NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

55 Kenmount Road
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DELIVERED BY HAND

July 8, 2011

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 2012 Capital Budget Application

A. 2012 Capital Budget Application

Enclosed are the original and 10 copies of Newfoundland Power Inc.'s (the "Company") 2012 Capital Budget Application and supporting materials (the "Filing").

The Filing outlines proposed 2012 capital expenditures totaling $77,293,000. There are also 3 multi-year projects involving 2013 capital expenditures totaling $7,745,000 and a 2014 expenditure of $150,000. In addition, the Filing seeks approval of a 2010 rate base in the amount of $875,210,000.

B. Compliance Matters

B.1 Board Orders

In Order No. P.U. 28 (2010) (the "2011 Capital Order"), the Board required a progress report on 2011 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. *2011 Capital Expenditure Status Report*: this meets the requirements of the 2011 Capital Order;

2. *2012 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 *2012 Capital Plan* provides a breakdown of the overall 2012 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.

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

D. Concluding

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

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

Yours very truly,

Gerard M. Hayes
Senior Counsel

Enclosures

c. Geoffrey Young
Newfoundland & Labrador Hydro

Thomas Johnson
O'Dea Earle Law Offices

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

Newfoundland Power Inc.
2012 Capital Budget Application
Filing Contents

Application

Supporting Materials

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

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

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:
(a) approving a 2012 Capital Budget of $77,293,000;
(b) approving certain leases to be entered into in 2012;
(c) approving certain capital expenditures related to multi-year projects commencing in 2012; and
(d) fixing and determining a 2010 rate base of $875,210,000

2012 Capital Budget Application

NEWFOUNDLAND POWER
A FORTIS COMPANY

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

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

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

(a) approving a 2012 Capital Budget of $77,293,000;
(b) approving certain leases to be entered into in 2012;
(c) approving certain capital expenditures related to multi-year projects commencing in 2012; and
(d) fixing and determining a 2010 rate base of $875,210,000

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 2012 Capital Budget in the amount of $77,293,000, 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 2012. All contributions to be recovered from customers shall be calculated in a manner approved by the Board.

3. Schedule B to this Application provides detailed descriptions of the projects for which the proposed capital expenditures included in Newfoundland Power's 2012 Capital Budget are required.

4. Schedule C to this Application is an estimate of future required expenditures on improvements or additions to the property of Newfoundland Power that will commence as part of the 2012 Capital Budget but will not be completed in 2012.

5. Schedule D to this Application is a list of leases in excess of $5,000 per year which are included in Newfoundland Power's 2012 Capital Budget.

6. The proposed expenditures as set out in Schedules A, B, C and D 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.

7. Schedule E to this Application shows Newfoundland Power's actual average rate base for 2010 of $875,210,000.

8. 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.

9. 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 2012 of the improvements and additions to its property in the amount of $77,293,000 as set out in Schedules A and B to the Application;

   (b) pursuant to Section 41 of the Act, approving Newfoundland Power's purchase and construction of improvements and additions to its property in the amount of $7,745,000 in 2013, and $150,000 in 2014, as set out in Schedule C to the Application;

   (c) pursuant to Section 41 of the Act, approving Newfoundland Power's lease of improvements to its property in the amount of $80,000 per year as set out in Schedule D to the Application; and

   (d) pursuant to Section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2010 in the amount of $875,210,000 as set out in Schedule E to the Application.

DATED at St. John's, Newfoundland and Labrador, this 8th day of July, 2011.

NEWFOUNDLAND POWER INC.

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

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

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

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

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:
(a) approving a 2012 Capital Budget of $77,293,000;
(b) approving certain leases to be entered into in 2012;
(c) approving certain capital expenditures related to multi-year projects commencing in 2012; and
(d) fixing and determining a 2010 rate base of $875,210,000

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 8th day of July, 2011:

Barrister

Peter Alteen

2012 CAPITAL BUDGET SUMMARY

Asset Class	**Budget (000s)**
1. Generation - Hydro	$ 9,933
2. Generation - Thermal	156
3. Substations	12,776
4. Transmission	5,577
5. Distribution	36,510
6. General Property	1,651
7. Transportation	2,306
8. Telecommunications	454
9. Information Systems	3,680
10. Unforeseen Allowance	750
11. General Expenses Capitalized	3,500
Total	**$ 77,293**

2012 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
1. Generation – Hydro		
Facility Rehabilitation	$1,362	2
Rattling Brook Fisheries Compensation	5,000	4
Hydro Plant Production Increase	120	6
Lockston Plant Refurbishment	3,451	8
Total Generation – Hydro	**$ 9,933**	
2. Generation – Thermal		
Facility Rehabilitation Thermal	$ 156	11
Total Generation – Thermal	**$ 156**	
3. Substations		
Substations Refurbishment and Modernization	$ 2,482	14
Replacements Due to In-Service Failures	2,276	16
Additions Due to Load Growth	5,439	18
PCB Bushing Phase-out	1,500	20
Substation Addition – Portable Substation	879	22
Lockston Substation Upgrades	200	24
Total Substations	**$12,776**	
4. Transmission		
Transmission Line Rebuild	$ 5,577	27
Total Transmission	**$ 5,577**	

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

2012 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
5. Distribution		
Extensions	$ 10,326	30
Meters	1,884	32
Services	3,351	35
Street Lighting	2,115	38
Transformers	7,944	41
Reconstruction	2,861	43
Rebuild Distribution Lines	3,403	45
Relocate/Replace Distribution Lines for Third Parties	2,205	48
Trunk Feeders	848	50
Feeder Additions for Growth	1,391	52
Allowance for Funds Used During Construction	182	54
Total Distribution	**$ 36,510**	
6. General Property		
Tools and Equipment	$ 457	57
Additions to Real Property	234	60
Company Building Renovations	685	62
Stand-by Generator System Control Centre	275	64
Total General Property	**$ 1,651**	
7. Transportation		
Purchase Vehicles and Aerial Devices	$ 2,306	67
Total Transportation	**$ 2,306**	

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

2012 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
8. Telecommunications		
Replace/Upgrade Communications Equipment	$ 150	71
Fibre Optic Circuit Replacement	304	73
Total Telecommunications	**$ 454**	
9. Information Systems		
Application Enhancements	$ 1,013	76
System Upgrades[2]	1,276	78
Personal Computer Infrastructure	390	80
Shared Server Infrastructure	607	83
Network Infrastructure	394	85
Total Information Systems	**$ 3,680**	
10. Unforeseen Allowance		
Allowance for Unforeseen Items	$ 750	88
Total Unforeseen Allowance	**$ 750**	
11. General Expenses Capitalized		
General Expenses Capitalized	$ 3,500	90
Total General Expenses Capitalized	**$ 3,500**	

[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.

2012 CAPITAL PROJECTS SUMMARY

2012 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 2012 Capital Project Summary provides a summary of the planned capital expenditures contained in Newfoundland Power's 2012 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
2012 Capital Projects by Definition
(000's)**

Clustered	**$3,651**	**Page**
Generation-Hydro	**3,451**	
Lockston Plant Refurbishment	3,451	8
Substations	**200**	
Lockston Substation Upgrades	200	24

Pooled	**$63,118**	**Page**
Distribution	**36,510**	
Allowance for Funds Used During Construction	182	54
Extensions	10,326	30
Feeder Additions for Growth	1,391	52
Meters	1,884	32
Rebuild Distribution Lines	3,403	45
Reconstruction	2,861	43
Relocate/Replace Distribution Lines for Third Parties	2,205	48
Services	3,351	35
Street Lighting	2,115	38
Transformers	7,944	41
Trunk Feeders	848	50
General Property	**1,376**	
Additions to Real Property	234	60
Tools and Equipment	457	57
Company Building Renovations	685	62
Generation-Hydro	**1,362**	
Facility Rehabilitation	1,362	2
Generation-Thermal	**156**	
Facility Rehabilitation Thermal	156	11
Information Services	**3,680**	
Application Enhancements	1,013	76
Network Infrastructure	394	85
Personal Computer Infrastructure	390	80
Shared Server Infrastructure	607	83
System Upgrades	1,276	78
Substations	**11,697**	
Additions Due to Load Growth	5,439	18
PCB Bushings Phase-out	1,500	20
Replacements Due to In-Service Failures	2,276	16
Substations Refurbishment & Modernization	2,482	14
Telecommunications	**454**	
Fibre Optic Circuit Replacement	304	73
Replace/Upgrade Communications Equipment	150	71

Transmission	**5,577**	
Rebuild Transmission Lines	5,577	27
Transportation	**2,306**	
Purchase Vehicles and Aerial Devices	2,306	67

Other	**$10,524**	**Page**
Allowance for Unforeseen	**750**	
Allowance for Unforeseen Items	750	88
General Expenses Capitalized	**3,500**	
General Expenses Capitalized	3,500	90
General Property	**275**	
Stand-by Generator System Control Centre	275	64
Generation-Hydro	**5,120**	
Hydro Plant Production Increase	120	6
Rattling Brook Fisheries Compensation	5,000	4
Substations	**879**	
Substation Addition - Portable Substation	879	22

**Summary of
2012 Capital Projects by Classification
(000's)**

Normal Capital	**$68,477**	**Page**
Allowance for Unforeseen	**750**	
Allowance for Unforeseen Items	750	88
Distribution	**36,510**	
Allowance for Funds Used During Construction	182	54
Extensions	10,326	30
Feeder Additions for Growth	1,391	52
Meters	1,884	32
Rebuild Distribution Lines	3,403	45
Reconstruction	2,861	43
Relocate/Replace Distribution Lines for 3rd Parties	2,205	48
Services	3,351	35
Street Lighting	2,115	38
Transformers	7,944	41
Trunk Feeders	848	50
General Expenses Capitalized	**3,500**	
General Expenses Capitalized	3,500	90
General Property	**1,651**	
Additions to Real Property	234	60
Tools and Equipment	457	57
Stand-by Generator System Control Centre	275	64
Company Building Renovations	685	62
Generation-Hydro	**4,813**	
Facility Rehabilitation	1,362	2
Lockston Plant Refurbishment	3,451	8
Generation-Thermal	**156**	
Facility Rehabilitation Thermal	156	11
Information Services	**2,667**	
Network Infrastructure	394	85
Personal Computer Infrastructure	390	80
Shared Server Infrastructure	607	83
System Upgrades	1,276	78
Substations	**10,397**	
Additions Due to Load Growth	5,439	18
Replacements Due to In-Service Failures	2,276	16
Substations Refurbishment & Modernization	2,482	14
Lockston Substation Upgrades	200	24
Telecommunications	**150**	
Replace/Upgrade Communications Equipment	150	71

Transmission	**5,577**	
Rebuild Transmission Lines	5,577	27
Transportation	**2,306**	
Purchase Vehicles and Aerial Devices	2,306	67

Justifiable	**$2,316**	**Page**
Generation-Hydro	**120**	
Hydro Plant Production Increase	120	6
Information Services	**1,013**	
Application Enhancements	1,013	76
Substations	**879**	
Substation Addition - Portable Substation	879	22
Telecommunications	**304**	
Fibre Optic Circuit Replacement	304	73

Mandatory	**$6,500**	**Page**
Generation-Hydro	**5,000**	
Rattling Brook Fisheries Compensation	5,000	4
Substations	**1,500**	
PCB Bushings Phase-out	1,500	20

Summary of
2012 Capital Projects by Materiality
(000's)

Large – Greater than $500	**$74,431**	**Page**
Allowance for Unforeseen	**750**	
Allowance for Unforeseen Items	750	88
Distribution	**36,328**	
Extensions	10,326	30
Feeder Additions for Growth	1,391	52
Meters	1,884	32
Rebuild Distribution Lines	3,403	45
Reconstruction	2,861	43
Relocate/Replace Distribution Lines for 3rd Parties	2,205	48
Services	3,351	35
Street Lighting	2,115	38
Transformers	7,944	41
Trunk Feeders	848	50
General Expenses Capitalized	**3,500**	
General Expenses Capitalized	3,500	90
General Property	**685**	
Company Building Renovations	685	62
Generation-Hydro	**9,813**	
Facility Rehabilitation	1,362	2
Lockston Plant Refurbishment	3,451	8
Rattling Brook Fisheries Compensation	5,000	4
Information Services	**2,896**	
Application Enhancements	1,013	76
Shared Server Infrastructure	607	83
System Upgrades	1,276	78
Substations	**12,576**	
Additions Due to Load Growth	5,439	18
Replacements Due to In-Service Failures	2,276	16
Substations Refurbishment & Modernization	2,482	14
PCB Bushings Phase-out	1,500	20
Substation Addition Portable Substation	879	22
Transmission	**5,577**	
Transmission Line Rebuild	5,577	27
Transportation	**2,306**	
Purchase Vehicles and Aerial Devices	2,306	67

Medium - Between $200 and $500	**$2,254**	**Page**
General Property	**966**	
Additions to Real Property	234	60
Tools and Equipment	457	57
Stand-by Generator System Control Centre	275	64
Information Services	**784**	
Network Infrastructure	394	85
Personal Computer Infrastructure	390	80
Substations	**200**	
Lockston Substation Upgrades	200	24
Telecommunications	**304**	
Fibre Optic Circuit Replacement	304	73

Small – Under $200	**$608**	**Page**
Distribution	**182**	
Allowance for Funds Used During Construction	182	54
Generation-Hydro	**120**	
Hydro Plant Production Increase	120	6
Generation-Thermal	**156**	
Facility Rehabilitation Thermal	156	11
Telecommunications	**150**	
Replace/Upgrade Communications Equipment	150	71

GENERATION - HYDRO

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

Project Cost: **$1,362,000**

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 3 hydro dams and spillways;
- Refurbishment of 1 gatehouse structure; 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 2012 proposed expenditures are included in ***1.1*** *2012 Facility Rehabilitation*.

Justification

The Company's 23 hydroelectric plants range in age from 12 to 111 years old. These facilities provide relatively inexpensive energy to the Island interconnected system. Maintaining these generating facilities reduces the need for additional, more expensive, generation.

Replacement and rehabilitation projects are identified during ongoing inspections and maintenance activities. These projects are necessary for the continued operation of generation facilities in a safe, reliable and environmentally compliant manner.

The alternative to maintaining these generation facilities would be to retire them. The Company's hydro generation facilities produce a combined normal annual production of 430.5 GWh. Replacing the energy produced by these facilities by increasing production at Newfoundland and Labrador Hydro's Holyrood generation facility would require approximately 683,000 barrels of fuel annually. At an oil price of $103.10 per barrel, this translates into approximately $70 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 2012 and a projection of expenditures through 2016.

Table 1

Projected Expenditures (000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$1,096	-	-	-
Labour – Internal	47	-	-	-
Labour – Contract	-	-	-	-
Engineering	189	-	-	-
Other	30	-	-	-
Total	**$1,362**	**$1,350**	**$4,250**	**$6,962**

Costing Methodology

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

Table 2

Expenditure History (000s)

Year	2007	2008	2009	2010	2011F
Total	**$780**	**$3,551**[1]	**$2,519**[2]	**$1,301**	**$1,450**

[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: Rattling Brook Fisheries Compensation (Other)

Project Cost: $5,000,000

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 53 years of reliable energy production. The normal annual plant production is approximately 78.3 GWh of energy, or about 18.2% of Newfoundland Power's total hydroelectric system.

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. Upgrades are ongoing in 2011 at Rattling Brook associated with the civil infrastructure at Rattling Lake spillway, Amy's Lake dam, Amy's Lake freeboard dam and Rattling Lake dam.

Newfoundland Power was advised by the Department of Fisheries and Oceans ("DFO") in 2005 of a requirement to reintroduce Atlantic Salmon into Rattling Brook and its tributaries. Since 2005, the Company has been engaged with DFO and a technical working group to determine if a practical and cost effective solution existed for re-establishing fish passage in Rattling Brook.

In 2010, the Company received an order from DFO indicating that, pursuant to section 20 of the Fisheries Act, fish passage must be in place to allow downstream migration of salmon kelts and smolts by May 1, 2013 and the upstream migration of grilse and adult salmon by June 2014. This project is intended to allow Newfoundland Power to conform to this 2010 DFO order.

Details on the proposed expenditures are included in ***1.2*** *Rattling Brook Fisheries Compensation*.

Justification

This project is necessary at this time to conform with the 2010 order of DFO.

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 1.57¢ 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 16.37¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $103.10 per barrel for 2011 as per Newfoundland Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated April 14, 2011.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2012 to 2016.

Table 1
Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$4,030	-	-	-
Labour – Internal	245	-	-	-
Labour – Contract	-	-	-	-
Engineering	625	-	-	-
Other	100	-	-	-
Total	**$5,000**	**-**	-	**$5,000**

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: **$120,000**

Project Description

In 2008, Newfoundland Power conducted a study into alternative ways to improve the efficiency and energy production of existing hydroelectric plants.[2] 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. *Complete Engineering La Manche Canal ($100,000).* Newfoundland Power's Rocky Pond/Tors Cove development is comprised of two generating plants, Rocky Pond and Tors Cove, and is located on the southern shore of the Avalon Peninsula, approximately 40 km south of the city of St. John's.

   Storage is provided by structures at Franks Pond, Cape Pond, Rocky Pond Forebay and Tors Cove Forebay. Water flows from Franks Pond to Cape Pond through the Franks Pond canal. Water flows from Cape Pond to Rocky Pond Forebay through the Cluneys and La Manche canals. Increasing capacity of La Manche canal to increase energy production within the Rocky Pond /Tors Cove system was identified as a potential project in the 2008 study.

   The La Manche canal is a side hill excavation and earthfill dyke structure approximately 5,600 metres long and incorporates a total of seven spillways along its length. Increasing La Manche canal capacity would increase the amount of storage capacity in this system and reduce the amount of water spilled at Cape Pond and Cluneys canal.

   The project involves completing the necessary engineering design work to proceed with the construction in 2013.

2. *Complete Engineering New Chelsea Runner Replacement ($20,000).* Newfoundland Power's New Chelsea/Pittman's development is composed of two generating plants, New Chelsea and Pittman's Pond. The New Chelsea plant was placed into service in 1956 and has one generating unit with a capacity of 3.7 MW under a net head of 83.8 metres. The normal annual energy production at New Chelsea is approximately 16.30 GWh or 3.8% of the total hydroelectric production of Newfoundland Power.

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

The runner at New Chelsea is 52 years old. Efficiency testing on this unit indicated that the turbine efficiency was acceptable considering the age of the unit.[3] Best efficiency was estimated to be just over 83% and efficiency at maximum load was over 82%. A new runner design is estimated to increase these efficiency values to approximately 89% and 85%, respectively. The increase in annual energy production resulting from the runner replacement is estimated to be 1.0 GWh, or about 6%.

The project involves completing the necessary engineering design work to proceed with the construction in 2013.

Justification

Increased energy production at Newfoundland Power's existing hydroelectric plants would displace energy produced at Hydro's Holyrood thermal generating plant.[4]

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016.

Table 1
Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material		-	-	-
Labour – Internal	$2	-	-	-
Labour – Contract		-	-	-
Engineering	115	-	-	-
Other	3	-	-	-
Total	**$120**	**1,693**	**3,025**	**$4,838**

Costing Methodology

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

Future Commitments

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

3 Efficiency testing was completed on this unit by Hatch in 1997 as part of a Water Management Study.
4 The cost of electricity from the Holyrood thermal generating station is estimated at 16.37¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $103.10 per barrel for 2011 as per Newfoundland Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated April 14, 2011.

Project Title: **Lockston Plant Refurbishment (Clustered)**

Project Cost: **$3,451,000**

Project Description

This generation hydro project involves a major refurbishment of electrical and mechanical systems at Lockston Plant. The components requiring replacement or refurbishment include the plant controls, governor controls, electrical protection, power cables, station service, AC and DC electricity distribution panels, and switchgear.

The project includes more extensive refurbishment of Lockston generating unit G1, as compared to generating unit G2. For generating unit G1, this includes a rewind of the generator and the exciter, replacement of the turbine runner and wicket gates, and replacement of the main valve.

The project also includes replacement of substation and transmission line protection panels, a building extension, and implementation of a water management algorithm in the generating unit G1 control system.

Details on the proposed expenditures are included in ***1.3*** *Lockston Hydro Plant Refurbishment*.

Justification

The Lockston hydroelectric generating plant, located on the Bonavista Peninsula in eastern Newfoundland near the town of Port Rexton, was commissioned in 1956 with a capacity of 1.5 MW. In 1962, an identical second generating unit was added to the plant increasing capacity to 3.0 MW.

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

A present worth feasibility analysis of projected capital and operating expenditures for the Lockston Plant has determined the levelized cost of energy from the plant over the next 50 years to be 5.92¢ per kWh, which is significantly less than the cost of replacement energy at Holyrood.[5]

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[5] The cost of electricity from the Holyrood thermal generating station is estimated at 16.37¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $103.10 per barrel for 2011 as per Newfoundland Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated April 14, 2011.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2012 to 2016.

Table 1

Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$2,784	-	-	-
Labour – Internal	280	-	-	-
Labour – Contract		-	-	-
Engineering	190	-	-	-
Other	197	-	-	-
Total	**$3,451**	**-**	-	**$3,451**

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: **$156,000**

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 2012 project consists of the refurbishment or replacement of thermal plant structures and equipment due to damage, deterioration, corrosion and in-service failure. This equipment is critical to the safe and reliable operation of thermal generating facilities and must be replaced in a timely manner. Based upon historical information $156,000 is required for 2012.

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

Justification

The Company maintains 43.0 MW of thermal generation consisting of gas turbine and diesel units. These units are generally used to provide emergency generation, both locally and for the Island interconnected system, and to facilitate scheduled maintenance. Replacement and rehabilitation projects are identified during ongoing inspections and maintenance activities. These projects are necessary for the continued operation of thermal generation facilities in a safe, reliable and environmentally compliant manner.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016.

Table 1 Projected Expenditures (000s)				
Cost Category	**2012**	**2013**	**2014 - 2016**	**Total**
Material	$ 100	-	-	-
Labour – Internal	28	-	-	-
Labour – Contract		-	-	-
Engineering	20	-	-	-
Other	8	-	-	-
Total	**$ 156**	**$284**	**$770**	**$1,210**

Costing Methodology

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

Table 2 Expenditure History (000s)					
Year	**2007**	**2008**	**2009**	**2010**	**2011F**
Total	**$37**	**$301**	**$202**	**$196**	**$268**

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: **$2,482,000**

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*** *2012 Substation Refurbishment and Modernization*.

The Company has 130 substations varying in age from 9 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 2012 and a projection of expenditures through 2016.

Table 1

Projected Expenditures
(000s)

Cost Category	2012	2013	2014 – 2016	Total
Material	$1,887	-	-	-
Labour – Internal	67	-	-	-
Labour – Contract	-	-	-	-
Engineering	455	-	-	-
Other	73	-	-	-
Total	**$2,482**	**$1,712**	**$15,919**	**$20,113**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2007	2008	2009	2010	2011F
Total	$2,364	$2,508	$4,153	$4,101[1]	$1,366

Note: [1] Includes a $1,060,000 carryover into 2011

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: **$2,276,000**

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 2012 and a projection of expenditures through 2016.

Table 1
Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$1,477	-	-	-
Labour – Internal	482	-	-	-
Labour – Contract	-	-	-	-
Engineering	221	-	-	-
Other	96	-	-	-
Total	**$2,276**	**$2,333**	**$7,340**	**$11,949**

Costing Methodology

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

Table 2 **Expenditure History** **(000s)**					
Year	**2007**	**2008**	**2009**	**2010**	**2011F**
Total	**$2,134**	**$2,357**	**$2,329**	**$2,388**	**$2,221**

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: **$5,439,000**

Project Description

This substations project includes:

1. The installation of a new 66/12.5 kV 25 MVA substation transformer at Cobbs Pond substation to accommodate load growth in the Gander area. This area includes customers serviced from Cobbs Pond (COB) and Gander (GAN) substations. ($4,135,000)

2. The completion of civil work at Glendale Substation in Mount Pearl in preparation for the installation of a new 66/12.5 kV 25 MVA substation transformer in 2013 to accommodate load growth in the St. John's South - Mount Pearl area. The St. John's South - Mount Pearl area includes customers serviced from Glendale (GDL), Goulds (GOU) and Hardwoods (HWD) substations. The Glendale Substation portion of this Capital Project is to be treated as a multi-year project. ($1,156,000)

3. The termination of a new feeder at Kelligrews Substation. ($148,000)

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 2012 proposed expenditures are included in ***2.2*** *2012 Additions Due to Load Growth*.

Justification

A 20-year load forecast has projected electrical demand for the Gander and St. John's South Mount Pearl 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 Cobbs Pond and Glendale 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.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016.

Table 1 **Projected Expenditures** **(000s)**				
Cost Category	**2012**	**2013**	**2014 - 2016**	**Total**
Material	$4,721	$5,076	-	-
Labour – Internal	82	51	-	-
Labour – Contract	-	-	-	-
Engineering	535	485	-	-
Other	101	102	-	-
Total	**$5,439**	**$5,714**	**$15,655**	**$26,808**

Costing Methodology

The budget estimate for this project is comprised of engineering estimates of the cost of individual budget items.

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

Future Commitments

The Glendale addition is a multi-year project. In 2012 the Company will complete civil work at Glendale Substation in Mount Pearl in preparation for the installation of a new 66/12.5 kV 25 MVA substation transformer in 2013. Table 2 details the complete multi-year project expenditure included above in Table 1 for the Glendale substation multi-year project.

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

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*** *2012 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 to December 31, 2014 in accordance with subsection 17(2) of the *PCB Regulations*.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016.

Table 1
Projected Cost
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$1,043	-	-	-
Labour – Internal	244	-	-	-
Labour – Contract		-	-	-
Engineering	207	-	-	-
Other	6	-	-	-
Total	**$1,500**	**$5,000**	**$7,000**	**$13,500**

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. Expenditures beyond the end-of-life extension date of December 31, 2014 will be to address PCB concentrations greater than 50 ppm and less than 500 ppm.

Project Title: **Substation Addition – Portable Substation (Other)**

Project Cost: **$879,000**

Project Description

Newfoundland Power's fleet of portable substations includes 3 units ranging in age from 19 years to 45 years old. The 3 units have capacity of 10 MVA, 25 MVA and 50 MVA, respectively, at a variety of operating voltages. The Company uses portable substations to minimize customer power outages resulting from failure of substation power transformers and from execution of the Company's substation capital and maintenance programs.

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

This substations project is multi-year project to purchase a new 50 MVA portable substation. The order for the new portable substation will be placed early in 2012. Subsequent detail design and commencement of actual construction in 2012 will permit delivery in late 2013.[6]

Details on proposed expenditures are included in ***2.4** Portable Substation Study*.

Justification

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

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6 Manufacturers have advised Newfoundland Power that the time required to manufacture a portable substation is in the range of 18 to 24 months.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016.

Table 1
Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$844	$3,374	-	$4,218
Labour – Internal	-	110	-	110
Labour – Contract	-	-	-	-
Engineering	30	95	-	125
Other	5	42	-	47
Total	**$879**	**$3,621**	**-**	**$4,500**

Costing Methodology

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

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

Future Commitments

This is a multi-year project, commencing in 2012 and finishing in 2013. The complete multi-year project expenditure is included above in Table 1.

Project Title: **Lockston Substation Upgrades (Clustered)**

Project Cost: **$200,000**

Project Description

This substation project is proposed in conjunction with the major refurbishment of the Company's Lockston hydroelectric generating plant. This substation upgrade project will involve the addition of a three phase station service transformer and upgrading of substation bus protection and transmission line 110L protection panels.

Details on 2012 proposed expenditures are included in ***1.3*** *Lockston Hydro Plant Refurbishment*.

Justification

This substation project is clustered with the Lockston Plant Refurbishment project. The addition of a three phase station service transformer and upgrading of substation bus protection and transmission line 110L protection panels will conform to existing standards for recent refurbishment projects. The three phase station service is required to power ancillary equipment in the plant during normal operating conditions and when the generator is isolated from the power system.

A feasibility analysis of projected capital and operating expenditure requirements for the complete Lockston Plant has determined the levelized cost of energy from the plant over the next 50 years to be 5.92¢ per kWh, which is significantly less than the cost of replacement energy.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016.

Table 1

Projected Expenditures
(000s)

Cost Category	**2012**	**2013**	**2014 - 2016**	**Total**
Material	$152	-	-	-
Labour – Internal	5	-	-	-
Labour – Contract	-	-	-	-
Engineering	39	-	-	-
Other	4	-	-	-
Total	**$200**	**-**	**-**	**$200**

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.

TRANSMISSION

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

Project Cost: **$5,577,000**

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 2012 transmission line rebuilding work will take place on transmission lines 21L, 110L and 124L. Transmission line 21L is a 66 kV transmission line connecting Horsechops Plant to the Island interconnected system. Transmission line 110L operates between Clarenville Substation and Lockston Substation on the Bonavista Peninsula. Transmission line 124L operates between Clarenville Substation and Gambo Substation in central Newfoundland.

   Details on the 2012 rebuilds are included in ***3.1*** *Transmission Line Rebuild* ($3,477,000).

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 ($2,100,000).

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

Justification

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

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

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016. Appendix A of ***3.1*** *Transmission Line Rebuild* details the transmission line rebuilds planned for each year.

Table 1
Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$1,970	-	-	-
Labour – Internal	301	-	-	-
Labour – Contract	2,882	-	-	-
Engineering	159	-	-	-
Other	265	-	-	-
Total	**$5,577**	**$5,368**	**$15,642**	**$26,587**

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	2007	2008	2009	2010	2011F
Total	**$4,440**	**$5,236**	**$4,520**	**$6,409**[1]	**$4,002**

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

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: **$10,326,000**

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 2012 and a projection of expenditures through 2016.

Table 1
Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$3,223	-	-	-
Labour – Internal	3,037	-	-	-
Labour – Contract	2,431	-	-	-
Engineering	1,303	-	-	-
Other	332	-	-	-
Total	**$10,326**	**$10,694**	**$38,270**	**$59,290**

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 2012.

Table 2
Expenditure History and Unit Cost Projection

Year	2007	2008	2009	2010	2011F	2012B
Total (000s)	**$ 9,285**	**$ 10,592**	**$ 12,892**	**$ 14,616**	**$ 11,650**	**$ 10,326**
Adjusted Cost (000s)[1]	$ 10,458	$ 11,571	$ 13,606	$ 15,129	$ 11,650	-
New Customers	4,038	4,625	5,051	5,300	4,894	4,670
Unit Cost ($/customer)[1]	$ 2,590	$ 2,502	$ 2,694	$ 2,855	$ 2,380	$ 2,211

[1] 2011 Dollars.

The project cost for the connection of new customers is calculated on the basis of historical data.[7] 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.

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

Project Title: **Meters (Pooled)**

Project Cost: **$1,884,000**

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 2012.

Table 1
2012 Proposed Meter Acquisition

Program	Number of Meters
Energy Only Domestic Meters	16,056
Other Energy Only and Demand Meters	3,058

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.[8]

Justification

The purchase of new meters is necessary to accommodate customer growth and to replace deteriorated meters. Revenue metering of electrical service is regulated under the *Electricity and Gas Inspection Act (Canada)*. The additional cost associated with expenditures on AMR meters is justified by safety and on an economic basis.

[8] The *Metering Strategy* filed with the 2006 Capital Budget Application identified a number of high cost meter read locations that could be addressed at that time with AMR meters.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016.

Table 2
Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$1,458	-	-	-
Labour – Internal	388	-	-	-
Labour – Contract	38	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$1,884**	**$1,929**	**$6,071**	**$9,884**

Costing Methodology

Table 3 shows the annual expenditures for the most recent five-year period, as well as a projection for 2012.

Table 3
Expenditure History and Unit Cost Projection

Year	2007	2008	2009	2010	2011F	Avg	2012B
Meter Requirements							
New Connections	4,038	4,625	5,051	5,300	4,894		4,670
GROs/CSOs	3,546	13,691	14,188	10,284	9,730		10,288
Other	1,667	2,156	1,097	7,494	8,364		4,156
Total	9,251	20,472	20,336	23,078	22,988		19,114
Meter Costs							
Actual (000s)	$ 1,154	$ 1,474	$ 1,962	$ 1,872	$ 1,806		$ 1,884
Adjusted[1] (000s)	$ 1,282	$ 1,586	$ 2,024	$ 1,924	$ 1,806		
Unit Cost[1]	$ 139	$ 77	$ 100	$ 83	$ 79	$ 96	$ 98

[1] 2011 dollars.

The project cost for meters is calculated on the basis of historical data. Historical annual expenditures over the most recent five-year period, including the current year, are expressed in current year dollars ("Adjusted Meter Costs") 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: **$3,351,000**

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 2012 and a projection of expenditures through 2016.

Table 1
Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$1,008	-	-	-
Labour – Internal	1,859	-	-	-
Labour – Contract	163	-	-	-
Engineering	281	-	-	-
Other	40	-	-	-
Total	**$3,351**	**$3,453**	**$11,865**	**$18,669**

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 2012.

Table 2

Expenditure History and Unit Cost Projection
New Services

Year	**2007**	**2008**	**2009**	**2010**	**2011F**	**2012B**
Total (000s)	**$ 1,949**	**$ 2,111**	**$ 2,828**	**$ 3,255**	**$ 2,746**	**$ 2,738**
Adjusted Cost (000s)[1]	$ 2,197	$ 2,308	$ 2,988	$ 3,371	-	-
New Customers	4,038	4,625	5,051	5,300	4,894	4,670
Unit Cost ($/customer)[1]	$ 544	$ 499	$ 592	$ 636	$ 561	$ 586

[1] 2011 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 2012.

Table 3

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

Year	**2007**	**2008**	**2009**	**2010**	**2011F**	**2012B**
Total	**$472**	**$427**	**$410**	**$1,083**	**$678**	**$613**
Adjusted Cost[1]	$532	$467	$433	$852[2]	$678	

[1] 2011 dollars.
[2] Excludes cost associated with Hurricane Igor related damage in September 2010.

The process of estimating the budget requirement for *replacement* services is similar to that for *new* services, except the budget estimate is based on the historical average of the total cost of replacement services, as opposed to a unit cost. To ensure 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: **$2,115,000**

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 2012 and a projection of expenditures through 2016.

Table 1
Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$1,145	-	-	-
Labour – Internal	753	-	-	-
Labour – Contract	163	-	-	-
Engineering	32	-	-	-
Other	22	-	-	-
Total	**$2,115**	**$2,172**	**$7,269**	**$11,556**

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 2012.

Table 2
Expenditure History and Unit Cost Projection
New Street Lights

Year	2007	2008	2009	2010	2011F	2012B
Total (000s)	**$ 977**	**$ 1,315**	**$ 1,805**	**$ 1,781**	**$ 1,512**	**$ 1,428**
Adjusted Cost (000s)[1]	$ 1,094	$ 1,428	$1,887	$ 1,838	-	
New Customers	4,038	4,625	5,051	5,300	4,894	4,670
Unit Cost ($/cust.)[1]	$ 271	$ 309	$ 374	$ 347	$ 309	$ 306

[1] 2011 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 2012.

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

Year	2007	2008	2009	2010	2011F	2012B
Total	**$ 1,112**	**$ 692**	**$ 683**	**$ 797**	**$ 767**	**$ 687**
Exclusions[1]	140	-	-	-	-	
Adjusted Cost[2]	$ 1,088	$ 751	$ 715	$ 823	$ 767	

[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] 2011 dollars

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

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

Future Commitments

This is not a multi-year project.

Project Title: **Transformers (Pooled)**

Project Cost: **$7,944,000**

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 2012 and a projection of expenditures through 2016.

Table 1

Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$7,944	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$7,944**	**$8,119**	**$25,436**	**$41,499**

Costing Methodology

Table 2 shows the annual expenditures for the most recent five-year period, as well as an estimate for 2012.

