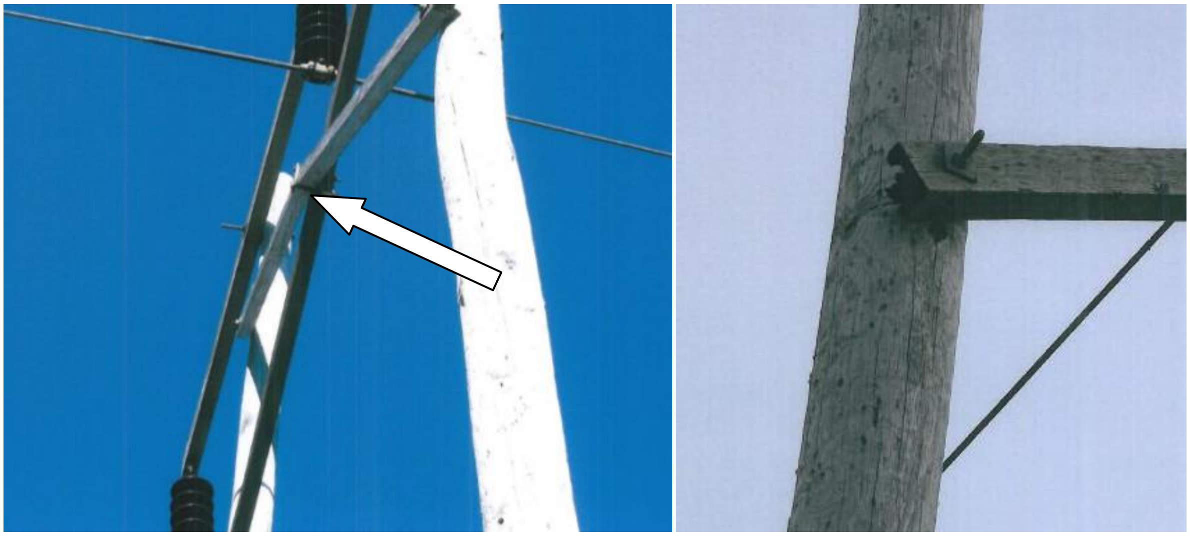

Figure 11 – Broken and deteriorated crossbraces 21L

Figure 12 – Deteriorated pole and crossarm 21L

<u>Transmission Line 25L</u>

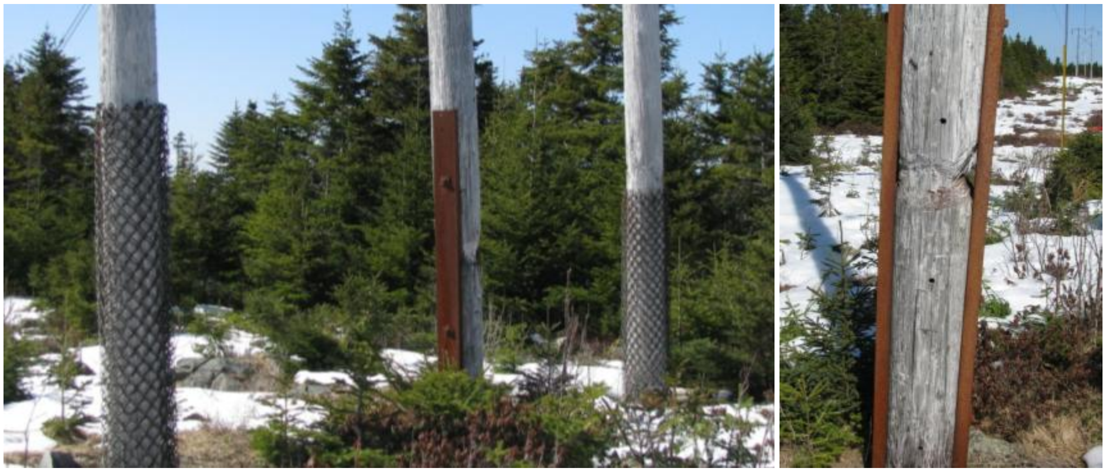

Figure 13 – Damaged pole requiring external support 25L

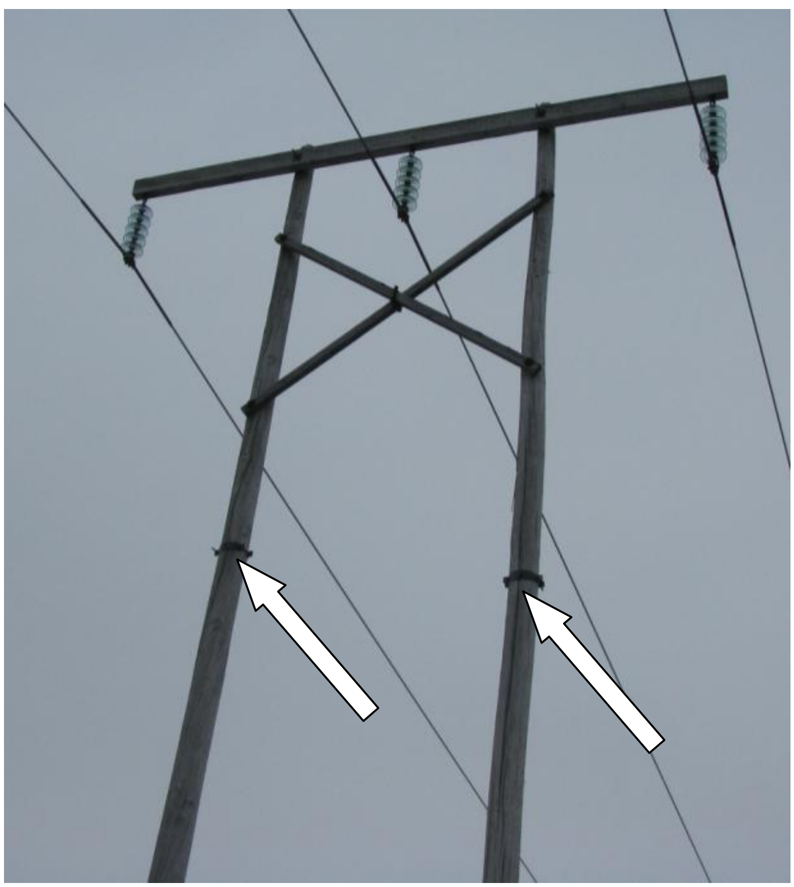

Figure 14 – Pole bands bracing damaged poles 25L

Figure 15 – Rotten poles 25L

Figure 16 – Rusted guys and hardware 25L

Figure 17 – Split crossarm 25L

Figure 18 – Deteriorated poles, crossarms and hardware 25L

Distribution Reliability Initiative

June 2010

Prepared by:

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1.0 Distribution Reliability Initiative

The Distribution Reliability Initiative is a capital project focusing on the reconstruction of the worst performing distribution feeders. Customers on these feeders experience more frequent and longer duration outages than the majority of customers.

Newfoundland Power manages system reliability through capital investment, maintenance practices and operational deployment. On an ongoing basis, Newfoundland Power examines its actual distribution reliability performance to assess where targeted capital investment is warranted to improve service reliability. Through this process, the Company identifies the worst performing feeders in the power system based upon reliability measures. Engineering assessments are completed for each of the worst performing feeders and, where appropriate, the Company makes capital investment to improve the reliability of these feeders.

Appendix A contains the five-year average distribution reliability data of the 15 worst performing feeders based on data for 2005 - 2009.

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: 2009

In 2009, the Company completed work under the Distribution Reliability Initiative project on sections of the NWB-02 feeder at a cost of $455,000. The work was detailed in 4.*1.1 Northwest Brook NWB-02 Planning Study* filed with the 2009 Capital Budget Application. This is a three year project with additional work planned for 2010 and 2011.

3.0 Distribution Reliability Initiative Projects: 2010

In 2010, the Company will continue the Distribution Reliability Initiative. The 2010 Capital Budget Application proposed work on the NWB-02 feeder. The work is a continuation of projects initially proposed in the 2009 Capital Budget Application. The forecasted expenditure in 2010 is $496,000.

4.0 Distribution Reliability Initiative Projects: 2011

The 2011 Capital Budget Application includes the third phase of the proposed work on NWB-02 as outlined in 4.*1.1 Northwest Brook NWB-02 Planning Study* filed with the 2009 Capital Budget Application.

Two significant pieces of work remain for 2011.

Hillview to the Hatchet Cove Tap

This 8.9 km section of single phase line consists of poles installed in the early 1960's with #2 ACSR conductor. The line is remote from the road right of way ("ROW") with long spans. In 2011, 7 km of single phase line will be relocated to the road ROW. The estimate for planned work in this section is approximately $350,000.

Hatchet Cove Tap to St. Jones Within

This 3.4 km section of single phase line consists of poles installed in the early 1960's with #2 ACSR conductor. The line is remote from the road ROW and includes long span lengths. There have been no upgrades on this section of line since the initial construction. In 2011, 3.4 km of single phase line will be relocated to the road ROW. The estimate for planned work in this section is approximately $171,000.

Table 1 details reliability statistics for the past five years.

Table 1

NWB-02 – Reliability Analysis

	2005	**2006**	**2007**	**2008**	**2009**
SAIDI	4.60	8.98	4.82	9.51	0.48
SAIFI	2.63	5.33	1.25	3.10	0.26

The 2009 reliability numbers show vastly improved reliability on the NWB-02 feeder. Efforts to date have contributed to this improvement. Work will continue as planned in the original study as condition assessments have confirmed that sections of the feeder still require work to ensure reliability continues at an acceptable level. The estimated expenditure in 2011 is $521,000.

The examination of the worst performing feeders as listed in Appendix A and B has determined, other than the proposed work on NWB-02, no work is required on other feeders under the Distribution Reliability Initiative at this time.

Appendix A

Distribution Reliability Data

Unscheduled Distribution Related Outages Five-Year Average 2005-2009 Sorted By Customer Minutes of Interruption				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
DUN-01	2,904	401,689	3.06	7.05
DOY-01	4,720	380,267	2.96	3.97
GLV-02	4,172	371,498	3.22	4.78
RRD-09	2,622	328,010	1.84	3.83
CHA-03	3,828	324,421	1.82	2.56
NWB-02	2,844	300,740	2.72	4.80
BOT-01	3,257	290,314	1.99	2.95
CAB-01	3,712	283,127	3.08	3.92
GFS-02	3,198	270,391	2.23	3.14
BCV-02	2,478	260,706	1.63	2.85
HOL-01	7,258	258,487	3.57	6.14
MIL-02	4,570	252,864	3.30	3.04
CHA-02	2,262	250,136	1.32	2.43
HWD-08	2,695	245,683	1.62	2.47
DLK-03	1,770	236,932	1.53	3.42
Company Average	**899**	**99,319**	**1.18**	**2.18**

Unscheduled Distribution Related Outages Five-Year Average 2005-2009 Sorted By Distribution SAIFI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
GDL-01	1,980	174,131	3.59	5.26
HOL-01	7,258	258,487	3.57	6.14
VIR-02	1,228	48,354	3.36	2.20
MIL-02	4,570	252,864	3.30	3.04
GLV-02	4,172	371,498	3.22	4.78
HWD-04	2,641	199,431	3.18	3.48
CAB-01	3,712	283,127	3.08	3.92
DUN-01	2,904	401,689	3.06	7.05
FER-01	1,889	142,100	2.99	3.75
DOY-01	4,720	380,267	2.96	3.97
NWB-02	2,844	300,740	2.72	4.80
SLA-13	1,797	71,557	2.67	1.77
SCT-02	643	80,934	2.63	5.51
HOL-02	1,269	181,520	2.57	2.12
GLV-01	2,692	201.952	2.56	3.20
Company Average	**899**	**99,319**	**1.18**	**2.18**

Unscheduled Distribution Related Outages Five-Year Average 2005-2009 Sorted By Distribution SAIDI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
DUN-01	2,904	401,689	3.06	7.05
HOL-02	7,258	258,487	3.57	6.14
SCT-02	643	80,934	2.63	5.51
GDL-01	1,980	174,131	3.59	5.26
BUC-02	230	47,262	1.45	4.99
GRH-02	1,855	235,819	2.34	4.96
NWB-02	2,844	300,740	2.72	4.80
GLV-02	4,172	371,498	3.22	4.78
SCT-01	1,094	165,374	1.66	4.17
COL-02	508	79,924	1.55	4.07
MKS-01	484	111,220	1.04	3.99
DOY-01	4,720	380,267	2.96	3.97
CAB-01	3,712	283,127	3.08	3.92
RRD-09	2,622	328,010	1.84	3.83
GIL-01	1,157	221,757	1.18	3.76
Company Average	**899**	**99,319**	**1.18**	**2.18**

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. No further work is required at this time.
DUN-01	Reliability statistics were poor in both 2006 and 2007; however, the statistics were driven by a sleet storm in 2006, a broken recloser bushing in 2007 and a broken pole in 2008. Reliability performance was below average again in 2009. No work is proposed for 2011, however the feeder's performance will be monitored closely in 2010.
BOT-01	A substantial amount of work was completed on this feeder since 2006. Reliability has improved considerably. No further work is required at this time.
NWB-02	Work has been carried out in 2009 and 2010 on this feeder. Additional work is proposed for 2011.
BCV-02	Problems in 2003, 2004 & 2005. This feeder was rebuilt under the Distribution Reliability Initiative in 2006. There have been no reliability issues since 2006. 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.
FER-01	Reliability statistics were poor in 2005. Work was carried out under the Rebuild Distribution Lines program in 2005; and with the exception of some sleet related outages in 2009, there have been no reliability issues since 2005. No work is required at this time.
CAB-01	Reliability statistics were poor in 2004. Work was carried out under the Rebuild Distribution Lines program in 2005 and there have been no reliability issues since 2005. 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 2006. No work is required at this time.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
MIL-02	The MIL-02 feeder has displayed consistently poor reliability from 2002 to 2006. Significant work was carried out under the Rebuild Distribution Lines program in 2006 and there were no reliability issues since. No work is required at this time.
GRH-02	Reliability statistics were poor in 2004 & 2005. Work was carried out under the Rebuild Distribution Lines program in 2005; and with the exception of a weather related outage in 2009, there have been no reliability issues since 2005. No work is required at this time.
BUC-02	Reliability problems in 2008 were due to three insulator failures in 2008. Insulators were replaced in 2009. 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.
CHA-02	Reliability statistics were driven by a single event, a broken insulator in June 2009. No work is required at this time.
CHA-03	Reliability problems were due to a single event caused by broken conductor in 2006. No work is required at this time.
COL-02	Reliability statistics were driven by a single sleet related event in May 2006. No work is required at this time.
DLK-03	Reliability statistics were driven by a single event, broken conductor in November 2009. No work is required at this time.
GDL-01	Reliability statistics were driven by a single lightning related event in May 2005. 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.
GLV-01	Reliability statistics were driven by two events in 2007. One involved a broken pole and the other, a broken conductor. No work is required at this time.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
HOL-01	Reliability problems were due to a single event, a broken cutout in January 2007. No work is required at this time.
HWD-04	Reliability statistics were driven by a single weather related event in December 2007. No work is required at this time.
HWD-08	Reliability on HWD-08 has dramatically improved since 2007 principally due to work done under the Rebuild Distribution Line program. 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 a single event, broken conductor in 2008. 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.
SCT-01	Reliability problems were due to two tree related events, one in 2008 and the other in 2009. No work is required at this time.
SLA-13	Reliability problems were due to two sleet related events, one in 2005 and the other in 2006. No work is required at this time.
VIR-02	Reliability problems were due to two conductor related events in 2008. No work is required at this time.