Table 2

Expenditure History and Budget Estimate (000s)

Year	2007	2008	2009	2010	2011F	2012B
Total	**$6,992**	**$8,545**	**$6,909**	**$6,588**	**$7,799**	**$7,944**
Adjusted Cost[1]	$7,744	$9,162	$7,089	$6,759		

[1] 2011 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: **$2,861,000**

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 2012 and a projection of expenditures through 2016.

Table 1

Projected Expenditures (000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$177	-	-	-
Labour – Internal	774	-	-	-
Labour – Contract	981	-	-	-
Engineering	812	-	-	-
Other	117	-	-	-
Total	**$2,861**	**$3,398**	**$11,197**	**$17,456**

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 2012.

Table 2

Expenditure History and Budget Estimate (000s)

Year	2007	2008	2009	2010	2011F	2012B
Total	**$3,563**	**$3,193**	**$4,123**	**$5,202**[2]	**$3,009**	**$2,861**
Adjusted Cost[1]	$3,450	$3,488	$4,351	3,146[3]		

1 2011 dollars.
2 Includes actual expenditures of $996,000 approved under P.U. No. 17 (2010) for work associated with the March 2010 ice storm and $1,167,000 approved under P.U. 35 (2010) for work associated with Hurricane Igor. These expenditures are excluded from Adjusted Cost.
3 The adjusted cost excludes costs associated with the March 2010 ice storm and Hurricane Igor referred to in Note 2.

The process of estimating the budget requirement for Reconstruction is based on a historical average.[9] 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.

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

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

Project Cost: **$3,403,000**

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 2012 includes 43 of the Company's 303 feeders. A listing of the feeders upon which work is proposed for 2012 follows:

BCV-02	BIG-02	FER-01	GDL-05	GDL-06	KBR-06
KEN-03	PEP-02	SLA-09	VIR-07	VIR-08	BFS-02
GFS-01	GFS-10	NWB-01	PAS-02	CAR-03	CLK-02
HOL-01	NHR-01	CLV-02	LLK-02	MIL-02	PBD-01
SPO-01	SPO-02	ABC-02	BOT-02	GFS-03	GFS-04
GFS-05	GLV-02	GPD-01	LGL-01	CLK-03	HGR-02
ISL-01	WAL-02	WAL-07	CAR-04	CLK-04	GAN-04
SMV-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 2012 and a projection of expenditures through 2016.

Table 1
Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$1,640	-	-	-
Labour – Internal	1,391	-	-	-
Labour – Contract	187	-	-	-
Engineering	33	-	-	-
Other	152	-	-	-
Total	**$3,403**	**$3,505**	**$11,155**	**$18,063**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2007	2008	2009	2010	2011F
Total	**$3,249**	**$3,566**	**$1,608**	**$1,268**	**$2,888**

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*;[10]

[10] 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;[11]

d) Locations where current limiting fuses are required in accordance with the internal memo dated January 11, 2000;[12] and

e) Hardware for which a high risk of failure has been identified, such as automatic sleeves and porcelain cutouts.[13]

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.

[11] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment C for further details on problem insulators.

[12] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment D for further detail on current limiting fuse requirements.

[13] 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: **$2,205,000**

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 2012 and a projection of expenditures through 2016.

Table 1

Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$771	-	-	-
Labour – Internal	767	-	-	-
Labour – Contract	380	-	-	-
Engineering	245	-	-	-
Other	42	-	-	-
Total	**$2,205**	**$1,383**	**$4,485**	**$8,073**

Costing Methodology

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

Table 2 **Expenditure History** **(000s)**					
Year	**2007**	**2008**	**2009**	**2010**	**2011F**
Total	**$1,604**	**$1,585**	**$2,077**	**$2,363**	**$2,110**
Adjusted Cost[1]	$1,800	$1,724	$2,178	$2,441	

[1] 2011 dollars.

The budget estimate is based on historical expenditures.[14] Generally these expenditures are associated with a number of small projects that are not specifically identified at the time the budget is prepared. Historical annual expenditures related to distribution line relocations and replacements over the most recent five-year period, including the current year, are expressed in current-year dollars ("Adjusted Cost") using the Statistics Canada Distribution Systems Price Index. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and adjusting it using the GDP Deflator for Canada.

Estimated contributions from customers and requesting parties associated with this project have been included in the contribution in aid of construction amount referred to in the Application.

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

Future Commitments

This is not a multi-year project.

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

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

Project Cost: **$848,000**

Project Description

This Distribution project consists of:

1. The replacement of the submarine cable feeding the community of Charlottetown in Terra Nova Park with the extension of an aerial distribution line from Glovertown Substation. ($723,000)

2. The replacement of approximately 3.5 km of underground cable running under the Stephenville Airport runway feeding the area known as Little Port Harmon with an aerial distribution line and a small section of underground cable west of the airport runway. ($125,000)

Details on the proposed expenditures are included in ***4.3*** *Trunk Feeders.*

Justification

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

In both the Charlottetown and Port Harmon situations the age and condition of the existing facilities combined with the difficulties anticipated in either repairing or replacing the facilities when they fail have necessitated the proactive replacement of the cables servicing these customers.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016.

Table 1
Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$441	-	-	-
Labour – Internal	149	-	-	-
Labour – Contract	158	-	-	-
Engineering	75	-	-	-
Other	25	-	-	-
Total	**$848**	**$428**	**$4,202**	**$5,478**

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: **$1,391,000**

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 Kelligrews substation. ($318,000)

2. The increase in capacity of existing Pulpit Rock feeder PUL-02 to accommodate residential growth in the towns of Flatrock and Pouch Cove. ($538,000)

3. Relocate 1.1 km of feeder SJM-08 to the new duct bank between Hutching Street and Beck's Cove ($535,000)

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

Justification

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

Actual peak load conditions and customer growth indicate that this project is warranted in order to maintain the electrical system within recommended guidelines.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016.

Table 1
Projected Expenditures
(000s)

Cost Category	**2012**	**2013**	**2014 - 2016**	**Total**
Material	$742	-	-	-
Labour – Internal	109	-	-	-
Labour – Contract	222	-	-	-
Engineering	80	-	-	-
Other	238	-	-	-
Total	**$1,391**	**$451**	**$495**	**$2,337**

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: **$182,000**

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 2012 and a projection of expenditures through 2016.

Table 1

Projected Expenditures
(000s)

Cost Category	2011	2012	2013 - 2015	Total
Material	-	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering		-	-	-
Other	$182	-	-	-
Total	**$182**	**$186**	**$584**	**$952**

Costing Methodology

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

Table 2
Expenditure History and Budget Estimate
(000s)

Year	2007	2008	2009	2010	2011F
Total	**$77**	**$176**	**$172**	**$172**	**$175**

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: **$457,000**

Project Description

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

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

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

1. *Operations Tools and Equipment ($100,000)*: This is the replacement of tools and equipment used by line and field technical staff in the day to day operations of the Company. These tools are maintained on a regular basis. However, over time they degrade and wear out, especially hot line equipment which must meet rigorous safety requirements. Where appropriate, such tools will be replaced with battery and hydraulic alternatives to improve productivity and working conditions.

2. *Engineering Tools and Equipment ($180,000)*: 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 ($77,000)*: 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.[15]

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[15] 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 2012 and a projection of expenditures through 2016.

Table 1

Projected Expenditures
(000s)

Cost Category	2012	2013	2014 – 2016	Total
Material	$457	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$457**	**$414**	**$1,288**	**$2,159**

Costing Methodology

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

Table 2

Expenditure History
(000s)

Year	2007	2008	2009	2010	2011F
Total	**$617**	**$673**	**$384**	**$383**	**$528**

The project cost is based on an assessment of historical expenditures for the replacement of tools and equipment that become broken or worn out, and is adjusted for anticipated expenditure requirements for extraordinary items. Historical expenditures in recent years have included items such as thermo scan cameras and arc flash equipment.

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

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

Future Commitments

This is not a multi-year project.

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

Project Cost: **$234,000**

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 2012 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 $234,000 is required for 2012. 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 2012 and a projection of expenditures through 2016.

Table 1
Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$145	-	-	-
Labour – Internal	11	-	-	-
Labour – Contract	56	-	-	-
Engineering	12	-	-	-
Other	10	-	-	-
Total	**$234**	**$238**	**$740**	**$1,212**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2007	2008	2009	2010	2011F
Total	**$165**	**$244**	**$244**	**$219**	**$304**

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

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

Future Commitments

This is not a multi-year project.

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

Project Cost: **$685,000**

Project Description

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

The items within this project include:

1. *Kenmount Road Parking Lot Resurfacing ($325,000)*: This item involves the resurfacing of the 43 year old parking lot at Newfoundland Power's Head Office at 55 Kenmount Road in St. John's. The parking lot is original to the 1968 construction of the building. Approximately 6,800 m^2 of asphalt will be replaced and deteriorated curbs and catch basins refurbished or replaced as required.

2. *Kenmount Road Office Renovations ($110,000)*: This item includes the replacement of flooring and wall coverings as well as reconfiguration of office space on the southern half of the 1st floor of 55 Kenmount Road office building.

3. *EMC Building Renovations ($250,000)*: This item includes the replacement of a section of roof and an expansion and renovation of the existing Equipment Maintenance Centre on Topsail Road. The expansion and renovation is required to provide female washroom and locker facilities in the building, along with additional space for employees.

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

Justification

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

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016.

Table 1
Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$583	-	-	-
Labour – Internal	12	-	-	-
Labour – Contract	-	-	-	-
Engineering	55	-	-	-
Other	35	-	-	-
Total	**$685**	**$690**	**$1,418**	**$2,793**

Costing Methodology

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

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

Future Commitments

This is not a multi-year project.

Project Title: **Standby Diesel Generator - System Control Centre (Other)**

Project Cost: **$275,000**

Project Description

This General Property project consists of the replacement of the 31 year old diesel generating unit to provide an emergency power supply to the Company's System Control Centre ("SCC") building. The existing diesel generator is a 120/208 volt, 60 kW Kohler generator originally installed in 1980 at the site of the old control centre. The unit was relocated to the new SCC in 1999.

The main service capacity for the SCC is 216 KVA. The existing diesel generating unit is only capable of carrying essential services and requires load shedding inside the building for extended operation. The replacement diesel generator will be sized to carry the entire building load in emergency situations.

Justification

The Company's SCADA system and associated communications equipment are integral to the provision of least cost reliable customer service. The reliability of the Company's SCC based SCADA system, Information System servers and critical communications equipment is dependent on a reliable standby generator.

The existing diesel generating unit is 31years old, is operating at maximum capacity and is no longer capable of providing the standby capability for the entire building.

The critical role of the SCC in providing least cost reliable service necessitates that the standby generator equipment operate reliably 24 hours a day, 365 days of the year.

This project, for which there is no feasible alternative, is required to ensure the continued provision of reliable standby power for the SCC and SCADA system.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016.

Table 1

Projected Expenditures (000s)

Cost Category	2012	2013	2014 – 2016	Total
Material	$250	-	-	-
Labour – Internal	15	-	-	-
Labour – Contract	-	-	-	-
Engineering	10	-	-	-
Other	-	-	-	-
Total	**$275**	-	-	**$275**

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: **$2,306,000**

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 summarizes the units to be acquired in 2012.

Table 1
2012 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 2012 and a projection of expenditures through 2016.

Table 2
Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$2,306	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$2,306**	**$2,358**	**$7,395**	**$12,059**

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

Table 3
Expenditure History
(000s)

Year	2007	2008	2009	2010	2011F
Total	**$2,231**	**$2,384**	**$2,087**	**$2,287**	**$2,254**

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: **$150,000**

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 2012 and a projection of expenditures through 2016.

Table 1
Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$138	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	10	-	-	-
Other	2	-	-	-
Total	**$150**	**$153**	**$477**	**$780**

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	**2007**	**2008**	**2009**	**2010**	**2011F**
Total	**$110**	**$96**	**$105**	**$149**	**$146**
Adjusted Cost[1]	$122	$103	$108	$153	$146

[1] 2011 dollars.

The process of estimating the budget requirement for communications equipment is based on a historical average. Historical annual expenditures related to upgrading and replacing communications equipment over the most recent five-year period, including the current year, expressed in current-year dollars ("Adjusted Cost") are modified by the Statistics Canada Distribution Systems Price Index for the budget year to determine the budget estimate. The estimate for the budget year is calculated by taking the average of the Adjusted Costs and inflating it using the GDP Deflator for Canada to determine the budget estimate. To ensure consistency from year to year, expenditures related to plan projects are excluded from the calculation of the historical average.

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 (Pooled)**

Project Cost: **$304,000**

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.

In 2007 the Company had 32 fibre optic systems in service which were 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.[16]

In 2008 and 2009 the Company replaced 6 leased fibre optic circuits. In 2010, 5 leased fibre optic circuits were identified for replacement. Only 2 of the original 5 fibre optic circuits were actually replaced in 2010. Two of these fibre optic leases were abandoned and not replaced. One fibre optic cable was not replaced in 2010 due to problems securing a satisfactory cable route between substations. This leaves 6 leased fibre optic cables from the original 16 requiring replacement. The Company will replace 3 of the remaining 6 fibre optic cables in 2011, leaving 3 fibre optic cables to be replaced in 2012.[17]

The 3 fibre optic cables to be replaced in 2012 include a cable between the System Control Centre on Topsail Road and Molloys Lane Substation, between Molloys Lane Substation and Stamps Lane substation, and between Molloys Lane substation and St. John's Main substation.

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.

[16] Details of the engineering review are found in report ***5.1** Fibre Optic Circuit Replacement* included in the 2008 Capital Budget Application.

[17] The 3 fibre optic circuits being replaced in 2011 include a cable between Pepperell Substation and Virginia waters Substation, between Pepperell Substation and Kings Bridge Substation and between Goulds Substation and Glendale Substation.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016.

Table 1
Projected Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$204	-	-	-
Labour – Internal	58	-	-	-
Labour – Contract	-	-	-	-
Engineering	37	-	-	-
Other	5	-	-	-
Total	**$304**	**-**	**$577**	**$881**

Costing Methodology

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

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

Future Commitments

This is not a multi-year project.

INFORMATION SYSTEMS

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

Project Cost: **$1,013,000**

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 2012 include Outage Management Improvements, Financial Management enhancements and Customer Service Internet and Energy Conservation Website enhancements.

The application enhancements proposed for 2012 are not inter-dependent. But, they are similar in nature and justification and are therefore pooled for consideration as a single capital project.

Details on proposed expenditures are included in ***6.1*** *2012 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 ***6.1*** *2012 Application Enhancements*.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016.

Table 1

Projected Expenditures (000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	$92	-	-	-
Labour – Internal	764	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	157	-	-	-
Total	**$1,013**	**$950**	**$3,775**	**$5,738**

Costing Methodology

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

Table 2

Expenditure History (000s)

Year	2007	2008	2009	2010	2011F
Total	**$1,353**	**$1,485**	**$1,444**	**$945**	**$963**

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

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

Future Commitments

This is not a multi-year project.

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

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

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 2012, the project includes upgrades to the Aspect Customer Contact Centre System and the Itron Hand Held Meter Reading System.

This project also includes the Microsoft Enterprise Agreement. This Agreement covers the purchase of Microsoft software and provides access to the latest versions of each software product purchased under this agreement. Details on Microsoft Enterprise Agreement are included in *Schedule C* of the 2012 Capital Budget.

Details on proposed expenditures are included in ***6.2*** *2012 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 2012 and a projection of expenditures through 2016.

Table 1

Projected Expenditures (000s)

Cost Category	2012	2013	2014 – 2016	Total
Material	$730	-	-	-
Labour – Internal	356	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	190	-	-	-
Total	**$1,276**	**$1,500**	**$3,700**	**$6,476**

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	**2007**	**2008**	**2009**	**2010**	**2011F**
Total	**$679**	**$668**	**$630**	**$1000**	**$813**

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 2012 through 2014 inclusive.

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 2012, a total of 90 PCs will be purchased, consisting of 50 desktop computers and 40 laptop computers. This project also includes the purchase of peripheral equipment such as monitors, mobile devices, and printers to replace existing units that have reached the end of their useful life.

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

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

Newfoundland Power is currently able to achieve an approximate 5 year life cycle for its PCs before they require replacement.

Table 1 outlines the PC additions and retirements for 2010 and 2011, as well as the proposed additions and retirements for 2012.

Table 1
PC Additions and Retirements
2010 – 2012

	2010			**2011F**			**2012B**		
	Add	**Retire**	**Total**	**Add**	**Retire**	**Total**	**Add**	**Retire**	**Total**
Desktop	96	104	458	76	76	458	50	50	458
Laptop	66[1]	26	261	42[1]	22	281	40	40	281
Total	**162**	**130**	**719**	**118**	**98**	**739**	**90**	**90**	**739**

[1] Total laptops include 80 ruggedized laptop computers related to the Vehicle Mobile Computing Infrastructure project since 2009. In 2009, 25 ruggedized laptop computers were added. In 2010, an additional 35 computers were added. In 2011, an additional 20 ruggedized laptop computers are forecast for this project. In 2012 there are no additional computers budgeted for the Vehicle Mobile project.

Justification

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

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016.

Table 2
Projected Expenditures
(000s)

Cost Category	2012	2013	2014 – 2016	Total
Material	$266	-	-	-
Labour – Internal	89	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	35	-	-	-
Total	**$390**	**$375**	**$1,125**	**$1,890**

Costing Methodology

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

Table 3
Expenditure History
(000s)

Year	2007	2008	2009	2010	2011F
Total	**$409**	**$415**	**$459**	**$449**	**$390**

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

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

Future Commitments

This is not a multi-year project.

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

Project Cost: **$607,000**

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 2012, 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.

The four projects for 2012 include:

1. Replacement of technology used to provide employees with remote computing access.
2. Addition of security infrastructure to protect Corporate and Customer information.
3. Infrastructure to ensure compliance with software policies and licensing agreements.
4. Replacement of infrastructure used to provide internal and external email services.

The shared server infrastructure requirements for 2012 are not inter-dependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Details on proposed expenditures are included in ***6.3*** *2012 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 2012 and a projection of expenditures through 2016.

Table 1

Projected Expenditures
(000s)

Cost Category	2012	2013	2014 – 2016	Total
Material	$210	-	-	-
Labour – Internal	302	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	95	-	-	-
Total	**$607**	**$900**	**$2,700**	**$4,207**

Costing Methodology

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

Table 2

Expenditure History
(000s)

Year	2007	2008	2009	2010	2011F
Total	**$883**	**$903**	**$632**	**$577**	**$1036**

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: **$394,000**

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 2012, this project includes the purchase and implementation of network equipment that has reached the end of useful life and to increase overall network capacity.

The individual network infrastructure requirements for 2012 are not inter-dependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Justification

The reliability and availability of the network infrastructure is critical to enabling the Company to continue to provide least cost reliable service to customers. This project will replace the equipment that facilitates communication between all of the Company's shared servers and related applications. This equipment is 8 years old and has reached the end of its useful life.

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

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016.

Table 1

Projected Expenditures
(000s)

Cost Category	2012	2013	2014 – 2016	Total
Material	$265	-	-	-
Labour – Internal	89	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	40	-	-	-
Total	**$394**	**$100**	**$300**	**$794**

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 2007.

Table 2

Expenditure History
(000s)

Year	**2007**	**2008**	**2009**	**2010**	**2011F**
Total	**-**	**$162**	**$115**	**$148**	**$152**

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

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

Future Commitments

This is not a multi-year project.

UNFORESEEN ALLOWANCE

Project Title: Allowance for Unforeseen Items (Other)

Project Cost: $750,000

Project Description

This 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: **$3,500,000**

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.
2012 Capital Budget
Future Required Expenditures

Improvement to Property		Estimated Annual Expenditure	Timing
1. Additions Due to Load Growth – Glendale Substation[1]		$3,974,000	2013
2. Substation Addition – Portable Substation[2]		3,621,000	2013
3. Microsoft Enterprise Agreement[3]		150,000	2013 and 2014
Total	**2013**	**$7,745,000**	
	2014	**$150,000**	

1 Detailed description provided in *2.2 2012 Additions Due to Load Growth*.
2 Detailed description provided in *2.4 2012 Portable Substation Study*.
3 Detailed description provided in *6.2 2012 System Upgrades.*

Newfoundland Power Inc.
2012 Capital Budget
Leases

Lease	Annual Cost	Term
Production Printers	$40,000	5 Years
Color Copier Production Center	$40,000	5 Years

Title: **Production Printers**

Lease Cost: **$40,000/Year**

Project Description

This lease is necessary for the replacement of two high volume printers used to print customer bills, customer letter correspondence, and various other business reports with a printing volume of approximately 350,000 pages per month.

The current lease agreement for the existing high volume printers costs $45,000 per year, paid in monthly instalments, expiring in December 2011. The lease had a five year term beginning in December 2005, and was extended for 1 additional year in December 2010.

Justification

This project is justified on the need to provide customers with printed copies of their bills, energy usage, and any associated correspondence.

Projected Expenditures

The estimated annual cost for the lease of the 2 replacement high volume printers will be $40,000 per year for a five-year term. The lease will end December 31, 2016.

Table 1 provides a breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016.

Table 1

Project Expenditures
(000s)

Cost Category	2012	2013	2014 - 2016	Total
Material	-	-		-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	$40	$40	$120	$200
Total	**$40**	**$40**	**$120**	**$200**

Future Commitments

This is multi-year project, with commitments expected for a lease term of 5 years.

Title: **Color Copier - Production Center**

Lease Cost: **$40,000/Year**

Project Description

This lease is necessary for the replacement of the high volume color copier used in the Production Center. Most large-scale printing jobs that cannot efficiently be accommodated by regular office printers are produced by the colour copier. These jobs include such items as customer information brochures, major regulatory filings, internal manuals and booklets, maps and drawings, competitive tender packages and business cards.

The existing colour copier in the Production Centre is a Xerox DocuColor 250. The existing unit was acquired in February 2006, and leased for a period of 5 years at an annual cost of $34,819.92 (excluding service contract). The lease expires in December 2011.

Justification

This project is justified on the need to provide the Company and Customers with color correspondence including brochures, regulatory filings, maps and drawings.

The performance of the existing copier has deteriorated over the last two years. This is attributed to the age of the photocopier, and the fact that it has surpassed its anticipated capacity.

The projected production lifetime of the existing copier was estimated at 1,380,000 high quality copies. To date, the photocopier has produced over 1,800,000 copies. Reflecting the high level of usage, there has been an increase in unplanned maintenance. There is a correlation between the volume of copies produced and unplanned maintenance. In 2010, when annual usage of the photocopier was at its highest, the amount of unplanned maintenance increased causing extended periods of downtime.

Projected Expenditures

The estimated annual cost for the lease of the color photocopier is $40,000 per year for a five-year term. The lease will end December 31, 2016.

Table 1 provides a breakdown of the proposed expenditures for 2012 and a projection of expenditures through 2016.

Table 1 **Project Expenditures** **(000s)**				
Cost Category	**2012**	**2013**	**2014 - 2016**	**Total**
Material	-	-		-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	$40	$40	$120	$200
Total	**$40**	**$40**	**$120**	**$200**

Future Commitments

This is multi-year project, with commitments expected for a lease term of 5 years.

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

	2010	2009
Net Plant Investment		
Plant Investment	1,393,801	1,338,408
Accumulated Amortization	(585,245)	(562,009)
Contributions in Aid of Construction	(30,266)	(29,017)
	778,290	747,382
Additions to Rate Base		
Deferred Charges	102,807	103,761
Deferred Energy Replacement Costs	-	383
Cost Recovery Deferral - Hearing Costs	507	201
Cost Recovery Deferral - Depreciation	-	3,862
Cost Recovery Deferral - Conservation	682	948
Customer Finance Programs	1,647	1,679
Weather Normalization Reserve	(1,954)	3,919
	103,689	114,753
Deductions from Rate Base		
Municipal Tax Liability	-	1,363
Unrecognized 2005 Unbilled Revenue	-	4,618
Customer Security Deposits	705	581
Accrued Pension Obligation	3,548	3,379
Future Income Taxes	3,617	2,297
Demand Management Incentive Account	676	-
Purchased Power Unit Cost Variance Reserve	-	447
	8,546	12,685
Year End Rate Base	873,433	849,450
Average Rate Base Before Allowances	861,442	834,228
Rate Base Allowances		
Materials and Supplies Allowance	4,476	4,366
Cash Working Capital Allowance	9,292	9,899
Average Rate Base at Year End	875,210	848,493

2012 Capital Plan

June 2011

Table of Contents

1.0 Introduction

Newfoundland Power's 2012 Capital Plan provides an overview of the Company's 2012 Capital Budget together with an outlook for capital expenditure through 2016.

Newfoundland Power's 2012 Capital Budget totals $77,293,000.

Newfoundland Power's annual capital expenditure for the next 5 years will average approximately $83 million. This level of annual expenditure is consistent on an inflation adjusted basis with that in the period 2007 through 2011.

The composition of Newfoundland Power's annual capital expenditure is, however, changing somewhat. Over the next 5 years, increased expenditure will be required to expand electrical system capacity, particularly transformer capacity. In this period, the Company also plans to add a portable substation and a portable generator at a total cost of approximately $14 million. Expenditures on compliance with federal regulations governing PCBs and water management will total approximately $19 million from 2012 through 2016. These additional capital expenditures over the next 5 years will be substantially offset through the period by reduced expenditure on plant replacement. This is partially the result of reduced planned expenditure aimed at reliability improvement. It is also partially the result of proposed new joint use arrangements agreed with Bell Aliant.

Newfoundland Power's 2012 capital budget is part of a series of stable and predictable annual capital budgets which the Board has recognized assist in fostering stable and predictable rates for consumers into the future.[1]

2.0 2012 Capital Budget

Newfoundland Power's 2012 capital budget is $77,293,000.

This section of the 2012 Capital Plan provides an overview of the 2012 capital budget by origin (root cause) and asset class. In addition, this section summarizes 2012 capital projects by the various categories set out in the Board's October 2007 Capital Budget Application Guidelines.

2.1 2012 Capital Budget Overview

Newfoundland Power's 2012 capital budget contains 37 projects totalling $77.3 million. From 2007 to 2011, the Company's annual capital program averaged $70.2 million in a range of $63.2 million to $75.7 million.

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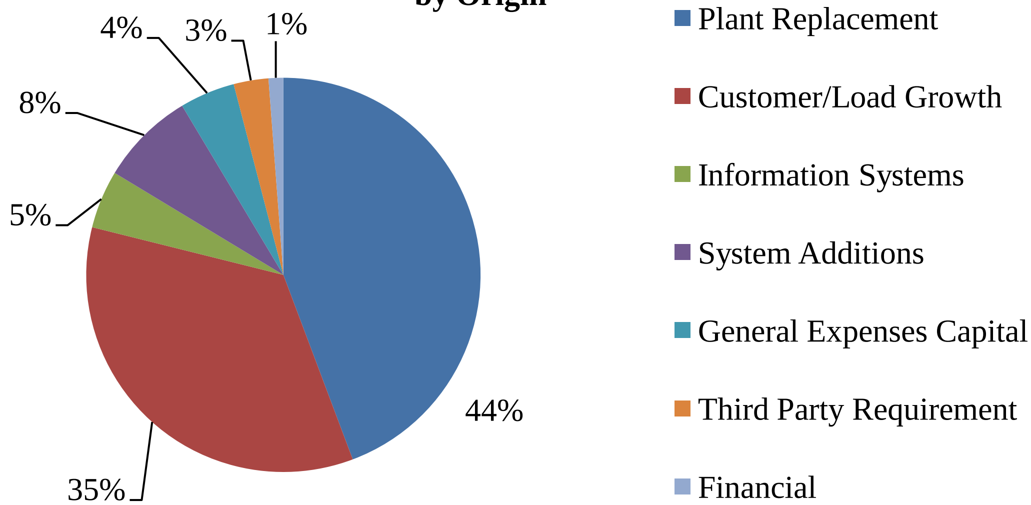
1 See Order No. P.U. 36 (2002-2003).

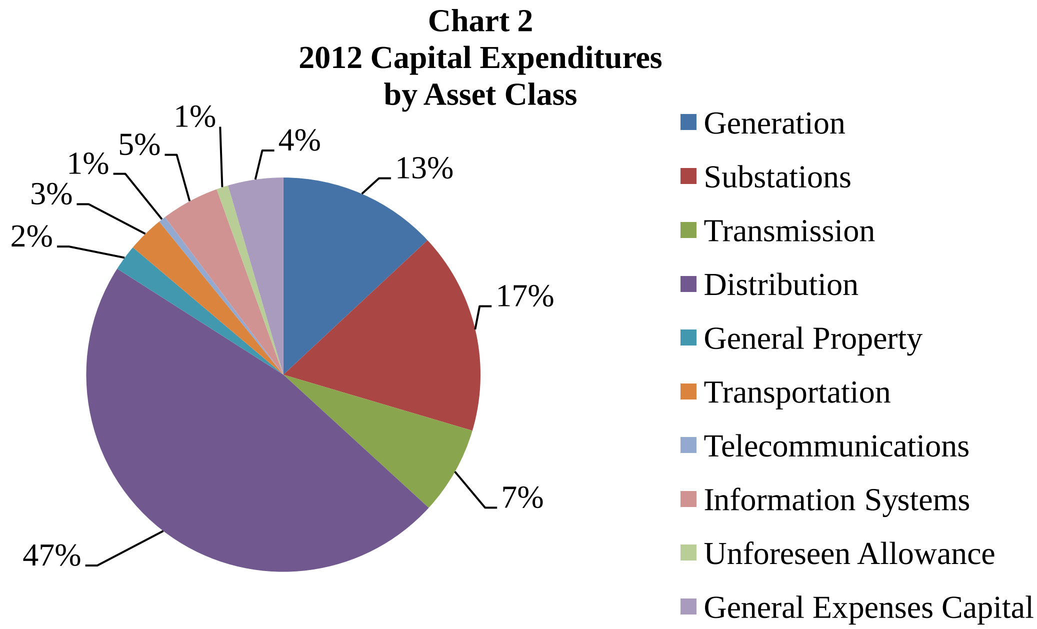
Chart 1 shows the 2012 capital budget by origin, or root cause.

Chart 1
2012 Capital Expenditures
by Origin



Approximately 44% of proposed 2012 capital expenditure is related to the replacement of plant. A further 35% of proposed 2012 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 8% of proposed 2012 capital expenditure associated with System Additions include an additional portable substation and construction of a fish pass at Rattling Brook. The remaining 13% of forecast capital expenditures for 2012 relate to information systems, capitalized general expenses, third party requirements and financial carrying costs (allowance for funds used during construction). The allocation of 2012 capital expenditures is broadly consistent with capital budgets for the past five years.

Chart 2 shows the 2012 capital budget by asset class.



As in past years, Distribution capital expenditure accounts for the greatest percentage of overall expenditure at $36.5 million, or 47% of the 2012 capital budget. Substations capital expenditure accounts for $12.8 million, or 17% of the 2012 capital budget. Generation capital expenditure accounts for $10.1 million, or 13% of the 2012 capital budget. Transmission capital expenditure accounts for $5.6 million, or 7% of the 2012 capital budget. Together, expenditure for these four asset classes comprises 84% of the Company's 2012 capital budget.

Distribution capital expenditure is primarily driven by customer requests for new connections to the electrical system. Expenditures in 2012 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. Also, the Distribution capital projects that involve the installation of new joint use support structures have been adjusted to reflect that Bell Aliant will assume 40% ownership of joint use support structures in 2011.[2]

In 2012, the Company plans to install a new power transformer at Cobb's Pond substation in Gander and complete preparatory work to install a new power transformer at Glendale substation in Mount Pearl in 2013. Also in 2012 and 2013, the Company will purchase a portable substation.

[2] The Distribution capital projects that involve the installation of new joint use support structures include Extensions, Reconstruction, Rebuild Distribution Lines and Relocate/Replace Distribution Lines for Third Parties.

Changes in the regulation of polychlorinated biphenyls ("PCB") by the Government of Canada have effectively accelerated the removal of PCBs from bushings and instrument transformers. In February 2010 Newfoundland Power was granted an extension of the December 31, 2009 end-of-use date for equipment and liquids containing PCB to December 31, 2014. The change in regulations has resulted in a forecast capital expenditure of $1.4 million in 2011 and an additional $13.5 million in expenditures in the forecast period.

Transmission lines proposed for rebuild in 2012 include 110L (built in 1958) serving the Bonavista Peninsula and 124L (built in 1964) between Clarenville and Gambo substations in Central Newfoundland and one Southern Shore transmission line, 21L (built in 1952).

In 2012, the Company plans to upgrade the governor, switchgear, protection and control systems at the Lockston hydroelectric plant. The project to provide fish passage at the Rattling Brook development will also proceed in 2012.

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 2012 Capital Budget Application complies with the CBA Guidelines.

The 2012 Capital Budget Application includes 37 projects, as detailed in *Schedule A*. Included in *Schedule B* is a summary of these projects organized by definition, classification, and segmentation by materiality.

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

2012 Capital Projects by Definition
Table 1 summarizes Newfoundland Power's proposed 2012 capital projects by definition as set out in the CBA Guidelines.

Table 1
2012 Capital Projects
By Definition

Definition	**Number of Projects**	**Budget (000s)**
Pooled	29	$63,118
Clustered	2	3,651
Other	6	10,524
Total	**37**	**$77,293**

There are a total of 31 *pooled* or *clustered* projects accounting for 86% of total expenditures.

2012 Capital Projects by Classification

Table 2 summarizes Newfoundland Power's proposed 2012 capital projects by classification as set out in the CBA Guidelines.

Table 2
2012 Capital Projects
By Classification

Classification	**Number of Projects**	**Budget (000s)**
Mandatory	2	$6,500
Normal	31	68,477
Justifiable	4	2,316
Total	**37**	**$77,293**

There are 31 *normal* projects accounting for 89% of total expenditures.

2012 Capital Projects Costing

Table 3 summarizes Newfoundland Power's proposed 2012 capital projects by costing method (i.e., identified need vs. historical pattern) as set out in the CBA Guidelines.

Table 3
2012 Capital Projects
By Costing Method

Method	**Number of Projects**	**Budget (000s)**
Identified Need	22	$38,902
Historical Pattern	15	38,391
Total	**37**	**$77,293**

Projects with costing method based on *identified need* account for 50% of total expenditures, while those based on *historical pattern* also account for 50% of total expenditures.

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2012 Capital Projects Materiality

Table 4 segments Newfoundland Power's proposed 2012 capital projects by materiality as set out in the CBA Guidelines.

Table 4
2012 Capital Projects
Segmentation by Materiality

Segment	**Number of Projects**	**Budget (000s)**
Under $200,000	4	$608
$200,000 - $500,000	7	2,254
Over $500,000	26	74,431
Total	**37**	**$77,293**

There are 26 projects budgeted at over $500,000 accounting for 96% of total expenditures.

3.0 5-Year Outlook

Newfoundland Power's 5-year capital outlook for 2012 through 2016 includes forecast average annual capital expenditure of $83.3 million. Over the five year period 2007 through 2011, the average annual capital expenditure is expected to be $70.2 million.

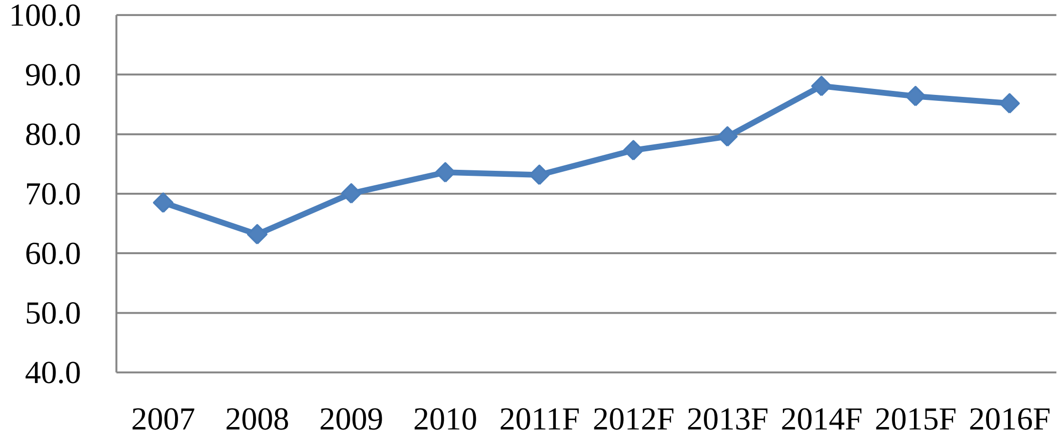
The increase in forecast annual capital expenditure reflects inflation and requirements for specific projects, related to replacement of deteriorated facilities, meeting customer and load growth, maintaining compliance with federal regulations and additional portable substations and generation. Increases are partially offset by lower Distribution costs associated with the sale of support structures to Bell Aliant.

3.1 Capital Expenditures: 2007 - 2016

The Company plans to invest $417 million in plant and equipment during the 2012 through 2016 period. On an annual basis, capital expenditures are expected to average approximately $83.3 million and range from a low of $77.3 million in 2012 to a high of $88.1 million in 2014.

Chart 3 shows actual capital expenditures for the period 2007 through 2010 and forecast capital expenditures for the period 2011 through 2016.

Chart 3
Capital Expenditures
2007 to 2016
($000,000)



Overall planned capital expenditures for the 5-year period from 2012 through 2016 are expected to be greater than those in the 5-year period from 2007 through 2011. This is principally the result of inflation. The composition of annual capital expenditures is changing somewhat, reflecting forecast requirements for additional power transformers due to load growth, the phase out of PCB equipment, the fish pass at Rattling Brook, the replacement penstock for Pierre's Brook plant, 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 51% of total expenditure for the 10-year period from 2007 through 2016.

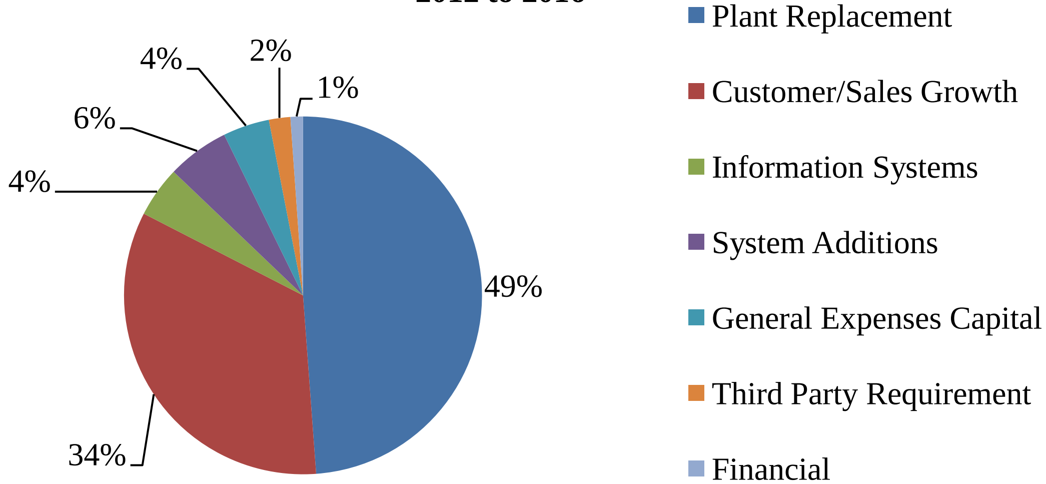
Capital expenditures to meet increased customer connections and electricity sales over the same 10-year period account for approximately 33% of total expenditure.

3.2 2012 – 2016 Capital Expenditures

3.2.1 Overview

Chart 4 shows aggregate forecast capital expenditures by origin for the period 2012 through 2016.

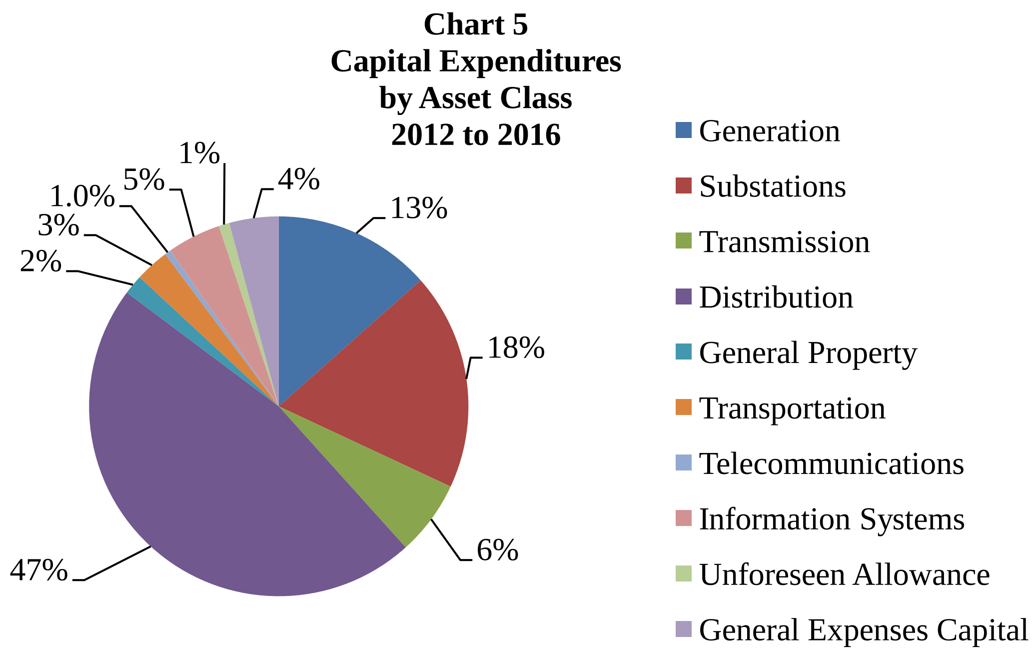
Chart 4
Capital Expenditures
by Origin
2012 to 2016



Plant replacement accounts for 49% of all planned expenditures over the 5-year period from 2012 through 2016. Capital expenditure related to customer and sales growth accounts for 34% of planned expenditures for this period. This is consistent with the average of 33% in the previous 5-year period from 2007 through 2011.

The remaining 17% of total capital expenditures for the 2012 through 2016 period relate to a variety of origins including information systems, system additions, third party requirements and financial costs.

Chart 5 shows aggregate forecast capital expenditures for the period 2012 through 2016 by asset class.



The Distribution asset class accounts for 47% of all planned expenditures over the next five years, followed by Substations (18%), Generation (13%) and Transmission (6%). The remaining six asset classes account for 16% of total capital expenditures for the 2012 through 2016 period.

Overall, planned expenditures for the period 2012 through 2016 are expected to remain relatively stable in all asset classes with the exception of generation and substations which vary annually due to refurbishment and system load growth requirements, and the addition of portable substations and generation over the forecast period.

A summary of planned capital expenditures by asset class and by project for 2012 to 2016 is provided in Appendix A.

3.2.2 Generation

Generation capital expenditures will average approximately $11.2 million per year from 2012 through 2016, which is greater than the annual average of $9.1 million from 2007 through 2011. The increase is attributable to the $12.6 million estimate for the Pierre's Brook Penstock, the $9.0 million estimate for a new portable generator and the $5.0 million estimate for the Rattling Brook fish pass.

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 2012 the Company plans to upgrade the 55 year old governors, switchgear, protection and control systems at the Lockston hydroelectric plant at an estimated cost of $3.5 million as described in ***1.3*** *Lockston Hydro Plant Refurbishment*.

- In 2012, the Company plans to construct fish pass structures downstream from the Rattling Brook spillway at an estimated cost of $5.0 million as described in ***1.2*** *Rattling Brook Fisheries Compensation*. This project is required to satisfy a directive from the Government of Canada.

- In 2013 the Company plans refurbish the 61 year old Mobile hydroelectric plant at an estimated cost of $2.6 million.[3]

- In 2013, the Company plans to rewind the generator of the 54 year old New Chelsea hydroelectric plant at an estimated cost of $1.0 million.

- In 2014, the Company plans to replace the Pierre's Brook hydroelectric plant penstock at an estimated cost of $12.6 million. The existing penstock was installed in 1965.

- In 2014 and 2015, the Company plans to refurbish the governor, protection and control systems and replace the Heart's Content hydroelectric plant penstock at an estimated cost of $5.8 million. The existing penstock was installed in 1965.

- In 2015 and 2016, the Company plans to purchase a 5 MW mobile generator at an estimated cost of $9.0 million. The mobile generator will be used for both emergency generation and to minimize customer outages during planned work.

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

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

3.2.3 Transmission

Transmission capital expenditures are expected to average $5.3 million annually from 2012 through 2016 compared with $4.5 million annually from 2007 through 2011.

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. An update of the strategic plan is included in report *3.1 Transmission Line Rebuild Strategy*.

3.2.4 Substations

Substations capital expenditures are expected to average $15.4 million annually from 2012 through 2016, a material increase from the average of $8.0 million annually from 2007 through 2011. The increase in expenditure is largely attributable to the requirement for additional system capacity to serve increased customer load, compliance with revised PCB regulations, and the purchase of a portable substation.

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

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

The company has a preventive capital maintenance program in place for its substation assets. Preventive maintenance is expected to counter the continuous aging of substation assets such that the overall reliability of substation assets remains stable.

In its 2007 Capital Budget Application, the Company submitted its 10-year substation strategy in a report titled *Substation Strategic Plan*. The 2007 plan addressed substation refurbishment and modernization work in 80% of the Company's substations in an orderly way over a 10-year planning horizon. This is consistent with the maintenance of reasonable year to year stability in the Company's annual capital budgets. Since 2007, work performed as part of the Substation Refurbishment and Modernization capital project has broadly reflected this approach. An update of the strategic plan is included in report ***2.1*** *2012 Substation Refurbishment and Modernization*.

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

Over the 2012 to 2016 forecast period there is a requirement to purchase 8 large power transformers to accommodate load growth.[4] In 2012, a new power transformer is required at Cobbs Pond substation due to the customer and load growth experienced in Gander over the past decade.[5] Commencing in 2013 and continuing through 2016, new substation transformers will be required for Mount Pearl, Paradise, St. John's west, St. John's east, Bay Roberts, Grand Falls and Clarenville areas.[6]

Regulatory changes by the Government of Canada with respect to the phase out of bushings and instrument transformers containing polychlorinated biphenyls ("PCB") have increased capital expenditures by approximately $13.5 million over the next 5 years.[7] A detailed report on the impact of the change in PCB regulations is included as ***2.3*** *2012 PCB Removal Strategy.*

An additional portable substation is required in 2013, increasing the Company's fleet from 3 units to 4 units. Work on this project will commence in 2012. The additional portable substation will increase availability in the event of an in-service transformer failure and will provide greater flexibility in scheduling planned substation projects.[8] This additional portable substation is estimated to cost approximately $4.5 million over 2 years. Refurbishment of portable substation P4 is also scheduled in 2013.

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4 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.

5 Planning studies for the Gander and St. John's/Mount Pearl areas are included in ***2.2*** *2012 Additions Due To Load Growth* report.

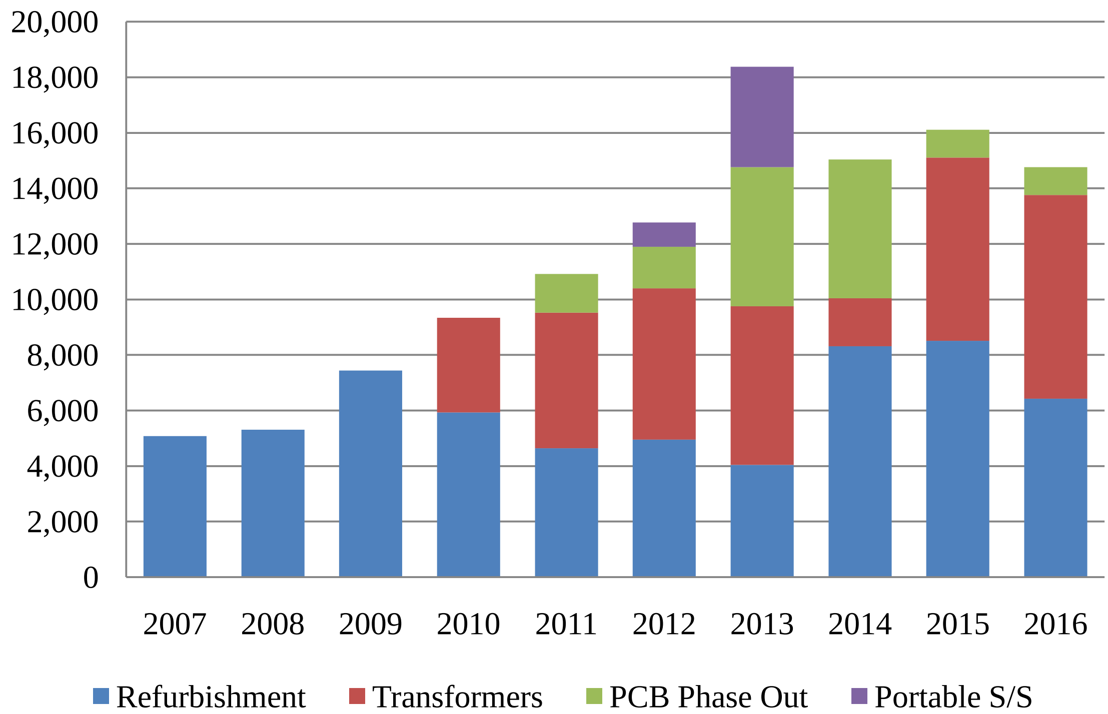
6 The Company's annual Capital Budget Applications will include engineering studies detailing the requirements for additional power transformers in the years in which they are required.

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

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

Chart 6 shows the impact of the required new transformers including a new portable substation and the PCB phase out program on the substations capital plan for the 2012 to 2016 period, as compared to substation capital expenditures from 2007 to 2011.

Chart 6
Substation Capital Plan[9]
2007 to 2016
($000)



As shown in Chart 6, the Company will reduce substation refurbishment expenditures in 2012 and 2013 in order to moderate the overall increase in the substation capital budget. A degree of flexibility is necessarily required for ongoing planning of capital expenditures if a reasonable degree of stability in the Company's annual capital budgets is to be achieved.[10]

3.2.5 Distribution

Distribution capital expenditures from 2012 through 2016 are expected to increase to an average of approximately $39.1 million annually, compared to an average of $36.3 million annually from 2007 through 2011.

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9 2008 excludes expenditures for interconnection of wind turbines ($1.4 million) and conversion of 403L to 66Kv to reduce losses ($0.3 million).

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

The Company operates approximately 8,800 km of distribution lines serving approximately 245,000 customers. Distribution capital expenditures are primarily driven by:

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

Capital expenditures associated with new customer connections are forecast to gradually increase over the planning period. This is primarily due to inflationary increases. The costs to connect new customers to the electricity system are included in several distribution projects including *Extensions*, *Transformers*, *Services*, *Meters* and *Street Lighting*.

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

Table 5
New Customer Connections

	2012	**2013**	**2014**	**2015**	**2016**
New Customer Connections	4,670	4,649	4,879	5,149	5,074
Average Cost/Connection	$4,267	$4,416	$4,545	$4,673	$4,850
Capital Expenditure (000s)	$19,926	$20,529	$22,175	$24,061	$24,611

Over the period 2012 to 2016, 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 9.2%. These combined effects result in an increase to total capital expenditures to connect new customers over the period.

Capital expenditures associated with the installation of joint use support structures are forecast to decrease over the planning period. Bell Aliant will be responsible for a percentage of capital cost included in several distribution projects including *Extensions*, *Reconstruction*, *Rebuild Distribution Lines* and *Relocate/Replace Distribution Lines for Third Parties*.

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.

Capital expenditures associated with the replacement of meters are based upon the historical average expenditures. This forecast may increase over the planning period as the result of changes to compliance sampling regulations for electricity meters. The new regulations came into effect for digital meters in 2011 and will come into effect for electromechanical meters in

2014. In 2014 and beyond it is anticipated that an increase in electromechanical meter replacements will occur under the new regulations. In 2011 the Company will test samples of electromechanical meters to both the old and new standards to better understand the implications for our existing meter inventory, and future capital budget expenditures.

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.

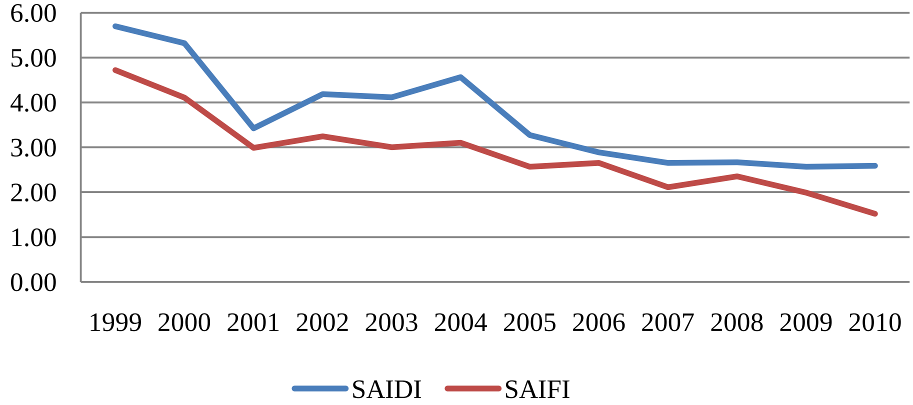
Distribution capital expenditure related to system load growth primarily reflects growth in customer electricity requirements. The majority of this growth continues to be located in the St. John's metropolitan area. This requires the transfer of customer load or the upgrade of feeders to increase capacity. Expenditure for feeder modifications and additions due to system load growth from 2012 through 2016 is expected to remain relatively constant though increased in comparison to the previous five years.

The Company ranks its distribution feeders based on reliability performance and completes in-field assessments of those with the poorest performance statistics. Capital upgrades are performed on the worst performing feeders under a project titled *Distribution Reliability Initiative*. There is no project planned for 2012 based upon the information provided in the report ***4.1*** *Distribution Reliability Initiative*.

Chart 7 shows SAIDI, or system average interruption duration index, and SAIFI, or system average interruption frequency index, for the years 1999 through 2010. Chart 7 has been adjusted to remove the effects of severe weather events.[11]

[11] Adjustments exclude 1999 Burin 2007 and 2010 Bonavista severe weather events. If these severe weather events were included, 1999 SAIDI and SAIFI would be 9.37 and 5.28, respectively; 2007 SAIDI and SAIFI would be 5.94 and 2.46, respectively and 2010 SAIDI and SAIFI would be 13.82 and 2.69 respectively.

Chart 7
SAIDI and SAIFI
1999 - 2010



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

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 2012 capital budget includes renovations to the Company's Kenmount Road office building and parking lot, renovations and roof replacement at the Equipment Maintenance Centre on Topsail Road and replacement of the emergency standby generator at the System Control Centre.

General Property capital expenditures are expected to average $1.4 million annually from 2012 through 2016 which is the same as the average of $1.4 million annually from 2007 through 2011.

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 2012 through 2016 which is slightly more than the annual average of $2.2 million from 2007 through 2011.

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 $0.4 million annually from 2012 through 2016 which is the similar to the annual average of $0.3 million annually from 2007 through 2011.

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 2012 through 2016 compared to an average of $3.6 million annually from 2007 through 2011.

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 2012 through 2016.

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 $3.5 million is reflected in each year's capital budget from 2012 through 2016.

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 2012 through 2016.

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 change in future years to reflect new compliance sampling regulations for electromechanical meters coming into effect in 2014. Commencing in 2011 the Company will test electromechanical meters to the existing and new compliance sampling standards to better understand implications for forecast expenditures over the period 2012 through 2016.

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 and its refurbishment was approved in Board Order No. P.U. 29 (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. In September 2010 Hurricane Igor caused extensive damage to the Company's generation and distribution assets. The occurrence and costs of severe storms are not predictable.

Appendix A

2012 – 2016 Capital Plan

Newfoundland Power Inc.
2012-2016 Capital Plan
(000s)

Asset Class	2012	2013	2014	2015	2016
Generation	$10,089	$7,217	$17,100	$11,560	$10,053
Substations	12,776	18,380	15,039	16,114	14,761
Transmission	5,577	5,368	4,776	5,156	5,710
Distribution	36,510	36,218	39,072	41,461	42,087
General Property	1,651	1,342	1,407	1,225	1,339
Transportation	2,306	2,358	2,411	2,465	2,519
Telecommunications	454	653	156	316	582
Information Systems	3,680	3,825	3,875	3,850	3,875
Unforeseen Allowance	750	750	750	750	750
General Expenses Capitalized	3,500	3,500	3,500	3,500	3,500
Total	**$77,293**	**$79,611**	**$88,086**	**$86,397**	**$85,176**

Newfoundland Power Inc.
2012-2016 Capital Plan
(000s)

GENERATION

Project	**2012**	**2013**	**2014**	**2015**	**2016**
Facility Rehabilitation – Hydro	$1,362	$1,350	$1,400	1,400	1,450
Facility Rehabilitation - Thermal	156	284	312	290	168
Hydro Plant Production Increase	120	1,693	775	1,450	800
Lockston Plant Refurbishment	3,451	0	0	0	0
Rattling Brook – Fish Passage	5,000	$0	0	0	0
Mobile Plant Refurbishment	0	2,635	0	0	0
New Chelsea Turbine Overhaul & Rewind	0	1,047	0	0	0
Pierre's Brook Penstock	0	200	12,600	0	1,040
Tors Cove Runners and Wicket Gates	0	8	573	575	545
Hearts Content Plant Refurbishment	0	0	1,440	4,345	0
Purchase Portable Generation	0	0	0	3,500	5,500
Morris Plant Refurbishment	0	0	0	0	550
Total - Generation	**$10,089**	**$7,217**	**$17,100**	**$11,560**	**$10,053**

Newfoundland Power Inc.
2012-2016 Capital Plan
(000s)

SUBSTATIONS

Project	2012	2013	2014	2015	2016
Substations Refurbishment & Modernization	$2,482	$1,712	$5,926	$6,070	$3,923
Replacements Due to In-Service Failure	2,276	2,333	2,391	2,444	2,505
Additions Due to Load Growth	5,439	5,714	1,722	6,600	7,333
PCB Bushing Phase Out	1,500	5,000	5,000	1,000	1,000
Purchase portable Substation P5	879	3,621	0	0	0
Lockston Plant Refurbishment	200	0	0	0	0
Total – Substations	**$12,776**	**$18,380**	**$15,039**	**$16,114**	**$14,761**

Newfoundland Power Inc.
2012-2016 Capital Plan
(000s)

TRANSMISSION

Project	**2012**	**2013**	**2014**	**2015**	**2016**
Rebuild Transmission Lines	$3,477	$3,218	$2,576	$3,706	$4,260
Transmission Line Reconstruction	2,100	2,150	2,200	1,450	1,450
Total – Transmission	**$5,577**	**$5,368**	**$4,776**	**$5,156**	**$5,710**

Newfoundland Power Inc.
2012-2016 Capital Plan
(000s)

DISTRIBUTION

Project	2012	2013	2014	2015	2016
Extensions	$10,326	$10,694	$11,803	$13,092	$13,375
Meters	1,884	1,929	1,976	2,024	2,071
Services	3,351	3,453	3,721	4,029	4,115
Street Lighting	2,115	2,172	2,306	2,457	2,506
Transformers	7,944	8,119	8,298	8,480	8,658
Reconstruction	2,861	3,398	3,608	3,731	3,858
Rebuild Distribution Lines	3,403	3,505	3,612	3,717	3,826
Relocations For Third Parties	2,205	1,383	1,438	1,494	1,553
Distribution Reliability Initiative	0	500	515	530	546
Feeder Additions for Load Growth	1,391	451	0	0	495
Trunk Feeders	848	428	1,605	1,712	885
Allowance for Funds Used During Construction	182	186	190	195	199
Total – Distribution	**$36,510**	**$36,218**	**$39,072**	**$41,461**	**$42,087**

Newfoundland Power Inc.
2012-2016 Capital Plan
(000s)

GENERAL PROPERTY

Project	**2012**	**2013**	**2014**	**2015**	**2016**
Tools and Equipment	$457	$414	$422	$429	$437
Additions to Real Property	234	238	243	247	250
Renovations Company Buildings	685	690	742	199	477
Standby Generators	275	0	0	350	175
Total – General Property	**$1,651**	**$1,342**	**$1,407**	**$1,225**	**$1,339**

Newfoundland Power Inc.
2012-2016 Capital Plan
(000s)

TRANSPORTATION

Project	2012	2013	2014	2015	2016
Purchase Vehicles and Aerial Devices	$2,306	$2,358	$2,411	$2,465	$2,519
Total – Transportation	**$2,306**	**$2,358**	**$2,411**	**$2,465**	**$2,519**

Newfoundland Power Inc.
2012-2016 Capital Plan
(000s)

TELECOMMUNICATIONS

Project	**2012**	**2013**	**2014**	**2015**	**2016**
Replace/Upgrade Communications Equipment	$150	$153	$156	$159	$162
Fibre Optic Cable	304	0	0	157	420
Replace/Upgrade Mobile Radios	0	500	0	0	0
Total – Telecommunications	**$454**	**$653**	**$156**	**$316**	**$582**

Newfoundland Power Inc.
2012-2016 Capital Plan
(000s)

INFORMATION SYSTEMS

Project	2012	2013	2014	2015	2016
Application Enhancements	$1,013	$950	$1,200	$1,275	$1,300
System Upgrades	1,276	1,500	1,300	1,200	1,200
Personal Computer Infrastructure	390	375	375	375	375
Shared Server Infrastructure	607	900	900	900	900
Network Infrastructure	394	100	100	100	100
Total – Information Systems	**$3,680**	**$3,825**	**$3,875**	**$3,850**	**$3,875**

Newfoundland Power Inc.
2012-2016 Capital Plan
(000s)

UNFORESEEN ALLOWANCE

Project	2012	2013	2014	2015	2016
Allowance for Unforeseen	$750	$750	$750	$750	$750
Total – Unforeseen Allowance	**$750**	**$750**	**$750**	**$750**	**$750**

Newfoundland Power Inc.
2012-2016 Capital Plan
(000s)

GENERAL EXPENSES CAPITALIZED

Project	**2012**	**2013**	**2014**	**2015**	**2016**
General Expenses Capitalized	\$3,500	\$3,500	\$3,500	\$3,500	\$3,500
Total – General Expenses Capitalized	**\$3,500**	**\$3,500**	**\$3,500**	**\$3,500**	**\$3,500**

2011 Capital Expenditure Status Report

June 2011

NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

2011 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. 28 (2010).

Page 1 of the 2011 Capital Expenditure Status Report outlines the forecast variances from budget of the capital expenditures approved by the Board in Order Nos. P.U. 28 (2010) and P.U. 11 (2011). The detailed tables on pages 2 to 13 provide additional detail on capital expenditures in 2011, and also include information on those capital projects approved for 2010 that were not completed prior to 2011.

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 2011 Capital Expenditure Status Report.

Newfoundland Power Inc.

2011 Capital Budget Variances
(000s)

	Approved by Order Nos. P.U.28 (2010) P.U.11 (2011)	Forecast	Variance
Generation – Hydro[1]	$9,496	$9,336	($ 160)
Generation - Thermal	268	268	-
Substations	11,647	9,858	(1,789)
Transmission	4,745	4,002	(743)
Distribution	36,842	37,597	755
General Property	1,792	1,899	107
Transportation	2,254	2,254	-
Telecommunications	572	472	(100)
Information Systems	3,603	3,532	(71)
Unforeseen Items	750	750	-
General Expenses Capitalized	2,800	3,350	550
Total	$74,769	$73,318	($1,451)
Projects carried forward from 2010		$2,390	

Notes:

1 Includes $1,800,000 in estimated cost associated with Hurricane Igor approved in Order No. P.U. 11 (2011).

2011 Capital Expenditure Status Report
(000s)

	Capital Budget			Actual Expenditures			Forecast			
	2010	2011	Total	2010	2011	Total To Date	Remainder 2011	Total 2011	Overall Total	Variance
	A	B	C	D	E	F	G	H	I	J
2011 Projects	$ -	$ 74,769	$ 74,769	$ -	$ 22,674	$ 22,674	$ 50,644	$ 73,318	$ 73,318	$ (1,451)
2010 Projects	9,958	-	$ 9,958	6,340	-	6,340	2,390	2,390	8,730	(1,228)
Grand Total	**$ 9,958**	**$ 74,769**	**$ 84,727**	**$ 6,340**	**$ 22,674**	**$ 29,014**	**$ 53,034**	**$ 75,708**	**$ 82,048**	**$ (2,679)**

Column A	Approved Capital Budget for 2010
Column B	Approved Capital Budget for 2011
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2010
Column E	Actual Capital Expenditures for 2011
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2011
Column H	Total of Columns E and G
Column I	Total of Columns D and H
Column J	Column I less Column C

2011 Capital Expenditure Status Report
(000s)

Category: Generation - Hydro

Project	Capital Budget 2011 (A)	Capital Budget Total (B)	Actual Expenditures 2011 (C)	Actual Expenditures Total To Date (D)	Forecast Remainder 2011 (E)	Forecast Total 2011 (F)	Forecast Overall Total (G)	Variance (H)	Notes*
2011 Projects									
Hydro Plants - Facility Rehabilitation	$ 1,610	$ 1,610	$ 185	$ 185	$ 1,265	$ 1,450	$ 1,450	$ (160)	
Horse Chops Rewind and Rotor Re-Insulation	1,276	1,276	24	24	1,252	$ 1,276	1,276	-	
Rattling Brook Dam Refurbishnment	2,600	2,600	169	169	2,431	$ 2,600	2,600	-	
Hydro Plant Production Increase	650	650	34	34	616	$ 650	650	-	
Sandy Brook Plant Refurbishment	1,560	1,560	336	336	1,224	$ 1,560	1,560	-	
Port Union Plant Refurbishment	1,350	1,350	279	279	1,071	$ 1,350	1,350	-	
Lawn Plant Refurbishment	450	450	16	16	434	$ 450	450	-	
Total - Generation Hydro	**$ 9,496**	**$ 9,496**	**$ 1,043**	**$ 1,043**	**$ 8,293**	**$ 9,336**	**$ 9,336**	**$ (160)**	

* See Appendix A for notes containing variance explanations.

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

2011 Capital Expenditure Status Report
(000s)

Category: Generation - Thermal

Project	Capital Budget 2011 (A)	Capital Budget Total (B)	Actual Expenditures 2011 (C)	Actual Expenditures Total To Date (D)	Forecast Remainder 2011 (E)	Forecast Total 2011 (F)	Forecast Overall Total (G)	Variance (H)	Notes*
2011 Projects									
Thermal Plants - Facility Rehabilitation	$ 268	$ 268	$ 17	$ 17	$ 251	$ 268	$ 268	$ -	
Total - Generation Thermal	**$ 268**	**$ 268**	**$ 17**	**$ 17**	**$ 251**	**$ 268**	**$ 268**	**$ -**	

* See Appendix A for notes containing variance explanations.

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

2011 Capital Expenditure Status Report
(000s)

Category: Substations

Project	Capital Budget 2010 (A)	Capital Budget 2011 (B)	Capital Budget Total (C)	Actual Expenditures 2010 (D)	Actual Expenditures 2011 (E)	Actual Expenditures Total To Date (F)	Forecast Remainder 2011 (G)	Forecast Total 2011 (H)	Forecast Overall Total (I)	Variance (J)	Notes*
2011 Projects											
Substation Refurbishment and Modernization	$ -	$ 3,074	$ 3,074	$ -	$ 620	$ 620	$ 746	$ 1,366	$ 1,366	$ (1,708)	1
Replacement Due to In-Service Failures	-	2,221	2,221	-	1,456	1,456	$ 765	$ 2,221	$ 2,221	-	
Additions Due to Load Growth	-	4,852	4,852	-	1,178	1,178	$ 3,693	$ 4,871	$ 4,871	19	
PCB Bushing Phase-out	-	1,500	1,500	-	230	230	$ 1,170	$ 1,400	$ 1,400	(100)	
Total 2011 Substations	-	11,647	11,647	-	3,484	3,484	6,374	9,858	9,858	(1,789)	
2010 Projects											
Substation Refurbishment and Modernization	$ 4,043	$ -	$ 4,043	$ 3,201	$ -	$ 3,201	1,060	$ 1,060	$ 4,261	$ 218	
Total - Substations	**$ 4,043**	**$ 11,647**	**$ 15,690**	**$ 3,201**	**$ 3,484**	**$ 6,685**	**$ 7,434**	**$ 10,918**	**$ 14,119**	**$ (1,571)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2010
Column B	Approved Capital Budget for 2011
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2010
Column E	Actual Capital Expenditures for 2011
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2011
Column H	Total of Columns E and G
Column I	Total of Columns D and H
Column J	Column I less Column C

2011 Capital Expenditure Status Report
(000s)

Category: Transmission

Project	Capital Budget 2010 A	Capital Budget 2011 B	Capital Budget Total C	Actual Expenditures 2010 D	Actual Expenditures 2011 E	Actual Expenditures Total To Date F	Forecast Remainder 2011 G	Forecast Total 2011 H	Forecast Overall Total I	Variance J	Notes*
2011 Projects											
Rebuild Transmission Lines	$ -	$ 4,745	$ 4,745	$ -	$ 912	$ 912	$ 3,090	$ 4,002	$ 4,002	$ (743)	2
Total 2011 Transmission	-	4,745	4,745	-	912	912	3,090	4,002	4,002	(743)	
2010 Projects											
Rebuild Transmission Lines	$ 5,915	$ -	$ 5,915	$ 3,139	$ -	$ 3,139	1,330	$ 1,330	$ 4,469	$ (1,446)	3
Total - Transmission	**$ 5,915**	**$ 4,745**	**$ 10,660**	**$ 3,139**	**$ 912**	**$ 4,051**	**$ 4,420**	**$ 5,332**	**$ 8,471**	**$ (2,189)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2010
Column B	Approved Capital Budget for 2011
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2010
Column E	Actual Capital Expenditures for 2011
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2011
Column H	Total of Columns E and G
Column I	Total of Columns D and H
Column J	Column I less Column C

2011 Capital Expenditure Status Report
(000s)

Category: Distribution

	Capital Budget		Actual Expenditures		Forecast				
Project	**2011**	**Total**	**2011**	**Total To Date**	**Remainder 2011**	**Total 2011**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2011 Projects									
Extensions	$ 11,568	$ 11,568	$ 4,081	$ 4,081	$ 7,569	$ 11,650	$ 11,650	$ 82	
Meters	1,810	$ 1,810	669	669	1,137	$ 1,806	$ 1,806	(4)	
Services	3,073	$ 3,073	1,633	$ 1,633	1,791	$ 3,424	$ 3,424	351	4
Street Lighting	2,195	$ 2,195	855	$ 855	1,424	$ 2,279	$ 2,279	84	
Transformers	7,999	$ 7,999	2,521	$ 2,521	5,278	$ 7,799	$ 7,799	(200)	
Reconstruction	3,609	$ 3,609	1,418	$ 1,418	1,591	$ 3,009	$ 3,009	(600)	5
Rebuild Distribution Lines	3,088	$ 3,088	405	$ 405	2,483	$ 2,888	$ 2,888	(200)	
Relocate/Replace Distribution Lines For Third Parties	782	$ 782	851	$ 851	1,259	$ 2,110	$ 2,110	1,328	6
Distribution Reliability Initiative	521	$ 521	26	$ 26	320	$ 346	$ 346	(175)	7
St. John's Trunk Feeders	160	$ 160	144	$ 144	5	$ 149	$ 149	(11)	
Feeder Additions for Growth	1,281	$ 1,281	81	$ 81	1,300	$ 1,381	$ 1,381	100	
Replace Mercury Vapour Street Lights	581	$ 581	205	$ 205	376	$ 581	$ 581	-	
Allowance for Funds Used During Construction	175	$ 175	73	$ 73	102	$ 175	$ 175	-	
Total - Distribution	**$ 36,842**	**$ 36,842**	**$ 12,962**	**$ 12,962**	**$ 24,635**	**$ 37,597**	**$ 37,597**	**$ 755**	

* See Appendix A for notes containing variance explanations.