Feeder Additions for Load Growth

June 2010

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A FORTIS COMPANY

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1.0 Introduction

As load increases on an electrical system, the components of the system can become overloaded. These overload conditions occur at the substation level, on equipment such as transformers, breakers and reclosers, or on specific sections of the distribution system.

When an overload condition has been identified, it can often be mitigated through operating practices such as feeder balancing or load transfers.[1] Such practices are low cost solutions and are completed as normal operating procedures. However, in some cases it becomes necessary to complete upgrades to the distribution system to either increase capacity or alter system configuration.

This report proposes 3 projects included as part of the 2011 Capital Budget. These projects address overload conditions and provide additional capacity to address growth in customers and sales. One project involves the construction of a new feeder at Pulpit Rock substation. The second project addresses available capacity for growth in the St. John's downtown. The third project involves the upgrading of sections of single-phase distribution lines to three phase distribution lines to allow for balanced load growth on selected feeders.

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 New Feeder PUL-04 ($638,000)

The Northeast St. John's area includes customers serviced from Pulpit Rock (PUL), Broad Cove (BCV) and Hardwoods (HWD) substations. Transformer loading at each of these substations is 91%, 102% and 96% of rated capacity, respectively.[2] An engineering study has been completed on the distribution system alternative that best meets the electrical demands of the Northeast St. John's area.[3]

The study examines alternatives to determine the least cost approach to deal with the forecast overload conditions in the Northeast St. John's area. Each of the three alternatives included the installation of new feeder capacity from either PUL or BCV substations. Each alternative was evaluated using a 20-year load forecast. Based on net present value calculations the least cost alternative was selected.

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[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] Peak substation transformer loads recorded this past winter for each of these substations are as follows:

- Transformer No. 1 at Broad Cove ("BCV") substation ("BCV-T1") is rated at 25 MVA. The load on this transformer peaked at 25.6 MVA in 2009.
- Transformer No. 1 at Pulpit Rock ("PUL") substation ("PUL-T1") is rated at 25 MVA. The load on this transformer peaked at 22.7 MVA in 2009.
- Transformer No. 3 at Hardwoods ("HWD") substation ("HWD-T3") is rated at 25 MVA. The load on this transformer peaked at 23.9 MVA in 2009.

[3] The study is included as Attachment B to the report ***2.2*** *2011 Additions Due to Load Growth*, filed with the Newfoundland Power 2011 Capital Budget.

The study identifies a project to be included in the Company's 2011 Capital Budget. The project involves installing an additional 25MVA 66/12.5kV power transformer at PUL substation, as well as adding a fourth distribution feeder from PUL substation. The additional distribution feeder from PUL is required in order to transfer load from BCV substation to PUL substation. Due to the proximity of BCV distribution feeders to PUL substation, the installation of this additional feeder provides the least cost alternative to dealing with the existing transformer overload at BCV substation.

3.0 Aerial Feeders SJM Substation ($491,000)

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"). Much of the electrical system in this area consists of a series of duct banks, manholes, switches and cables that form the downtown underground distribution system.

There are twelve distribution feeders that originate at SJM substation, each of which exits the substation via an underground cable.[4] Nine of these feeders pass under the Waterford River in a duct bank.[5] Three feeders within this duct bank, SJM-03, SJM-07 and SJM-08, supply the downtown underground system.

The main trunk of the downtown underground system runs along Water Street from Pitts Memorial Drive at Hutchings Street, east to the Sir Humphrey Gilbert Building. It supplies the downtown core of St. John's including the commercial areas of Water Street, Harbour Drive, and parts of Duckworth Street and New Gower Street, including Mile One Stadium and City Hall.

Newfoundland Power ("the Company") has completed upgrades to the downtown underground system over the past decade.[6] These were required due to changes in safety practices and the condition of the underground infrastructure. Future capital projects will be required in order to complete the replacement of the remaining deteriorated infrastructure.

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 will be required to accommodate growth in electrical load.

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4 Three of these feeders, SJM-10, SJM-11 and SJM-12, become aerial just outside the substation and supply customers on Southside Road, Topsail Road and Shea Heights.

5 Of these, five feeders, SJM-02, SJM-04, SJM-06, SJM-09 and SJM-13, become aerial at various locations and supply primarily residential areas from Leslie Street and Symonds Avenue to Bond Street and Prescott Street. SJM-14 is an underground feeder that supplies the Delta Hotel, 100 New Gower Street and the John Cabot Building.

6 Between 2000 and 2004, the Company completed upgrades to the Water Street underground system. This work included the installation of civil infrastructure as well as new cables and switches to facilitate the removal or replacement of 13 oil filled switches supplying the downtown core of the City. Since 2008, installation of new duct banks, manholes, and switch pads is being undertaken in coordination with the Harbour Interceptor Sewer Project.

A planning study assessing the remaining aging infrastructure, as well as the requirements for additional distribution capacity within the downtown underground system is provided as Appendix A of this report. This study identifies a project to be included 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. This project will increase distribution capacity to allow for additional load growth in the downtown underground system, and address reliability and safety risks in the existing system.

This feeder relocation project includes the installation of two manholes, 100 metres of duct bank, twelve 100 metre 750 MCM cross-linked polyethylene single phase cables, and approximately 0.5 km of double circuit distribution line.

4.0 Overloaded Single Phase Lines ($152,000)

The capacity of a single phase line is limited by the performance of feeder protection. A heavily loaded single phase tap can result in unbalanced loads on the three phases of a feeder, and subsequent undesirable operation of the feeder breaker at the substation[7]. This results in unnecessary outages to customers. The unbalanced load condition can occur during peak load, or when a protection fuse operates on the single phase tap. Eliminating the unbalanced condition will result in a more reliable distribution system.

An analysis of distribution feeders in the Northeast Avalon area was completed using a distribution feeder computer modelling application to identify single phase lines that may be overloaded.[8] Actual load measurements were taken to verify the results of the computer simulation.

Where practical, load transfers were completed to deal with overload conditions. For the remaining single phase lines, upgrades must be completed. This project involves upgrading approximately 2 km of single phase distribution line to three phases at various locations. This will improve the overall reliability of the feeders involved.

The sections of line requiring upgrades from single phase to three phase are as follows.

- Virginia Waters 06 Feeder: 1.1 km upgrade on Middle Cove Road
- Petty Harbour 01 Feeder: 0.4 km upgrade on Maddox Cove Road
- Kelligrews 01 Feeder: 0.5 km upgrade on Middle Bight Road

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7 To detect faults, such as when a conductor breaks and falls to the ground, protection schemes are based on the measurement of differences between the current levels on each of the three phases on a distribution feeder. To maximize the chance that a line-to-ground fault is detected, the protection settings on a feeder are designed based on a minimal amount of difference, or unbalanced current.

8 Overloaded single phase taps typically start out as only a few spans in length, but over time grow into much larger feeder extensions. The growth is most often the result of new subdivisions, where a large number of customers requiring single phase service are added.

5.0 Project Cost

Table 1 shows the estimated project costs for 2011.

Table 1
Project Costs

Description	Cost Estimate
New Feeder PUL-04	$638,000
Aerial Feeders SJM Substation	$491,000
Overloaded Single Phase Lines	$152,000
Total	**$1,281,000**

6.0 Concluding

The Feeder Additions for Load Growth for 2011 includes distribution system upgrades to:

- Install a new distribution feeder at Pulpit Rock Substation PUL-04,
- Install aerial feeders at St. John's Main Substation, and
- Upgrade single phase lines to three phase.

The estimated cost to complete this work in 2011 is $1,281,000.

Attachment A

St. John's Main Planning Study

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1.0 Introduction

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 SJM substation has a transformer capacity of 57.5 MVA, the bulk of which (50 MVA) supplies 11 distribution feeders that operate at a voltage of 12.5 kVA.

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. This underground system also includes a major duct bank that runs under the Waterford River and contains the main trunks of nine distribution feeders. The underground system supplies the St. John's downtown area, which has a dense population of large commercial businesses.

Newfoundland Power (the "Company") has completed upgrades to the underground system over the past decade.[1] These were required due to the condition of the underground infrastructure and changes in safety practices. Future capital projects will be required in order to complete the replacement of the remaining deteriorated infrastructure.

The existing SJM distribution system has limited capacity to accommodate new development in the downtown area. System planning for the underground infrastructure must consider forecast load growth in the area.

The purpose of this planning study is to develop a five year plan which will address the remaining deteriorated underground infrastructure concerns as well as provide adequate capacity to supply new development in the St. John's downtown area.

2.0 St. John's Main System Assessment

Three 66kV transmission lines, 4L, 13L and 25L supply power to the SJM substation. Three power transformers step down the 66kV voltage to distribution voltages. SJM-T1 and SJM-T2 are both 66kV to 12.5kV transformers, rated at 25MVA each. These transformers operate in parallel and supply eleven distribution feeders. SJM-T4 is a 66kV to 4.16kV transformer, rated at 7.5MVA. This transformer supplies one distribution feeder.[2]

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[1] Between 2000 and 2004, the Company completed upgrades to the Water Street underground system. This work included the installation of civil infrastructure as well as new cables and switches to facilitate the removal or replacement of 13 oil filled switches. Since 2008, installation of new duct banks, manholes, and switch pads has been undertaken in coordination with the Harbour Interceptor Sewer Project. In 2010, the SJM-03 feeder will be relocated to the new duct bank. This will improve the capability of the underground system to fully serve customers in the event of a single cable failure on the underground trunk.

[2] SJM-T4 transformer supplies SJM-12 feeder, which runs from St. John's Main substation east to Fort Amherst along Southside Road. The load on SJM-T4 has been reduced in past years as other feeders have been converted from 4.16 kV to 12.5kV.

There are twelve distribution feeders that originate at SJM substation, each of which exits the substation via an underground cable.[3] Nine of these feeders pass under the Waterford River in a duct bank.[4] Three feeders within this duct bank, SJM-03, SJM-07 and SJM-08, form an interconnected underground network that supplies the downtown underground system.

The assessment of the SJM system was divided into three areas:

- Assessment of the SJM substation,
- Assessment of the feeders that are primarily aerial distribution feeders, and
- Assessment of the feeders that are primarily underground.

2.1 Technical Criteria

The following technical criteria were used in assessing the capacity of the major components of the SJM system.

- The steady state substation power transformer loading should not exceed the transformer nameplate rating.
- The conductor loading should not exceed the ampacity rating established in the Company's Distribution Planning Guidelines.
- The distribution feeder normal peak loading should be restricted to permit cold load pickup during outage conditions. These restrictions are based on three factors: substation equipment capacity, underground cable capacity and trunk feeder conductor capacity.
- The Water Street underground distribution system should be designed for N-1 contingency.[5]

2.2 Assessment of the SJM substation

Condition Assessment

In 2005, upgrades were completed to protection and control equipment, distribution switchgear, and to the control buildings. This work was completed as part of the Company's substation refurbishment plan. Substation equipment condition was not considered in this SJM planning study.[6]

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3 Three of these feeders, SJM-10, SJM-11 and SJM-12, become aerial just outside the substation and supply customers on Southside Road, Topsail Road and Shea Heights.

4 Of these, five feeders, SJM-02, SJM-04, SJM-06, SJM-09 and SJM-13, become aerial at various locations and supply primarily residential areas from Leslie Street and Symonds Avenue to Bond Street and Prescott Street. SJM-14 is an underground feeder that supplies the Delta Hotel, 100 New Gower Street and the John Cabot Building.

5 For underground distribution systems, N-1 contingency, or single-contingency design, permits any one cable to be removed from service while the remaining system carries the load.

6 Bi-monthly substation inspections are completed which identify issues to be addressed through routine substation maintenance.

Capacity Assessment
To assess the ability of SJM substation to meet load growth, a 20 year load forecast has been completed for the SJM transformers. The results are shown in Table 1 below.

Table 1
St. John's Main Substation Transformers
20 Year Load Forecast

Device	Operating Voltage (kV)	Capacity (MVA)	2009 Measured Peak Load (MVA)	Forecast Peak Loads[7]				
				2010	2015	2020	2025	2030
SJM-T1	12.5	15/20/(25)	20.9	22.3	25.0	***28.1***	***31.4***	***35.2***
SJM-T2	12.5	15/20/(25)	20.9	22.3	25.0	***28.1***	***31.4***	***35.2***
SJM-T4	4.16	(7.5)/10	2.4	2.6	2.8	3.1	3.4	3.7

Both SJM-T1 and SJM-T2 are not forecast to overload within the next 5 years. It is expected that additional 12.5 kV transformer capacity will be required within 10 years, however this capacity shortfall is beyond the five year period that is the focus of the planning study.

Two primary alternatives may be considered to address the forecast shortfall in 12.5 kV transformer capacity at SJM substation by 2020.[8]

- Alternative 1: Convert the one remaining 4.16 kV feeder at SJM substation to 12.5 kV, and replace SJM-T4 with a 25 MVA, 66-12.5 kV transformer. This will increase the total 12.5 kV capacity at SJM substation to 75 MVA. The estimated cost for this alternative is $2,500,000.
- Alternative 2: Construct a new 66-12.5 kV substation on New Gower Street and transfer load from SJM substation to the new substation. The estimated cost for this alternative is $7,000,000.

Either of these alternatives would be required in the year that SJM 12.5 kV substation capacity exceeds 50 MVA. Based on the current load forecast, either alternative would provide sufficient capacity for the next 20 years, and would not require additional capital investment in other years. Therefore, alternative 1 is the least cost alternative.

[7] Bold and italic font indicates the forecast peak load exceeds the transformer capacity.
[8] A low cost option to addressing transformer capacity overload is to transfer load to an adjacent substation. This can defer the requirement for additional transformer capacity, but is limited by the system configuration and the available capacity at the adjacent substations. It is expected that load transfers can be used to defer both alternatives considered in this report for several years. However, the delay is likely to be limited and ultimately there will be a requirement for additional transformer capacity at SJM Substation.

2.3 Assessment of SJM Aerial Feeders

Condition Assessment

The aerial portions of these feeders are maintained through the Company's routine inspections and maintenance procedures. The condition of these feeders does not present issues that need to be considered in the SJM planning study. However the condition of the underground portions of these feeders, in particular the sections of six feeders that run through the duct bank under the Waterford River, are considered in the SJM planning study and are discussed in Section 2.4 of this report.

Capacity Assessment

To assess future capacity requirements of these feeders, a 20 year load forecast was completed. The results are shown in Table 2 below.

Table 2
St. John's Main Aerial Feeders
20 Year Load Forecast

Feeder	Operating Voltage (kV)	Capacity (MVA)	2009 Measured Peak Load (MVA)	Forecast Peak Loads[9] 2010	2015	2020	2025	2030
SJM-02	12.5	5.7	3.0	3.2	3.6	4.0	4.5	5.1
SJM-04	12.5	5.7	4.8	5.1	5.7	***6.4***	***7.1***	***8.0***
SJM-06	12.5	5.7	4.4	4.7	5.2	***5.9***	***6.6***	***7.4***
SJM-09	12.5	5.7	4.1	4.4	4.9	5.5	***6.2***	***6.9***
SJM-10	12.5	7.1	2.4	2.6	2.9	3.2	3.6	4.0
SJM-11	12.5	10.2	7.4	7.9	8.9	9.9	***11.1***	***12.5***
SJM-12	4.16	3.1	1.9	2.1	2.3	2.5	2.7	3.0
SJM-13	12.5	5.7	4.9	5.2	***5.9***	***6.6***	***7.4***	***8.3***

SJM-13 is the only feeder forecast to exceed its capacity limit within the next 5 years.[10] Three feeders are forecast to overload within 10 years, and five feeders are forecast to overload within 20 years. Beyond SJM-13 feeder, there are no overloads that need to be addressed within the next five years.

2.4 Assessment of SJM Underground Feeders

Condition Assessment

There are two characteristics of the SJM underground system that make it unique relative to other systems in the Company's distribution network. The first is the underground duct bank containing nine feeders that runs under the Waterford River. This duct bank carries a large

9 Bold and italic font indicates the forecast peak load exceed the transformer capacity.
10 The overload on SJM-13 can be addressed through a load transfer to SJM-06.

amount of system load and is not easily accessible due to the fact that it is beneath the ground and beneath the Waterford River.

The second unique characteristic of the SJM system is the underground network that supplies Water Street, Harbour Drive and parts of Duckworth Street and New Gower Street. This network includes four feeders running through a series of duct banks and manholes that supply many large commercial customers in downtown St. John's.[11] Attachment A shows the feeder schematic diagram of the existing downtown underground system.

The majority of the duct banks that make up the downtown underground system, including the one under the Waterford River, are more than 40 years old.[12] These duct banks are deteriorated. They also contain cables of the same age whose condition is uncertain and which are of a type that is no longer manufactured.[13] The age of the cables, the condition of the duct banks and close proximity of feeder cables within the duct banks presents certain physical risks to the main feeder trunk of the underground system.[14]

These risks associated with the downtown underground system were identified in the late 1990's and upgrading of the system has been ongoing since then. Included in these upgrades was the replacement of underground oil switches which at that time were 30 years old and deteriorated.[15] By 2004, the Company had completed the purchase of new equipment and the installation of civil infrastructure to facilitate the removal or replacement of 13 high voltage oil filled switches.[16]

By the end of 2010, the Company will complete the installation of new civil infrastructure, including concrete duct banks, manholes, and switch pads, along Water Street and Harbour Drive between Hutchings Street and Beck's Cove. Also during 2010, the Company will relocate a section of SJM-03 to this new duct bank and reconfigure the layout of the underground feeders.

There are currently four oil filled switches located in manholes. These oil switches are often submerged in water and recent inspections are showing deterioration of the oil switches. These

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[11] SJM-03 supplies Atlantic Place and the Fortis Building. SJM-07 supplies Oceanex, the Cormack Building, the Post Office, Mile One Stadium and City Hall. SJM-08 supplies the Murray Premises, Scotia Towers, the Court House, the London Building and the Delgato Building. SJM-14 supplies the Delta Hotel and the John Cabot Building.

[12] The majority of the downtown underground system was originally installed in the mid 1960s. The underground feeder running under New Gower Street was originally constructed in the mid 1980s.

[13] The cables that run in the duct banks cannot be physically inspected so their physical condition is uncertain.

[14] These physical risks range from the risk of multiple feeders being crushed by collapse of the duct bank to inadvertent damage by third parties, or a fault of one underground cable causing damage to an adjacent cable.

[15] The operation and maintenance of the oil switches in manholes along Water Street also present safety issues. Operating in confined spaces and arc flash hazards requires careful management of the risks. These risks are lowered when the oil switches are replaced by above ground padmount switches.

[16] This work also included the replacement of two sections of duct bank along Water Street from (1) Baird's Cove to Telegram Lane and from (2) Prescott Street to the Sir Humphrey Gilbert Building. It also involved replacement of deteriorated transformers and upgrades to several electrical vaults in the system.

oil switches also continue to present safety concerns to employees who operate, inspect and maintain this equipment. One of these oil switches will be removed in 2010.[17]

The condition of the underground system is such that continued upgrading of the system is required to address the risks associated with the deteriorated duct banks, aging cables and the oil switches that remain in manholes.

Capacity Assessment

The four feeders that supply the downtown underground system include SJM-03, SJM-07, SJM-08 and SJM-14. The capacity of these feeders was assessed by determining the amount of spare capacity available on each feeder and then comparing the spare capacity against the potential for new commercial building loads.[18] Factored into this calculation is the need to maintain N-1 contingency for the main trunks of the underground feeders.

The amount of spare capacity available to supply potential new commercial load is shown in Table 3 below.

Table 3
St. John's Main Underground Feeders
Available Feeder Capacity
(MVA)

Feeder	Feeder Capacity	2009 Measured Peak Load	Required Capacity for N-1[19]	Available Spare Capacity[20]
SJM-03	5.7	3.1	2.0	0.6
SJM-07	5.7	3.1	1.6	1.0
SJM-08	5.7	4.4	0.0	1.3
SJM-14	5.7	3.4	0.9	1.4

This analysis shows that each of the feeders in the downtown underground system has between 0.6 MVA and 1.4 MVA of spare capacity to meet load growth. It is estimated that a new commercial building would have a demand between 1.0 MVA and 2.0 MVA.[21]

17 The oil switch in manhole 13 will be replaced in 2010 as part of a project to provide service to a new customer. The location of Manhole 13 is shown in Appendix A. Replacement of the remaining 3 oil switches is included in this study.

18 This method more accurately reflects the growth of the downtown underground system. Load in this system typically does not increase at a constant rate, but instead increases in larger increments over time as new commercial customers are added.

19 The N-1 contingency analysis takes into account configuration changes that will be completed by relocating SJM-03 feeder as part of the Company's 2010 Capital Budget.

20 Available Spare Capacity is calculated by subtracting the 2009 Measured Peak Load and Required Capacity for N-1 from the Feeder Capacity.

21 Some examples of commercial customer loads in the downtown area are the Scotia Centre (1.6 MVA), the TD Building (0.8 MVA), Atlantic Place (2.1 MVA) and the Fortis Building (1.1 MVA).

The amount of spare capacity available on each feeder is less than 2.0 MVA which may limit the size of building load that can be accommodated without capacity additions to the main trunks of the underground feeders.

3.0 Development and Assessment of Alternatives

Based on the assessment of the St. John's Main system, the following objectives were set for the five year plan.

- Reduce the risk to the underground feeders from potential failure of the deteriorated underground duct banks or cables, in particular addressing:
    - The duct bank that runs from the SJM substation to Hutchings Street which includes the Waterford River crossing.
    - The duct bank that runs from Beck's Cove to Baird's Cove and from Telegram Lane to Prescott Street.
    - The portions of feeder trunks of SJM-07 and SJM-08 that are in the duct bank from Hutchings Street to Becks Cove.
- Address the safety concerns and deterioration of the three oil switches that remain in manholes at the end of 2010.
- Ensure adequate capacity to accommodate commercial load growth within the downtown system.

3.1 Replacement of duct bank from SJM substation to Hutchings Street and address capacity constraints

The amount of spare capacity in the downtown system is limited by the capacity of the cables that run from the SJM substation to Hutchings Street. Alternatives were reviewed for dealing with both capacity limitations and the deteriorated duct bank. The existing duct bank could be replaced by a new duct bank with either a larger number of feeders or cables with higher capacities. This presents certain logistical issues that require, as a minimum, a temporary aerial feed from SJM substation to Hutchings Street during construction.[22] Further, the lead time required to plan and install the replacement duct bank may delay the provision of service to a new commercial building.

The Company has also considered establishing permanent aerial feeders from the SJM substation to the Hutchings Street area. This would increase feeder capacity and potentially avoid the need to maintain or replace the underground duct bank. Technical and space considerations limit the number of aerial feeders that can currently be established in this area to four. This will require maintaining four underground feeders within a duct bank.

[22] Logistical issues primarily relate to limited space to construct a new duct bank next to the old duct bank while maintaining electricity supply to customers. The construction of a new duct bank crossing the Waterford River would take several months. Alternative electricity supply would be required to avoid extended power outages to customers during construction.

The Company has received approval from the City of St. John's that four permanent aerial feeders be established from the SJM substation to the Hutchings Street area. The increase in feeder capacity resulting from this option is shown in Appendix B.

The establishment of permanent aerial feeders will reduce the number of feeders that are exposed to the risk of potential failure of the existing duct bank or cables. This alternative will also facilitate the eventual replacement of the duct bank and increase the capacity of the feeders supplying the downtown underground system allowing for further growth. Due to the logistical issues and concerns with the lead time required to add capacity, this alternative is preferable to simply replacing the duct bank with one containing more feeders or feeders with larger cables. A full description of this project is provided in Section 4.0 of this report.

3.2 Replacement of the duct bank from Beck's Cove to Baird's Cove and from Telegram Lane to Prescott Street

Addressing the risk presented by the potential failure of the old cables and deteriorated duct banks requires replacing these sections of the system with either new duct banks and cables, or aerial distribution feeders. However, due to congestion along Water Street, aerial distribution is not a feasible option. There are also no alternative underground routing options. As a result the only alternative is replacing the duct bank along the same route under Water Street. The full description of this project including costs is provided in Section 4.0 of this report.

3.3 Relocation of the portions of SJM-07 and SJM-08 in the duct bank from Hutchings Street to Becks Cove

Addressing the risk of potential failure of the main trunks of SJM-07 and SJM-08 that are located in deteriorated duct banks would require either relocation of the main trunk to new duct banks or the construction of aerial distribution lines. A new duct bank that will be completed in 2010 will accommodate relocation of the main trunk of SJM-07 and SJM-08. Due to congestion along Water Street, aerial distribution is not a feasible option. As a result there is no practical alternative to relocating the main trunk section of SJM-07 and SJM-08 to the new duct bank completed in 2010. The full description of this project including costs is provided in Section 4.0 of this report.

3.4 Removal of the four oil switches that are in manholes

The Company has adopted the use of pad mounted switches to replace the oil-filled switches that have been in use within manholes along the downtown underground system. The only practical manner to remove these oil switches is to find space above ground for locating pad mounted switches as the duct bank infrastructure is upgraded. During 2008, the engineering design for the new duct bank along Water Street and Harbour Drive included strategic locations where pad mounted switches could be installed. Similarly, the installation of new duct banks as discussed in Section 3.2 will include the installation of pad mounted switches and the removal of underground oil switches.

4.0 Recommended Project Plan

Through the assessment of the alternatives, a number of projects have been identified to address deteriorated infrastructure, safety and capacity concerns. In developing the project plan, the timing of each project considered reliability, safety, and capacity improvements and certain timing issues such as the lead time required to design and obtain approvals for replacing the duct bank under the Waterford River.

The following outlines the recommended five year plan along with the estimated cost of each project.

2011: Construct Four Aerial Feeders - $491,000
Five feeders will be removed from the duct bank crossing under Waterford River, and reconfigured into four feeders that cross over the river. This will increase distribution capacity to allow for additional load growth in the downtown underground system, and address reliability and safety risks in the existing system.

This feeder relocation includes the installation of two manholes, 100 metres of duct bank, twelve 100 metre 750 MCM cross-linked polyethylene single phase cables, and approximately 0.5 km of double circuit distribution line.

2012: Relocate SJM-08 - $535,000
This project involves relocation of the section of SJM-08 feeder between Hutchings Street and Beck's Cove. 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 feeder relocation includes the installation of three 1,100 metre 500 MCM cross-linked polyethylene single phase cables in the new duct banks. With the relocation of SJM-07 and SJM-08, the feeders will be reconfigured to allow the removal of the oil switches in manhole 7 and manhole 8.

2013: Relocate SJM-07 - $428,000
This project involves relocation of the section of SJM-07 feeder between Hutchings Street and Beck's Cove. 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 feeder relocation includes the installation of three 1,100 metre 500 MCM cross-linked polyethylene single phase cables in the new duct banks, as well as the installation of a new pad mounted switch at the intersection of Bishop's Cove and Harbour Drive. The switch installation will be a 5 compartment 12.5 kV pad mounted switch. Installation of this switch will allow for the removal of the oil switch currently in manhole 5 at Queen's Street.