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

2011 Capital Expenditure Status Report
(000s)

Category: General Property

Project	Capital Budget 2011	Capital Budget Total	Actual Expenditures 2011	Actual Expenditures Total To Date	Forecast Remainder 2011	Forecast Total 2011	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2011 Projects									
Tools and Equipment	$ 508	$ 508	$ 130	130	$ 398	$ 528	$ 528	$ 20	
Additions to Real Property	224	224	87	87	217	$ 304	304	80	
Kenmount Road 2nd floor HVAC	435	435	8	8	427	$ 435	435	-	
Kenmount Road Building Flooring Replacement	150	150	20	20	90	$ 110	110	(40)	
Kenmount Road Building Entrance Renovation	125	125	4	4	198	$ 202	202	77	
Purchase Bill Inserter for Production Centre	350	350	312	312	8	$ 320	320	(30)	
Total - General Property	**$ 1,792**	**$ 1,792**	**$ 561**	**$ 561**	**$ 1,338**	**$ 1,899**	**$ 1,899**	**$ 107**	

* See Appendix A for notes containing variance explanations.

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

2011 Capital Expenditure Status Report
(000s)

Category: Transportation

	Capital Budget		Actual Expenditures		Forecast				
	2011	Total	2011	Total To Date	Remainder 2011	Total 2011	Overall Total	Variance	Notes*
Project	A	B	C	D	E	F	G	H	
2011 Projects									
Purchase Vehicles and Aerial Devices	$ 2,254	$ 2,254	$ 734	$ 734	$ 1,520	$ 2,254	$ 2,254	$ -	
Total - Transportation	**$ 2,254**	**$ 2,254**	**$ 734**	**$ 734**	**$ 1,520**	**$ 2,254**	**$ 2,254**	**$ -**	

* See Appendix A for notes containing variance explanations.

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

2011 Capital Expenditure Status Report
(000s)

Category: Telecommunications

Project	Capital Budget 2011	Capital Budget Total	Actual Expenditures 2011	Actual Expenditures Total To Date	Forecast Remainder 2011	Forecast Total 2011	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2011 Projects									
Replace/Upgrade Communications Equipment	$ 146	$ 146	$ 3	$ 3	$ 143	$ 146	$ 146	$ -	
Fibre Optic Circuit Replacement	426	426	15	15	311	326	326	(100)	8
Total - Telecommunications	**$ 572**	**$ 572**	**$ 18**	**$ 18**	**$ 454**	**$ 472**	**$ 472**	**$ (100)**	

* See Appendix A for notes containing variance explanations.

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

2011 Capital Expenditure Status Report
(000s)

Category: Information Systems

Project	Capital Budget 2011 (A)	Capital Budget Total (B)	Actual Expenditures 2011 (C)	Actual Expenditures Total To Date (D)	Forecast Remainder 2011 (E)	Forecast Total 2011 (F)	Forecast Overall Total (G)	Variance (H)	Notes*
2011 Projects									
Application Enhancements	$ 983	$ 983	$ 474	$ 474	$ 489	$ 963	$ 963	$ (20)	
System Upgrades	808	808	233	233	580	$ 813	813	5	
Personal Computer Infrastructure	390	390	177	177	213	$ 390	390	-	
Shared Server Infrastructure	1,092	1,092	214	214	822	$ 1,036	1,036	(56)	
Network Infrastructure	152	152	37	37	115	$ 152	152	-	
Vehicle Mobile Computing Infrastructure	178	178	136	136	42	$ 178	178	-	
Total - Information Systems	**$ 3,603**	**$ 3,603**	**$ 1,271**	**$ 1,271**	**$ 2,261**	**$ 3,532**	**$ 3,532**	**$ (71)**	

* See Appendix A for notes containing variance explanations.

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

2011 Capital Expenditure Status Report
(000s)

Category: Unforeseen Items

	Capital Budget		Actual Expenditures		Forecast				
Project	**2011**	**Total**	**2011**	**Total To Date**	**Remainder 2011**	**Total 2011**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2011 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 2011
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2011
Column D	Total of Column C
Column E	Forecast for Remainder of 2011
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2011 Capital Expenditure Status Report
(000s)

Category: General Expenses Capitalized

Project	Capital Budget 2011	Capital Budget Total	Actual Expenditures 2011	Actual Expenditures Total To Date	Forecast Remainder 2011	Forecast Total 2011	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2011 Projects									
Allowance for General Expenses Capitalized	$ 2,800	$ 2,800	$ 1,672	$ 1,672	$ 1,678	$ 3,350	$ 3,350	$ 550	9
Total - General Expenses Capitalized	**$ 2,800**	**$ 2,800**	**$ 1,672**	**$ 1,672**	**$ 1,678**	**$ 3,350**	**$ 3,350**	**$ 550**	

* See Appendix A for notes containing variance explanations.

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

Substations

1. Substation Refurbishment and Modernization:
Budget: $3,074,000 Forecast: $1,366,000 Variance: ($1,708,000)

As was indicated in the year-end 2010 Capital Expenditure Status Report, all of the work scheduled under the *2010 Substation Refurbishment and Modernization* capital project did not get completed in 2010. This was principally due to the redeployment of resources to respond to 2 major storms in 2010. The *2011 Substation Refurbishment and Modernization* capital project has been revised to allow for the completion of the outstanding 2010 work in 2011. Substation Refurbishment and Modernization work at Hearts Content and New Grand Falls substations originally approved for 2011 will now be completed as part of the *2012 Substation Refurbishment and Modernization* capital project.

Transmission

2. Transmission: Rebuild Transmission Lines (2011 Project)
Budget: $4,745,000 Forecast: $4,002,000 Variance: ($743,000)

The *2011 Rebuild Transmission Lines* capital project involved planned work on transmission lines 16L, 21L and 25L, along with replacement of poles, crossarms, insulators and miscellaneous hardware due to deficiencies identified during inspections and engineering reviews.

As detailed in item 3 below an estimated $1,330,000 was carried forward from 2010 to 2011. As a result of the work being carried forward, the *2011 Rebuild Transmission Lines* capital project was reviewed.

The worked planned on 21L has been deferred to 2012 resulting in a reduction in expenditure of $822,000.

All transmission lines are inspected annually. The lower priority deficiency work not completed in 2010 will be re-assessed through the 2011 inspections and corrected as required.

3. Transmission: Rebuild Transmission Lines (2010 Project)
Budget: $5,915,000 Forecast: $4,469,000 Variance: ($1,446,000)

The 2010 *Rebuild Transmission Lines* capital project involved planned work on transmission lines 23L, 24L and 110L. As was indicated in the yearend 2010 Capital Expenditure Status Report, all of the work scheduled under the *2010 Rebuild Transmission Lines* capital project did not get completed in 2010. An estimated $1,330,000 of expenditure related to transmission lines 23L and 24L was carried forward into 2011. The *2011 Rebuild Transmission Lines* capital project has been revised to allow for the completion of this work in 2011. This expenditure has been included in the forecast total.

The project variance of $1,446,000 includes approximately $600,000 of work not completed on transmission line 110L in 2010. This work is now included in the *2012 Rebuild Transmission Lines* capital project. The variance amount also includes approximately $700,000 related to deficiency correction work not completed in 2010. All high priority work identified in inspections was completed. However, a portion of the lower priority work identified in those inspections was not completed. This work will be completed in the *2011 Rebuild Transmission Lines* capital project.

Distribution

4. *Services:*
Budget: $3,073,000 Forecast: $3,424,000 Variance: $351,000

The original 2011 capital budget estimate for services was based on 4,625 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 4,894. It is estimated that an additional $151,000 is required to provide service to the 269 additional customers.

The number of replacement services is higher than budgeted. This is principally attributed to replacements required due to pole line upgrades to accommodate third parties. It is estimated that an additional $200,000 is required to accommodate these additional replacement services.

5. *Reconstruction:*
Budget: $3,609,000 Forecast $3,009,000 Variance: ($600,000)

The budget expenditure was based on the average expenditure over the past 5 years. *Reconstruction* consists of miscellaneous high priority projects that require immediate attention. The foreast reduction is reflective of a smaller number of these high priority projects being identified year to date in 2011.

6. *Relocate/Replace Distribution Lines for Third Parties:*
Budget: $782,000 Forecast: $2,110,000 Variance: $1,328,000

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 2011 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 $2,110,000. Contributions in Aid of Construction are expected to recover approximately 50% of the total capital cost of this project.

Distribution

7. Distribution Reliability Initiative:
Budget: $521,000 Forecast: $346,000 Variance: ($175,000)

In 2011 the only feeder included in the *Distribution Reliability Initiative* capital project is NWB-02. The NWB-02 rebuild is a three year project that started in 2009 and will be completed in 2011. The NWB-02 feeder was damaged during Hurricane Igor in September 2010 and some repairs were made at that time. This restoration effort on NWB-02 was originally planned for 2011. The current forcast reflects the revised estimate to complete the work originally planned on the feeder.

Telecommunications

8. Fibre Optic Circuit Replacement:
Budget: $426,000 Forecast: $326,000 Variance: ($100,000)

The Fibre Optic Replacement plan was filed with the 2008 Capital Budget Application. The plan provided for the replacement of 5 leased fibre optic circuits in each of 2010 and 2011. Only 2 of the original 5 fibre optic circuits were actually replaced in 2010. Two of these fibre optic leases were abandoned and not replaced. One fibre optic cable was not replaced in 2010 due to problems securing a satisfactory cable route between substations. At the end of 2010 6 leased fibre optic cables still require replacement. The Company is proposing to replace 3 of the remaining 6 fibre optic cables in 2011, leaving 3 fibre optic cables to be replaced in 2012. The cost of the 2011 cable replacement has been reduced by $100,000.

General Expenses Capitalized

9. *General Expenses Capitalized:*
Budget: $2,800,000 Forecast: $3,350,000 Variance: $550,000

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

2012 Facility Rehabilitation

June 2011

Prepared by:

Gary K. Humby, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
GARY K. HUMBY
SIGNATURE
June 29/2011
DATE
PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

The 2012 Facility Rehabilitation project is necessary for the replacement or rehabilitation of deteriorated plant components that have been identified through routine inspections, operating experience and engineering studies. The project includes expenditures necessary to improve the efficiency and reliability of various hydro plants or to replace plant due to in-service failures.

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

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

The 2012 Facility Rehabilitation project totalling $1,362,000 is comprised of Hydro Dam Rehabilitation and Generation Equipment Replacements Due to In-Service Failures.

2.0 Hydro Dam Rehabilitation

Cost: $784,000

The Company has over 150 dam structures throughout its 23 hydroelectric facilities. Based on the age of structures in the Newfoundland Power system, deterioration of embankment, timber crib, and concrete dams and appurtenant structures 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 2012 includes:

1. *Port Union Long Pond Spillway. ($212,000)*
   This project involves the replacement of the existing rock filled timber crib dam and outlet structure with a new concrete/rock filled dam and concrete outlet structure. Dam safety inspections indicate the existing dam and outlet has deteriorated with water infiltrating through the structure. Remedial work was completed during October 2008 and January 2010 as temporary measures to stabilize the surface of the structure. In September 2010, heavy rains from Hurricane Igor, as shown in Figure 1, caused severe erosion in the right abutment. Earth fill and riprap, in the eroded area,

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

were replaced in November 2010. The internal timbers and structural members, however, were not replaced during the 2008 and 2010 remediation work. As illustrated in Figures 2 and 3, these have now deteriorated to the point that replacement of the dam and outlet is required to maintain the integrity of the structure.

Figure 1 - Long Pond Dam (Hurricane Igor)

Figure 2 - Long Pond Dam (Deteriorated Decking)

Figure 3 - Long Pond Dam (Deteriorated Outlet and Cribbing)

2. *Tors Cove Forebay Spillway Rehabilitation ($191,000)*
   This project involves replacement of the existing stoplog spillway, shown in Figures 4 and 5, with a new concrete structure. Stability analysis indicates that the spillway does not meet requirements for overturning and the structure lacks available freeboard with the stoplogs in place. Accessing the structure to remove stoplogs during flood conditions is difficult, and presents a safety hazard for power plant operators. Replacing the stoplog spillway will address dam safety deficiencies and remove a significant safety hazard.

Figure 4 - Tors Cove Spillway (Upstream)

Figure 5 - Tors Cove Spillway (Downstream)

3. *Paddy's Pond Dam and Spillway ($381,000)*
   This project involves the replacement of the existing timber crib dam and spillway with a new embankment dam and rock filled overflow metal cut-off wall structure. The existing structure has deteriorated, timbers are rotted, the upstream face is misaligned and the spillway decking is in very poor condition as illustrated in Figures 6 and 7. Recent visual inspection also shows signs of seepage and water overtopping the dam, as shown in Figure 8. Recent dam safety review indicates that this structure has insufficient freeboard. Replacement of the structure is required to address all these issues.


Figure 6 - Misaligned Timber Facing with Ice Damage


Figure 7 - Delaminating Spillway Decking


Figure 8 - Deteriorated Timbers with Erosion of Rockfill from Overtopping

3.0 Generation Equipment Replacements Due to In-Service Failures

Cost: $578,000

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

This item involves the refurbishment or replacement of structures and equipment due to damage, deterioration, corrosion, technical obsolescence and in-service failure. This equipment is critical to the safe and reliable operation of generating facilities and must be replaced in a timely manner. Equipment replaced under this item includes civil infrastructure, instrumentation, mechanical, electrical, and protection and controls equipment.

Replacements under this item are typically due to one of two reasons:

1. Emergency replacements – where components fail and require immediate replacement to return a unit to service; or

2. Observed deficiencies – where components are identified for replacement due to imminent failure or for safety or environmental reasons.

Table 1 shows the expenditures for replacements due to in-service failures since 2007.

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

Year	**2007**	**2008**	**2009**	**2010**	**2011F**
Total	$409	$679	$475	$569[2]	$535

Based upon this recent historical information and engineering judgement, $578,000 is estimated to be required in 2012 for replacement of equipment due to in-service failures or equipment at risk of imminent failure.

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

[2] Excludes Hurricane Igor related costs from 2010.

4.0 Concluding

This project, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable generating plant operations. A 2012 budget of $1,362,000 for Facility Rehabilitation is recommended as follows:

- $784,000 for Hydro Dam Rehabilitation;
- $578,000 for Generation Equipment Replacements Due to In-Service Failures;

Rattling Brook Fisheries Compensation

June 2011

Prepared by:

David Ball, B.Eng.

Approved by:

Gary K. Humby, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
GARY K. HUMBY
SIGNATURE
June 29/2011
DATE
PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
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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 community of Norris Arm. The development was placed into service in December 1958 and has provided 53 years of reliable energy production. The normal annual plant production is approximately 78.3 GWh of energy, or about 18.2% of Newfoundland Power's total hydroelectric production.

Prior to the construction of the hydro plant in 1958, Rattling Brook was a well known salmon river in central Newfoundland. Records indicate that annual salmon returns for the period from 1956 to 1958 were in the range of 600 to 820 adult salmon per year. Over the period from 1957 to 1963 about 3,000 adult salmon were captured at Rattling Brook and transferred to Great Rattling Brook, a tributary of the Exploits River.[1]

In 2007, upgrades were completed at Rattling Brook, which included the replacement of the woodstave penstock, refurbishment of the surge tank, and upgrades and replacement of the electrical and mechanical systems in the plant. Upgrades in 2007 resulted in an additional 8.9 GWh/yr. Work is ongoing in 2011 to replace the Rattling Lake Spillway and refurbish the surrounding dams.

In 2005, Newfoundland Power was contacted by the Department of Fisheries and Oceans ("DFO") on a requirement to reintroduce salmon into Rattling Brook and its tributaries. Newfoundland Power has been engaged with DFO since 2005 and a technical working group was formed in May 2008 to determine if a practical and cost effective solution existed for re-establishing fish passage in Rattling Brook. The results of the technical working group are contained in two separate reports produced in December 2009, one by Newfoundland Power[2] and one by the DFO[3].

In 2010 an order was received from DFO indicating that pursuant to section 20 of the Fisheries Act, fish passage must be in place to allow the downstream migration of salmon kelts and smolts by May 1, 2013 and the upstream migration of grilse and adult salmon by June 10, 2014.[4] To meet these timelines, construction of these facilities will be required during the 2012 construction season.

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.

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1. Fishway and Counting Fence Data-1975 and 1976, R.B. Moores, Fisheries and Marine Service, Department of Fisheries and the Environment, May 1978.
2. *A Report on the Preliminary Engineering Assessment of a Proposal to Reintroduce Salmon into Rattling Brook*, prepared by Newfoundland Power, December 2009, included as Appendix B of this document.
3. *An Assessment of the Potential Re-introduction of Atlantic Salmon into Rattling Brook*, prepared by the Department of Fisheries and Oceans, December 2009 included as Appendix C of this document.
4. Appendix A contains the letter from Mr. R. D. Finn, Regional Director with the Department of Fisheries and Oceans ordering Newfoundland Power to provide a fish pass around the Rattling Brook hydro plant.

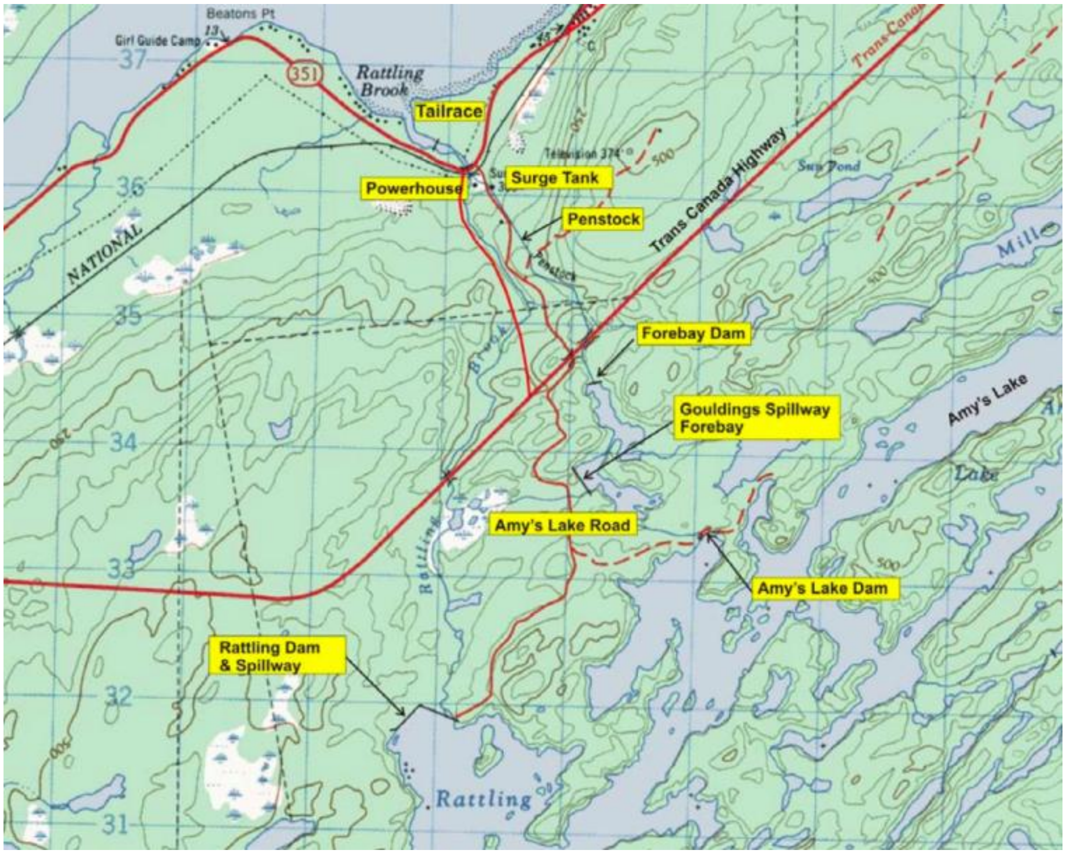

Figure 1 – Rattling Brook Hydroelectric Development

2.0 Results of the Technical Working Group

The technical working group, formed in May 2008 examined four options for providing fish passage in the Rattling Brook watershed. In December 2009, both DFO and Newfoundland Power produced reports summarizing the findings. The focus of the Newfoundland Power Report was to assess the engineering aspects of the project including quantifying the capital cost, lost energy, operating costs, and increases in greenhouse gas emissions of the identified options. The focus of the DFO report was to assess the likelihood of success of a preferred option as well as estimate the size of the salmon population that could be expected.

There were four options identified for reintroducing salmon:

1. Upstream migration through the existing Rattling Brook and through a manmade fishway structure at Rattling Spillway. Downstream passage would be provided through a channel at Amy's Lake Dam, into Amy's Canal, into the forebay and over Gouldings Spillway where salmon would travel through an old drainage stream to the original Rattling Brook.

2. Upstream migration for 3.5 kilometres up Rattling Brook, then 1.3 kilometres up a drainage stream to Gouldings spillway. Once over the spillway, salmon would travel through the forebay into Amy's canal where they would traverse the dam through a fishway to reach the Reservoir. Downstream passage would follow the same route.

3. Upstream migration for 3.5 kilometres up Rattling Brook, then 1.3 kilometres up a drainage stream to Gouldings spillway. Once over the spillway, salmon would travel through the forebay into Amy's canal where they would traverse the dam using an elevator to reach the Reservoir. Downstream passage would be provided through a channel at Amy's Lake Dam, into Amy's Canal, into the forebay and over Gouldings Spillway where salmon would travel through an old drainage stream to the original Rattling Brook.

4. Salmon would be trapped at the tailrace and transported to Amy's Lake Dam where they would be discharged into the Rattling Lake reservoir. Downstream passage would be provided through a channel at Amy's Lake Dam, into Amy's Canal, into the forebay and over Gouldings Spillway where they would travel through an old drainage stream to the original Rattling Brook.

Both 2009 reports recommended Option 4, the trap and transport option. This option was estimated to have the lowest capital cost, lost energy and operating costs of all four options examined. DFO has suggested that the maximum production of the Rattling Brook water shed is approximately 3,000 adult Atlantic salmon.

3.0 Project Execution

Detailed engineering work is required for this project including the design and optimization of the various structures as well as the design of habitat between the Rattling/Amy's Lake Reservoir and the tailrace. The engineering will be completed by a consultant with civil engineering, environmental and fisheries science expertise. The detailed engineering work must be submitted to DFO for review and approval as required in the order issued February 12, 2010.

Construction of the works associated with fish passage is necessary in 2012 to ensure the deadlines set by DFO in their 2010 directive are met. Construction will be completed from May 2012 to October 2012, utilizing the periods of lowest reservoir levels. During this construction period Rattling Brook hydro plant will remain in operation.

4.0 Project Cost

The original cost estimate provided with the December 2009 Preliminary Engineering Assessment included as Appendix B was $3,995,000. This amount was prepared for the purpose of comparing options to reintroduce salmon to Rattling Brook. As a result the cost estimates did not include any allowance for inflation or contingency associated with the actual construction of the project at some future date.

The project cost is currently estimated at $5,000,000. The cost estimate has increased by approximately 25% since the December 2009 report filed with DFO. The current cost estimate was increased to include inflation and a contingency to address potential changes resulting from the final engineering design by Newfoundland Power and subsequent changes requested by DFO.[5]

[5] The original cost estimates were based upon preliminary engineering design work. The final engineering design is subject to review and approval by DFO as required by the order issued February 12, 2010.

Table 1 provides a cost breakdown for the project.

Table 1
Projected Expenditures

Cost Category	Estimated Cost
Material	$4,030,000
Labour - Internal	245,000
Labour - Contract	0
Engineering	625,000
Other	100,000
Total	**$5,000,000**

5.0 Feasibility Analysis

Appendix E provides a feasibility analysis for continued operation of the Rattling Brook hydroelectric development assuming that the planned capital upgrades for 2012 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 1.574 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.[6]

6.0 Concluding

The Company will design and construct the trap and transport option as described in Appendix B to this report. This option is the least cost alternative for providing a fish passage around Rattling Brook hydroelectric generation facility.

Newfoundland Power has been ordered by DFO under section 20 of the Fisheries Act to provide fish passage around its hydroelectric generation facility on Rattling Brook to allow annual upstream and downstream migration of the Atlantic salmon. All reasonable alternatives have been evaluated for their capital, operating and lost energy costs as well as the probability of success with the least cost option being pursued.[7]

6 The cost of electricity from the Holyrood thermal generating station is estimated at 16.37¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $103.10 per barrel for 2011 as per Newfoundland Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated April 14, 2011.

7 Appendix B includes a detailed assessment of all reasonable alternatives.

Appendix A

Order From the Department of Fisheries and Oceans

Prepared by:

The Department of Fisheries & Oceans

Fisheries and Oceans Canada / Pêches et Océans Canada
PO Box 5667
St. John's NL A1C 5X1

Your File Votre référence

Our File Notre référence
BAB 3970-280

FEB 12 2010

RECEIVED
FEB 15 2010

Earl Ludlow
President and Chief Executive Officer
Newfoundland Power
55 Kenmount Road
PO Box 8910
St. John's NL A1B 3P6

Dear Mr. Ludlow:

I write to you in relation to the Newfoundland Power hydroelectric generation facility on Rattling Brook at Norris Arm, NL.

The mandate of Fisheries and Oceans Canada includes the protection and restoration of habitat that sustains fisheries resources. One such resource which is of major economic, social, and biological importance to Canada and throughout the North Atlantic is the Atlantic salmon.

As has been documented over the past several years by a DFO-Newfoundland Power Joint Technical Working Group, significant gains in the production of Atlantic salmon can be realized through the restoration of the access for Atlantic salmon to the headwaters of Rattling Brook. The collaborative efforts of that Working Group have also identified a technically feasible means of restoring passage for salmon that would not unreasonably interfere with the use of the river to generate electricity.

We believe that the recent and planned modernizations of the hydroelectric facility on Rattling Brook create the opportunity to achieve objectives for salmon enhancement and for hydroelectricity generation in a cooperative and balanced manner, as envisioned by the Memorandum of Understanding between DFO and the Canadian Electricity Association. We also acknowledge Newfoundland Power's request for a clear regulatory requirement to support the company's obtaining approval for the investment of resources in such an initiative.

Pursuant to section 20 of the *Fisheries Act*, Newfoundland Power is thus hereby ordered to provide a fish pass around the hydroelectric generation facility on Rattling Brook so as to allow the annual upstream and downstream migration of Atlantic salmon between the Bay of Exploits and the headwaters of Rattling Brook. The fish pass is to be in place to allow the downstream migration of salmon kelts and smolts by May 1, 2013, and the upstream migration of grilse and adult salmon by June 10, 2014.

Canada

As set out in section 20(3) of the *Fisheries Act*, the place, form and capacity of the fish-way or canal ordered to be provided above must be approved by the Minister before construction thereof is begun. We request that Newfoundland Power provide appropriate plans to DFO for review and approval in a timeframe that will allow the company to comply with the above order.

DFO will, in connection with this order, and pursuant to section 20(4) of the *Fisheries Act* specify the flows of water that Newfoundland Power will be required to supply in fishways associated with the fish pass at various times of the year so as to permit the safe and unimpeded descent of fish. The details of that direction, to be provided at a later date, will depend on specifications of the fish pass structures and procedures developed by Newfoundland Power.

DFO is willing to assist and advise Newfoundland Power as the company designs the structures and develops the operating procedures that will be required to satisfy the above order and directions.

I have attached copies of relevant sections of the *Fisheries Act* for your information and reference. I encourage you to contact my office at (709) 772-2442 if you have any questions.

We look forward to continuing to work with Newfoundland Power in realizing this significant contribution to the sustainability of Canada's fisheries resources in a collaborative and efficient manner.

Yours sincerely,

R. D. Finn
Regional Director
Oceans, Habitat and Species at Risk

TB/hr

Attachment

Excerpted Relevant Sections
of the
***Fisheries Act* R.S., c. F-14, s. 1.**

CONSTRUCTION OF FISH-WAYS

Fish-ways to be made as Minister directs

20. (1) Every obstruction across or in any stream where the Minister determines it to be necessary for the public interest that a fish-pass should exist shall be provided by the owner or occupier with a durable and efficient fish-way or canal around the obstruction, which shall be maintained in a good and effective condition by the owner or occupier, in such place and of such form and capacity as will in the opinion of the Minister satisfactorily permit the free passage of fish through it.

Idem

(2) Where it is determined by the Minister in any case that the provision of an efficient fish-way or canal around the obstruction is not feasible, or that the spawning areas above the obstruction are destroyed, the Minister may require the owner or occupier of the obstruction to pay to him from time to time such sum or sums of money as he may require to construct, operate and maintain such complete fish hatchery establishment as will in his opinion meet the requirements for maintaining the annual return of migratory fish.

Place, form, etc.

(3) The place, form and capacity of the fish-way or canal to be provided pursuant to subsection (1) must be approved by the Minister before construction thereof is begun and, immediately after the fish-way is completed and in operation, the owner or occupier of any obstruction shall make such changes and adjustments at his own cost as will in the opinion of the Minister be necessary for its efficient operation under actual working conditions.

To be kept open

(4) The owner or occupier of every fish-way or canal shall keep it open and unobstructed and shall keep it supplied with such sufficient quantity of water as the Minister considers necessary to enable the fish frequenting the waters in which the fish-way or canal is placed to pass through it during such times as are specified by any fishery officer, and, where leaks in a dam cause a fish-way therein to be inefficient, the Minister may require the owner or occupier of the dam to prevent the leaks therein.

Appendix B:

A Report on the Preliminary Engineering Assessment of a Proposal to Reintroduce Salmon to Rattling Brook

Prepared by:

Newfoundland Power

A Report on the
Preliminary Engineering Assessment of a Proposal to
Reintroduce Salmon into Rattling Brook

December, 2009

Rattling Lake Spillway at Low Level

Prepared by:
Newfoundland Power

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1.0 Introduction

The Rattling Brook Hydroelectric generating station was placed into service on December 16, 1958. Before the plant was commissioned, Rattling Brook salmon stock was captured and relocated to Great Rattling Brook. Great Rattling Brook is a tributary that feeds into the Exploits River.

This report is a broad based review of the requirements to complete the Norris Arm and Area Economic Development Committee's proposal (the "Proposal") to reintroduce salmon into Rattling Brook and its headwaters.

1.1 Background

In March of 2005, Newfoundland Power ("NP") submitted a report titled *"A Report on the Preliminary Engineering Assessment of a Proposal to Reintroduce Salmon into Rattling Brook"* (the "March 2005 Report") to the Department of Fisheries and Oceans ("DFO") . The March 2005 Report detailed the necessary infrastructure required to complete the Proposal, the capital costs associated with the infrastructure, the impact of lost energy and the ongoing costs to operate and maintain the infrastructure.

The March 2005 Report contained a salmon route using Amy's Lake Outlet. This route involved salmon moving from the tailrace into the original Rattling Brook upstream for approximately 3.5 kilometres. The salmon would then follow an old drainage stream for 1.3 kilometres to reach Gouldings Spillway. Once over the spillway, salmon would travel into the forebay and through an existing manmade canal to reach the dam at Amy's Lake. Based on the height of Amy's Lake dam, it was anticipated that the most feasible method of passing fish over the dam would be by means of an elevator lift. Appendix A contains a map of the Amy's Lake Outlet route.

A DFO technical committee[1] was established to review the March 2005 Report and to assess the feasibility of restoring access and utilization of fish habitat within Rattling Brook.

On December 6th, 2005, the technical committee met to review all project related information. DFO indicated in a letter to NP dated January 11th, 2006 that "*In order to fine tune the projected financial costs, it will be necessary to investigate technical options identified by the technical committee that were not part of NP's March 2005 report".*

In February of 2007 NP submitted to DFO a second report ("2007 Report") that assessed a different route (a fishway at Rattling Lake Spillway instead of an elevator lift at Amy's Lake dam) for salmon migration and incorporated information from the spill test conducted on June 22-23, 2005, technical discussions with DFO and further engineering review by NP.

Based on a Proposal by the Norris Arm and Area Economic Development Committee's to reintroduce salmon into Rattling Brook, NP and DFO agreed to explore the options and feasibility of the Proposal based on the provisions of the Fisheries Act and the principles set out in the Memorandum of Understanding between the Canadian Electricity Association and DFO.

[1] The DFO technical committee was comprised of regional science, engineering and habitat management staff.

NP and DFO agreed to collaborate on assessing additional options for re-establishing fish passage for salmon migration into Rattling Brook. A Steering Committee and Technical Working Group, consisting of both DFO and NP employees, was established in May 2008 to determine if a practical and cost-effective solution exists.

The objective of the Technical Working Group is to recommend the most practical and cost effective solution, providing such a solution exists, for re-establishing fish passage in Rattling Brook. Specifically, the Technical Working Group objectives were to:

1. Develop and examine options for providing fish passage in the Rattling Brook watershed;
2. Assess the likelihood of success of a preferred option for providing fish passage;
3. Estimate the size of salmon population that could be expected, the time frame of establishment of such a population and anticipated related benefits;
4. Determine the capital cost, lost energy costs, operating costs and increases in greenhouse gas emissions associated with the preferred fish passage option; and
5. Make a recommendation on the most practical and cost-effective option, providing such an option exists, for providing fish passage.

This report looks into objectives 1 and 4 above. A separate report prepared by DFO looks into objectives 2 and 3. DFO members of the Technical Working Group have expressed concern with some of the cost estimates provided by NP for the proposed infrastructure. These estimates are preliminary, based on conceptual design using sound engineering judgement, and are based on a 50 year design life to ensure additional significant capital expenditure is not required in the foreseeable future. While NP does not have the expertise to comment on the conclusions in the DFO report we do have some reservation concerning the lack of scientific data used in determining the estimated salmon population and in evaluating the probability of success. The estimate provided for salmon population is significantly greater than prior to 1958 when Rattling Brook was in its natural state.

2.0 Detailed Study Requirements

This report contains a preliminary assessment of the options to provide fish passage in the Rattling Brook watershed. Detailed studies would have to be completed prior to detailed engineering. The necessary studies would include a detailed assessment of the stream profile, minimum flow requirements, an evaluation of the existing fish habitat, and design and cost estimates of all fishways and other requirements.

The detailed engineering required for this project would be comprised of two components: 1) fishway and structure design and 2) habitat design.[2] Since most structures would be built in the flood route, all designs would have to take into consideration flood events to ensure that spill

[2] Habitat design would only be required for options that require passage of adult salmon upstream (i.e. Option 1, 2, and 3). Habitat design would not be required for Option 4 (Trap and Transport) due to the fact that adult salmon would not be travelling in the area between the tailrace and Rattling Lake reservoir (other than downstream migration). Therefore there would be no possibility of salmon spawning in this area.

capacity and dam safety are not affected. All structures in the flood path would have to withstand design floods and overtopping.

The studies and detailed engineering to complete the work are estimated to cost $500,000.[3]

2.1 Minimum Fish Passage Flow

On June 22-23, 2005 representatives of NP and DFO conducted several spill tests by spilling water over Gouldings Spillway and into the original Rattling Brook. The main purpose of the spill test was to provide information on stream and water passage conditions at various flows from 0.75 m^3/s up to 2.0 m^3/s. Measurements were taken at various locations along the river to quantify the flow rate. Pictures were also taken of various flows at the various locations of concern with respect to fish passage at low flow.