2014: Replace Duct Banks, Beck's Cove to Baird's Cove and Telegram Lane to Prescott Street - $1,110,000

This project involves the replacement of the two sections of aging duct bank along Water Street from Beck's Cove to Baird's Cove and from Telegram Lane to Prescott Street. This project will complete the replacement of the main trunk section of the underground distribution system along Water Street.

The project includes the installation of approximately 400 metres of duct bank along Water Street, as well as the installation of nine 400 metre 500 MCM cross-linked polyethylene single phase cables in the new duct banks.

2015: Replace Duct Bank, SJM Substation to Hutchings Street - $912,000

The project involves the replacement of the deteriorated duct bank from SJM substation to Hutchings Street that crosses under the Waterford River.[23] This project will complete the replacement of the main trunk section of the SJM underground distribution system.

This project includes the installation of approximately 300 metres of duct bank crossing under the Waterford River, as well as the installation of twelve 300 metre 500 MCM cross-linked polyethylene single phase cables in the new duct banks.

5.0 Conclusion

This report provides a five year plan to address deteriorated infrastructure, safety concerns and capacity concerns associated with the SJM distribution system. The recommended projects proposed for the Company's five year capital plan are shown in Table 4.

Table 4
Five Year Plan

Year	Project	Cost
2011	Construct four aerial feeders from SJM substation to Hutchings Street	$491,000
2012	Relocate SJM-08	$535,000
2013	Relocate SJM-07	$428,000
2014	Replace duct banks, Beck's Cove to Baird's Cove and Telegram Lane to Prescott Street	$1,110,000
2015	Replace duct bank, SJM substation to Hutchings Street	$912,000

[23] The Company will continue to assess alternatives for replacing the section of the underground system currently routed under the Waterford River.

Table 5 shows the cost estimate detail for the project to be included in the 2011 Capital Budget.

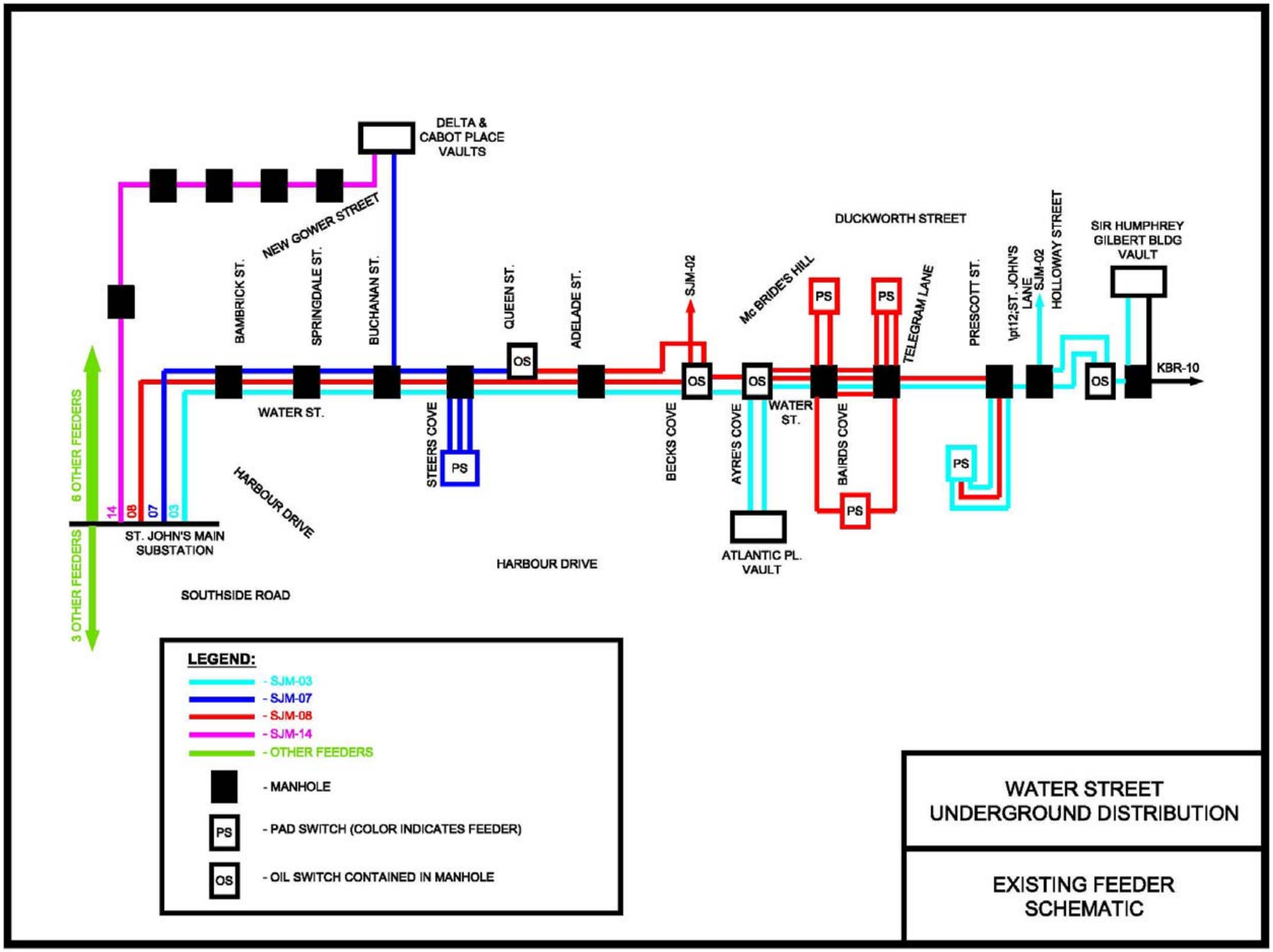
Table 5
2011 Project Cost

Cost Category	**Estimate**
Material	$380,000
Labour Internal	68,000
Engineering	20,000
Other	23,000
Total	**$491,000**

The 2011 project is not proposed as a multi-year project. The engineering assessments necessary for detailed design have not been completed for projects beyond 2011.

Appendix A

Existing Feeder Schematic Diagram


DELTA &
CABOT PLACE
VAULTS
NEW GOWER STREET
BAMBRICK ST.
SPRINGDALE ST.
BUCHANAN ST.
QUEEN ST.
ADELAIDE ST.
SJM-02
Mc BRIDE'S HILL
DUCKWORTH STREET
TELEGRAM LANE
PRESCOTT ST.
\pt12;ST. JOHN'S LANE
SJM-02
HOLLOWAY STREET
SIR HUMPHREY
GILBERT BLDG
VAULT
KBR-10
OS
PS
WATER ST.
STEERS COVE
BECKS COVE
AYRE'S COVE
WATER ST.
BAIRDS COVE
ATLANTIC PL.
VAULT
6 OTHER FEEDERS
3 OTHER FEEDERS
14
08
07
03
ST. JOHN'S MAIN
SUBSTATION
HARBOUR DRIVE
HARBOUR DRIVE
SOUTHSIDE ROAD
LEGEND:
- SJM-03
- SJM-07
- SJM-08
- SJM-14
- OTHER FEEDERS
- MANHOLE
- PAD SWITCH (COLOR INDICATES FEEDER)
- OIL SWITCH CONTAINED IN MANHOLE
WATER STREET
UNDERGROUND DISTRIBUTION
EXISTING FEEDER
SCHEMATIC

Appendix B

Changes in Feeder Capacities

Table 1
SJM Waterford River Crossing
Changes in Feeder Capacity

Device	Current Capacity (MVA)	Proposed Capacity (MVA)	% Increase
SJM-02	5.7	10.0	75%
SJM-03	5.7	7.6	43%
SJM-04	5.7	---	---
SJM-06	5.7	10.0	75%
SJM-07	5.7	7.6	43%
SJM-08	5.7	7.6	43%
SJM-09	5.7	10.0	75%
SJM-13	5.7	10.0	75%
SJM-14	5.7	7.6	43%
Total	**51.3**	**70.4**	**37%**

Table 2
Downtown Underground System
Changes in Available Spare Capacity
(MVA)

Device	Feeder Capacity	2009 Measured Peak Load	Required Capacity for N-1	Available Spare Capacity
SJM-03	7.6	3.1	0.0	4.5
SJM-07	7.6	3.1	1.6	2.9
SJM-08	7.6	4.4	0.0	3.2
SJM-14	7.6	3.4	0.0	4.2

SJM-02, SJM-06, SJM-09 and SJM-13 will be supplied through the new double circuit aerial lines.

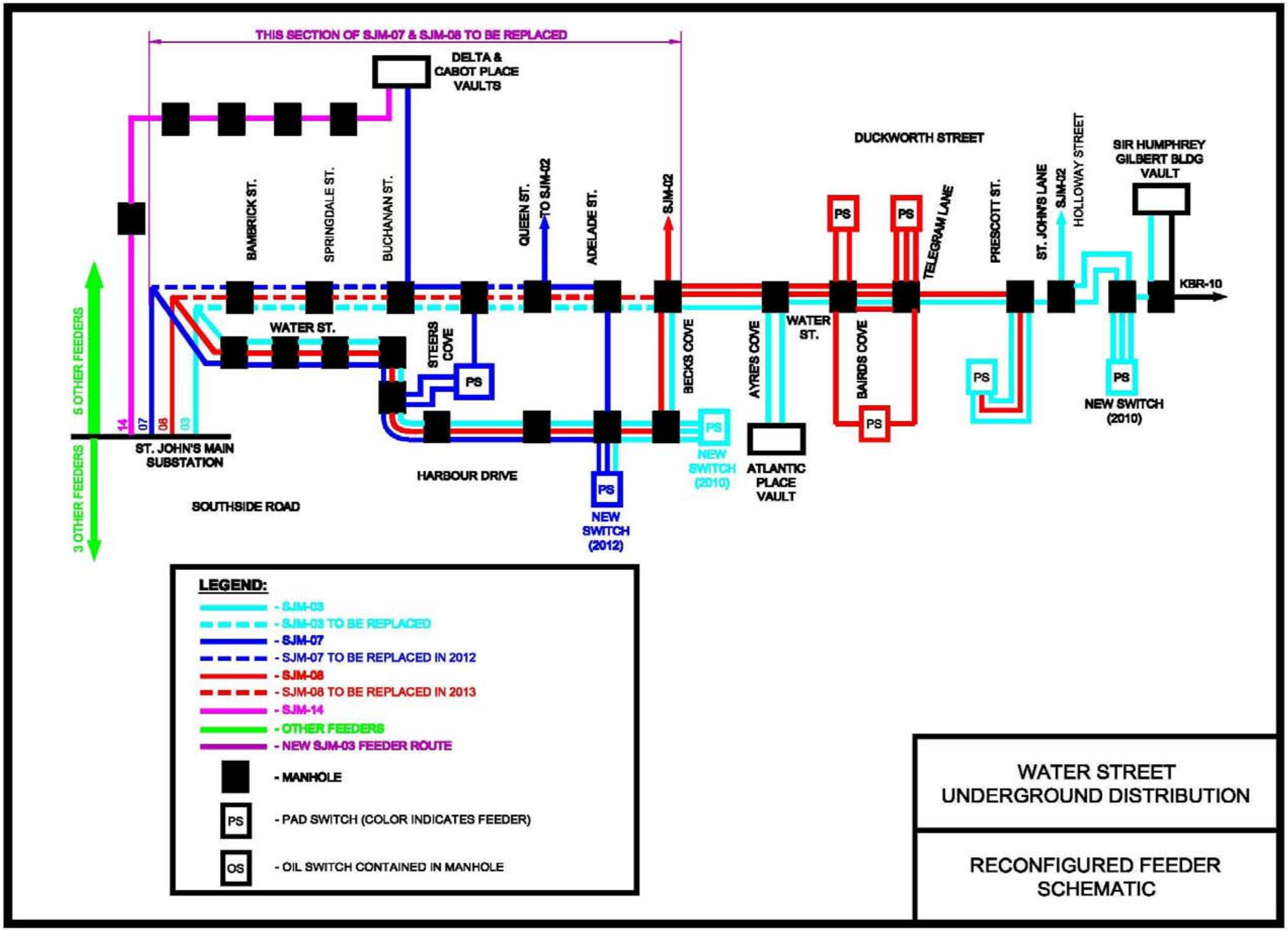
SJM-04 feeder will be removed from service and the customers it supplied will be transferred to other SJM feeders.

SJM-03, SJM-07, SJM-08 and SJM-14 will remain in the duct bank from SJM substation to Hutchings Street. Their exisiting capacity is limited by the proximity and number of other cables in the same duct bank. This is the result of heating between cables causing the maximum allowed conductor ampacity to decrease. With the removal of five feeders from the duct bank, cables remaining within the duct bank will be able to supply higher loads.

The capacity required for N-1 contingency and available spare capacity reflects the proposed configuration as shown in Appendix C.

Appendix C

Reconfigured Feeder Schematic Diagram


THIS SECTION OF SJM-07 & SJM-08 TO BE REPLACED
DELTA & CABOT PLACE VAULTS
BAMBRICK ST.
SPRINGDALE ST.
BUCHANAN ST.
QUEEN ST.
TO SJM-02
ADELADE ST.
SJM-02
DUCKWORTH STREET
PS
TELEGRAM LANE
PRESCOTT ST.
ST. JOHN'S LANE
SJM-02
HOLLOWAY STREET
SIR HUMPHREY GILBERT BLDG VAULT
KBR-10
5 OTHER FEEDERS
3 OTHER FEEDERS
14
07
08
03
ST. JOHN'S MAIN SUBSTATION
WATER ST.
STEERS COVE
BECKS COVE
AYRE'S COVE
WATER ST.
BAIRDS COVE
NEW SWITCH (2010)
HARBOUR DRIVE
SOUTHSIDE ROAD
NEW SWITCH (2012)
ATLANTIC PLACE VAULT
LEGEND:
- SJM-03
- SJM-03 TO BE REPLACED
- SJM-07
- SJM-07 TO BE REPLACED IN 2012
- SJM-08
- SJM-08 TO BE REPLACED IN 2013
- SJM-14
- OTHER FEEDERS
- NEW SJM-03 FEEDER ROUTE
- MANHOLE
- PAD SWITCH (COLOR INDICATES FEEDER)
OS
- OIL SWITCH CONTAINED IN MANHOLE
WATER STREET UNDERGROUND DISTRIBUTION
RECONFIGURED FEEDER SCHEMATIC

2011 AMR Project
Conception Bay South, Paradise and Southlands

June 2010

Prepared by:

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REGISTERED PROFESSIONAL ENGINEER
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BYRON A. CHUBBS
SIGNATURE
July 7/10
DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

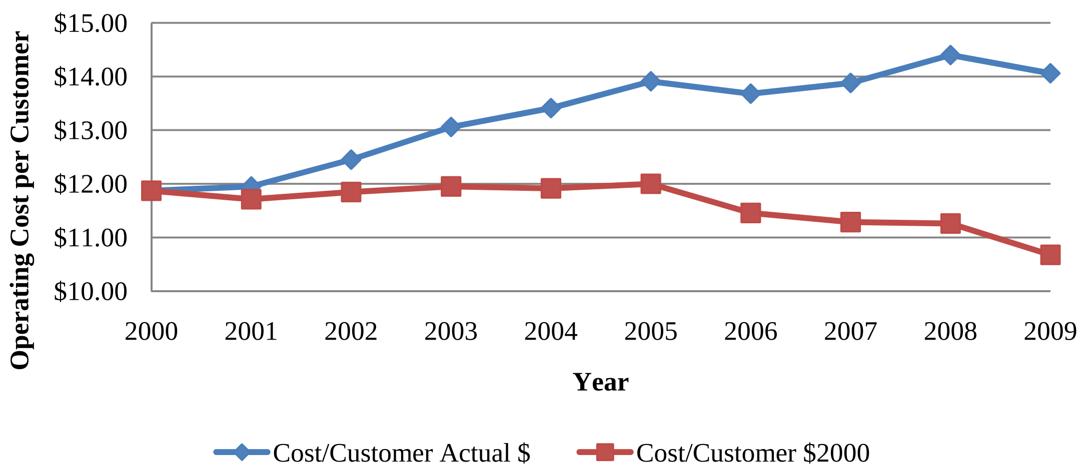
1.0 Introduction

As outlined in the 2006 Metering Strategy, Newfoundland Power ("the Company") focuses its metering cost management on improving the productivity and efficiency of the meter reading function, reducing high cost read locations and mitigating the meter reading cost associated with customer growth.[1]

The Company employs a number of cost control initiatives to improve the productivity and efficiency of the meter reading function. Together with meter reading route optimization, the strategic deployment of AMR meters has enabled reduction of meter reading costs.

Graph 1 demonstrates the effect of the Company's efforts to control operating costs associated with meter reading, with and without labour inflation impacts.[2]

Graph 1
Meter Reading Operating Cost
2000 - 2009



The operating cost per customer associated with meter reading, expressed in 2000 dollars, has decreased each year since 2005. The strategic deployment of AMR meters has contributed to the lower meter reading cost per customer. At the end of 2009, approximately 8% of domestic customers have AMR meters installed on their residence. In areas with strong customer growth, the percentage of customers with AMR meters is much higher.

Since 2006, AMR meters have been installed in high growth areas on the Northeast Avalon Peninsula, creating groups of AMR meters in new subdivisions. The operational effect has been to mitigate the

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1 See report *4.1 Metering Strategy – June 2005*, filed with the Newfoundland Power 2006 Capital Budget Application.

2 Bargaining unit labour rate increases over the period 2000 to 2009 have been used to estimate labour inflation for the analysis.

upward pressure on meter reading costs because, for the most part, these meters have been read with minimal impact on existing meter reading routes.

Table 1 shows the growth in AMR meter installations since 2001.

Table 1
AMR Meter Installations
2001 – 2009

Year	Total Number of AMR Meters Installed	Percentage of Total Meters
2001	177	0.08%
2002	905	0.43%
2003	1,905	0.89%
2004	4,718	2.19%
2005	5,017	2.29%
2006	6,334	2.87%
2007	8,612	3.85%
2008	12,886	5.67%
2009	18,050	7.84%

As part of its ongoing assessment of meter reading routes, the Company evaluates whether it is cost effective to replace all non-AMR meters with AMR meters on a specific route to take advantage of a high density of AMR meters that exist within a neighbourhood. For 2011, the Company has identified 10 meter reading routes in the Conception Bay South, Paradise and Southlands neighbourhoods as candidates for becoming AMR-only meter reading routes.

2.0 2011 AMR Deployment

In 2011, the Company proposes to take advantage of the high density of AMR meter installations in areas of Conception Bay South, Paradise and Southlands, by replacing all remaining conventional commercial and domestic meters with AMR meters on 10 meter reading routes in these areas.[3]

At present these 10 meter reading routes include 4,888 meters, 1,982 of which are AMR meters. The proposed 2011 project involves replacing the remaining 2,906 conventional meters with AMR meters. This includes 124 demand meters and 2,782 energy only meters.

The implementation of AMR meters is expected to result in consolidating these 4,888 meters into neighbouring meter reading routes. This will minimize the impact of accelerating the reading of these meters on customers' billing and payment schedules, and on Company business processes such as billing and customer communications. Operational savings are anticipated through a reduction of 10 meter reading days per month, as well as customer service functions associated with these meters.

[3] In the Conception Bay South, Paradise and Southlands area 41% of existing domestic meters have AMR technology.

3.0 Project Cost

The project cost is estimated at $220,000.[4]

The impact of this project on operating costs includes the reduction of 10 meter reading labour days per month plus vehicle and other expenses. The Company will also realize savings within the Contact Centre and with pre-billing analysis related to the elimination of meter reading estimates within this group of meters. Savings for special reads such as final readings and check reads will also be realized since these readings can be obtained while staff are in the vicinity of the meter in question, without having to visit the actual premises. As a result, savings associated with this project are estimated at approximately $49,800 per year.[5]

4.0 NPV Analysis

The net present value calculation for this project is included in Appendix A. The payback period has been calculated at approximately 6 years, at which time the initial $220,000 capital cost will be recovered in operating savings.

5.0 Concluding

The project involves the expenditure of $220,000 in 2011 to achieve an annual operating savings of approximately $49,800. The project has a payback period approximately 6 years for an asset that has an in-service life expectancy of 27 years.

The project is recommended to proceed in 2011 to achieve the operating cost savings identified in this report.

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4 The average unit cost per meter associated with this project is estimated to be $75.71. Due to the relatively high portion of domestic energy only meters included in this project, this cost is less than the historical average unit cost per meter of $90 (see Schedule B, page 31).

5 Annual operating cost includes meter reader labour, vehicle cost and incidentals including clothing allowance. Also an estimate of operating cost savings related to final reads, check reads and improved accuracy in meter reads is included.

Appendix A

Net Present Value Calculation

Present Worth Calculation

Initial Capital Investment:	$220,000
Operating Cost savings:	$49,800 per year
Average Incremental Cost of Capital:	7.68%
Payback Period:	6 years
CCA Rate:	8.00%

Year	Capital Expenditure	Capital Revenue Requirement	Operating Benefit	Net Benefit	PW Operating Benefit	Cum PW Operating Benefit
2011	220,000	23,064	24,900	1,836	23,124	23,124
2012		25,204	50,700	25,496	43,726	66,850
2013		24,935	51,588	26,653	41,318	108,168
2014		24,622	52,617	27,996	39,137	147,305
2015		24,268	53,639	29,372	37,052	184,357
2016		23,876	54,558	30,681	34,998	**219,355**
2017		23,450	55,519	32,068	33,075	252,429
2018		22,993	56,480	33,487	31,248	283,677
2019		22,507	57,462	34,956	29,523	313,200
2020		21,993	58,489	36,495	27,907	341,108
2021		21,455	59,551	38,096	26,388	367,496
2022		20,895	60,666	39,771	24,965	392,460
2023		20,313	61,765	41,452	23,604	416,064
2024		19,713	62,904	43,192	22,325	438,389
2025		19,094	64,091	44,997	21,124	459,513
2026		18,460	65,296	46,837	19,986	479,499
2027		17,810	66,469	48,659	18,894	498,393
2028		17,147	67,674	50,527	17,865	516,258
2029		16,471	68,884	52,413	16,887	533,145
2030		15,784	70,140	54,356	15,968	549,113
2031		15,085	71,432	56,347	15,103	564,216
2032		14,377	72,718	58,341	14,278	578,494
2033		13,660	74,027	60,367	13,498	591,993
2034		12,935	75,359	62,425	12,761	604,754
2035		12,198	76,716	64,518	12,064	616,818
2036		-	78,097	78,097	11,406	628,224
2037		-	79,502	79,502	10,783	639,007
2038		-	80,934	80,934	10,194	649,201
2039		-	82,390	82,390	9,637	658,838
2040		-	83,873	83,873	9,111	667,950

2011 Application Enhancements

June 2010

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Page

1.0 Introduction

The Company operates and supports over 50 computer applications including third party software products, such as the Great Plains financial system and the Telvent OASyS SCADA system, as well as internally developed software such as the Customer Service System ("CSS") and the Outage Management System. 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: Customer Service Systems, Operations and Engineering 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 2011.

2.0 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 2011, enhancements are proposed for Meter Reading Improvements.

Table 1 summarizes the estimated cost associated with these items.

Table 1
Customer Service System Enhancements
Project Expenditures
($000s)

Cost Category	2011 Estimate
Material	-
Labour – Internal	129
Labour – Contract	-
Engineering	-
Other	-
Total	**129**

2.1 Meter Reading Improvements ($129,000)

Description

Software enhancements are required to improve meter reading efficiency. The proposed enhancements will provide an effective means to create, re-organize and balance meter reading routes. Improvements will also include automating the assignment of new meters to a meter reading route and capturing additional meter location information. In addition, the number of field visits to the same premises will be reduced by coordinating multiple outstanding field activities into a single visit.

Operating Experience

Customers' electricity meters are routinely read by meter readers walking up to the meter, visually inspecting the dials or the display, and recording this information on a hand held device. Since 2006, the Company has installed Automatic Meter Reading ("AMR") meters where appropriate to manage metering costs and accessibility issues.[1] AMR meters allow meter readings to be captured by a handheld device from hundreds of feet away.

Cost savings from AMR meter installations can be enhanced by effectively integrating the AMR meters into the Company's meter reading walk routes.

Typically, the most efficient way to read a meter route is to complete one side of a road, then the other. Handheld devices present the route to the meter reader in this order. Since AMR meters can be read from hundreds of feet away, it is more efficient to identify a number of "access points" in a route that permit the meter reader to stand in a single location and receive a number of meter readings simultaneously.

The proposed enhancements will improve the Company's ability to adjust meter reading routes to efficiently address customer growth, including use of AMR technology and other route organization improvements.

In addition, requests for meter visits can originate from customers' or Company requirements, or third party requirements, such as Measurement Canada retest orders. These requirements can result in duplicate field visits due to difficulties in coordinating these requests using the current software. The proposed enhancement will also address coordination of this work.

[1] At the end of 2009 approximately 8% of all domestic meters in service were AMR meters.

Justification

This item is justified based on improved customer service.

Routes which are reasonably sized and sequenced allow all meters to be read during a normal work day. This will reduce delays and estimated meter readings, providing a higher level of customer service and satisfaction.

3.0 Operations and Engineering Systems Enhancements

Operations and Engineering Systems Enhancements include application enhancements necessary to support the Company's engineering and operations function. The information technology in this category includes the Asset Management System (Avantis), the Outage Management System, and various other applications used to engineer and maintain Company assets and manage work in a safe and environmentally responsible manner.

For 2011, enhancements include Electrical Engineering Software as well as Work Dispatch Improvements.

Table 2 summarizes the estimated cost associated with this item.

Table 2
Operations and Engineering Enhancements
Project Expenditures
($000s)

Cost Category	2011 Estimate
Material	60
Labour – Internal	167
Labour – Contract	-
Engineering	45
Other	75
Total	**347**

3.1 Electrical Engineering Software ($152,000)

Description

The purpose of this item is to purchase Electrical Engineering Software to assist with the management of electrical schematics, wiring diagrams and electric panel layout drawings. This addition to the existing engineering drawing software will automate the updating of drawings, including necessary adjustments to related documents like bills of materials, cable schedules, termination schedules and other related drawings.

Operating Experience

The Company manages an electrical system that has thousands of pieces of high voltage equipment and electronic components installed throughout its substations and power plants. This equipment is used to power, protect, monitor and control all aspects of the electrical system.

Currently, information regarding the physical attributes and layout of this equipment is managed through manual procedures which include maintaining physical drawings that are stored in a central location. New design drawings and changes to existing drawings are done using a series of non-automated processes. These include use of multiple drawing tools and manual review of individual related components. Crosschecking for accuracy and dependencies between related drawings and documents is a time consuming manual effort.

Each year the Company executes approximately 30 projects to maintain and improve the electricity system. These projects involve the creation or modification of approximately 500 drawings annually.

Electrical system drawing software is widely used in the utility industry. These tools ensure a high level of precision and accuracy. This software also enables efficiency improvement by providing the ability to automate the tracking of interdependencies and impacts of change between sets of related drawings and documents.

Justification

Electrical engineering software will improve the quality and availability of information contained in electrical system drawings, schematics and diagrams. This will improve efficiency of the associated engineering processes in maintaining and upgrading the electricity system. This efficiency improvement will support the Company's cost management in addressing customer load growth and requirements for equipment upgrades, refurbishment and modernization.

A financial analysis of the costs and benefits associated with this item results in a positive net present value of $6,378 over the next 5 years. The financial analysis is included in Appendix A.

3.2 Work Dispatch Improvements ($195,000)

Description

The purpose of this item is to implement an automated process to dispatch electronic work orders to field staff. It will allow the field staff to retrieve, update and complete work order information while working in the field. When crews arrive back at the Company's facilities, work order information will be automatically updated in database systems, such as CSS and Asset Management.

Operating Experience

The Company manages approximately 6,000 work orders performed in the field annually. This work ranges from street light repairs and new service connections to distribution and transmission system reconstruction and maintenance. The daily dispatch of this work to field personnel is currently a manual process. Work orders are printed, sorted and distributed to field staff. Crews record work details on these paper forms, which are returned to support personnel to encode the data into several corporate applications including CSS, Outage Management and Asset Management.