This information was used by DFO to provide guidance on the minimum flow requirements for fish passage and to assess obstructions along the route. NP also used the information to estimate the lost energy that would result in providing the minimum flow for fisheries purposes at Gouldings Spillway and Rattling Lake Spillway.

Based on the review by DFO the following guidance has been used in the evaluation of this report:

- Provide flow of 0.75 m^3/s from Rattling Lake Spillway or Amy's Lake Dam from June 1 – August 31 for passage of adult salmon upstream.
- Provide flow of 0.50 m^3/s from Rattling Lake Spillway and Gouldings Spillway from September 1 – May 31 to maintain fisheries.
- Provide flow of 0.75 m^3/s from Gouldings Spillway from May 1 – June 30 for passage of smolt and adult salmon downstream.
- Provide and attraction flow of 0.50 m^3/s from Gouldings Spillway from July 1 – September 15 for adult collection.[4]

3.0 Objective 1 – Develop and Examine Options for Providing Fish Passage in the Rattling Brook Watershed

Presently, salmon can only reach as far as the powerhouse tailrace. To reintroduce salmon into Rattling Brook and its headwaters several options were assessed by the Technical Working Group related to the upstream and downstream fish passage. A detailed description of the possible routes for upstream and downstream passage, required infrastructure, along with cost estimates to accommodate fish passage from the powerhouse tailrace to Rattling Brook reservoir are discussed in this Section.

3 This estimate is within the costs of similar studies such as the Rose Blanche Fisheries Development Studies which cost $450,000.

4 This attraction flow would only be required if the collection basin at the tailrace fails to provide the necessary attraction flow for the adult salmon.

3.1 Proposed Routes

For the purpose of adult migration there are three possible routes that the salmon could potentially utilize to migrate from the powerhouse tailrace to Rattling Lake reservoir:

1. **Proposed Route No. 1:**
   Salmon would move from the tailrace into the original Rattling Brook and follow this route until they reached Rattling Lake Spillway (a travel distance of approximately 5.0 kilometres). Upon arrival at Rattling Lake Spillway the adult salmon would traverse the existing manmade structure by the means of a fishway to reach their final destination of Rattling Lake reservoir;

2. **Proposed Route No. 2:**
   Salmon would move from the tailrace into the original Rattling Brook for approximately 3.5 kilometres upstream. From there they would follow an old drainage stream for 1.3 kilometres to reach Gouldings Spillway. Once over the spillway, salmon would travel into the forebay and through an existing manmade canal to reach the dam at Amy's Lake. The salmon would then traverse the dam, via a fishway or an elevator, to reach their final destination of Rattling Lake reservoir; or

3. **Proposed Route No. 3:**
   Salmon would be trapped at the tailrace and transported to Amy's Lake Dam where they would be discharged into Rattling Lake reservoir.

Appendix A contains a map of Proposed Route No. 1 and 2.

For the purpose of downstream migration there are two possible routes that adult salmon and smolt could use to return to the Bay of Exploits:

1. **Proposed Route No. 1:**
   Over Rattling Spillway (during April or May spills) or through a fishway at Rattling Lake Spillway and down Rattling Brook; or

2. **Proposed Route No. 2:**
   Through a channel at Amy's Lake Dam, into Amy's canal, into the forebay and over Gouldings Spillway. Once over Gouldings Spillway the salmon and smolt would travel through an old drainage stream for 1.3 kilometres until they reach the original Rattling Brook just upstream of the TCH Bridge.

3.2 Infrastructure Cost Estimates for Upstream Fish Passage

Each proposed route contains both manmade structures and natural obstructions that prohibit fish passage.

Infrastructure required to accommodate upstream migration for Proposed Route No. 1 includes:

- A ladder at the tailrace;

- Channel improvements from the tailrace to Rattling Lake Spillway (approximately 5 kilometres); and
- A Fishway at Rattling Lake Spillway.

Infrastructure required to allow upstream migration for Proposed Route No. 2 includes:

- A ladder at the tailrace;
- Channel improvements from the tailrace to the old stream bed (approximately 3.5 kilometres) and improvements from the old stream bed to Gouldings Spillway (approximately 1.3 kilometres);
- A Fishway at Gouldings Spillway; and
- A Fishway or Elevator at Amy's Lake Dam.

Infrastructure required to allow upstream migration for Proposed Route No. 3 includes:

- Collection basin at the tailrace to trap the salmon for transport.

It is anticipated that the following capital expenditures would be required for the above infrastructure.

3.2.1 Ladder at the Tailrace

A concrete fish ladder would be required at the tailrace to allow fish to move from the area below the tailrace tunnel into the natural brook area. This area is within a confined channel, downstream of the plant, and would require widening of the channel so as not to restrict the tailrace flow. The vertical drop in the area where the ladder would be located is about 3-4 metres. Blasting would be required to widen the channel and provide the foundation for the fish ladder. However, blasting work would have to be done with care to avoid damage to the existing tailrace tunnel. The location of the ladder should take this into consideration. Appendix B, Photo A contains a view of the tailrace tunnel.

The capital cost to install the tailrace fish ladder is estimated to be $300,000.

3.2.2 Ladder System at Rattling Lake Spillway

Rattling Lake Spillway is approximately 3 metres high and is adjacent to Rattling Lake dam which is over 12 metres high. The original Rattling Brook entered Rattling Lake at the current dam location. Due to the design nature of the main dam, it would not be cost effective to locate a fishway in the dam. The only possible location for the fish ladder is at the spillway structure.

Fish passage at the spillway is complicated by the fact that the shoreline on the upstream side of the spillway moves out into the reservoir as the water level is drawn down. Vertical drawdown on the reservoir is over 8 metres. During low water levels the horizontal distance from the spillway to the shoreline is 105 metres. Downstream of Rattling Lake Spillway the horizontal distance to reach the original Rattling Brook is an additional 170 metres over solid bedrock. Appendix B, Photos I to L show the area around Rattling Lake Spillway.

Based on site conditions and operating requirements for the spillway, the best location to construct a fishway would be on the west side of the spillway (i.e. on the dam side). In order for water and fish passage from Rattling Lake to Rattling Brook, a trench over 275 metres long and 6.4 metres deep (at the deepest section) would have to be blasted into the bedrock. Blasting work would have to be completed with care to avoid any damage to the dam and spillway.

A steel control gate would be installed at the spillway location to ensure the integrity of the spillway structure at full supply level and for maintenance of the fishway. Downstream of the gate structure approximately fifteen 3.0 metre long pools would be provided to serve as resting and jumping pools for the salmon.

Each pool would be separated by a number of 600 mm high stoplogs, which water would flow over to maintain a passage flow. Logs would be removed from each pool as the water level dropped in the reservoir to allow salmon to jump from the natural river through the series of pools until they reached the reservoir level. Appendix C contains a conceptual drawing of the fish ladder.

To maintain proper flows, a hoist system would be required that could reach down into the fishway to remove the logs as the water level drops. Approximately 100 removable 600 mm high stoplogs would be required for operation of the ladder system within the fifteen pools. A large area accessible by the hoist would be required between the dam and fishway for storage of the stoplogs. The stoplogs should be steel with rubber seals to reduce leakage and allow for practical installation and removal.[5]

Once all salmon have migrated upstream (September 1 – May 31) all stoplogs would be removed from the pools and the vertical steel control gate would be used to maintain the downstream fisheries flow. On June 1 of each year the stoplogs would be reinstalled in all pools and the gate would be fully opened allowing fish passage through the ladder system for the summer.

The fishway would be directly impacted by any spill or flood from the spillway. To protect the fish ladder system and hoist structure from floods, a wall would have to be installed along the fishway to separate the spill channel from the fish ladder. This wall would also serve as a barrier to the public from the hazard posed by the canal. To the west side of the fishway a chain link fence would be installed for safety purposes.

The 275 metre long canal, blasted in the bedrock, would pose a safety hazard to the general public in this area. The 105 metre section of canal upstream of the spillway is accessible to the public and cannot be fenced since it is in a reservoir with rising and falling water levels. For this reason, the section of canal upstream of the spillway would be covered with structural grating to remove the fall hazard. The structural grating would remain in place all year and would have to be designed to withstand wave and ice action.

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[5] Wooden logs at water depths of 8.2 metres would not be preferred due to the buoyancy forces and difficulty in installing and removing. In addition, wooden logs would not hold-up to the constant handling of installation and removal.

In addition, access to the main dam is via the existing spillway channel. Thus an access bridge would have to be provided across the fishway canal to the main dam.

3.2.2.1 Rattling Lake Spillway Challenges

The fishway system at Rattling Lake Spillway is unique and proposes several challenges with respect to design, construction and operation. Some of the more significant challenges and issues related to Rattling Brook Spillway include:

- In order to draw water out of the Rattling reservoir to supply flow downstream, excavation would be required through solid bedrock at depths of up to 6 metres for most of the 275 metre long canal. Because of the close proximity of blasting to the spillway structure, grouting of the spillway foundation would be required after blasting is complete to ensure the foundation meets design and dam safety criteria.
- Due to the difference in elevations from the low reservoir level to the natural river, proper slopes are not available to maintain minimum flows for fish passage. It is estimated that over 2.0 metres of reservoir supply would be lost to supply minimum fisheries flows to Rattling Brook. This requirement is subject to more detailed engineering.
- The stoplog system would have to be designed to allow for practical removal and installation. From the working deck level, logs would have to be installed and removed from 1.5 metres below the deck to 10 metres below the deck. An installation and removal system would be challenging and would require two operators due to the nature of the work and for safety reasons.
- Most of the flow into Rattling Lake reservoir is uncontrolled. As a result, the reservoir can rise or fall fairly quickly. Continual monitoring and operation to remove or install logs would be required to ensure that adequate fish flow is maintained or excessive water is not released through the spillway.
- Due to the fishway being in the spillway channel, there is a need for a concrete dividing wall. This wall will constrict the spill channel flow. An evaluation of the impact on the ability to pass design floods would have to be completed, especially at the lower channel bend. Parts of the fishway would be subject to flood conditions and siltation could also be a concern.

The capital cost to construct a fishway at Rattling Lake Spillway is estimated to be $4,800,000.

3.2.3 Ladder at Gouldings Spillway

Gouldings Spillway is approximately 1.5 metres high and 50 metres long. A fishway would be required at this location to allow the salmon to reach the forebay. Once over the spillway, salmon would travel into the forebay and through and existing manmade canal to reach Amy's Lake Dam.

The capital cost to construct a fishway at Gouldings Spillway is estimated to be $250,000.

3.2.4 Ladder System at Amy's Lake Dam

Amy's Lake Dam is over 11 metres high, making the installation of a fishway very difficult. Fish passage at the Amy's dam is further complicated by the fact that the shoreline on the upstream side of the dam moves out into the reservoir as the water level is drawn down. Vertical drawdown on the reservoir is over 8 metres. During low water levels the horizontal distance from the dam to the shoreline is approximately 60 metres. Downstream of Amy's Lake Dam the horizontal distance to reach Amy's Lake canal is an additional 190 metres. Appendix B, Photos O and Q show the area around Amy's Lake Dam.

Amy's Lake Dam fishway would be of similar construction and challenges to Rattling Lake Spillway fishway. In order to accommodate water and fish passage from Rattling Lake to Amy's Canal, a trench over 250 metres long and 10.5 metres deep (at the deepest section) would have to be blasted. Blasting work would have to be completed with care to avoid damage to the dam.

A steel control gate would be installed at the dam to ensure the integrity of the dam at full supply level and for maintenance of the fishway. To accommodate the installation of the control gate, a section of the dam, over 12 meters high and 12 meters wide would have to be removed.

Downstream of the gate structure approximately 19 three metre long pools would be provided to service as resting and jumping pools for the salmon. Each pool would be separated by a number of 600 mm high stoplogs, which water would flow over to maintain a passage flow. Logs would be removed from each pool as the water level dropped in the reservoir to allow salmon to jump from the natural river through the series of pools until they reached the reservoir level. Appendix D contains a conceptual drawing of the fish ladder.

To maintain proper flows, a hoist system would be required that could reach down into the fishway to remove the logs as the water level drops. Approximately 100 removable 600 mm high stoplogs would be required for operation of the ladder system within the 19 pools. A large area accessible by the hoist would be required between the dam and fishway for storage of the stoplogs. The stoplogs should be steel with rubber seals to reduce leakage and allow for practical installation and removal.

Once all salmon have migrated upstream (September 1 – May 31) all stoplogs would be removed from the pools and the vertical steel control gate would be used to maintain the downstream fisheries flow. On June 1 of each year the stoplogs would be reinstalled in all pools and the gate would be fully opened allowing fish passage through the ladder system for the summer.

The 190 metre long canal, blasted in the bedrock, would pose a safety hazard to the general public in this area. The 60 metre section of canal upstream of the spillway is accessible to the public and cannot be fenced since it is in a reservoir with rising and falling water levels. For this reason, the section of canal upstream of the spillway would be covered with structural grating to remove the fall hazard. The structural grating would remain in place all year and would have to be designed to withstand wave and ice action.

Due to the substantial amount of blasting and excavation required to remove the section of the dam and to install the steel gate, it is anticipated that the construction Amy's Lake Dam fishway would be completed over two construction seasons. To complete the work over two construction seasons a cofferdam would have to be constructed upstream of Amy's Lake Dam. To meet dam safety criteria the cofferdam would have to be constructed to the same integrity as the existing dam. The cofferdam would be approximately 107 m long and 11 metres high. Once the construction of the fishway is complete the cofferdam would then be removed. Appendix D contains a conceptual drawing showing the proposed location of the cofferdam.

3.2.4.1 Amy's Dam Fishway Challenges

The fishway system at Amy's Lake Dam is unique and proposes several challenges, similar to those discussed for the fishway at Rattling Lake Spillway, with respect to design, construction and operation. Some of the more significant challenges and issues related to Amy's Lake Dam include:

- In order to draw water out of the Rattling reservoir to supply flow downstream, excavation would be required through solid bedrock at depths of up to 11 metres. In addition a large portion of the dam would have to be removed to accommodate the installation of the steel control gate. Grouting of the dam foundation would be required after blasting is complete to ensure the foundation meets design and dam safety criteria.
- It is anticipated that the construction period for the fishway would be over two construction seasons. To complete the construction over two seasons a substantial cofferdam would have to be constructed upstream to the same integrity of the existing dam. The cofferdam would be removed when the construction of the fishway is complete.
- The stoplog system would have to be designed to allow for practical removal and installation. From the working deck level, logs would have to be installed and removed from 1.5 metres below the deck to 10 metres below the deck. An installation and removal system would be challenging and would require two operators due to the nature of the work and for safety reasons.
- Most of the flow into Rattling Lake reservoir is uncontrolled. As a result, the reservoir can rise or fall fairly quickly. Continual monitoring and operation to remove or install logs would be required to ensure that adequate fish flow is maintained or excessive water is not released through the spillway.

The capital cost to construct a fishway at Amy's Lake Dam (including the cost of the cofferdam) is estimated to be $9,000,000.

3.2.5 Elevator at Amy's Lake Dam

An alternate way for salmon to traverse Amy's Lake Dam would be by means of an elevator lift. A small collector area would be constructed just downstream of the dam. The elevator would be used to transport the salmon to the top of the dam where they would be discharged into a concrete chute that would then carry them to Rattling Lake reservoir. Appendix E contains a layout of the proposed location for the elevator and concrete chute.

The capital cost to install an elevator and concrete chute at Amy’s Lake Dam is estimated to be $2,500,000.

3.2.6 Rattling Brook Channel Improvements

Channel improvements would be required to allow fish passage in the natural brook system. As salmon would have to travel the natural brook with a minimum flow of 0.75 m^3/s in June through September (with little or no other local inflows), it is anticipated that six or seven fish passages (or modifications to the existing riverbed) would be required to allow adult salmon to move upstream. Some of these may be small and easy to construct, however a few would be more substantial. More information is needed to assess the full requirements along the existing channel. All of the structures necessary for the fishways would have to be able to handle significant flooding as this is the flood route for the entire Rattling Brook system. Appendix B, Photos B to H, are photos of some of the obstructions.

Channel development work of the old drainage stream from the original Rattling Brook to Gouldings Spillway would also be required. It is anticipated that channel development work would be required in this section to confine the flow in certain areas. In addition, excessive vegetation of alders and other tree growth would have to be removed from the brook to allow for the safe passage of salmon and smolt. The channel in this area would have to be able to withstand small spill flows during spring run-off which can occur at this location. Appendix B Photos M to P, are photos of this channel area.

The capital cost to make the necessary improvements to Rattling Brook and the old stream bed is estimated to be $350,000.

3.2.7 Collection Basin at the Tailrace

A collection basin would be required at the tailrace to trap salmon for transport to Amy’s Lake Dam.

The capital cost to construct the collection basin is estimated to be $50,000.

3.3 Infrastructure Cost Estimates for Downstream Fish Passage

Once salmon reach Rattling Lake reservoir, smolt and adult salmon would have to navigate downstream to return to the Bay of Exploits. Smolt and adult salmon from the previous year return downstream from mid-May to mid-June.

Infrastructure required to accommodate downstream migration for Proposed Route No. 1 and No. 2 includes:

- A ramp at Amy’s Lake Dam;
- A conduit fence at Gouldings Spillway;
- A concrete chute at Gouldings Spillway; and
- Channel improvements of Rattling Brook and old stream bed from Gouldings Spillway to the original Rattling Brook.

3.3.1 Channel at Amy's Lake Dam

Appendix F contains a conceptual drawing of the channel at Amy's Lake Dam. A channel of approximately 101 metres long would have to be excavated.

A steel control gate would be installed at the dam to ensure the integrity of the dam at full supply level and for maintenance of the channel. To accommodate the installation of the control gate, a section of the dam, over 8 meters high and 10 meters wide would have to be removed. The section of the dam that would have to be removed is bedrock, therefore blasting would be required. Blasting work would have to be completed with care to avoid damage to the dam. Concrete wing walls would be installed on the upstream and downstream side of the dam to ensure the dam is stable on each side of the excavation.

To regulate the flow into the channel a stoplog system would be installed immediately downstream of the steel control gate. A hoist system would be required to operate the gate and remove the logs to accommodate varying water levels. Approximately 12 removable 600 mm stoplogs would be required. The stoplogs would be steel with rubber seals to reduce leakage and allow for practical installation and removal.[6]

From the toe of the dam to Amy's canal the channel would be an open excavation. The channel would pass under the road that is currently used to access Amy's Lake Dam. A bridge would be constructed in this area to span the channel.

Once all salmon and smolt have migrated downsteam (mid-May – mid-June) all stoplogs would be removed. Downstream fisheries flow would be maintained either through release of water through the channel using the vertical steel control gate or through Amy's Outlet. Mid-May of each year the stoplogs would be reinstalled and the gate would be opened allowing downstream migration of salmon and smolt.

The capital cost to construct a channel at Amy's Lake Dam) is estimated to be $2,000,000.

3.3.2 Conduit Fence and Concrete Chute at Gouldings Spillway

One of the major concerns with returning salmon to the Rattling Brook system is the survival rate of smolt and the ability of smolt to get downstream to the Bay of Exploits without passing through the penstock and turbines. To address this issue a conduit fence would be installed in the forebay to direct the smolt over Gouldings Spillway and into Rattling Brook. The location proposed by DFO for the conduit fence spans across the full length of the forebay and is over 100 metres long. The water depth in this area varies from 1 to 5 metres. Appendix G contains a conceptual drawing of the conduit fence.

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6 Wooden logs at water depths of 8.2 metres would not be preferred due to the buoyancy forces and difficulty in installing and removing. In addition, wooden logs would not hold-up to the constant handling of installation and removal.

In the conceptual design of the conduit fence, 75 metres of the distance would be spanned with a rock berm. The remainder would be spanned with a concrete conduit structure. The concrete structure would have racks that would be placed in the water during May and June which would direct smolt into a concrete chute. The chute would direct the smolt over Gouldings Spillway into an old drainage stream that would then carry them to Rattling Brook. The flow from Rattling Lake spillway would then carry them to the Bay of Exploits.

The capital cost to construct the conduit fence is estimated at $540,000. The cost for the concrete chute at Gouldings Spillway is estimated at $180,000.

3.3.3 Channel Improvements

Channel improvements and associated capital costs required for downstream migration would be the same as those described for upstream migration in *Section 3.2.6 Rattling Brook Channel Improvements.*

3.4 Fish Habitat Development

It is anticipated that significant fish habitat development would be required for this Proposal. The brook has been predominantly dry for the last 49 years and many habitat areas required for fish passage may not be available in the brook particularly at low flow levels.

Habitat development ensures appropriate resting areas for salmon and spawning and rearing areas for brook trout and other species, which would most likely take up residency in the brook if a flow is restored. These areas are created using a combination of stream and shoreline vegetation, gravel, logs, and other natural elements.

Since the brook has been mostly dry for such a long time, it is anticipated that significant habitat development would be required in the original Rattling Brook river bed.

The capital cost to complete the necessary development of fish habitat is estimated to be $275,000.

4.0 Objective 4 - Determine the Capital Cost, Lost Energy Costs, Operating Costs and Increase in Greenhouse Gas Emissions for Each Alternative

A detailed description of the possible routes for upstream and downstream passage, and the required infrastructure were discussed in the previous section. This section summarizes the capital costs associated with the various alternatives, lost energy costs, operating costs and the increase in greenhouse gas emissions.

4.1 Summary of Capital Cost Estimates

A summary of the estimated capital costs for potential structures that could be utilized for upstream and downstream migration, including an estimate of $275,000 for project management and other costs such as travel is outlined in Table 1.

Table 1
Summary of Capital Costs

Description	Cost
Detailed Studies/Engineering Design	$500,000
Tailrace Fish Ladder	300,000
Ladder System at Rattling Lake Spillway	4,800,000
Ladder at Gouldings Spillway	250,000
Ladder System at Amy's Lake Dam	9,000,000
Elevator at Amy's Lake Dam	2,500,000
Rattling Brook Channel Improvements	350,000
Collection Basin at the Tailrace	50,000
Channel at Amy's Lake Dam	2,000,000
Conduit Fence at Gouldings Spillway	540,000
Concrete Chute at Gouldings Spillway	180,000
Fish Habitat Development	275,000
Project Management and Other	275,000

4.2 Annual Operating Estimates

Annual operating cost would vary depending on what option would be utilized for upstream and downstream fish passage.

It is anticipated that if the elevator system or fishway at Amy's Lake Dam or a fishway at Rattling Lake Spillway be used as the means of upstream migration, annual operating cost would be in the order of $100,000. It is estimated that $35,000 would be required for annual fish monitoring, which would include ongoing assessments and monitoring of the fishway system and fish habitat areas. Operating and maintenance costs for the fishway would be $65,000 per year, most of which would be for the operation of the elevator or fishway at Amy's Lake Dam or the fishway at Rattling Lake Spillway. The annual operating cost of $100,000 levelized over 50 years would be $127,000.

Should the trap and transport option be utilized annual operating cost would be lower than other options. It is anticipated that annual operating costs would be in the order of $50,000. It is estimated that $50,000 would be required to trap and transport salmon at the tailrace to Amy's Lake Dam. The annual operating cost of $50,000 levelized over 50 years would be $64,000.

4.3 Lost Energy Costs

Lost energy cost would also vary depending on what option would be utilized for upstream and downstream fish passage.

Water spilled at either Rattling Lake Spillway or Amy's Lake Dam for passage of smolt and adult salmon and at Gouldings Spillway for smolt would not be available to produce electrical energy.

It is estimated that lost energy due to spilled water would be in the order of 5 GWh per year for either the Rattling Lake Spillway or Amy's Lake Dam option. This is based on the flows outlined in *Section 2.1 Minimum Fish Passage Flow*. The levelized cost of energy over 50 years is 12.06 cents/kWh[7]. Annually, 5 GWh or $603,000 in energy would be lost.

In addition, to the 5 GWh lost from spilling water, it is anticipated that another 2.5 GWh of energy would be lost due to operating restrictions on Rattling Lake reservoir if the Rattling Spillway option was utilized. This additional 2.5 GWh of energy would be lost because proper slopes are not available to maintain minimum flows for fish passage due to the difference in elevations from the low reservoir level to the natural river. This requirement would be subject to more detailed engineering. This represents another $301,500 annually in lost energy for the Rattling Lake Spillway route.

Should the trap and transport option be utilized, lost energy costs would be much lower. Since adult salmon would not be travelling in the area between the tailrace and Rattling Lake reservoir (other than downstream migration), there would be no possibility of salmon spawning in this area. Therefore, there would be no requirement for maintenance flows throughout the year. The only water spilled would be over Gouldings Spillway from the beginning of May to the end of June to accommodate downstream migration of adult salmon and smolt. It is estimated that lost energy due to spilled water for the trap and transport option would be in the order of 1.2 GWh per year. This represents $144,720 of lost energy annually.

However, DFO has indicated that if the collection basin proposed in Option 4 fails to attract the adult salmon then additional attraction flows shall be released through Gouldings Spillway. Additional attraction flows would be in the order of 0.5 m^3/s and would be released from July 1 – September 15. It is estimated that lost energy due to spilled water for adult attraction flows would be in the order of 1.0 GWh per year. This represents an additional $120,600 of lost energy annually.

For the purposes of this study we will assume that the collection basin will properly attract the adult salmon and no additional water will be spilled to provide attraction flows.

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[7] The current cost of electricity at Holyrood thermal generating plant is now estimated at 12.06 cents/kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $75.95 per barrel.

Table 2 shows the annual cost for the lost energy.

Table 2
Annual Lost Energy Costs

Description	Cost
Rattling Lake Spillway Route	$ 904,500
Amy's Lake Dam Route	$ 603,000
Trap and Transport	$ 144,720

4.4 Greenhouse Gas Impact

The power purchased to replace the lost energy from Rattling Brook would be replaced by thermal electricity generated at Newfoundland and Labrador Hydro's Holyrood Plant. Based on a loss of 7.5 GWh, 5.0 GWh, and 1.0 GWh of hydroelectric production, an additional 5,750, 3,833 and 767 tons of greenhouse gases would be released annually into the environment from the additional energy productions at Holyrood. The greenhouse gas environmental impact analysis for the replacement of energy is provided in Appendix H.

5.0 Summary

Based on the infrastructure identified for upstream and downstream fish passage in Section 3.2 and Section 3.3 four options were assessed for re-introducing salmon into Rattling Lake reservoir. Descriptions of the four options are as follows:

1. Option 1: Salmon would migrate upstream through the original Rattling Brook until they reach Rattling Lake Spillway. They would traverse the existing manmade structure through a fishway to reach their final destination of Rattling Lake reservoir. To return downstream the smolt and adult salmon would use a channel at Amy's Lake Dam, into Amy's canal, into the forebay and over Gouldings Spillway and to the Bay of Exploits.

2. Option 2: Salmon would move from the tailrace into the original Rattling Brook for approximately 3.5 kilometres upstream. From there they would follow and old drainage stream for 1.3 kilometres to reach Gouldings Spillway. Once over the spillway, salmon would travel into the forebay and through an existing manmade canal to reach the dam at Amy's Lake. The salmon will then traverse the dam through a fishway, to reach their final destination of Rattling Lake reservoir. To return downstream the smolt and adult salmon would use the same fishway at Amy's Lake Dam that was used for upstream migration. Once through the fishway they would then travel down Amy's canal, into the forebay and over Gouldings Spillway and to the Bay of Exploits.

3. Option 3: Salmon would move from the tailrace into the original Rattling Brook for approximately 3.5 kilometres upstream. From there they would follow and old drainage stream for 1.3 kilometres to reach Gouldings Spillway. Once over the spillway, salmon would travel into the forebay and through an existing manmade canal to reach the dam at Amy's Lake. The salmon will then traverse the dam via an elevator, to reach their final destination of Rattling Lake reservoir. To return downstream the smolt and adult salmon would use a channel at Amy's Lake Dam. Once through the channel they would travel down Amy's canal, into the forebay and over Gouldings Spillway and to the Bay of Exploits.

4. Option 4: Salmon would be trapped at the tailrace and transported to Amy's Lake Dam where they would be discharged into Rattling Lake reservoir. To return downstream the smolt and adult salmon would use a channel at Amy's Lake Dam. Once through the channel they would travel down Amy's canal, into the forebay and over Gouldings Spillway and to the Bay of Exploits.

A summary of all cost estimates for each option can be found in Table 3.

Table 3
Summary of Preliminary Cost Estimates

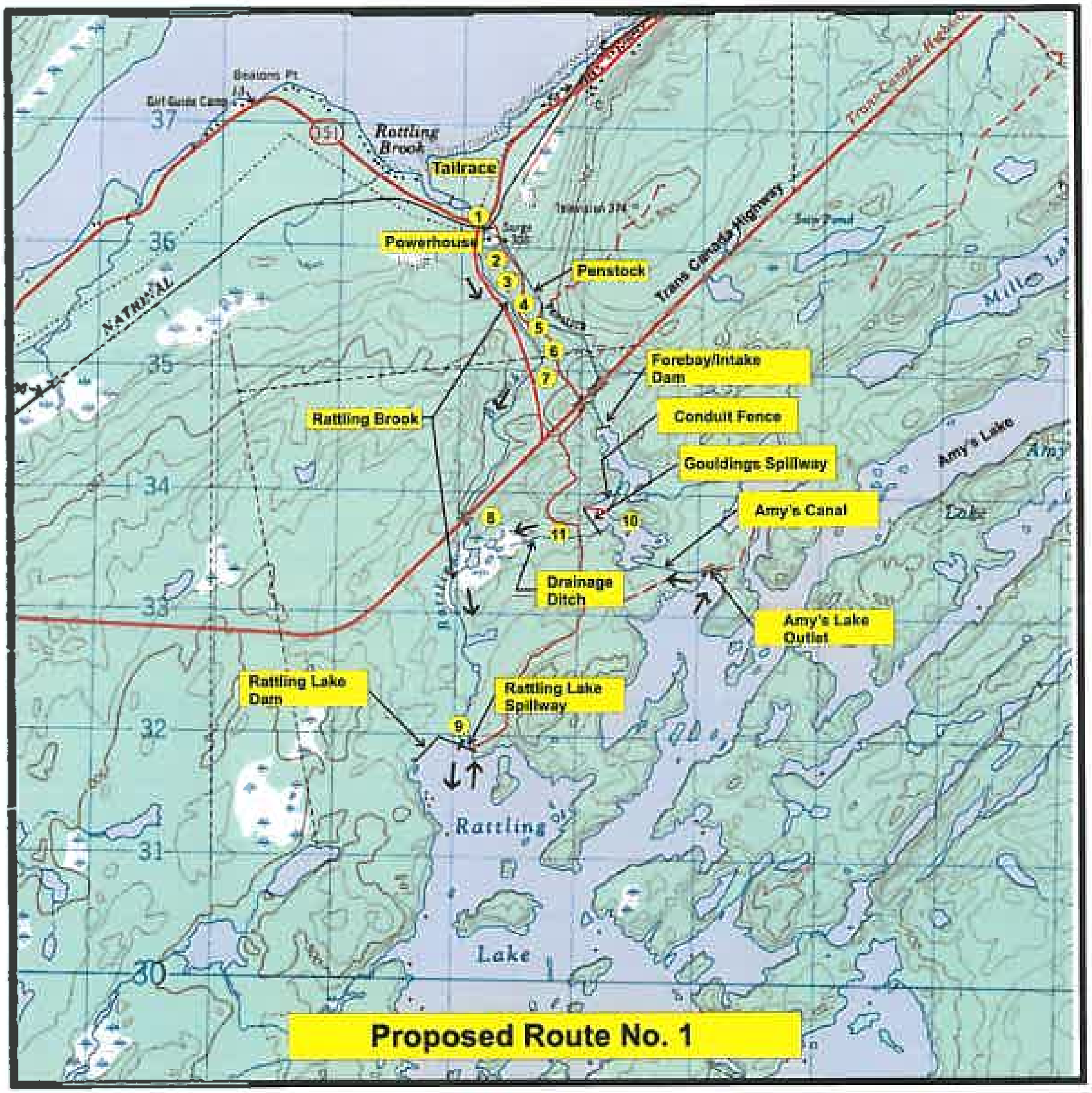
Capital Infrastructure Cost	**Option 1**	**Option 2**	**Option 3**	**Option 4**
Studies/Engineering Design	$500,000	$500,000	$500,000	$500,000
Tailrace Fish Ladder	300,000	300,000	300,000	300,000
Rattling Brook Channel Improvements	350,000	350,000	350,000	150,000
Ladder System at Rattling Spillway	4,800,000			
Ladder System at Amy's Lake Dam		9,000,000		
Elevator at Amy's Lake Dam			2,500,000	
Channel at Amy's Lake Dam	2,000,000		2,000,000	2,000,000
Concrete Chute or Fish Ladder at Gouldings Spillway	180,000	250,000	250,000	180,000
Gouldings Smolt Conduit Fence	540,000	540,000	540,000	540,000
Collection Basin at Tailrace				50,000
Fish Habitat Development	275,000	275,000	275,000	
Project Management and Other	275,000	275,000	275,000	275,000
Total	**$9,220,000**	**$11,490,000**	**$6,990,000**	**$3,995,000**

Table 3 (continued)

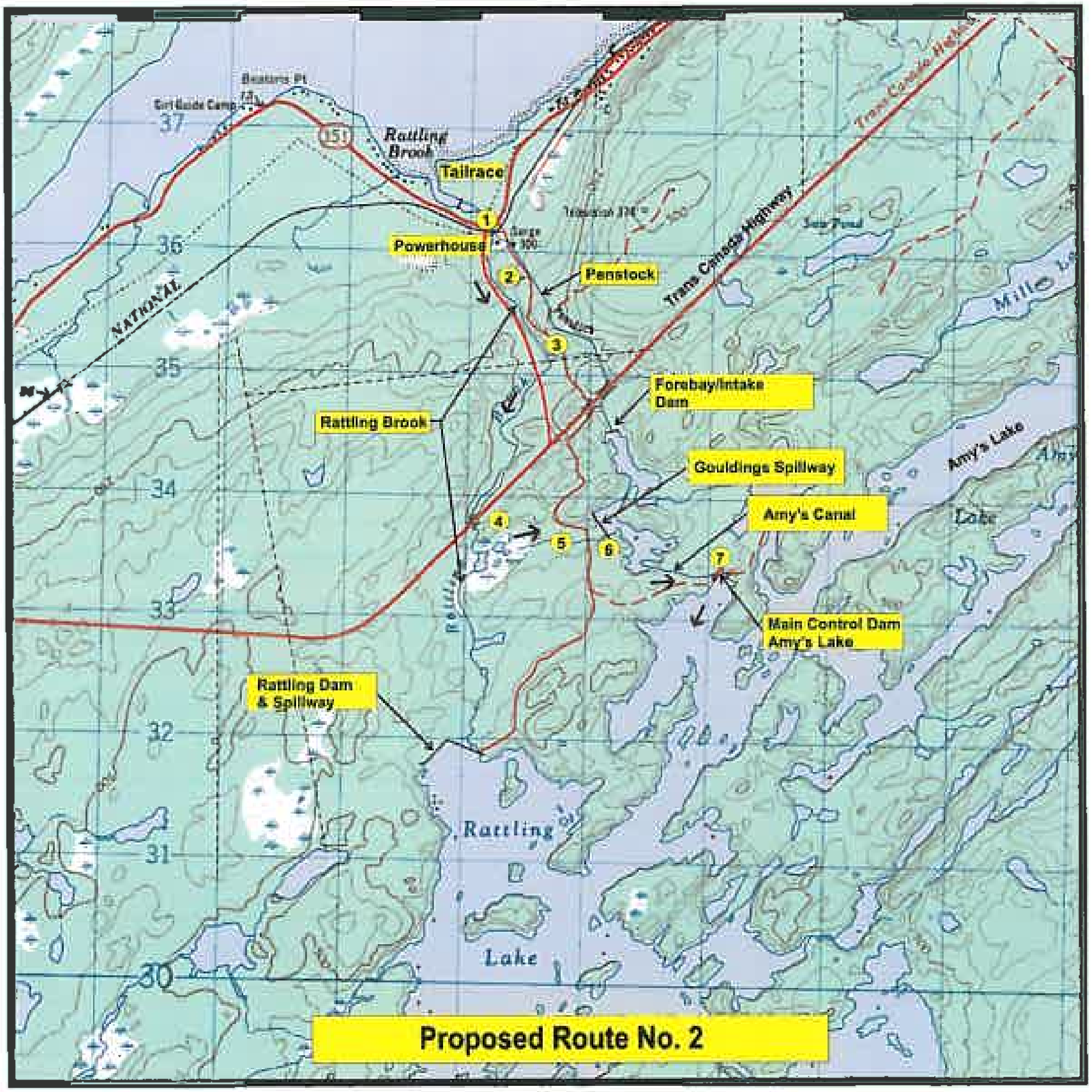
Annual Lost Energy Costs				
Lost Energy from Spill	$603,000	$603,000	$603,000	$144,720
Lost Energy due to Reservoir Limitations	$301,500			
Total	**$904,500**	**$603,000**	**$603,000**	**$144,720**
Annual Operating Cost				
Fish Monitoring/Operations/Maintenance	$127,000	$127,000	$127,000	$64,000
Total	**$127,000**	**$127,000**	**$127,000**	**$64,000**

As can be seen from Table 3 each Option has a different capital cost, with Option 1 being the most expensive and Option 4 being the least expensive. The lost energy and annual operating cost are very similar for Options 1, 2 and 3 and higher than Option 4. Option 4 has the least capital cost, least lost energy and least operating cost of all the four options examined.