Justification

Work dispatch improvements will enable efficiency gains in the Company's line and maintenance operations. Efficiency of field work order management will increase by eliminating paper-based forms and automating routine tasks.

This will also increase the accuracy and completeness of information available to crews performing work, dispatchers managing the work and Contact Centre staff responding to customer inquiries.

A financial analysis of the costs and benefits associated with this project results in a positive net present value of $6,964 over the next 5 years. The financial analysis is included in Appendix A.

4.0 Internet Enhancements

Internet Enhancements include enhancements to the Company's web-based applications. The information technology in this category includes 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 2011, enhancements are proposed for both the customer service website and the takeCHARGE! energy conservation website.

Table 3 summarizes the estimated cost associated with this item.

Table 3
Internet Enhancements
Project Expenditures
($000s)

Cost Category	**2011 Estimate**
Material	-
Labour – Internal	227
Labour – Contract	-
Engineering	-
Other	130
Total	**357**

4.1 Customer Service Internet Enhancements ($226,000)

Description

For 2011, this item includes improvements to customer self service functions on Newfoundland Power's website, including final meter reading requests and automated payment and equal payment plan enrolment.

Outage notification functionality will also be enhanced to allow customers to more effectively locate and monitor outages. As well, the appearance of several frequently used web site functions will be adapted to suit the smaller screen size of mobile devices such as smart phones.

Enhancements to website security are also proposed to protect customers' sensitive data. This will ensure effective protection and privacy of customer information.

Operating Experience

Customers continue to increasingly choose internet based technologies to do business with the Company. In 2009, over 10,000 customers created on-line profiles to access their account information on the Company's website. Since the Company introduced e-correspondence in the second quarter of 2009, over 25,000 customers have chosen email as their primary means of communication.

Approximately 35,000 customers are enrolled in the Company's Equal Payment/Automatic Payment Plans. Currently, customer requests to join these plans can be initiated on the web site, but require significant manual intervention by Contact Centre staff in order to complete the transaction. Automation of this processing will ensure timely, efficient completion of customer requests.

Similarly, customers can use the web site to request a final meter reading, typically when moving out of one premise and into another. These requests are also processed through manual intervention by Contact Centre staff, and would be improved by further automation. The Company receives approximately 37,000 final reading requests from customers annually.

During the March 2010 ice storm, the outage notification information on the Company's website content received over 52,000 customer views, compared to less than 5,000 in the previous week. Given this level of increased activity, the Company proposes to improve the information and search capabilities available to customers during an outage situation.

The use of smart phone devices to access the Company's website has increased from less than 150 visits in the first quarter of 2009 to over 1,060 in the same period in 2010. Over 25% of the increased activity in 2010 occurred during the March ice storm. The existing website is difficult to use with mobile devices such as smart phones, which have much smaller screen sizes than typical desktop or laptop computers. The most commonly used functions of the Company's web site will be adapted to be suitable to these smaller screens. This will provide customers with further options regarding their electronic interactions with the Company.

Internet security is an issue that the Company must manage on a continual basis. The risk and frequency of potential internet threats such as identity theft and internet fraud continue to challenge organizations. The Company will continue to invest in appropriate methods to ensure the security and privacy of customer information.

Justification

This item is justified primarily on improved customer service and effective protection of customer information.

4.2 Energy Conservation Website Enhancements ($131,000)

Description

The purpose of this item is to enhance the internet based functionality which supports the Company's energy conservation initiatives. This functionality will include information and tools that allow customers to assess their energy conservation behaviour, and identify and evaluate opportunities for improvement.

For 2011, enhancements will include improved web site content management capabilities. This will enable the Company's conservation staff to update the site with information in a more timely, efficient manner, improving responsiveness to customer and partner feedback and events. Improvements are also proposed for the existing interactive tools, as well as additional capabilities for customer interaction and discussion through the web site.

Operating Experience

In 2008, Newfoundland and Labrador Hydro and Newfoundland Power launched a joint energy conservation initiative including the takeCHARGE! web site. The site provides residents of Newfoundland and Labrador access to information and tools regarding energy efficiency and conservation. This website is an integral part of the Company's customer energy conservation communications portfolio.

Since the initial launch of the web site, customer visits continue to increase. For example, customer visits to takeCHARGE! increased 83% from the first quarter of 2009 to the same period in 2010. Usage of the site's online energy calculators more than doubled in this period.

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.

5.0 Various Minor Enhancements ($150,000)

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 track customer participation and rebates provided through the Company's energy conservation programs, as well as implementing changes to the Human Resource management system in response to new collective agreements.

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

Electrical Engineering Software

Net Present Value Analysis

		Additions			Cost Increases		Cost Benefits						
	Year	New Software A	New Hardware B	Tax Deductions C	Labour D	Non-Lab	Labour E	Non-Lab	Net Savings F	Income Tax G	After-Tax Cash Flow H	After-Tax Discounted Cash Flow I	Cumulative Discounted Cash Flow J
0	2011	($152,000)	$0	$76,000	$0	$0	$30,000	$0	$30,000	$14,030	($107,970)	($107,970)	($107,970)
1	2012			$76,000	$0	$0	$35,400	$0	$35,400	$11,484	$47,884	$44,953	($63,017)
2	2013			$0	$0	$0	$37,856	$0	$37,856	($10,978)	$26,878	$23,688	($39,329)
3	2014			$0	$0	$0	$39,370	$0	$39,370	($11,417)	$27,953	$23,127	($16,202)
4	2015			$0	$0	$0	$40,945	$0	$40,945	($11,874)	$29,071	$22,580	$6,378

5 Yr Present Value (See Note K) @ 6.52% $6,378

Notes:

A Is the sum of the software additions by year.
B Is the sum of the hardware additions by year.
C Is the Capital Cost Allowance deduction. The Capital Cost Allowance for New Software reflects a 50% rule for capitalizing additions.
D Is any software maintenance fees and internal support costs associated with the project. The cost estimates are escalated using the GDP Deflator.
E Is the reduced costs. The cost estimates are escalated using the GDP Deflator.
F Is the sum of columns D and E.
G Is the impact on taxes from the CCA and cost expenditures. It is equal to column C less column F times the tax rate.
H Is the after tax cash flow which is the sum of the capital expenditure (column A + B) plus net savings (column F) plus income tax (column G).
I Is the after tax cash flow discounted to the first year of the cash flow analysis using a discount rate equal to NP's weighted average incremental cost of capital.
J Is the cumulative value of the discounted cash flow in column I.
K Is the present value of the after tax cash flows and equal to the sum of column I.

Work Dispatching Improvements

Net Present Value Analysis

	Year	Additions: New Software A	Additions: New Hardware B	Additions: Tax Deductions C	Cost Increases D: Labour	Cost Increases D: Non-Lab	Cost Benefits E: Labour	Cost Benefits E: Non-Lab	Net Savings F	Income Tax G	After-Tax Cash Flow H	After-Tax Discounted Cash Flow I	Cumulative Discounted Cash Flow J
0	2011	($195,200)	$0	$97,600	$0	$0	$0	$0	$0	$29,768	($165,432)	($165,432)	($165,432)
1	2012			$97,600	$0	$0	$56,675	$0	$56,675	$11,868	$68,543	$64,347	($101,085)
2	2013			$0	$0	$0	$58,942	$0	$58,942	($17,093)	$41,849	$36,882	($64,203)
3	2014			$0	$0	$0	$61,299	$0	$61,299	($17,777)	$43,523	$36,009	($28,194)
4	2015			$0	$0	$0	$63,751	$0	$63,751	($18,488)	$45,264	$35,157	$6,964
	5 Yr	Present Value (See Note K) @ 6.52%										$6,964	

Notes:

A Is the sum of the software additions by year.
B Is the sum of the hardware additions by year.
C Is the Capital Cost Allowance deduction. The Capital Cost Allowance for New Software reflects a 50% rule for capitalizing additions.
D Is any software maintenance fees and internal support costs associated with the project. The cost estimates are escalated using the GDP Deflator.
E Is the reduced costs. The cost estimates are escalated using the GDP Deflator.
F Is the sum of columns D and E.
G Is the impact on taxes from the CCA and cost expenditures. It is equal to column C less column F times the tax rate.
H Is the after tax cash flow which is the sum of the capital expenditure (column A + B) plus net savings (column F) plus income tax (column G).
I Is the after tax cash flow discounted to the first year of the cash flow analysis using a discount rate equal to NP's weighted average incremental cost of capital.
J Is the cumulative value of the discounted cash flow in column I.
K Is the present value of the after tax cash flows and equal to the sum of column I.

2011 System Upgrades

June 2010

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1.0 Introduction

Newfoundland Power ("the Company") depends on the effective 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 ($608,000)

Business Application Upgrades involve third party software that supports the Company's business applications. For 2011, upgrades are proposed for the Meter Equipment System, Customer Service System, and Transmission & Distribution Mobile Application.

Table 1 summarizes the cost associated with these items.

Table 1
Business Application Upgrades
Project Expenditures
($000s)

Cost Category	2011 Estimate
Material	-
Labour – Internal	508
Labour – Contract	-
Engineering	-
Other	100
	608

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 2011, upgrades include:

1) Meter Equipment System Upgrade – ($213,000)

   This item involves upgrading the Company's Meter Equipment System. This system manages approximately 237,000 electric service meters and related equipment with regard to inventory, premises installation, inspections and billing.

   The system has been in operation for almost 20 years and has reached the end of its useful life. It is based on development tools that the Company no longer has internal skills to maintain and support. The Company anticipates upgrades to this system will be required for compliance with changing regulatory requirements of Measurement Canada. For example, regulations anticipated to come into effect in 2011 will require tracking and reporting meter usage (time in inventory, in service and in transit) as well as additional information regarding meter inspection history. The current system infrastructure impedes the application enhancements required for continuing regulatory compliance and operational improvements.

   Upgrading the Meter Equipment System to use modern application development technologies will ensure the Company is able to continue to support efficient operations. It will also allow the Company to respond effectively to regulations regarding metering equipment management.

2) Customer Service System ("CSS") Upgrade – ($240,000)

   This item involves upgrading CSS to address a number of outstanding technical issues.

   During routine operations of CSS, completing certain customer service transactions may require support or intervention by Information Services staff. For example, a customer account adjustment issue may require changes to customer information using manual procedures performed and validated by subject area experts. This upgrade will resolve a number of technical issues with the underlying software, which is expected to eliminate over 80% of such manual interventions.

   This upgrade to CSS will enable the Company's Customer Relations staff to complete customer requests without delay, improving customer service and productivity.

3) Transmission & Distribution Mobile Application Upgrade – ($155,000)

   This item involves an upgrade to the Company's transmission and distribution inspection software. This software is used on mobile computing devices to record the results of field inspections. The current application environment does not effectively support new inspection procedures due to current device limitations. This includes limited data storage capacity and slow device response time. This upgrade will enable the Company to maintain an acceptable level of operational efficiency.

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 ($200,000)

Description

This Agreement covers the purchase of Microsoft software and provides access to the latest versions of each software product purchased under this agreement.

Newfoundland Power achieves overall cost savings through the Microsoft Enterprise Agreement. 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 D of the 2009 Capital Budget Application.

Operating Experience

This project includes year three of the Microsoft Enterprise Agreement (2009 – 2011).

Justification

The Microsoft Enterprise Agreement is the least cost option to ensuring access to current Microsoft software products.

2011 Shared Server Infrastructure

June 2010

Introduction

Shared server infrastructure consists of over 100 shared servers that are used for production, testing, and disaster recovery of Newfoundland Power's ("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 the 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	2011 Estimate
Material	705
Labour – Internal	272
Labour – Contract	-
Engineering	-
Other	115
Total	**1,092**

For 2011, this project includes:

1. The replacement of the Storage Area Network ("SAN") that is used to store and manage the Customer Service System databases and other corporate information. This SAN has been in service for over seven (7) years and has reached the end of its useful life, and the end of vendor support. The estimate for this item is $489,000.

2. The replacement of servers used to operate the Company's website. This ensures the security of information used by customers to perform self-service functions via the Internet. The servers being considered for replacement have been in service for an

average of 7 years and have reached the end of its useful life. The estimate for this item is $130,000.

3. The replacement of the remittance processor servers used to process customer payments received by mail. These servers have been in service over 10 years and have reached the end of its useful life and end of vendor support. The estimate for this item is $211,000.

4. The replacement of the SCADA firewall infrastructure. This hardware is 7 years old and has reached the end of its useful life. This project also includes the addition of infrastructure to protect customer and corporate information from the continuously changing profile of cyber security. The estimate for this project is $262,000.

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 if the component fails.

Gartner Inc. has indicated that computer servers have a useful life of approximately 5 years.[1] By making appropriate investments in its shared server infrastructure, Newfoundland Power's experience is that the average useful life of its corporate servers is about 7 years.

In order to ensure high availability of applications and to minimize the vulnerability of its computer systems to external interference, the Company invests in system availability and 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

The 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

[1] Gartner Inc. is the leading provider of research and analysis on the global Information Technology industry.

therefore is critical to the Company's overall operations and to the provision of least cost customer service.

Investments in the shared server infrastructure are based on evaluating the alternatives of modernizing or replacing technology components and selecting the least cost alternative.

Vehicle Mobile Computing

July 2010

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1.0 Introduction

In Order No. P.U. 41 (2009), the Board indicated that it expected Newfoundland Power to document the opportunities for improvements in safety and efficiency associated with its investment in vehicle mobile computing infrastructure.

This report is filed in compliance with Order No. P.U. 41 (2009).

2.0 Background

The genesis of Newfoundland Power's investment in vehicle mobile computing infrastructure was ensuring compliance and ongoing adherence of safety and environmental standards and processes in use by the Company.

In 2008, the Company determined that it was no longer practical to maintain paper copies of various manuals containing safety, environment and other related work procedures in the field. Providing employees with current policies and procedures in electronic format, including mobile workers using computers in Company vehicles, was more cost-effective than creating, updating and distributing multiple paper copies of this documentation.[1] In addition, ongoing safety and environmental compliance will be improved by having current detailed procedures available in electronic format in the field.[2]

At the time that vehicle mobile computing infrastructure was proposed, it was recognized that mobile computing presented the opportunity to improve customer service and operating efficiency. These improvements may arise from efficiency gains associated with automating processes. They may also arise from making better or more timely information available to field operations employees.

3.0 Assessing Opportunity

3.1 General

Each year Newfoundland Power spends approximately $16 to $17 million on electrical system maintenance. This work is predominantly performed by the Company's electrical line and maintenance crews. Approximately 60% of Newfoundland Power's annual capital expenditure relates to distribution and substation work, a substantial portion of which is performed by the

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1 A financial analysis of the costs and benefits associated with making the Company's safety and environmental policies and procedures available to employees with mobile computers in their vehicles indicated a positive net present value of $59,087 over 5 years. See 2009 Capital Budget Application, report ***5.1 Application Enhancements***, Appendix A, page A-4.

2 Safe work regulations require that *current* safe operating procedures be in every vehicle engaged in operational electrical work. Over the past 2 years, Occupational Health and Safety inspectors have increased inspections for compliance with this requirement.

Company's electrical line and maintenance crews.[3] In 2011, the Company is budgeting over $48 million in distribution and substation capital expenditure.

Currently, Newfoundland Power's dispatch of line and maintenance work to crews is a paper based process. This includes paper work orders. It also includes, where required, paper copies of supporting material such as technical drawings, switching orders and single line diagrams of the electrical system. Following completion of the work, paper reports are typically completed by the workers indicating the details of work performed, job status and time spent. These reports are subsequently entered into the Company's computer systems by office support staff.

The cost of a two-person Newfoundland Power line or maintenance crew is approximately $115 per hour, or $920 per day.[4] Newfoundland Power has approximately 80 such crews. The Company's vehicle mobile computing infrastructure investment is aimed at improvements in electrical line maintenance and operations.

The investment in infrastructure, or computer hardware, is the foundation upon which greater efficiency in electrical line maintenance and operations can be pursued. These efficiencies will be achieved by applications, or computer software, that target specific opportunities for productivity improvement. Some of these opportunities will relate to the replacement of manual paper-based processes with automated electronic processes. Others will relate to more effective scheduling and execution of routine electrical system work.

3.2 Some Practical Examples

The Work Dispatch application included in the Company's proposed 2011 capital budget is a practical example of an efficiency which can be achieved via vehicle mobile computing infrastructure.[5] This application will provide an automated process to dispatch electronic work orders to field staff and allow them to retrieve, update and complete these work orders while in the field. Updates to work order information will then be processed to a central database automatically when crews return to the Company's facilities.[6]

These work dispatch improvements will streamline operations and increase the efficiency of work order assignments by eliminating paper-based dispatching and largely automating routine tasks. This will also increase the accuracy and completeness of information available to crews working in the field, dispatchers managing the work, and Customer Contact Centre staff responding to customer inquiries.

Since the installation of the first mobile computers in line and maintenance operations in the fourth quarter of 2009, the Company has experimented with mobile computer technology in

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3 The remainder of Newfoundland Power's annual capital budgets relate principally to expenditures in generation, transmission, information services, general property and transportation assets. Labour associated with these capital expenditures does not typically include the Company's electrical line and maintenance forces.

4 Most crews are two person crews. Some crews, typically those engaged in heavier construction work, will have three members. Other crews, typically those engaged in routine substation maintenance, will have one member.

5 2011 Capital Budget Application, report ***5.1 2011 Application Enhancements***, page 6.

6 The Company manages approximately 6,000 field work orders annually. This work ranges from street light repairs and new service connections to distribution and transmission system reconstruction and maintenance.

execution of its mercury vapour streetlight replacement project in Gander and St. John's.[7] The location of mercury vapour lights can now be plotted on a map using mapping software on the in-vehicle computer. This Global Positioning System ("GPS") location information is then included with the work order used to dispatch a line crew to complete the street light replacement. The GPS information is used to provide directions to assist the crew in effectively locating the work site.

In addition, a street light data entry form has been created for use on the in-vehicle computers. This form allows line crews to retrieve and update street light information, including GPS coordinates, when a light is being installed, changed, or removed from service. Previously, a paper copy of this form was completed by the crew in the field. This manual process was not only more time consuming but tended to greater inaccuracy resulting from manual data entry.[8]

While the Company-wide use of GPS in mobile computing to improve efficiency in operations and maintenance is not envisaged before 2012 at the earliest, the opportunity for reduced cost is evident. This is another practical example of a potential efficiency opportunity which exists as a result of the Company's investment in vehicle mobile computing infrastructure.

3.3 Deployment

At the time of writing, the Company has 25 computers installed in electrical line and maintenance vehicles.[9] In the third quarter of 2010, the Company will install an additional 35 units across the Company's service territory. By year-end 2011, it is proposed that a total of 80 vehicles will be equipped with mobile computers. This reflects a measured approach to the deployment of mobile computing infrastructure.

As the deployment of vehicle mobile computing infrastructure proceeds, the opportunities to improve efficiency and customer service will become more achievable. Part of this will result from the capability to make such improvements across the Company's entire service territory. Part will also result from further improvement opportunities being identified by those who work in electrical line and maintenance operations.[10]

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[7] The materials costs for this experimental initiative have been approximately $1,000.

[8] To date in 2010, approximately 600 forms have been completed electronically, saving at least 50 hours of manual effort.

[9] The budget in 2009 was $350,000, while actual project cost was $289,000. This cost included ruggedized laptop computers, mounting hardware, security software, power supplies and labour. The reduction of $61,000 in 2009 is attributed to the lower than expected cost of security products required to protect Company and customer data. Of the 25 computers installed in 2009, 6 were installed in electrical maintenance vans and 19 in line trucks. Sixteen of the units were located in St. John's, 5 in Gander, 3 in Grand Falls, and 1 in Clarenville.

[10] Company personnel are, at times, required to coordinate field work with third-parties such as electricians. As a result of a recommendation from a Powerline Technician early in 2010, vehicle mobile computers now have a telephone directory which includes staff on-call rosters and contact information for third-parties. The recommendation was based on the employee's experience of delays in work performance or customer service resulting from his having to phone a Company office to get contact information. While improvements in efficiency or customer service resulting from provision of a telephone directory may not be material on a Company wide basis, they are achieved at virtually no cost.

4.0 Costs and Benefits

4.1 Costs

Table 1 shows the cost breakdown associated with all capital projects in 2009, 2010 and 2011 that relate to vehicle mobile computing.

Table 1
Vehicle Mobile Computing
Capital Costs 2009 – 2011
($000s)

	2009	2010F	2011F	Total
Infrastructure	289	272	178	739
Applications	136	-	195	331
Server/Network	72	-	-	72
Total	**497**	**272**	**373**	**1,142**

In the period from 2009 to 2011 Newfoundland Power expects to spend approximately $1.1 million on vehicle mobile computing.

Of this amount, the Company expects to spend $739,000 on vehicle mobile computing infrastructure. A total of $331,000 is forecast to be spent on applications. These applications include the automation of safety and environmental standards and related work procedures completed in 2009 and the work dispatch application proposed for 2011. In addition to these costs, a total of $72,000 was expended in 2009 to provide the necessary server and network infrastructure required to support mobile computing.

4.2 Benefits

The benefits associated with vehicle mobile computing will be achieved as applications are deployed on the mobile computing infrastructure.

The prospective valuation of those benefits requires an element of judgment. A primary judgment concerns the life expectancy of the application. Some computer applications, such as the Company's customer service system, have expected useful lives of 20 years or more.[11] Other applications, such as the Company's financial management system, have expected useful lives of approximately 10 years or more.[12] Other applications, such as the Company's substation and distribution field inspection applications have shorter expected useful lives of approximately 5 years.

[11] The customer service system was put in service in 1991. The Company's current streetlight management system and metering equipment system are both of similar vintage.

[12] The Great Plains financial management system was put in service in 2002. The Company's current switching order system and outage management system are both of similar vintage.

Over the period 2009 through 2011, the two applications which utilize the vehicle mobile computing infrastructure have a combined positive net present value of approximately $86,000 over 5 years; approximately $543,000 over 10 years; and approximately $1 million over 20 years. Given that mobile computing is evolving at a greater pace than more traditional centralized computing, a life expectancy of 20 years for these applications is unrealistic. Given the Company's overall experience, a life expectancy of 5 years for these applications is unduly conservative.[13]

The two applications which are expected to be deployed through 2011 are representative of the efficiencies which can be achieved via mobile computing. Conceptually, both applications displace existing manual processes with electronic processes in electrical line and maintenance operations. Further opportunities along these lines exist in, for example, daily crew reporting in electrical line and maintenance operations.

There is potential for efficiencies to be achieved by mobile computing in areas other than automation of *existing* processes. The use of GPS is one example of this. Its potential applications are varied. They range from improved efficiency in the execution of streetlight operations and maintenance to improved response to customer outages.[14]

5.0 Outlook

By the end of 2011, Newfoundland Power expects to have fully deployed mobile computing in its electrical line and maintenance operations. By that time, the Company will have deployed two applications on the vehicle mobile computing infrastructure. Both will improve the Company's operational efficiency and capital execution into the foreseeable future.

Further mobile applications are expected to be deployed after 2011. These applications will be subject to the same economic analysis as current Company capital expenditures. Further efficiencies in management processes associated with electrical line and maintenance operations will be a focus of these applications. It is expected that efficiencies achieved through introduction of electronic processes in electrical line and maintenance operations will ultimately exceed the Company's investment in vehicle mobile computing infrastructure.

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13 In economic assessment of software applications, Newfoundland Power assumes a 5 year life expectancy. This is conservative and does not reflect average life expectancy achieved. Recent experience shows the payback period for the Company's cost of development or acquisition of software applications tends to be approximately 5 years.

14 This might include expedited response to routine customer trouble as well as more effective management of major storm outages. As well, dispatch of routine field work based on crew location has potential to reduce travel time for most operations and maintenance work.

Use of mobile computing is becoming increasingly common amongst Canadian utilities.[15] Accordingly, other utility experience should yield increasingly useful information to inform the Company's future choices in mobile computing. It is expected that this experience, taken together with Newfoundland Power's experience, will yield meaningful improvements in customer service and operating efficiency. The nature and extent of such improvements will become more apparent over time.

[15] As a part of this project, the Company contacted 9 utilities across Canada to determine how other utilities were approaching vehicle mobile computing. Of the 8 who provided information, 7 are actively utilizing computing technology in vehicles. Information provided indicated that 5 of the 7 were using the mobile technology to provide documentation similar to that provided by the Company. In addition, 4 of the utilities are managing work orders using mobile technologies. Information was also gathered to help determine the hardware and infrastructure configurations most commonly used in fleet vehicles.

Rate Base:
Additions, Deductions & Allowances

June 2010

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1.0 Introduction

1.1 General

In the 2011 Capital Budget Application (the "Application"), Newfoundland Power seeks final approval of its 2009 average rate base. This is consistent with current regulatory practice before the Board.

Newfoundland Power's 2009 average rate base of $848,493,000 is set out in Schedule D to the Application.

To meet the cost of service standard, rate base, as calculated in accordance with the Asset Rate Base Method, should reflect what the utility must finance. For investment in utility plant, it is the depreciated value of the plant that must be effectively financed. However, for rate base to fully reflect the financing requirements associated with the provision of regulated service, it must also be adjusted to reflect other costs required to provide service.

Conceptually, additions to rate base are costs that have been incurred to provide service but have not yet been recovered through customer rates. Deductions from rate base represent amounts that have been recovered through customer rates in advance of the required utility payment for those costs. Rate base allowances simply reflect the cost associated with maintaining the required working capital and inventories necessary to provide service. Each of these items affect what the utility must finance.

In Order No. P.U. 32 (2007), the Board approved Newfoundland Power's calculation of rate base in accordance with the Asset Rate Base Method. That calculation included the additions to, deductions from, and allowances in rate base which are more fully described in this report.

1.2 Compliance and Related Matters

In Order No. P.U. 19 (2003), the Board, in effect, ordered Newfoundland Power file with its capital budget applications (i) evidence related to changes in deferred charges, including pension costs, and (ii) a reconciliation of average rate base and average invested capital.

Commencing in 2008, Newfoundland Power's rate base is calculated in accordance with the Asset Rate Base Method. This includes provision for allowances calculated in accordance with accepted regulatory practice. The use of allowances versus average year-end balances result in permanent differences between Newfoundland Power's average rate base and average invested capital. Accordingly, they are, in effect, the principal reconciling items between the Company's average rate base and average invested capital.

This report provides evidence relating to (i) changes in deferred charges including pension costs and (ii) the cash working capital allowance and materials and supplies allowance included in rate base. 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 2008 and 2009 and the forecast additions for 2010 and 2011.

Table 1
Additions to Rate Base
2008-2011F
($000s)

	2008	**2009**	**2010F**	**2011F**
Deferred Charges	100,321	103,761	102,549	99,569
Weather Normalization Reserve	5,910	3,919	858	(508)
Deferred Replacement Energy Costs	766	383	-	-
Cost Recovery Deferral - Depreciation	7,724	3,862	-	-
Cost Recovery Deferral - Conservation	-	948	711	474
Cost Recovery Deferral – Hearing Costs	402	201	572	286
Customer Finance Programs	1,776	1,679	1,628	1,628
Total Additions	116,899	114,753	106,318	101,449

Additions to rate base were approximately $114.8 million in 2009. This is approximately $2.1 million less than 2008. The lower forecast additions to rate base through 2011 reflect the effect of the amortizations of a number of deferred costs approved by the Board in Order No. P.U. 32 (2007).

This section outlines the additions to rate base in further detail.

2.2. Deferred Charges

Table 2 shows details of changes in Newfoundland Power's deferred charges from 2008 through 2011.

Table 2
Deferred Charges
2008-2011F
($000s)

	2008	2009	2010F	2011F
Deferred Pension Costs	100,196	103,723	102,549	99,569
Deferred Capital Stock Issue Costs	75	38	-	-
Deferred Credit Facility Issue Costs	50	-	-	-
Total Deferred Charges	100,321	103,761	102,549	99,569

2.2.1 Deferred Pension Costs

Deferred pension costs are the largest component of Newfoundland Power's deferred charges. The difference between pension plan *funding* and pension plan *expense* associated with the Company's defined benefit pension plan is captured as a deferred pension cost in accordance with Order No. P.U. 17 (1987).[1]

Table 3 shows details of changes in Newfoundland Power's deferred pension costs from 2008 through 2011.