Appendix A



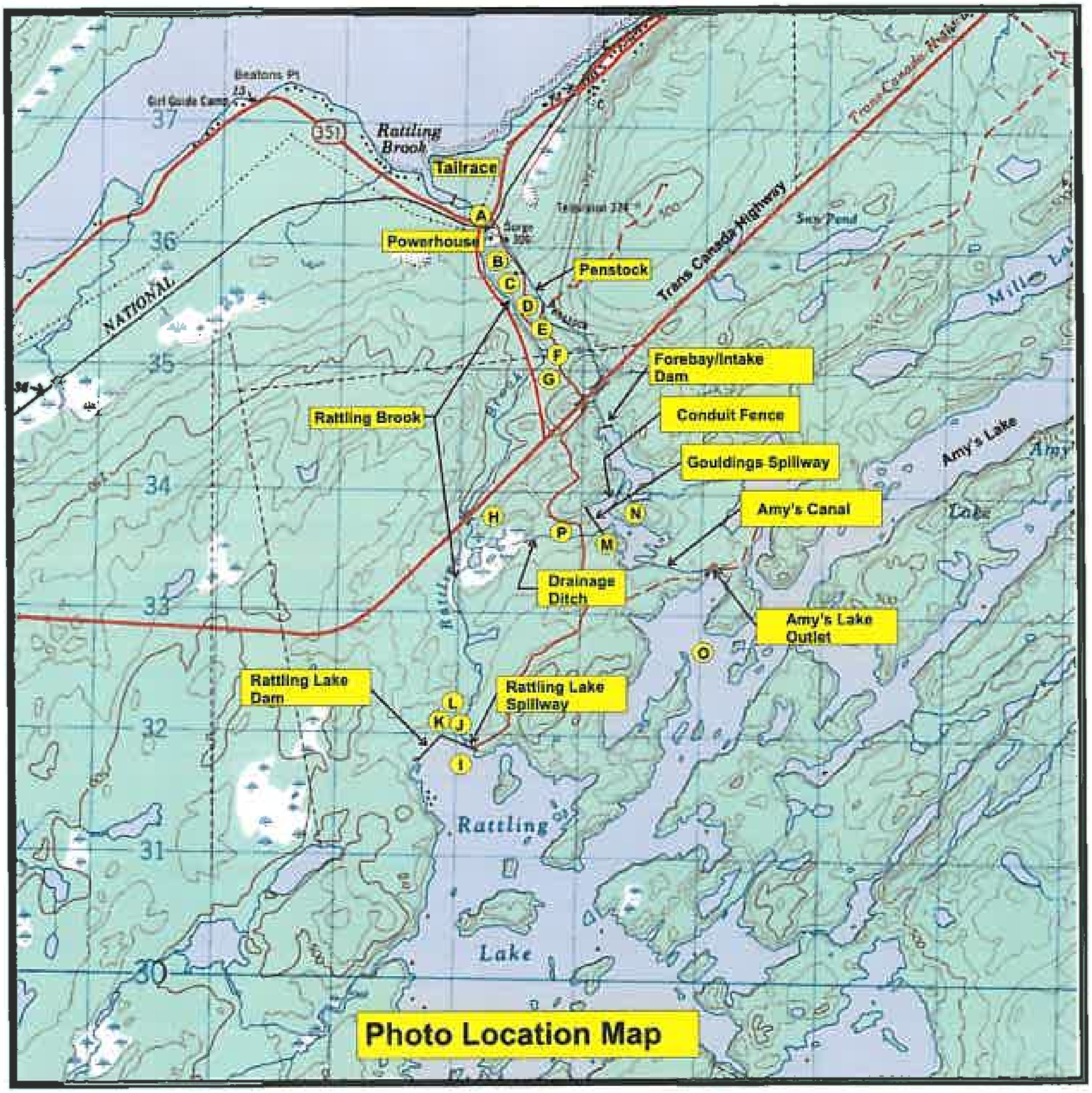
1	Tailrace Ladder
2 3 4 5 6 7 8	Obstruction In Rattling Brook
9	Rattling Lake Spillway Ladder
10	Conduit Fence
11	Drainage Ditch
→	Direction Of Proposed Salmon Migration



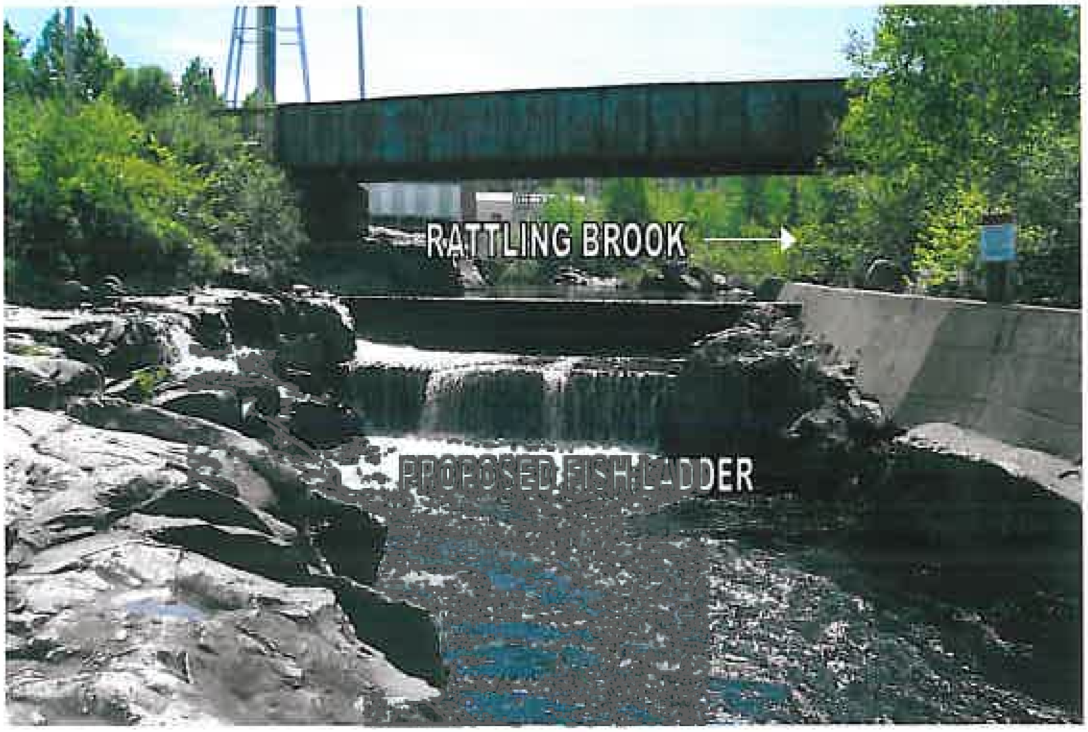
1	Tailrace Ladder
2 3 4	Fish Ladder In Rattling Brook
5	Channeling
6	Forebay Fish Ladder
7	Amy's Dam Ladder
→	Direction Of Proposed Salmon Migration

Appendix B

Photographs



A	Tailrace Ladder Location
B C D E F G H	Obstructions
I J K L	Rattling Lake Spillway
M N	Goulding's Spillway
O	Amy's Lake
P	Drainage Ditch



A. Tailrace tunnel (before spill test)

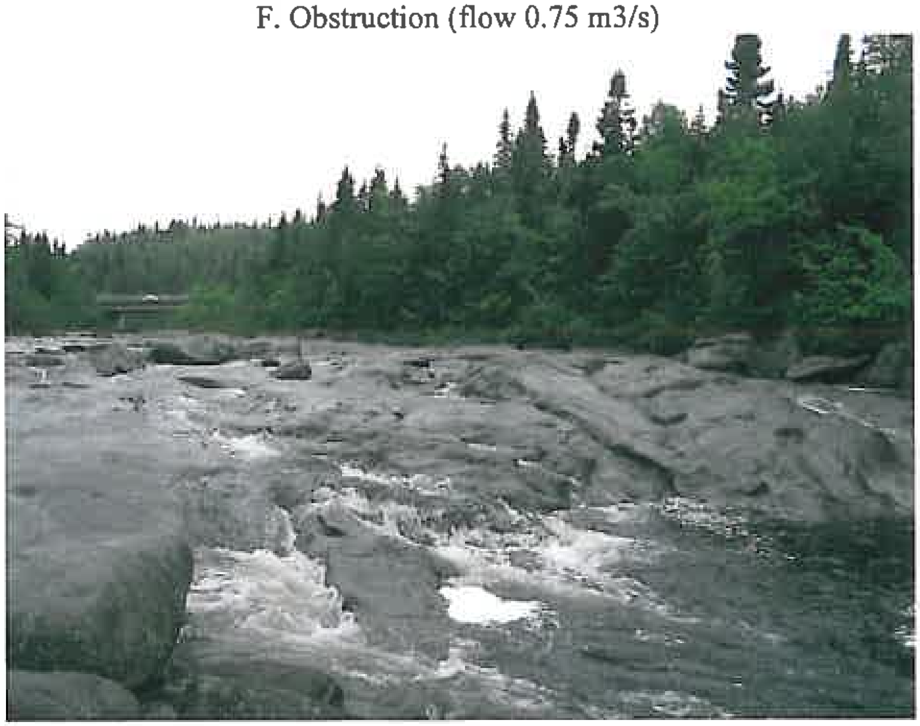
B. Obstruction (before spill test)

C. Obstruction (before spill test)

D. Obstruction (before spill test)

E. Obstruction (flow 0.75 m3/s)

F. Obstruction (flow 0.75 m3/s)

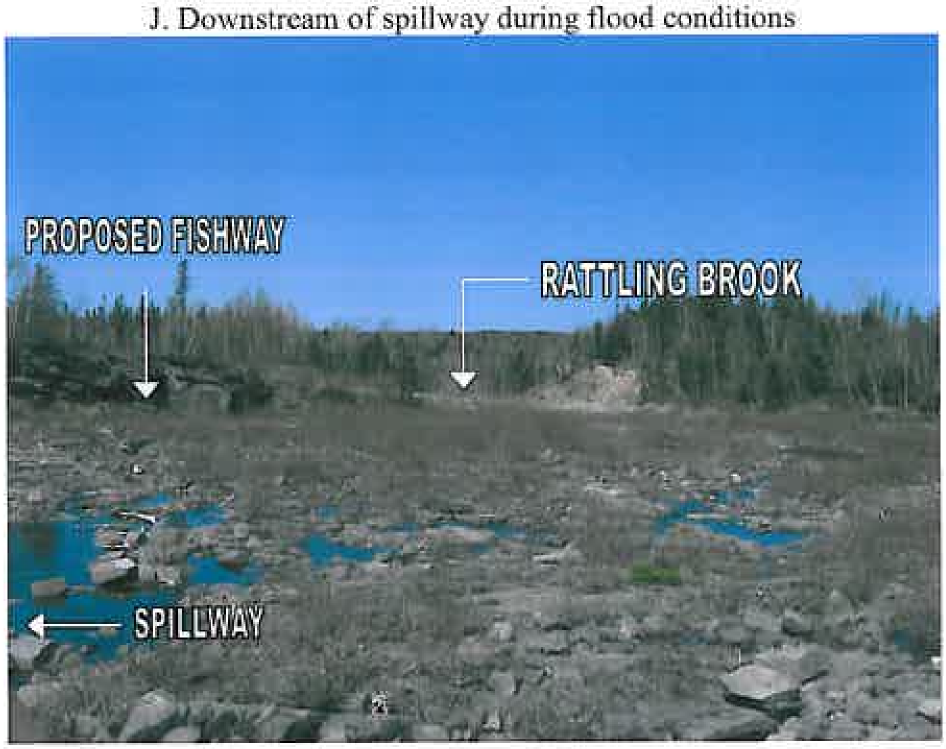


G. Obstruction (flow 0.75 m3/s)

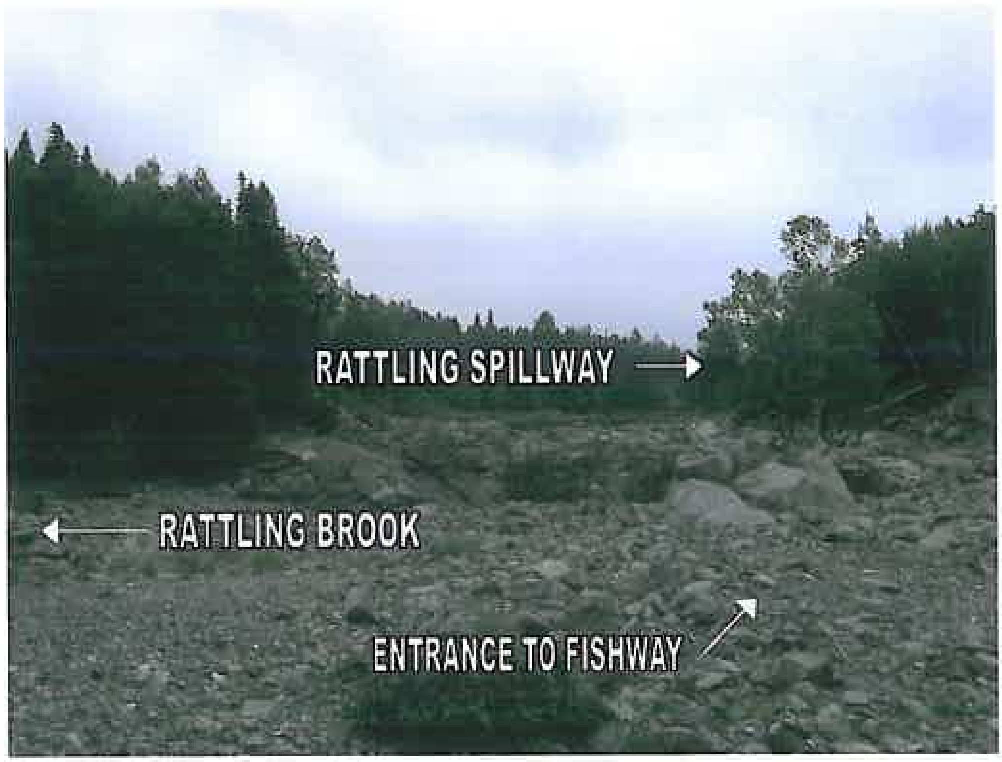
H. Obstruction at TCH bridge (flow 0.75 m3/s)

I. Aerial view of Rattling Lake Spillway at low water

J. Downstream of spillway during flood conditions



K. Downstream of Rattling Lake Spillway



L. Looking back towards Rattling Lake Spillway

M. Gouldings Spillway in the forebay.

N. Aerial view of Gouldings Spillway

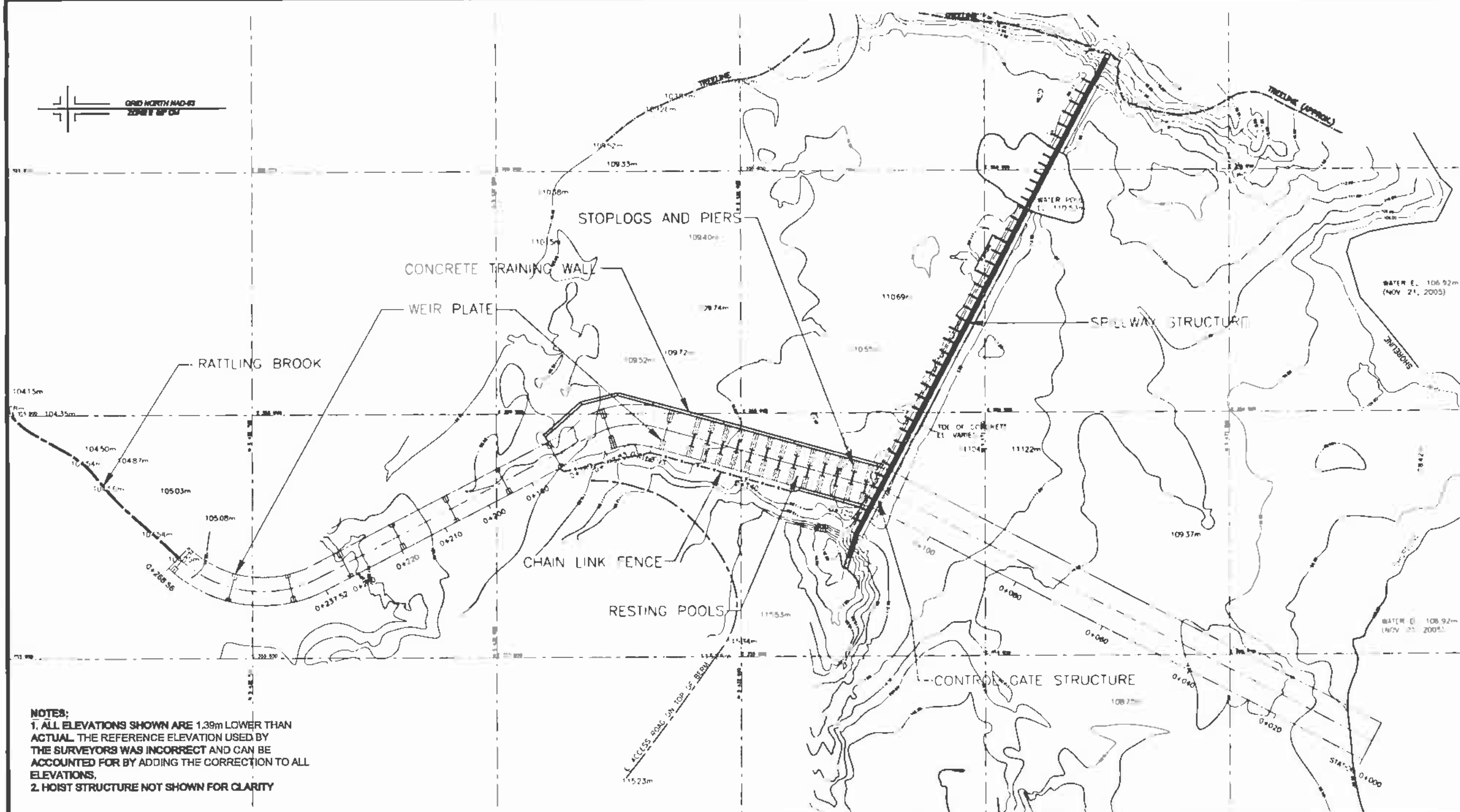
O. Aerial View of Amy's outlet structure and forebay

P. Vegetation in stream bed at Gouldings spillway

Q. Aerial View of Amy's outlet structure

Appendix C

Rattling Lake Spillway Fishway



NOTES:
1. ALL ELEVATIONS SHOWN ARE 1.39m LOWER THAN ACTUAL. THE REFERENCE ELEVATION USED BY THE SURVEYORS WAS INCORRECT AND CAN BE ACCOUNTED FOR BY ADDING THE CORRECTION TO ALL ELEVATIONS.
2. HOIST STRUCTURE NOT SHOWN FOR CLARITY

REFERENCE DRAWINGS	REV	DATE	REVISIONS	DRAWN BY	MADE BY	APP. BY

Project: RATTLING BROOK GENERATING STATION

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A FORTIS COMPANY

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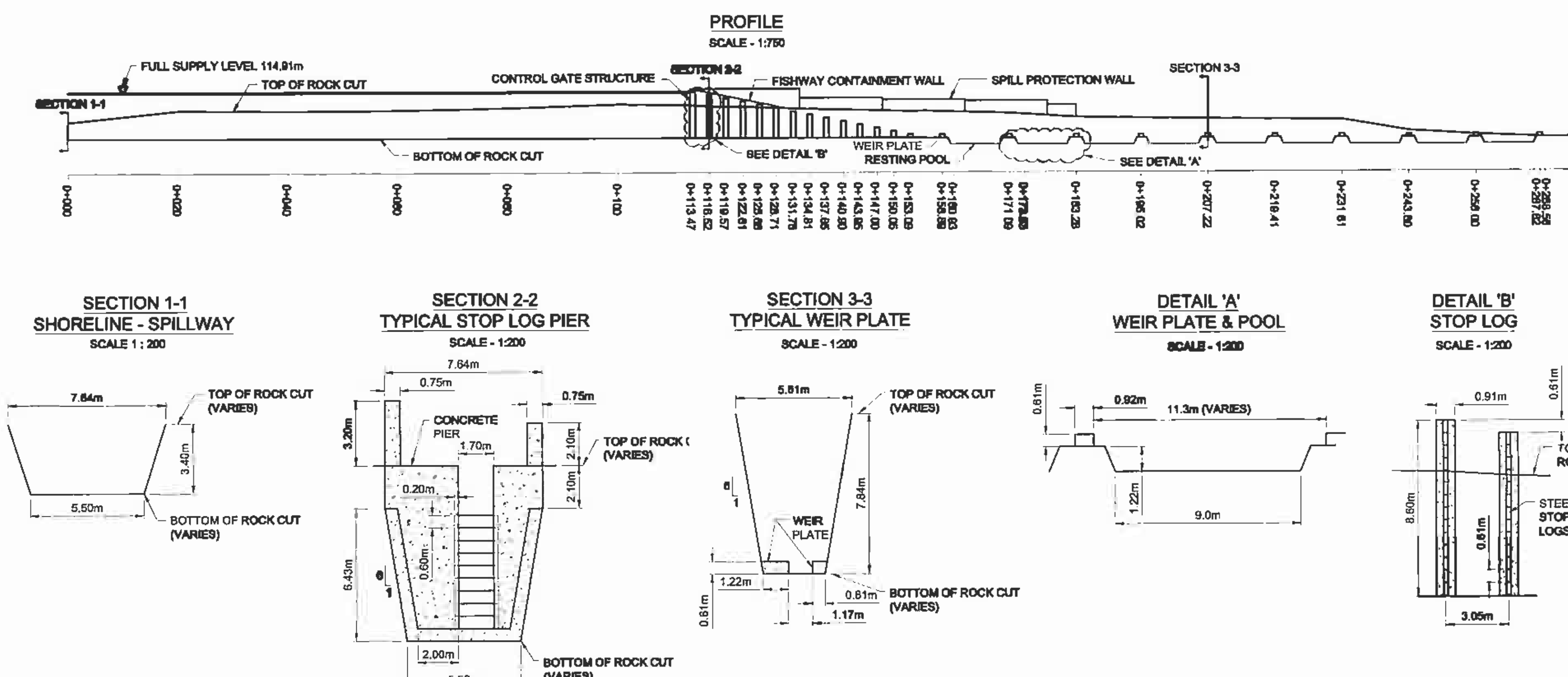
which is valid for the year 2009

Title: ALTERNATIVE No.1
CONCEPTUAL FISHWAY AT RATTLING SPILLWAY - SITE PLAN

Scale: 1 : 750

Date: 2009-03-27

DWG. NO. 1 OF 2



NOTES:
1. ADULT SALMON WILL MIGRATE UPSTREAM THROUGH FISHWAY AT RATTLING LAKE SPILLWAY.
2. SMOLT WILL MIGRATE DOWNSTREAM THROUGH A SMOLT CHANNEL AT AMY'S LAKE DAM. REFER TO ALTERNATIVE No.3 DRAWINGS FOR SITE PLAN, PROFILE, SETIONS AND DETAILS.
3. HOIST STRUCTURE NOT SHOWN FOR CLARITY.

REV	DATE		DRAWN BY	MADE BY	APP. BY

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Title: ALTERNATIVE No.1
PROFILE, SECTIONS & DETAILS

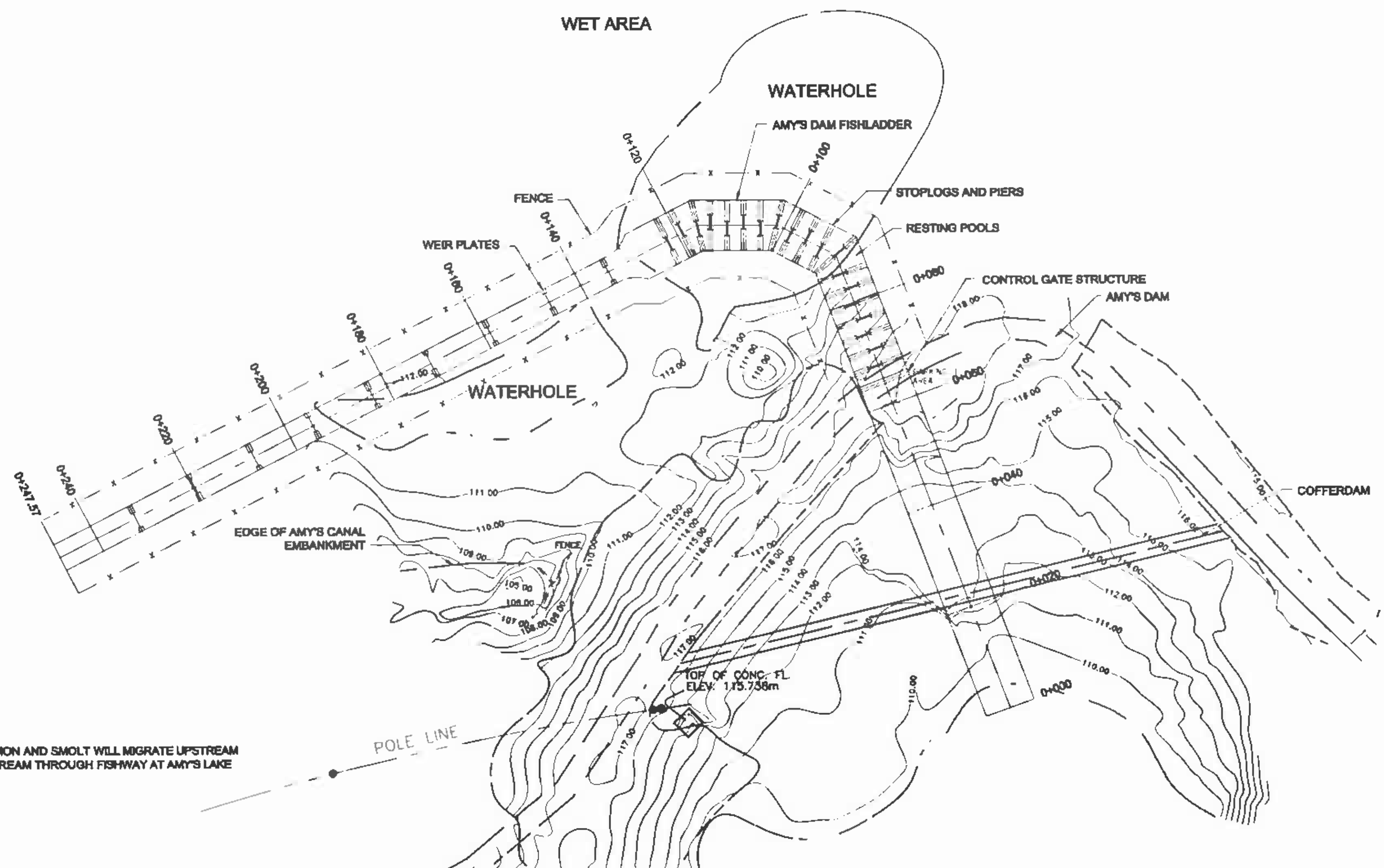
Scale: AS SHOWN

Date: 2009-03-27

DWG. NO.
2 OF 2

Appendix D

Amy's Lake Dam Fishway



NOTES:
1. ADULT SALMON AND SMOLT WILL MIGRATE UPSTREAM AND DOWNSTREAM THROUGH FISHWAY AT AMY'S LAKE DAM.

REV	DATE		DRAWN BY	MADE BY	APP. BY

REFERENCE DRAWINGS

REVISIONS

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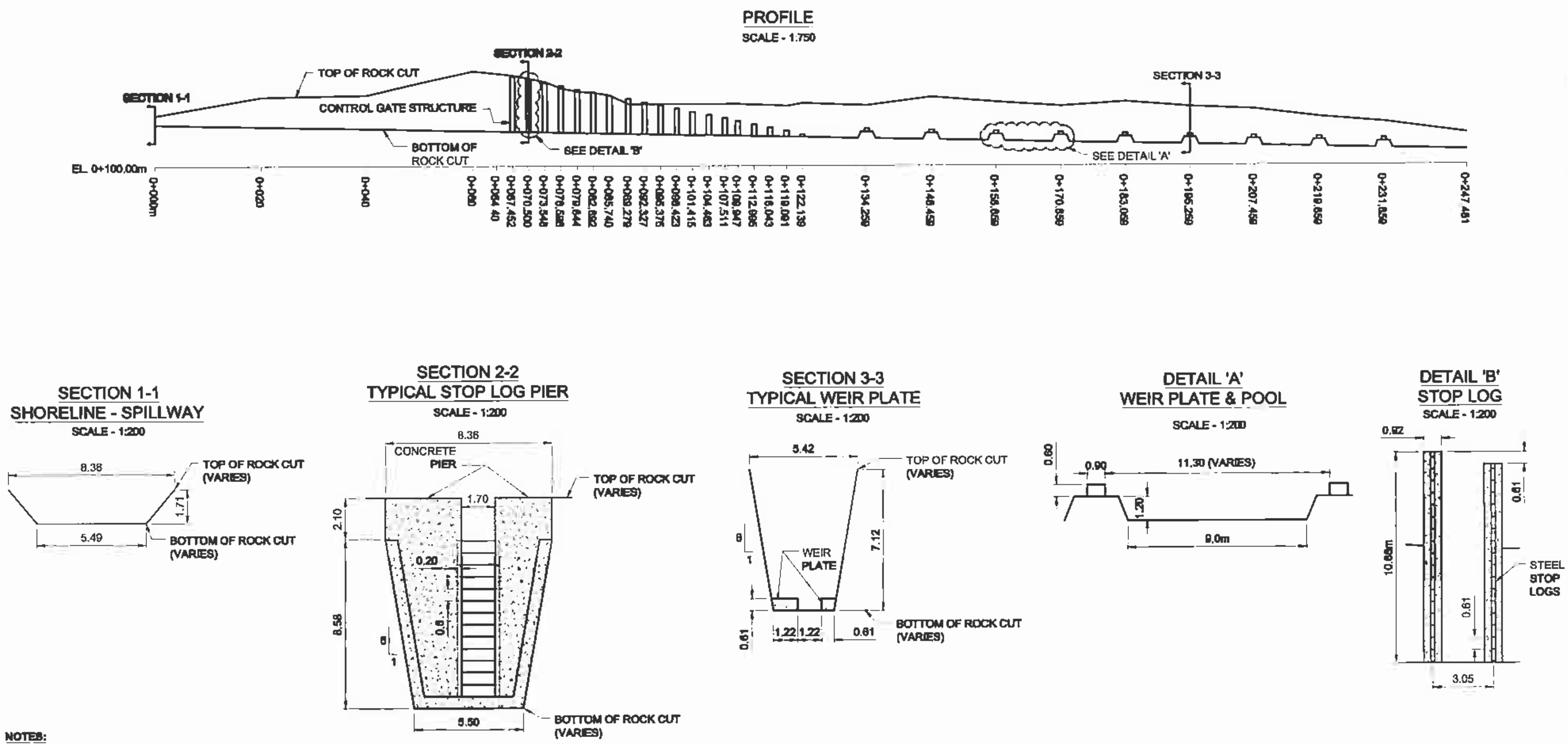
Title: ALTERNATIVE No.2 CONCEPTUAL FISHWAY AT AMY'S DAM FOR ADULT SALMON AND SMOLT MIGRATION SITE PLAN

Scale: AS NOTED

Date: 2009-03-27

DWG. NO. 1 OF 2



NOTES:
1. ADULT SALMON AND SMOLT WILL MIGRATE UPSTREAM AND DOWNSTREAM THROUGH FISHWAY AT AMY'S LAKE DAM.

REV	DATE		DRAWN BY	MADE BY	APP. BY

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Title: ALTERNATIVE No.2 CONCEPTUAL FISHWAY AT AMY'S DAM FOR ADULT SALMON AND SMOLT MIGRATION PROFILE AND SECTION DETAILS

Scale: AS NOTED

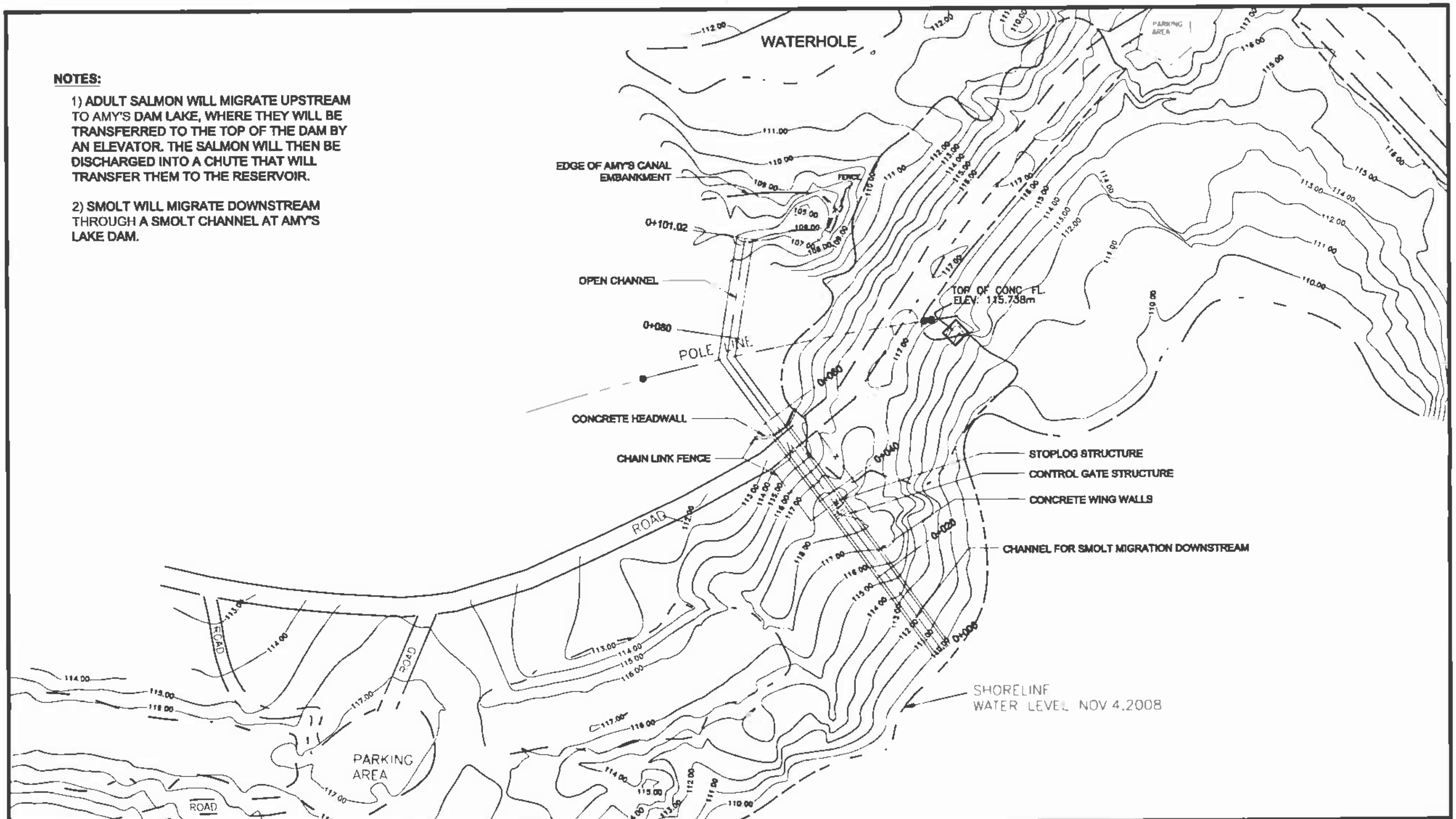
Date: 2009-03-27

DWG. NO. 2 OF 2

NOTES:

1) ADULT SALMON WILL MIGRATE UPSTREAM TO AMY'S DAM LAKE, WHERE THEY WILL BE TRANSFERRED TO THE TOP OF THE DAM BY AN ELEVATOR. THE SALMON WILL THEN BE DISCHARGED INTO A CHUTE THAT WILL TRANSFER THEM TO THE RESERVOIR.