Table 3
Deferred Pension Costs
2008-2011F
($000s)

	2008	2009	2010F	2011F
Deferred Pension Costs, January 1st	96,654	100,196	103,723	102,549
Pension Plan Funding	5,425	4,866	4,999	5,137
Pension Plan Expense	(1,883)	(1,339)	(6,173)	(8,117)
Deferred Pension Costs, December 31st	100,196	103,723	102,549	99,569

For 2009, deferred pension costs were approximately $104 million.

[1] Deferred pension costs were approved for inclusion in average rate base in Order No. P.U. 19 (2003).

2.2.2. Deferred Capital Stock Issue Costs

Deferred capital stock issue costs are related to the issuance of capital stock. They are amortized over 20 years.

Table 4 shows details of Newfoundland Power's amortization of capital stock issue costs from 2008 through 2011.

Table 4
Deferred Capital Stock Issue Costs
2008-2011F
($000s)

	2008	2009	2010F	2011F
Balance, January 1st	137	75	38	-
Amortization	(62)	(37)	(38)	-
Balance, December 31st	75	38	-	-

For 2009, the deferred capital stock issue costs were $38,000. The deferred capital stock issue costs will be fully amortized by 2010.

2.2.3. Deferred Credit Facility Issue Costs

In Order P.U. 1 (2005), the Board approved Newfoundland Power's issue of a $100 million committed revolving term credit facility. In Order No. P.U. 22 (2008), the Board approved the extension of the maturity date of the Company's 3-year committed revolving credit facility from 2009 to 2011. The Company incurred $50,000 in credit facility issue costs in 2008 relating to this renewal.

Table 5 shows details of Newfoundland Power's amortization of deferred credit facility issue costs from 2008 through 2011.

Table 5
Deferred Credit Facility Issue Costs
2008-2011F
($000s)

	2008	2009	2010F	2011F
Balance, January 1st	59	50	-	-
Cost	50	-	-	-
Amortization	(59)	(50)	-	-
Balance, December 31st	50	-	-	-

The deferred credit facility costs were fully amortized in 2009.

2.3 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 6 shows details of changes in the balance of the Weather Normalization Reserve from 2008 through 2011.

Table 6
Weather Normalization Reserve
2008-2011F
($000s)

	2008	2009	2010F	2011F
Balance, January 1st	10,516	5,910	3,919	858
Operation of the reserve	(3,240)	(625)	(1,695)	-
Amortization	(1,366)	(1,366)	(1,366)	(1,366)
Balance, December 31st	5,910	3,919	858	(508)

For 2009, the Weather Normalization Reserve balance was $3.9 million. This balance was approved by the Board in Order No. P.U. 11 (2010).

2.4 Deferred Energy Replacement Costs

During the construction period of the Rattling Brook refurbishment project in 2007, Newfoundland Power purchased energy from Newfoundland and Labrador Hydro (“Hydro”) to replace the normal production of the Rattling Brook hydroelectric plant. In Order No. P.U. 39 (2006), the Board ordered Newfoundland Power to defer recovery of an after-tax amount of $1.1 million related to the replacement of energy costs associated with the Rattling Brook Project. In Order No. P.U. 32 (2007), the Board ordered the deferral be amortized over three years beginning in 2008.

Table 7 shows details of the amortization of the deferred energy replacement costs from 2008 through 2011.

Table 7
Deferred Energy Replacement Costs
2008-2011F
($000s)

	2008	2009	2010F	2011F
Balance, January 1st	1,147	766	383	-
Cost	-	-	-	-
Amortization	(381)	(383)	(383)	-
Balance, December 31st	766	383	-	-

For 2009, the deferred energy replacement costs were $383,000. The balance of the deferred replacement energy cost will be fully amortized in 2010.

2.5 Cost Recovery Deferral-Depreciation

In Order No. P.U. 32 (2007), the Board approved a three year amortization of $11.6 million in deferred costs related to depreciation.[2]

Table 8 shows details of the amortization of the deferred cost recovery related to depreciation from 2008 through 2011.

Table 8
Cost Recovery Deferral-Depreciation
2008-2011F
($000s)

	2008	2009	2010F	2011F
Balance, January 1st	11,586	7,724	3,862	-
Cost	-	-	-	-
Amortization	(3,862)	(3,862)	(3,862)	-
Balance, December 31st	7,724	3,862	-	-

For 2009, the cost recovery deferral was $3.9 million. The balance of the deferred cost recovery related to depreciation will be fully amortized in 2010.

[2] In Order Nos. P.U. 40 (2005) and P.U. 39 (2006), the Board approved the deferred recovery of $5.8 million in depreciation costs in each of 2006 and 2007, respectively.

2.6 Cost Recovery Deferral-Conservation

Table 9 shows details of forecast amortization of the deferred cost recovery related to conservation in 2010 and 2011.

Table 9
Cost Recovery Deferral-Conservation
2008-2011F
($000s)

	2008	2009	2010F	2011F
Balance, January 1st	-	-	948	711
Cost	-	948	-	-
Amortization	-	-	(237)	(237)
Balance, December 31st	-	948	711	474

For 2008, Newfoundland Power did not defer costs related to conservation.

In Order No. P.U. 13 (2009), the Board approved the deferred recovery of certain forecast 2009 conservation costs. These costs totalled $948,000 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.

2.7 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 of external costs related to the Company's 2010 General Rate Application beginning in 2010.

Table 10 shows details of the changes in Newfoundland Power's deferred hearing costs from 2008 through 2011.

Table 10
Deferred Hearing Costs
2008-2011F
($000s)

	2008	2009	2010F	2011F
Balance, January 1st	603	402	201	572
Cost	-	-	858	-
Amortization	(201)	(201)	(487)	(286)
Balance, December 31st	402	201	572	286

For 2009, the deferred hearing costs were $201,000. The deferred hearing costs associated with the Company's 2008 General Rate Application will be fully amortized in 2010. The deferred hearing costs associated with the Company's 2010 General Rate Application will be fully amortized in 2012.

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 11 shows details of changes to balances related to customer finance programs for 2008 through 2011.

Table 11
Customer Finance Programs
2008-2011F
($000s)

	2008	2009	2010F	2011F
Balance, January 1st	1,811	1,776	1,679	1,628
Change	(35)	(97)	(51)	-
Balance, December 31st	1,776	1,679	1,628	1,628

For 2009, the customer finance programs balance was $1.7 million.

3.0 Deductions from Rate Base

3.1 Summary

Table 12 summarizes Newfoundland Power's deductions from rate base for 2008 and 2009 and the Company's forecasts for 2010 and 2011.

Table 12
Deductions from Rate Base
2008-2011F
($000s)

	2008	2009	2010F	2011F
2005 Unbilled Revenue	9,236	4,618	-	-
Accrued Pension Liabilities	3,142	3,379	3,622	3,871
Municipal Tax Liability	2,727	1,363	-	-
Future Income Taxes	1,187	2,297	2,323	1,852
Purchased Power Unit Cost Variance Reserve	895	447	-	-
Demand Management Incentive Account	426	-	602	602
Customer Security Deposits	785	581	529	529
Accrued OPEBs Liability[3]	-	-	-	-
Total Deductions	18,398	12,685	7,076	6,854

Deductions from rate base were approximately $12.7 million in 2009. Newfoundland Power's deductions from rate base in 2009 have decreased approximately $5.7 million from 2008. The forecast reduction through 2011 primarily reflects the effect of amortizations approved by the Board in Order No. P.U. 32 (2007).

This section outlines the deductions from rate base in further detail.

[3] On June 30th, 2010, Newfoundland Power filed an application with the Board seeking approval to adopt the accrual method of accounting for OPEBs beginning in 2011. This Application is currently outstanding and has not yet been considered by the Board. For purposes of the 2011 Capital Budget Filing, the 2011 rate base reflects the cash basis of accounting for OPEBs.

3.2 2005 Unbilled Revenue

Table 13 shows details of the amortization of the 2005 unbilled revenue from 2008 through 2011.

Table 13
2005 Unbilled Revenue
2008-2011F
($000)

	2008	2009	2010F	2011F
January 1, Balance	16,446	9,236	4,618	-
Amortization	(7,210)	(4,618)	(4,618)	-
December 31, Balance	9,236	4,618	-	-

For 2009, the 2005 unbilled revenue balance was $4.6 million.

In Order No. P.U. 32 (2007), the Board approved a three year amortization of the remaining balance of the 2005 unbilled revenue. The balance of the 2005 unbilled revenue will be fully amortized in 2010.

3.3 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 2008 through 2011.

Table 14
Accrued Pension Liabilities
2008-2011F
($000)

	2008	2009	2010F	2011F
January 1, Balance	2,943	3,142	3,379	3,622
Change	199	237	243	249
December 31, Balance	3,142	3,379	3,622	3,871

For 2009, the accrued pension liabilities were $3.4 million.

3.4 Municipal Tax Liability

The municipal tax liability is a timing difference related to the recovery and payment of municipal taxes. In Order No. P.U. 32 (2007), the Board approved a three year amortization of the municipal tax liability beginning in 2008.

Table 15 shows details of the amortization of the municipal tax liability from 2008 through 2011.

Table 15
Municipal Tax Liability
2008-2011F
($000)

	2008	**2009**	**2010F**	**2011F**
January 1, Balance	4,089	2,727	1,363	-
Amortization	(1,362)	(1,364)	(1,363)	-
December 31, Balance	2,727	1,363	-	-

For 2009, the municipal tax liability was $1.4 million. The balance of the municipal tax liability will be fully amortized in 2010.

3.5 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[4] and pension costs.[5]

Table 16 shows details of changes in the future income taxes from 2008 through 2011.

Table 16
Future Income Taxes
2008-2011F
($000)

	2008	**2009**	**2010F**	**2011F**
January 1, Balance	-	1,187	2,297	2,323
Change	1,187	1,110	26	(471)
December 31, Balance	1,187	2,297	2,323	1,852

4 In Order Nos. 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.

5 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.

For 2009, future income taxes were $2.3 million.

3.6 Purchased Power Unit Cost Variance Reserve

In Order No P.U. 32 (2007), the Board approved a three year amortization of a $2.1 million credit balance in the Purchase Power Unit Cost Variance Reserve beginning in 2008.

Table 17 shows details of the amortization of Purchase Power Unit Cost Variance Reserve from 2008 through 2011.

Table 17
Purchase Power Unit Cost Variance Reserve
2008-2011F
($000)

	2008	2009	2010F	2011F
January 1, Balance	1,650	895	447	-
Change	(308)	-	-	-
Amortization	(447)	(448)	(447)	-
December 31, Balance	895	447	-	-

For 2009, the Purchase Power Unit Cost Variance Reserve balance was $447,000. This balance will be fully amortized in 2010.

3.7 Demand Management Incentive Account

In Order No. P.U. 32 (2007) the Board approved the Demand Management Incentive Account (the "DMI Account") to replace the Purchase Power Unit Cost Variance Reserve.

Table 18 shows details of the amortization of the DMI Account from 2008 through 2011.

Table 18
DMI Account
2008-2011F
($000)

	2008	2009	2010F	2011F
January 1, Balance	-	426	-	602
Change	426	(426)	602	-
December 31, Balance	426	-	602	602

3.8 Customer Security Deposits

Customer security deposits are provided by customers in accordance with the Schedule of Rates, Rules and Regulations.

Table 19 shows details on the changes in customer security deposits from 2008 through 2011.

Table 19
Customer Security Deposits
2008-2011F
($000)

	2008	**2009**	**2010F**	**2011F**
January 1, Balance	612	785	581	529
Change	173	(204)	(52)	-
December 31, Balance	785	581	529	529

For 2009, the balance of customer security deposits was $581,000.

3.9 Accrued OPEBs Liability

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.

Table 20 shows details of the changes related to the accrued OPEBs liability from 2008 through 2011.

Table 20
Accrued OPEBs Liability
2008-2011F
($000)

	2008	**2009**	**2010F**	**2011F**
Regulatory Asset	41,074	46,713	52,364	55,855
Regulatory Liability	(41,074)	(46,713)	(52,364)	(55,855)
Net OPEBs Liability	-	-	-	-

Newfoundland Power currently recognizes OPEBs costs on a cash basis.[6] On the cash basis, the OPEBs asset and the OPEBs liability are equal. As a result, there is no impact on Newfoundland Power's rate base due to OPEBs costs.

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 21 shows details on changes in the cash working capital allowance from 2008 through 2011.

Table 21
Rate Base Allowances
Cash Working Capital Allowance
2008-2011F
($000)

	2008	2009	2010F	2011F
Gross Operating Costs	382,799	395,731	413,436	425,548
Income Taxes	20,131	15,590	16,946	15,903
Municipal Taxes Paid	12,394	12,942	12,958	13,263
Non-Regulated Expenses	(995)	(1,203)	(1,156)	(1,181)
Total Operating Expenses	414,329	423,060	442,184	453,533
Cash Working Capital Factor	2.1%[7]	2.1%	2.0%[8]	2.0%
	8,701	8,884	8,844	9,071
HST Adjustment	1,015	1,015	386	386
Cash Working Capital Allowance	9,716	9,899	9,230	9,457

For 2009, the cash working capital allowance was $9.9 million.

6 See Note 4.
7 The calculation of the 2008 rate base including a cash working capital allowance based upon a cash working capital factor of 2.1% was approved by the Board in Order No. P.U. 32 (2007).
8 The calculation of the 2010 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.[9]

Table 22 shows details on changes in the materials and supplies allowance from 2008 through 2011.

Table 22
Rate Base Allowances
Materials and Supplies Allowance
2008-2011F
($000)

	2008	2009	2010F	2011F
Average Materials and Supplies	5,369	5,417	5,301	5,378
Expansion Factor[10]	19.4%	19.4%	20.2%[11]	20.2%
Expansion	1,042	1,051	1,070	1,086
Materials and Supplies Allowance	4,327	4,366	4,231	4,292

For 2009, the materials and supplies allowance was $4.4 million.

9 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.

10 The expansion factor is based on a review of actual inventories used for expansion projects. The calculation of the 2008 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).

11 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).