2) SMOLT WILL MIGRATE DOWNSTREAM THROUGH A SMOLT CHANNEL AT AMY'S LAKE DAM.



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Title: ALTERNATIVE NO.3
CONCEPTUAL SMOLT CHANNELAT AMY'S DAM
SITE PLAN

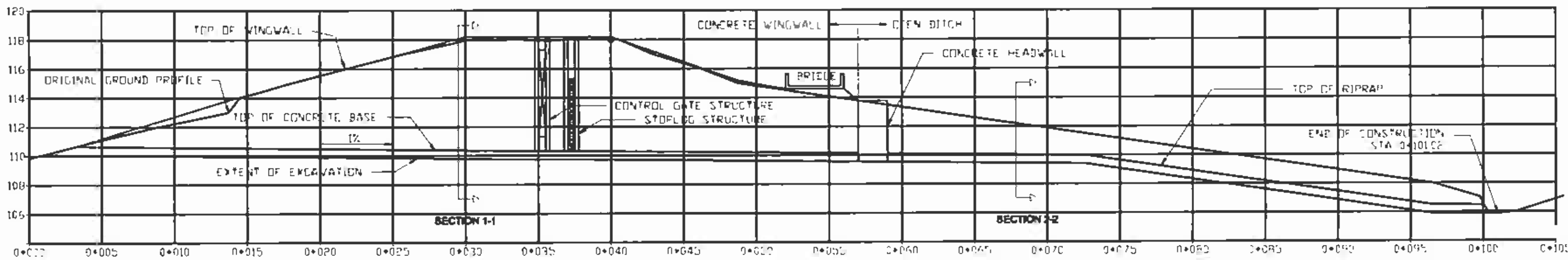
Scale: 1:750

Date: 09.10.26

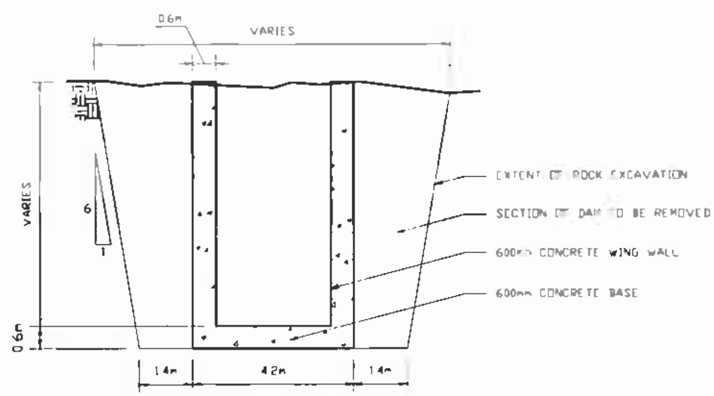
DWG. NO. 1 OF 2

NEWFOUNDLAND POWER
A FORTIS COMPANY

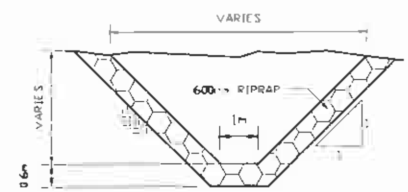
PROFILE
SCALE - 1:300



SECTION 1-1
TYPICAL SECTION THROUGH DAM
SCALE 1:125



SECTION 2-2
TYPICAL SECTION OPEN CHANNEL
SCALE 1:125



NOTES:

1) ADULT SALMON WILL MIGRATE UPSTREAM TO AMY'S DAM LAKE, WHERE THEY WILL BE TRANSFERRED TO THE TOP OF THE DAM BY AN ELEVATOR. THE SALMON WILL THEN BE DISCHARGED INTO A CHUTE THAT WILL TRANSFER THEM TO THE RESERVOIR.

2) SMOLT WILL MIGRATE DOWNSTREAM THROUGH A SMOLT CHANNEL AT AMY'S LAKE DAM.

REFERENCE DRAWINGS	REV	DATE	REVISIONS	DRAWN BY	MADE BY	APP. BY

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Title: ALTERNATIVE NO.3
CONCEPTUAL SMOLT CHANNEL AT AMY'S DAM
PROFILE AND SECTION DETAILS

Scale: AS SHOWN

Date: 09.10.28

DWG. NO. 2 OF 2

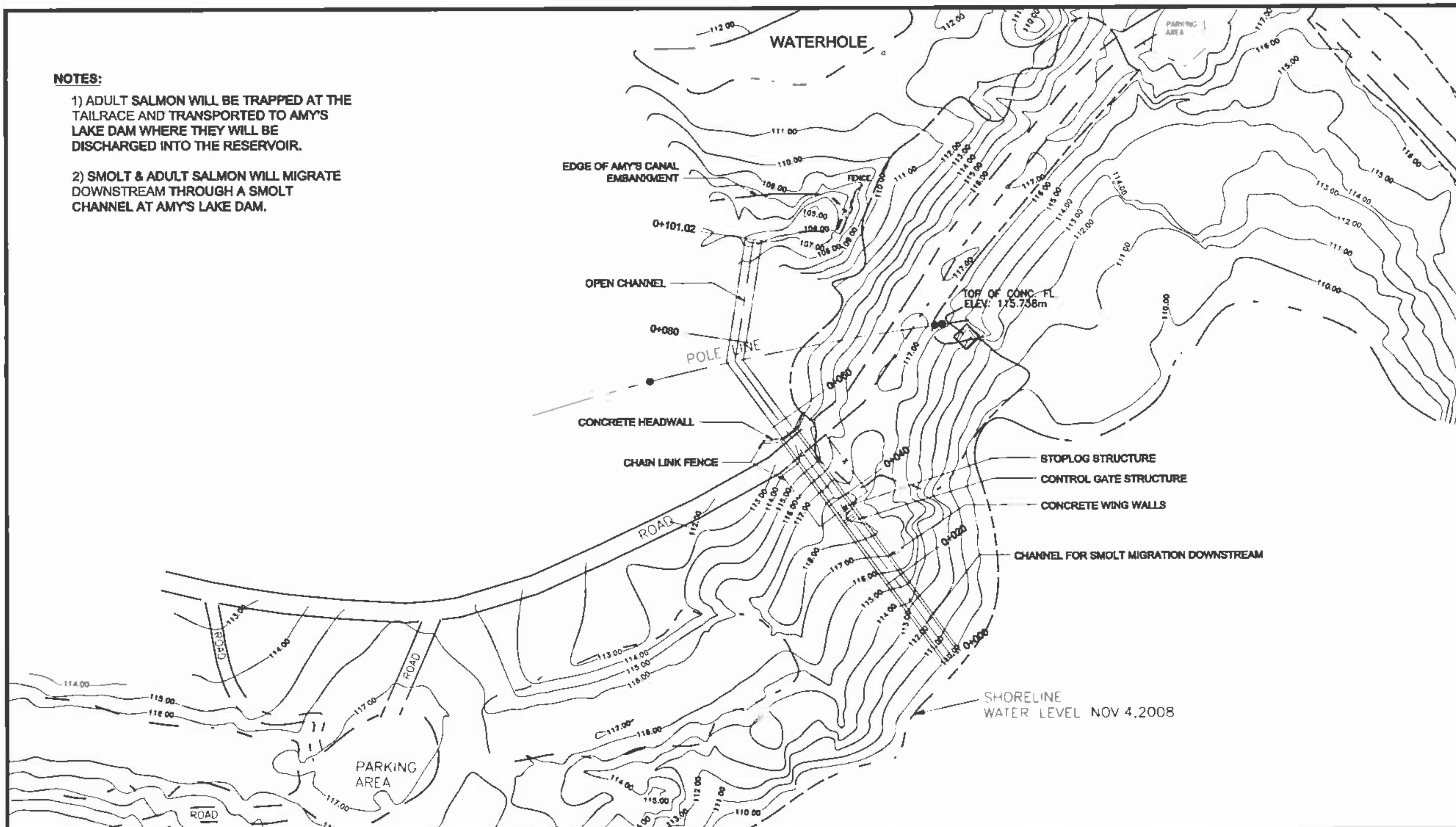
Appendix F

Amy's Lake Dam Channel

NOTES:

1) ADULT SALMON WILL BE TRAPPED AT THE TAILRACE AND TRANSPORTED TO AMY'S LAKE DAM WHERE THEY WILL BE DISCHARGED INTO THE RESERVOIR.

2) SMOLT & ADULT SALMON WILL MIGRATE DOWNSTREAM THROUGH A SMOLT CHANNEL AT AMY'S LAKE DAM.



REV	DATE		DRAWN BY	MADE BY	APP. BY

REFERENCE DRAWINGS

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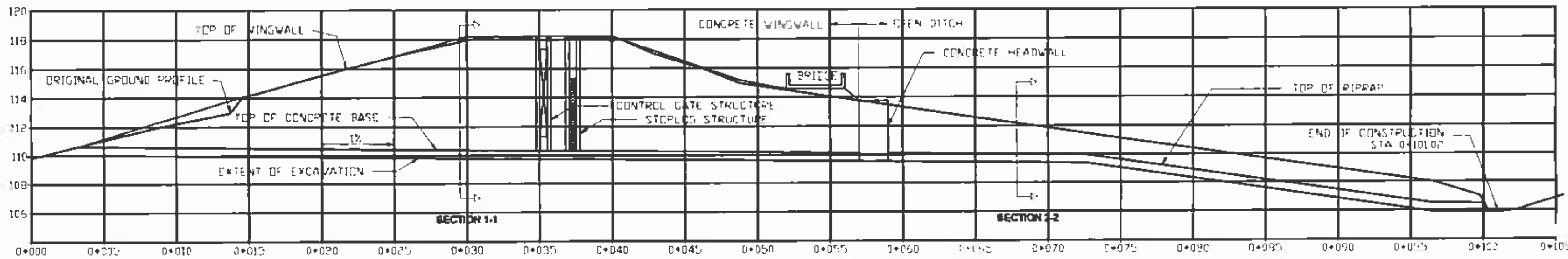
Title: ALTERNATIVE NO.4 CONCEPTUAL SMOLT CHANNELAT AMY'S DAM SITE PLAN

Scale: 1:750

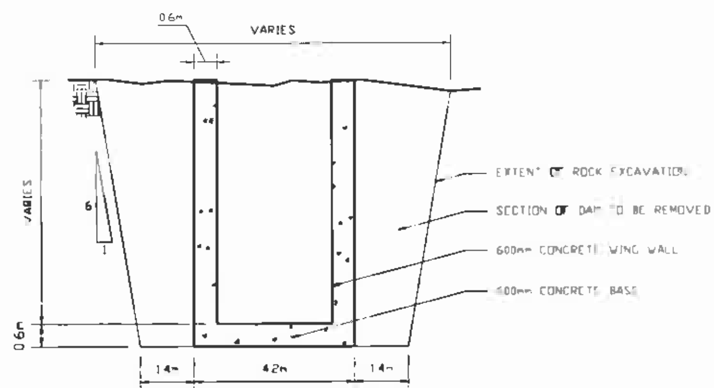
Date: 09.10.28

DWG. NO. 1 OF 2

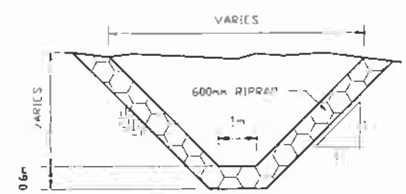
PROFILE
SCALE - 1:300



SECTION 1-1
TYPICAL SECTION THROUGH DAM
SCALE 1:125



SECTION 2-2
TYPICAL SECTION OPEN CHANNEL
SCALE 1:125



NOTES:

1) ADULT SALMON WILL BE TRAPPED AT THE TAILRACE AND TRANSPORTED TO AMY'S LAKE DAM WHERE THEY WILL BE DISCHARGED INTO THE RESERVOIR.

2) SMOLT & ADULT SALMON WILL MIGRATE DOWNSTREAM THROUGH A SMOLT CHANNEL AT AMY'S LAKE DAM.

REFERENCE DRAWINGS	REV	DATE	REVISIONS	DRAWN BY	MADE BY	APP. BY

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Title: ALTERNATIVE NO.4 CONCEPTUAL SMOLT CHANNEL AT AMY'S DAM PROFILE AND SECTION DETAILS

Scale: AS SHOWN

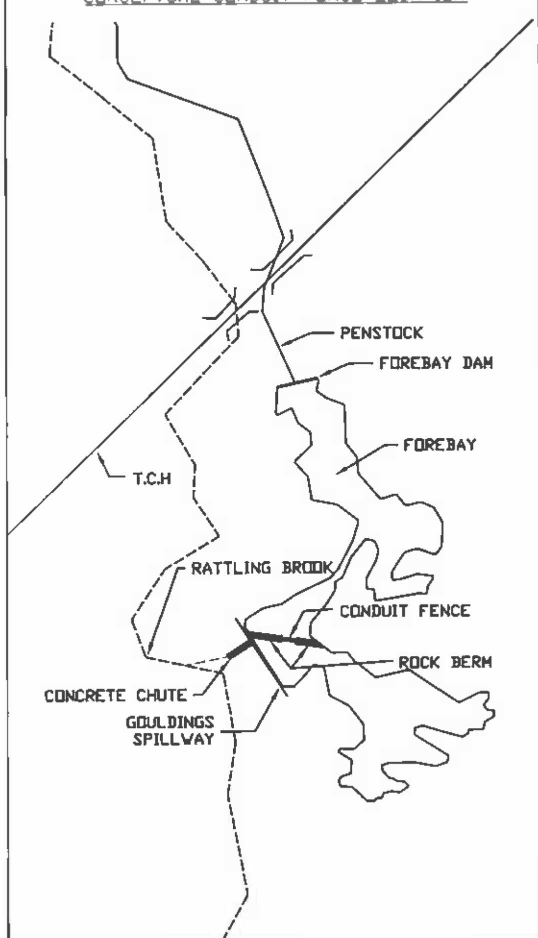
Date: 09.10.26

DWG. NO. 2 OF 2

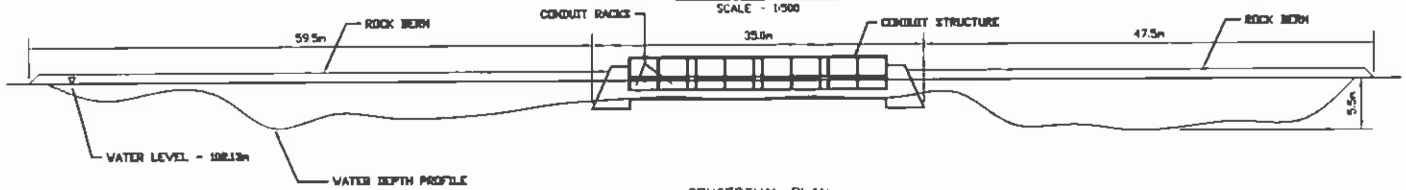
Appendix G

Gouldings Conduit Fence

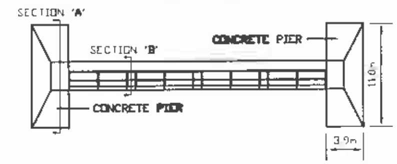
CONCEPTUAL CONDUIT FENCE LOCATION



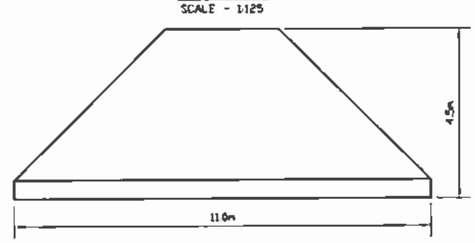
CONCEPTUAL PROFILE
SCALE - 1:500



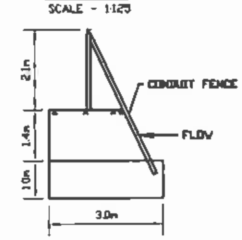
CONCEPTUAL PLAN
SCALE - 1:500



SECTION 'A'
SCALE - 1:125



SECTION 'B'
SCALE - 1:125



NOTES	REFERENCE DRAWINGS
1. HOIST STRUCTURE NOT SHOWN FOR CLARITY	

RATTLING BROOK GENERATING STATION

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NEWFOUNDLAND POWER INC.
N0057
2008

CONCEPTUAL CONDUIT FENCE AT GOULDINGS SPILLWAY
PLAN, PROFILE & SECTION DETAILS

Date:	PAGE 1 OF 1
App:	DWG No.

Appendix H

Greenhouse Gas Emission Calculation

Overview

Calculating greenhouse gas emissions in Newfoundland is straightforward as the province's grid is supplied by electricity generated using hydro or fossil fuel.

Hydro generation is a very clean source of energy as it is renewable and does not produce any air emissions. Electricity produced by conventional thermal plants, such as the Holyrood thermal generating plant, produces air emissions. These emissions contain a number of pollutants and greenhouse gases. Any reduction in electricity from hydro generation must be replaced with thermal generation. This is because the contribution that hydro plants can make to the grid is limited – they can only produce as much electricity as water flows permit. If hydro generated electricity is reduced, generation at the Holyrood thermal generating plant will have to increase in order to meet the demands of customers. This in turn causes increased environmental impacts.

Calculation

Newfoundland Hydro has determined net output rate of 630 kWh/bbl[1] and a CO2 emission factor of 0.483 t/bbl[2] at their Holyrood facility. Following is the calculation to determine the amount of greenhouse gas produced by displacing 7,500,000 kWh of hydro electricity.

$$\text{Greenhouse Gas} = \boxed{\frac{7{,}500{,}000}{630} \times 0.483} = \underline{5{,}750\text{ tons}}$$

A reduction of 7,500,000, 5,000,000 and 1,000,000 kWh from the Rattling Brook hydro generating plant will result in the production of an additional 5,750, 3,833 and 767 tons of greenhouse gas emissions at the Holyrood thermal generating plant.

1 The conversion rate of 630 kWh/bbl for No. 6 fuel at the Holyrood thermal generating plant was approved by the Public Utilities Board in Order No. P.U. 14 (2004).

2 0.483 tons of greenhouse gas emissions per barrel is based upon the fuel used at the Holyrood thermal generating plant.

Appendix C

An Assessment of the Potential Re-introduction of Atlantic salmon into Rattling Brook

Prepared by:

The Department of Fisheries & Oceans

An Assessment of the Potential Re-introduction of Atlantic salmon into Rattling Brook

December 2009

Headwaters of Rattling Brook

Prepared by:
The Department of Fisheries & Oceans

Table of Contents

Introduction

A Technical Working Group was struck in May of 2008 and tasked with determining if a viable means exists to address fish passage issues on Rattling Brook while ensuring that electricity generation from the plant, in terms of capacity and energy, not be less than the plant's output prior to the 2007 upgrade of the facility.

Specifically, the Technical Working Group was asked to explore the following objectives:

1. develop and examine options for providing fish passage in the Rattling Brook watershed,
2. assess the likelihood of success of a preferred option for providing fish passage,
3. estimate the size of salmon population that could be expected, the time frame of establishment of such a population and anticipated related benefits,
4. determine the capital cost, loss energy costs, operating costs and increases in greenhouse gas emissions associated with the preferred fish passage option, and
5. make a recommendation on the most practical and cost-effective option, providing such an option exists within the scope, for providing fish passage.

The technical working group held nine meetings from June 2008 to September 2009. The report summarizes discussions that took place during those meetings and addresses the five objectives that were outlined for the Technical Working Group. Newfoundland Power prepared the estimates on the cost of constructing fish passage facilities and the cost of lost power.

Objective 1. Develop and examine options for providing fish passage in the Rattling Brook watershed.

Rattling Brook has four major obstacles to fish passage:

1. Tailrace – the natural streambed cascades over a 2.5 meter rock and concrete embankment. Under normal low summer flows this would not permit upstream fish passage.

2. Gouldings Spillway – This spillway is approximately 3 meters high and consists of blasted rock. Any flow that passes over the spillway is distributed across the face of the spillway.

3. Amy's Lake Dam - Amy's Lake dam is approximately 105 meters long and 13 meters high. The dam is an earth core structure approximately 60 meters wide at the base and surrounded on both ends by large bedrock outcrops. Currently water is released through the dam via a submerged tunnel. At full supply, water passes through the tunnel at an estimated 13.1 m/s, thus preventing upstream and downstream fish passage.

4. Rattling Lake Spillway – This structure consists of concrete footing with creosoted timber to approximately 2 meters high. Water is only discharged over the spillway when the lake level exceeds the full supply level.

Based on the strategy that is ultimately chosen for providing upstream and downstream fish passage, a number of options are available. These options as well as the pros and cons of each are listed in the following table.

1.1 Options for Providing Upstream Fish Passage

Site	Option	Advantages	Disadvantages
Tailrace	Do nothing.	This option is the easiest and requires no construction or modification.	Does not provide fish passage.
	Construct a fishway.	This option will provide unimpeded fish passage into the original streambed. Fish can then access either Amy's or Rattling Dam, depending upon flow release options.	Requires continuous security of the fishway to ensure safety of the fish for duration of the run. Requires that water be spilled to provide passage along the original streambed.
	Trap and Transport	Most cost effective option for addressing fish passage obstacles since there is very little infrastructure cost associated with this option. No costs for stream remedial work in the lower reaches of the stream. Requires less water than the other options.	Requires continuous monitoring and operation for duration of the adult run. Requires construction of several pools to allow installation of the trap. Also requires that water be spilled to provide attraction into the trap.
Gouldings Spillway	Do nothing.	This option is the easiest and requires no construction or modification.	Does not provide fish passage.
	Construct a fishway.	This option will provide unimpeded fish passage into the original streambed. Fish can then access either Amy's Dam.	Requires continuous security of the fishway to ensure safety of the fish for duration of the run. Requires that water be spilled to provide passage along the original streambed.
Amy's Lake Dam	Do nothing.	This option is the easiest and requires no construction or modification.	Does not provide fish passage.
	Fishway	This option will	Costly to construct a fishway

		provide unimpeded fish passage into Amy's Lake.	that addresses the variation in lake level. Requires that water be spilled to provide passage along the original streambed.
	Elevator	This option will provide fish passage into Amy's Lake.	Will require extensive construction. Elevator will require constant monitoring to provide fish passage, and to ensure efficient operation. Requires that water be spilled to provide passage along the original streambed.
Rattling Lake Dam	Do nothing.	This option is the easiest and requires no construction or modification.	Does not provide fish passage.
	Fishway	This option will provide unimpeded fish passage into Rattling Lake.	Costly to construct a fishway that addresses the variation in lake level. Must work in combination with smolt facilities at Amy's Lake. This option may lead to stranding of fish in the "switch over" from smolt flows to adults flows. Requires that water be spilled to provide passage along the original streambed.

1.2 Options for Providing Downstream Fish Passage

Site	Option	Advantages	Disadvantages
Rattling Lake Spillway	Do nothing.	This option is the easiest and requires no construction or modification.	Does not provide fish passage.
	Construct a smolt bypass at the Rattling Lake Dam.	Construction can be incorporated into the proposed upgrading of the dam.	Smolt will follow the major flow of water toward Amy's Lake Dam, and away from the proposed bypass.
Amy's Lake Dam	Do nothing.	Option is the easiest and requires no construction or modification.	Atlantic salmon smolt moving downstream will tend to follow the flow and may hold at Amy's Lake prior to entering the

Site	Option	Advantages	Disadvantages
			tunnel. At full supply level, the tunnel may be 8.7 meters below the lake surface, producing a velocity through the tunnel of approximately 13.1 m/s. Any encounter with trash tracks or the sides of the tunnel at this velocity will no doubt affect the odds of survival for smolt. Both abrasion and delayed passage may contribute to increased mortality.
	Construct a surface spill bypass.	This option is the most desirable since it will address all downstream fish passage issues. Operation of the bypass will not affect operation of the reservoir.	This option will require extensive construction. Based on storage data for the past 10 years, the spillway should function down to a lake level of 365' in order to provide smolt passage.
Gouldings Spillway	Do nothing.	This option is the easiest and requires no construction or modification.	Smolt will follow the flow through the headpond and be into the penstock. Smolt will not survive this passage.
Gouldings Spillway	Construct a smolt diversion facility.	This option will require construction of a conduit fence to ensure that smolt are directed to the spillway and away from the penstock. It will also require construction of a small concrete spillway at the existing site to control flows and ensure safe downstream passage.	This option will require some construction and modification. Requires that water be spilled to provide passage along the original streambed.

Estimates for the cost of all major undertakings are outlined in Appendix 2.

1.3 Preferred Options for Providing Fish Passage

Based on the above assessment, the preferred routes are:

Upstream - Salmon would be trapped at the tailrace and transported to Amy's Lake Dam where they would be discharged directly into Rattling Lake reservoir. Given that this option requires the lowest capital investment and has the least impact on power generation, this is the preferred option for providing upstream fish passage.

Downstream – Smolt and kelt would pass through a channel at Amy's Lake Dam, into Amy's canal, into the forebay and over Gouldings Spillway. Once over Gouldings Spillway the kelt and smolt would travel through an old drainage stream for 1.3 kilometres until they reach the original Rattling Brook just upstream of the TCH Bridge. Fish would then follow the original stream to the Bay of Exploits.

Water Release – In order to provide fish passage, the following schedule of flows would be required on an annual basis:

- May 1 to June 30 – 0.7 cms spilled over the Goulding Spillway for smolt passage
- July 1 to September 15 – 0.5 cms spilled over the Goulding Spillway to provide attraction flow at the tailrace collection facility.

The exact timing of the flows may be modified based when information becomes available on the timing of the smolt and adult runs. In addition, an option has been presented that may eliminate the need to provide attraction flows in the tailrace. This option has not been fully explored to date.

Objective 2. Assess the likelihood of success of a preferred option for providing fish passage

When the fish passage obstacles have been addressed, Atlantic salmon are very adept at taking advantage of available habitat. Salmon enhancement activities have been employed successfully throughout Atlantic Canada and the Great Lakes region to introduce these fish to new or restored habitats. In the Province of Newfoundland and Labrador, Atlantic salmon have been introduced to the Terra Nova River, Great Rattling Brook, headwaters of the Exploits River, Rocky River, and Torrent River. Atlantic salmon have also been successfully re-introduced to previously dewatered habitats at Pamehac Brook (Scruton et al., 1998).

Given that anadramous salmon have historically inhabited Rattling Brook and that the technologies proposed to address the fish passage have been used successfully at other sites within the province and other jurisdictions, the probability of success of this project is absolute.

Objective 3. Estimate the size of salmon population that could be expected, the time frame for establishment of such a population and anticipated related benefits.

3.1. Potential size of the salmon population

Estimates of potential salmon production in a river system normally require information on the amount of available habitat. Since the hydro-electric development at Rattling Brook preceded efforts by DFO to quantify available habitat in the larger river systems of the province, detailed information is not available on this system. Therefore we will use several alternate means of estimating production. These methods are routinely used when detailed habitat information is non-existent.

3.1.a Based on an examination of the existing production data

We do have one measure of the productivity of Rattling Brook, ie. the actual number of fish that were counted at the Rattling Brook counting fence from 1956 to 1965 . The maximum number of fish enumerated during this period was 820 (Table 1). The counting fence data can be adjusted for commercial and recreational exploitation – assuming the commercial fishery harvested between 50-60% of production (Dempson et al., 2001) and the recreational fishery harvested between 20-30% of river escapement (C. Bourgeois, pers. com) , maximum production would be estimated at approximately **3000 adult Atlantic salmon**. These estimates of exploitation are on the very conservative end of the spectrum for the late 1950's since management measures to conserve salmon stocks have been introduced since the 1970's to reduce exploitation on all salmon stocks.

Table 1: Rattling Brook Counting Fence Data (Porter et al, 1974).

Year	Grilse	Salmon	Total
1956	372	224	596
1957	439	188	627
1958	690	130	**820**
1959	308	67	375
1960	600	112	712
1961	212	51	263
1962	130	21	151
1963	44	7	51
1964	19	3	22
1965	5	0	5

River Escapement = number enumerated/(Percent surviving the recreational harvest)
= 820/(0.7)
= 1171

Potential production = River escapement / (Percent surviving the commercial harvest)
= 1171/(0.4)
= 2927

3.1.b Based on a visual inspection of the habitat

A helicopter flight was conducted on July 29, 2008 to assess the habitat on Rattling Brook and Campbellton River, and to determine whether or not a comparison of the two watersheds is reasonable. Based on the flight, it was the unanimous opinion of Chuck Bourgeois, Keith Clarke, and Leon King that the production potential of Rattling Brook (with sufficient flow and free fish passage) would at least be equal to that of Campbellton River. Given the similarities in the watersheds, we estimate that the production potential of Rattling Brook would compare very favourably with the mean annual production on Campbellton River of approximately **3,100 adult Atlantic salmon**.

3.1.c Based on a comparison of adjacent watersheds

Other estimates of production can be obtained by comparing the ratios of drainage areas , area of standing water and total stream length on adjacent streams. Fortunately data sets exit for all of the major streams surrounding Rattling Brook, including Campbellton River, Salmon Brook and Great Rattling Brook. Physical attributes of all four streams are given in Table 2.

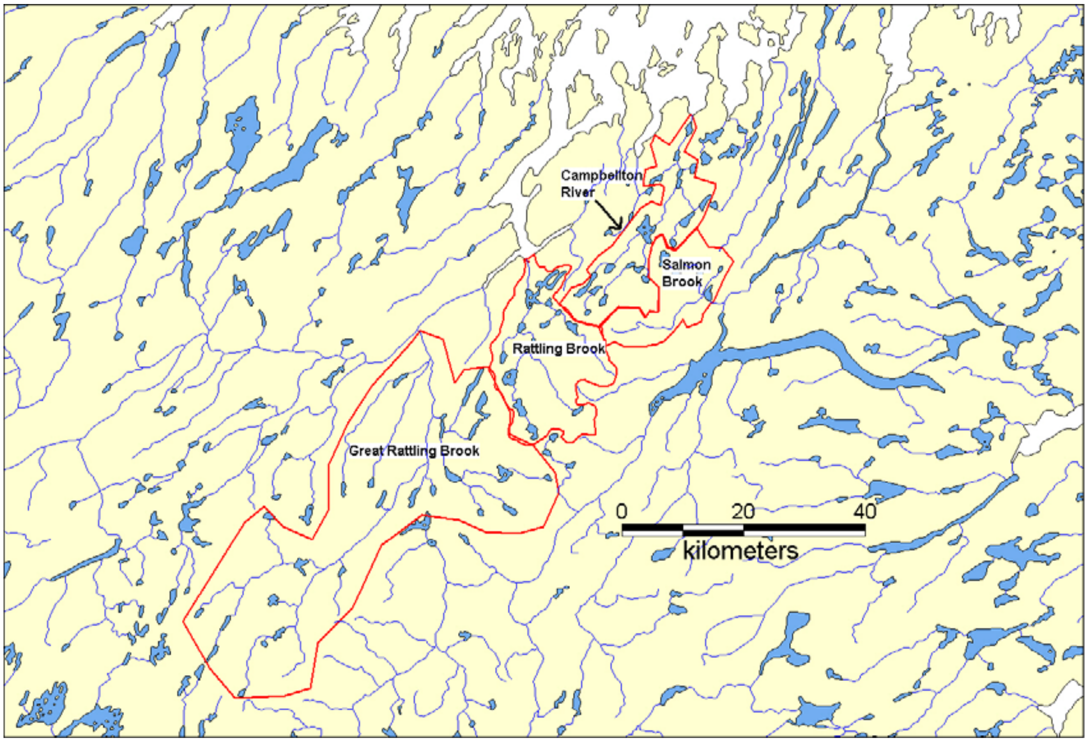


Figure 1 - Rattling Brook and Surrounding Watersheds

Table 2: Physical Attributes of Rattling Brook and Campbellton River

Attribute	Rattling Brook	Campbellton River	Salmon Brook	Great Rattling Brook
Drainage Area (km^2)- Note1	367-Note 2	295	195	1155
Length of stream (km)- Note 1	238	94	124	723
Area of Lakes (ha)- Note1	2332-Note 3	2307	1700	6700
Maximum Salmon Production –Note 4	-	4429	1825	14490

Notes:
1- extracted from DFO GIS
2- Only includes the area upstream from Amy's Lake
3 - does not include Amy's/Rattling Lake (959ha)
4 – DFO unpublished

Using the ratio of drainage areas, the following estimates of production on Rattling Brook can be calculated:

Stream	Drainage Area (km^2)	Maximum Production	Projected Production for Rattling Brook
Salmon Brook	195	1825	3435
Campbellton River	295	4430	5511
Great Rattling Brook	1155	14490	4604
		Mean	**4516**

Using the ratio of standing water, the following estimates of production on Rattling Brook can be calculated:

Stream	Standing Water	Maximum Production	Projected Production for Rattling Brook
Salmon Brook	1700	1825	2503
Campbellton River	2307	4430	4478
Great Rattling Brook	6700	14490	5043
		Mean	**4008**

Using the ratio of stream length, the following estimates of production on Rattling Brook can be calculated:

Stream	Stream Length	Maximum Production	Projected Production for Rattling Brook
Salmon Brook	124	1825	3429
Campbellton River	94	4430	10981
Great Rattling Brook	723	14490	4670
		Mean	**6359**

If we exclude the highest and lowest of all nine estimates, the combined mean of the remaining seven estimates is **4453 adult Atlantic salmon**. This suggests that the estimates obtained in Sections 3.1.a and 3.1.b may be very conservative.

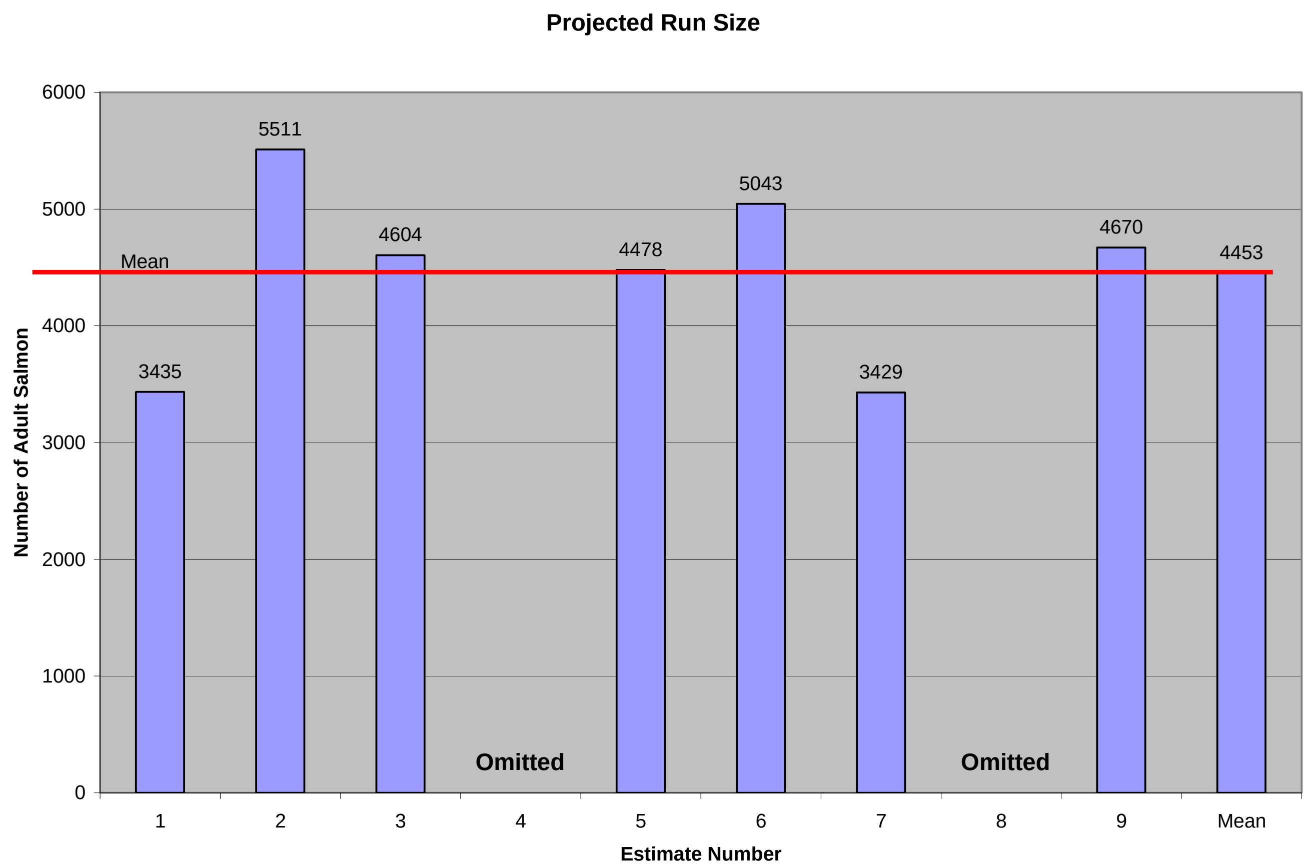


Figure 2 - Projected Run Size based on a Comparison with Adjacent Watersheds

3.2. Time frame for establishment of such a population

Three options are available to re-establish an anadramous population of Atlantic salmon on Rattling Brook, 1.) natural straying, 2.) fry stocking, and 3.) adult transfer. Although natural straying is the most cost effective method of achieving colonization, population growth is slow (Mullins et. al.,2003). Therefore the preferred options are either fry stocking and/or adult transfer. The time frame for achieving full production potential from any watershed is dependant upon a variety of factors but two to three generations (10 – 15 years) should be adequate to establish a self sustaining population of Atlantic salmon. Assessment of the level of returns could better define the timeframe required which would occur with the trap and transport option.

3.3. Anticipated related benefits

If we accept the most conservative estimate of annual production, 3000 adult salmon as outlined in Section 3.1.a, Rattling Brook will still rank in the top 20% of scheduled salmon rivers in Newfoundland and Labrador. Examples of streams of this size include, Terra Nova River, Campbellton River, Indian River, and Torrent River.

The benefits associated with the re-establishment of a salmon run include improved recreational fishing, increased opportunities for tourism, as well as other ancillary benefits associated with a more pristine environment.

From an economic perspective, based on the most recent (2005) recreational fisheries survey conducted by DFO, each retained salmon equates to approximately $550 of expenditures. The recreational harvest in Salmon Fishing Area 4 generally takes 20-30% of river escapement. If we estimate the run at 3000 salmon and the harvest at 20%, then the fishery will contribute $330,000 to the economy annually.

Objective 4. Determine the capital cost, loss energy costs, operating costs and increases in greenhouse gas emissions associated with the preferred fish passage option

The following information was prepared by Newfoundland Power.

4.1 Capital Costs

4.1.a Detailed Study Requirements

This report contains a preliminary assessment of the options to provide fish passage in the Rattling Brook watershed. Detailed studies would have to be completed prior to detailed engineering. The necessary studies would include a detailed assessment of the stream profile, minimum flow requirements, an evaluation of the existing fish habitat, and design and cost estimates of all fishways and other requirements.

The detailed engineering required for this project would be comprised of two components: 1) fishway and structure design and 2) habitat design. Since most structures would be built in the flood route, all designs would have to take into consideration flood events to ensure that spill capacity and dam safety are not affected. All structures in the flood path would have to withstand design floods and overtopping.

Newfoundland Power has estimated the costs of studies and detailed engineering to complete the work are $500,000.

4.1.b Ladder at the Tailrace

A concrete fish ladder would be required at the tailrace to allow fish to move from the area below the tailrace tunnel into the natural brook area. This area is within a confined channel, downstream of the plant, and would require widening of the channel so as not to restrict the tailrace flow. The vertical drop in the area where the ladder would be located is about 3-4 metres. Blasting would be required to widen the channel and provide the foundation for the fish ladder. However, blasting work would have to be done with care to avoid damage to the existing tailrace tunnel. The location of the ladder should take this into consideration. Appendix 6 contains a view of the tailrace.

Newfoundland Power has estimated the capital cost to install the tailrace fish ladder is $300,000.

4.1.c Collection Basin at the Tailrace

A collection basin would be required at the tailrace to trap salmon for transport to Amy's Lake Dam.

Newfoundland Power has estimated the capital cost to construct the collection basin is to be $50,000.

4.1.d Smolt Channel at Amy's Lake Dam

Appendix 3 contains a conceptual drawing of the channel at Amy's Lake Dam. A channel of approximately 101 metres long would have to be excavated.

A steel control gate would be installed at the dam to ensure the integrity of the dam at full supply level and for maintenance of the channel. To accommodate the installation of the control gate, a section of the dam, over 8 meters high and 10 meters wide would have to be removed. The section of the dam that would have to be removed is bedrock, therefore blasting would be required. Blasting work would have to be completed with care to avoid damage to the dam.
Concrete wing walls would be installed on the upstream and downstream side of the dam to ensure the dam is stable on each side of the excavation.

To regulate the flow into the channel a stoplog system would be installed immediately downstream of the steel control gate. A hoist system would be required to operate the gate and remove the logs to accommodate varying water levels. Approximately 12 removable 600 mrn stoplogs would be required. The stoplogs would be steel with rubber seals to reduce leakage and allow for practical installation and remova1.

From the toe of the dam to Amy's canal the channel would be an open excavation. The channel would pass under the road that is currently used to access Amy's Lake Dam. A bridge would be constructed in this area to span the channel.

Once all salmon and smolt have migrated downstream (mid-May - mid-June) all stoplogs would be removed. Downstream fisheries flow would be maintained either through release of water through the channel using the vertical steel control gate or through Amy's Outlet. Mid-May of each year the stoplogs would be reinstalled and the gate would be opened allowing downstream migration of salmon and smolt.

The capital cost to construct a channel at Amy's Lake Dam is estimated to be $2,000,000.

4.1.e Conduit Fence and Concrete Chute at Gouldings Spillway

One of the major concerns with returning salmon to the Rattling Brook system is the survival rate of smolt and the ability of smolt to get downstream to the Bay of Exploits without passing through the penstock and turbines. To address this issue a conduit fence would be installed in the forebay to direct the smolt over Gouldings Spillway and into Rattling Brook. The location proposed by DFO for the conduit fence spans across the full length of the forebay and is over 100 metres long. The water depth in this area varies from 1 to 5 metres. Appendix 5 contains a conceptual drawing of the conduit fence.

In the conceptual design of the conduit fence, 75 metres of the distance would be spanned with a rock berm. The remainder would be spanned with a concrete conduit structure. The concrete structure would have racks that would be placed in the water during May and June which would direct smolt into a concrete chute. The chute would direct the smolt over Gouldings Spillway into an old drainage stream that would then carry them to Rattling Brook. The flow from Rattling Lake spillway would then carry them to the Bay of Exploits.

Newfoundland Power has estimated the capital cost to construct the conduit fence at $540,000. The cost for the concrete chute at Gouldings Spillway is estimated at $180,000.

4.2 Lost Energy Costs

Based on a levelized cost of energy over 50 years at 12.06 cents/kWh and spilled water for the trap and transport option in the order of 1.0 GWh per year,   Newfoundland Power has estimated $120,600 of lost energy annually.

If additional flows are required to provide for the attraction of adult fish near the tailrace, these flows may amount to another 1.0 GWh per year.

4.3 Operating Costs

Newfoundland Power has stated that should the trap and transport option be utilized annual operating cost would be lower than other options. It is estimated that $50,000 would be required to trap and transport salmon at the tailrace to Amy's Lake Dam. The annual operating costs of $50,000 levelized over 50 years would be $64,000.

4.4 Greenhouse Gas Impact

Newfoundland Power has suggested that power purchased to replace the lost energy from Rattling Brook would be replaced by thermal electricity generated at Newfoundland and Labrador Hydro's Holyrood Plant. Based on a loss of 1.0 GWh of hydroelectric production, an additional 767 tons of greenhouse gases would be released annually into the environment from the additional energy productions at Holyrood.

4.5 Summary of Costs for Trap & Transport:

Capital Infrastructure Cost		
Studies/Engineering Design	$	500,000.00
Tailrace Fish Ladder	$	300,000.00
Collection Basin at Tailrace	$	50,000.00
Channel at Amy's Lake Dam	$	2,000,000.00
Gouldings Smolt Conduit Fence	$	540,000.00
Concrete Chute at Gouldings Spillway	$	180,000.00
Project Management and Other	$	275,000.00
Total	**$**	**3,845,000.00**
Annual Lost Energy Costs		
Lost Energy from Spill	**$**	**120,600.00**
Annual Operating Cost		
Fish Monitoring/Operations/Maintenance	**$**	**64,000.00**

Objective 5. Make a recommendation on the most practical and cost-effective option, providing such an option exists within the scope, for providing fish passage.

The terms of Reference for the Technical Working Group specified that the assessment of the construction and operation of a fish passage facilities would be carried out within the constraints that water flows required for critical life stages and processes for salmon in Rattling Brook be maintained, and that electricity generation from the plant, in terms of capacity and energy, not be less than the plant's output prior to the 2007 upgrade of the facility.

The 2007 Rattling Brook Hydro Plant Refurbishment project increased annual energy generation by 6.2 GwH. Since lost energy associated with the Trap & Transport option amounts to only 1.0 GwH, the Trap & Transport option meets the criteria specified in the Terms of Reference.

References:

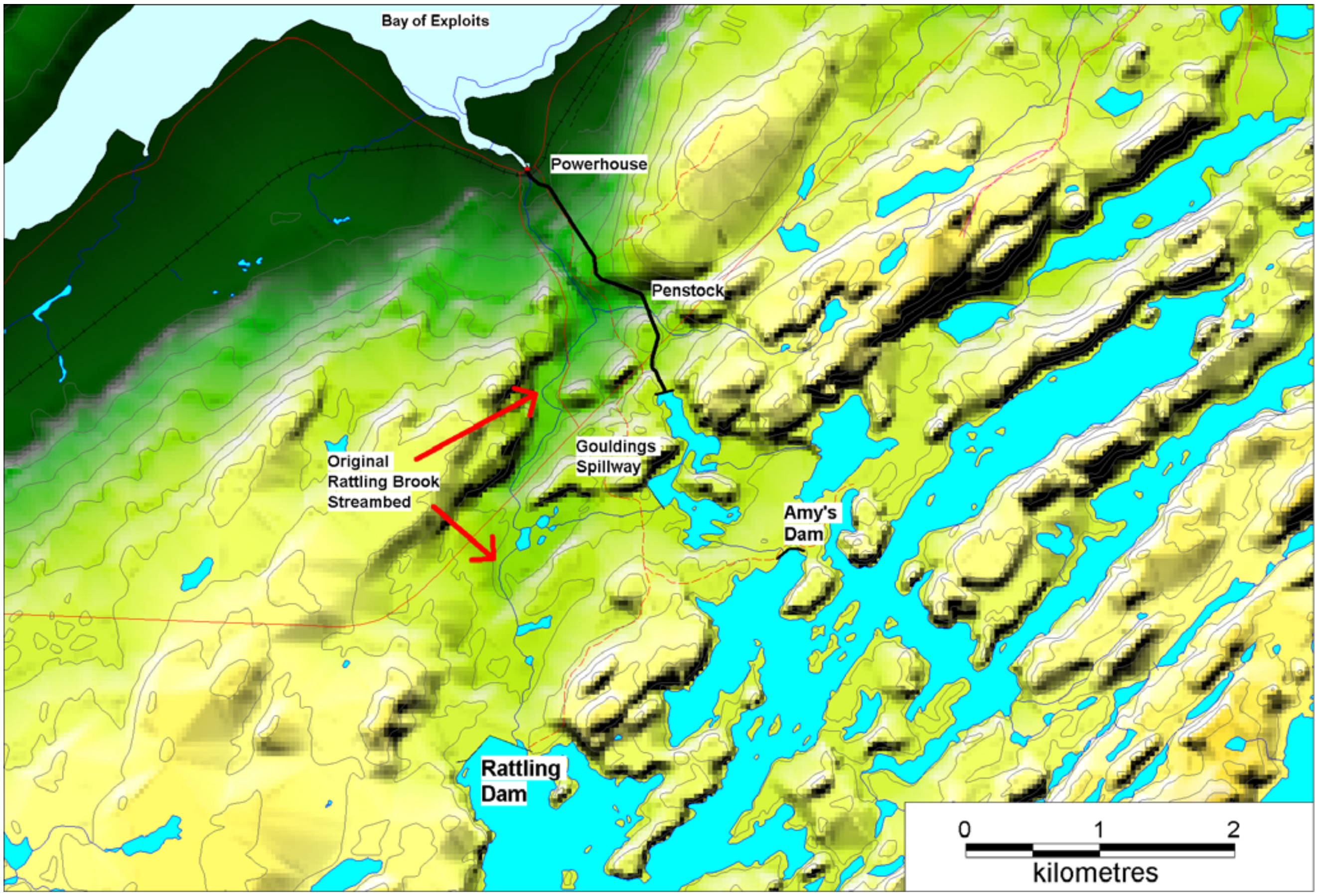
Dempson, J. B., C. J. Schwarz, D. G. Reddin, M. F. O'Connell, C. C. Mullins, and C. E. Bourgeois. 2001. Estimation of marine exploitation rates on Atlantic salmon (Salmo salar) stocks in Newfoundland, Canada. ***ICES Journal of Marine Science 58: 331-341.***

Mullins, C. C., C. E. Bourgeois, and T. R. Porter. 2003. Opening up new.
habitat: Atlantic salmon (Salmo salar L.) enhancement in Newfoundland, pp. 200-221. ***In: Mills, D. [ed.] Salmon at the edge. Blackwell Science Ltd. Oxford. 307 pp***

Porter, T.R., L.G. Riche and G.R. Traverse. 1974. Catalogue of Rivers in Insular Newfoundland, Volume D. Fisheries & Marine Service.

Scruton, D.A., T.C. Anderson, and L.W. King, 1998. Pamehac Brook: A case study of the restoration of a Newfoundland, Canada, river impacted by flow diversion for pulpwood transportation. ***Aquatic Conservation: Marine and Freshwater Ecosystems. 8: 145-157***

Appendix 1: Map of the lower section of Rattling Brook



Appendix 2. Summary of Preliminary Cost Estimates for all Possible Options

	Option 1	Option 2	Option 3	Option 4
Capital Infrastructure Cost				
Studies/Engineering Design	$ 500,000	$ 500,000	500,000	500,000
Tailrace Fish Ladder	300,000	300,000	300,000	300,000
Rattling Brook Channel Improvements	350,000	350,000	350,000	
Ladder System at Rattling Spillway	4,800,000			
Ladder System at Amy's Lake Dam		9,000,000		
Elevator at Amy's Lake Dam			2,500,000	
Channel at Amy's Lake Dam	2,000,000		2,000,000	2,000,000
Concrete Chute or Fish Ladder at Gouldings Spillway	180,000	250,000	250,000	180,000
Gouldings Smolt Conduit Fence	540,000	540,000	540,000	540,000
Collection Basin at Tailrace				50,000
Fish Habitat Development	275,000	275,000	275,000	
Project Management and Other	275,000	275,000	275,000	275,000
Total	**$9,220,000**	**$11,490,000**	**$6,990,000**	**$3,845,000**
Annual Lost Energy Costs				
Lost Energy from Spill	$ 603,000	$ 603,000	$ 603,000	$ 120,600
Lost Energy due to Reservoir Limitations	301,500			
Total	**$ 904,500**	**$ 603,000**	**$ 603,000**	**$ 120,600**
Annual Operating Cost				
Fish Monitoring/Operations/Maintenance	$ 127,000	$ 127,000	$ 127,000	$ 64,000
Total	**$ 127,000**	**$ 127,000**	**$ 127,000**	**$ 64,000**

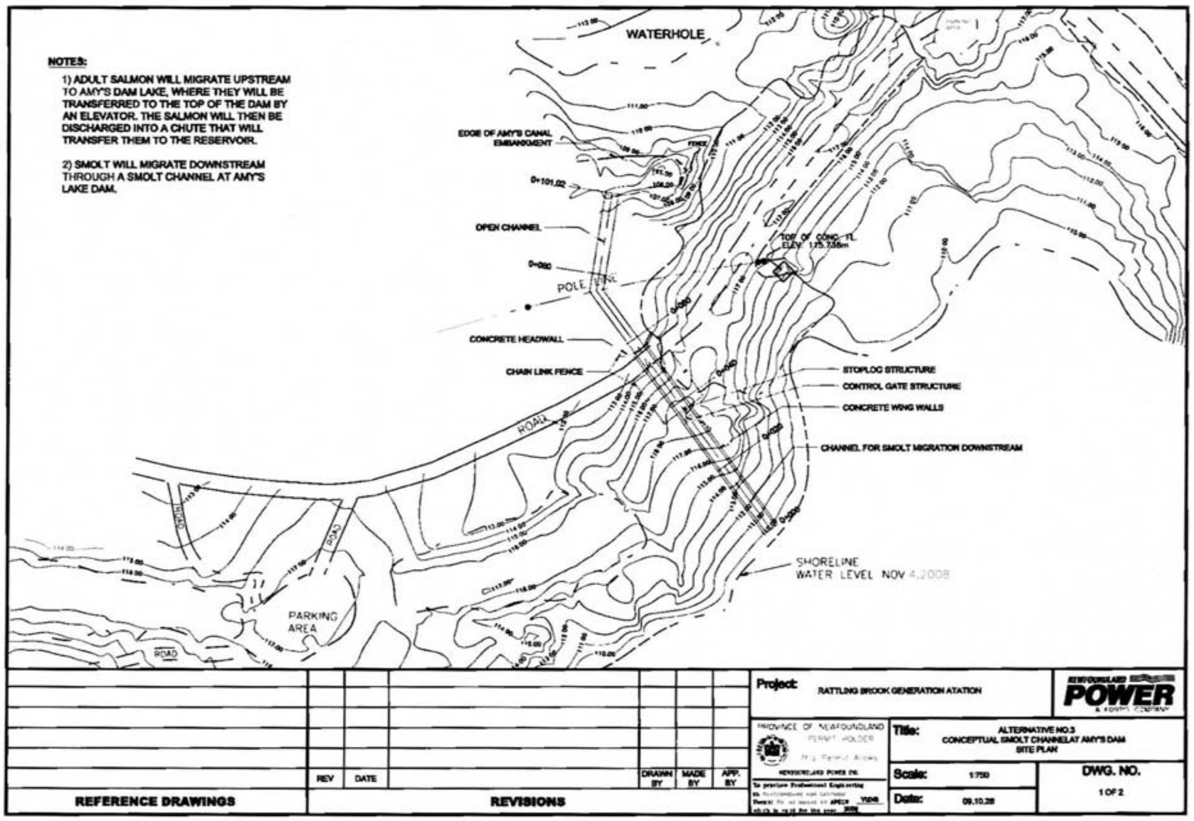
Option 1 – Rattling Spillway Fishway and Amy's Smolt Channel

Option 2 – Combined Fishway and Smolt Channel at Amy's Dam

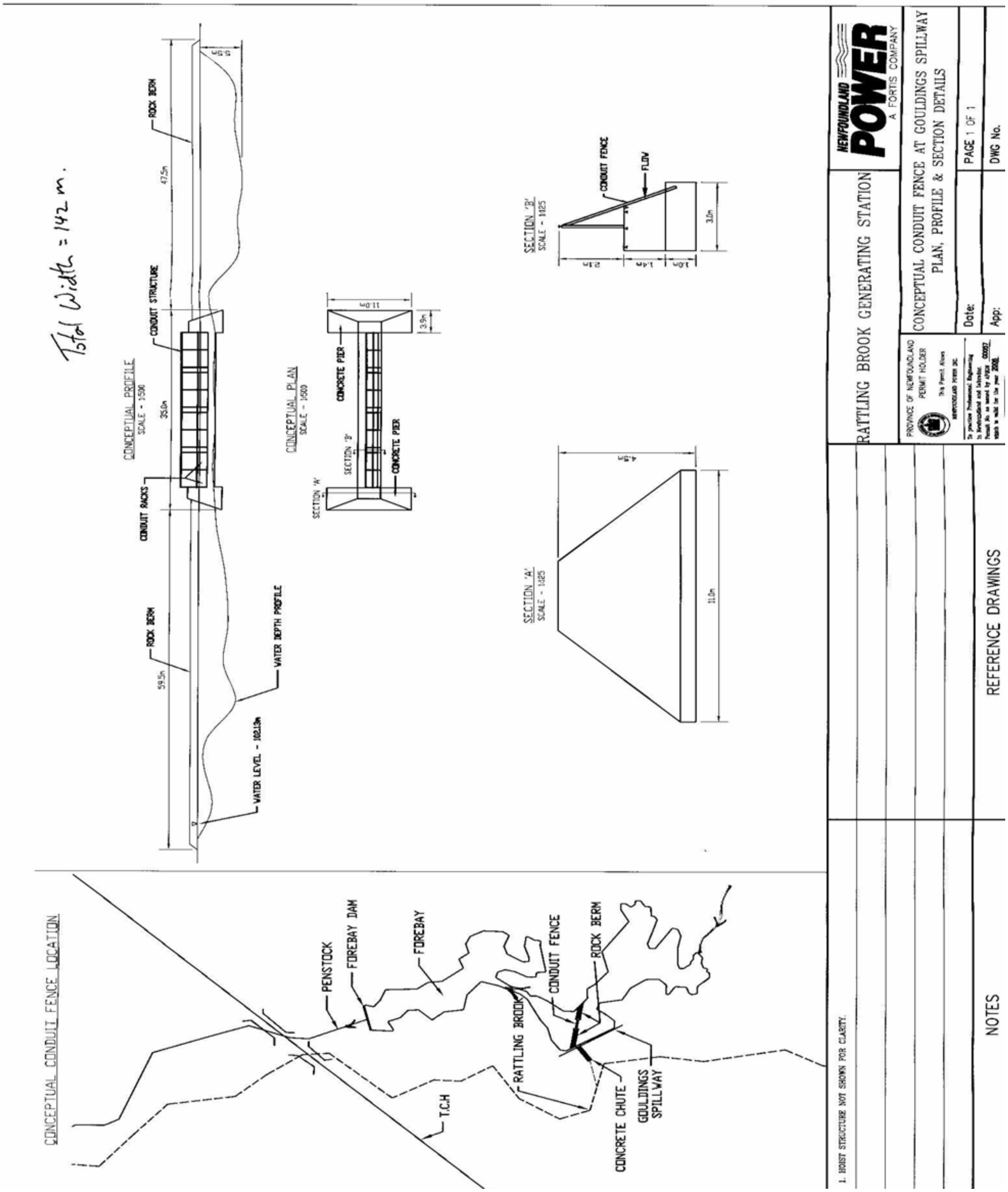
Option 3 – Elevator and Smolt Channel at Amy's Dam

Option 4 – Trap & Transport

Appendix 3: Conceptual Smolt Channel at Amy's Dam, Site Plan



Appendix 4: Conceptual Conduit Fence at Gouldings Spillway, Plan and Profile, and Section Details



Appendix 5: Photos of the Tailrace

Figure 3 - Dimensions of Tailrace obstacle

Figure 4 - Proposed trap location

Appendix 6: Photos of Gouldings Spillway

Figure 5 – Proposed fence and berm

Figure 6 - Goulding spillway during the 2005 water release exercise

Appendix 7: Photos of Amy’s Dam

Figure 7 - Entrance to the submerged exit from Amy's Lake

Figure 8 - Aerial view of Amy's Lake Dam

Appendix D

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 completion of the capital improvements planned for 2012 are required by DFO and are therefore part of the continued long-term operation of the Rattling Brook hydroelectric development. Planned improvements in 2012 include construction of all structures required to allow fish passage to the Rattling Lake Reservoir.

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)**
2012	5,000
2016	850
2017	1,050
2025	1,800
2030	1,500
2032	1,500
Total	**$11,700**

The total capital expenditure of all of the projects listed above is $11,700,000. 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 $416,672 per year when this project is completed in 2013. 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 after completion of this project 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.

The annual operating cost also includes the additional operating costs associated with operating the fish passage. In the 2009 report prepared by Newfoundland Power, this cost was estimated to be $64,000 per year.

4.0 Benefits

The estimated long-term normal production at this plant under present operating conditions is 78.3 GWh per year. This estimate is based on the 2010 Normal Production Review completed in 2010 by Newfoundland Power. This review incorporated updated models used previously in the Water Management Study completed by SGE Acres in 2005. The Rattling Brook system characteristics have been updated and now reflect 2007 plant upgrades. For the purpose of this study, the annual production has been reduced by 1.2 GWh to 77.1 GWh to reflect the lost energy associated with the fish passage.

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 1.574 cents per kWh.[1] 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

[1] The levelized cost of energy per kWh includes 1.2 GWh of lost energy annually. The estimate of 1.2 GWh of lost energy can be found on page 14 of Appendix B.

lower price than the cost of replacement energy, assumed to come from Newfoundland and Labrador Hydro's Holyrood thermal generating station.[2]

The future capacity benefits of the continued availability of 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.

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 a fish passage, as ordered by DFO, under section 20 of the Fisheries Act, will allow annual upstream and downstream migration of Atlantic salmon. The continued operation of the Rattling Brook generating facility guarantees the availability of low cost energy to the Province. Otherwise the annual production of 77.1 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 2012. The continued operation of the Rattling Brook plant will benefit the Company and its customers by providing least cost, reliable energy for years to come.

[2] The cost of electricity from the Holyrood thermal generating station is estimated at 16.37¢ per kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $103.10 per barrel for 2011 as per Newfoundland Hydro letter regarding Rate Stabilization Plan – Fuel Price Projection dated April 14, 2011.

Attachment A

Summary of Capital Costs

Description	2012	2016	2017	2025	2030	2032
Civil						
Dams, spillways						
Amy's Tunnel Upgrade					$1,500	$500
Fish Passage Structure	$5,000					
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 ($2012)	**$5000**	**$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 ($ 2011)	
Year	**Amount**
2006	318,268
2007[1]	153,095
2008	273,921
2009	302,034
2010	241,357
Average	**$ 283,895**

	2012	2013 Onward
5-Year Average Operating Cost	$283,895	$283,895
Water Power Rental Rate[2]	62,640	61,680
Fisheries Compensation[3]	0	64,000
Total Forecast Annual Operating Cost	$346,535	$409,575

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 Based on annual generation normal's, the annual water power rental rate is currently ($0.80/MWh x 78,300 MWh/yr =$62,640). In 2013 and future years this annual rate will be ($0.80/MWh x 77,100 MWh/yr =$61,680). The reduction in the annual production of 1,200 MWh/yr reflects the lost energy associated with the fish passage that will be in operation in 2013.

3 Fisheries Compensation will commence in 2013.

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted average Incremental Cost of Capital	7.40%
Present Worth Year	2011

YEAR	Generation Hydro 64.4yrs 8% CCA	Generation Hydro 64.4yrs 50% CCA	Capital Revenue Requireme	Operating Costs	Net benefit	Present Worth Benefit +ve	Cumulative Present Value Benefit +ve	Present Worth of Sunk Costs	Total Present Worth Benefit +ve	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2012	5,000,000	0	489,439	353,632	-843,071	-784,983	-784,983	-8,432,987	-9,217,970	1.077	1.574
2013	0	0	524,019	425,814	-949,833	-823,453	-1,608,435	-7,978,691	-9,587,127	1.232	1.574
2014	0	0	508,551	435,171	-943,722	-761,783	-2,370,218	-7,568,184	-9,938,402	1.224	1.574
2015	0	0	493,847	444,622	-938,469	-705,347	-3,075,565	-7,197,012	-10,272,577	1.217	1.574
2016	0	925,719	567,943	453,790	-1,021,733	-715,016	-3,790,582	-6,799,561	-10,590,143	1.325	1.574
2017	221,901	943,080	666,365	462,301	-1,128,665	-735,427	-4,526,008	-6,365,365	-10,891,373	1.464	1.574
2018	0	0	647,608	471,046	-1,118,654	-678,681	-5,204,690	-5,972,464	-11,177,154	1.451	1.574
2019	0	0	622,251	479,868	-1,102,119	-622,579	-5,827,269	-5,620,960	-11,448,228	1.429	1.574
2020	0	0	602,556	488,905	-1,091,461	-574,077	-6,401,345	-5,304,033	-11,705,378	1.416	1.574
2021	0	0	585,919	498,082	-1,084,001	-530,868	-6,932,214	-5,017,090	-11,949,304	1.406	1.574
2022	0	0	571,018	507,646	-1,078,664	-491,857	-7,424,071	-4,756,713	-12,180,784	1.399	1.574
2023	0	0	557,177	517,458	-1,074,635	-456,257	-7,880,328	-4,520,153	-12,400,481	1.394	1.574
2024	0	0	544,041	527,563	-1,071,604	-423,622	-8,303,950	-4,305,085	-12,609,035	1.390	1.574
2025	1,935,922	387,184	757,770	537,763	-1,295,533	-476,857	-8,780,808	-4,026,166	-12,806,974	1.680	1.574
2026	0	0	759,071	548,217	-1,307,288	-448,030	-9,228,838	-3,766,020	-12,994,857	1.696	1.574
2027	0	0	737,926	558,740	-1,296,667	-413,771	-9,642,609	-3,530,545	-13,173,153	1.682	1.574
2028	0	0	718,785	569,597	-1,288,382	-382,800	-10,025,408	-3,316,982	-13,342,390	1.671	1.574
2029	0	0	700,885	580,643	-1,281,528	-354,528	-10,379,937	-3,123,085	-13,503,022	1.662	1.574
2030	2,130,685	0	892,396	591,865	-1,484,261	-382,322	-10,762,259	-2,893,218	-13,655,477	1.925	1.574
2031	0	0	890,698	603,304	-1,494,003	-358,316	-11,120,574	-2,679,597	-13,800,171	1.938	1.574
2032	2,213,842	0	1,084,881	614,964	-1,699,845	-379,594	-11,500,168	-2,437,331	-13,937,499	2.205	1.574
2033	0	0	1,078,414	626,850	-1,705,264	-354,566	-11,854,734	-2,213,102	-14,067,837	2.212	1.574
2034	0	0	1,050,455	638,965	-1,689,421	-327,069	-12,181,803	-2,009,736	-14,191,539	2.191	1.574
2035	0	0	1,023,441	651,315	-1,674,756	-301,890	-12,483,694	-1,825,251	-14,308,945	2.172	1.574
2036	0	0	997,292	663,903	-1,661,195	-278,813	-12,762,507	-1,657,867	-14,420,374	2.155	1.574
2037	0	0	971,935	676,735	-1,648,669	-257,645	-13,020,152	-1,505,978	-14,526,130	2.138	1.574
2038	0	0	947,306	689,814	-1,637,120	-238,213	-13,258,365	-1,368,138	-14,626,503	2.123	1.574
2039	0	0	923,347	703,146	-1,626,493	-220,360	-13,478,725	-1,243,042	-14,721,766	2.110	1.574
2040	0	0	900,003	716,736	-1,616,739	-203,946	-13,682,671	-1,129,509	-14,812,180	2.097	1.574
2041	0	0	877,225	730,589	-1,607,814	-188,846	-13,871,517	-1,026,475	-14,897,992	2.085	1.574
2042	0	0	854,967	744,709	-1,599,677	-174,944	-14,046,461	-932,974	-14,979,435	2.075	1.574
2043	0	0	833,189	759,102	-1,592,292	-162,138	-14,208,599	-848,133	-15,056,732	2.065	1.574
2044	0	0	811,852	773,774	-1,585,626	-150,335	-14,358,934	-771,160	-15,130,094	2.057	1.574
2045	0	0	790,920	788,729	-1,579,648	-139,449	-14,498,383	-701,339	-15,199,722	2.049	1.574
2046	0	0	770,361	803,973	-1,574,333	-129,404	-14,627,787	-638,019	-15,265,805	2.042	1.574
2047	0	0	750,145	819,511	-1,569,656	-120,130	-14,747,916	-580,608	-15,328,524	2.036	1.574
2048	0	0	730,244	835,350	-1,565,595	-111,563	-14,859,479	-528,571	-15,388,051	2.031	1.574
2049	0	0	710,634	851,496	-1,562,130	-103,646	-14,963,126	-481,421	-15,444,547	2.026	1.574
2050	0	0	691,292	867,953	-1,559,244	-96,327	-15,059,453	-438,715	-15,498,167	2.022	1.574
2051	0	0	672,195	884,728	-1,556,923	-89,556	-15,149,009	-400,049	-15,549,058	2.019	1.574
2052	0	0	653,324	901,827	-1,555,151	-83,291	-15,232,300	-365,058	-15,597,358	2.017	1.574
2053	0	0	634,662	919,257	-1,553,919	-77,491	-15,309,790	-333,409	-15,643,200	2.015	1.574
2054	0	0	616,190	937,024	-1,553,214	-72,119	-15,381,909	-304,798	-15,686,707	2.015	1.574
2055	0	0	597,895	955,134	-1,553,029	-67,142	-15,449,050	-278,950	-15,728,000	2.014	1.574
2056	0	0	579,762	973,594	-1,553,357	-62,529	-15,511,579	-255,612	-15,767,191	2.015	1.574
2057	0	0	561,778	992,411	-1,554,189	-58,251	-15,569,830	-234,557	-15,804,387	2.016	1.574
2058	0	0	543,931	1,011,592	-1,555,523	-54,284	-15,624,115	-215,575	-15,839,689	2.018	1.574
2059	0	0	526,211	1,031,143	-1,557,354	-50,604	-15,674,719	-198,476	-15,873,195	2.020	1.574
2060	0	0	508,606	1,051,073	-1,559,678	-47,187	-15,721,906	-183,089	-15,904,994	2.023	1.574
2061	2,000,000	0	686,884	1,071,387	-1,758,271	-49,530	-15,771,436	-163,739	-15,935,175	2.281	1.574

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%	8.38%	3.77%
Total	**100.00%**		**7.40%**

CCA Rates:

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

Escalation Factors: Conference Board of Canada GDP deflator, February 4, 2011.

Lockston Hydro Plant

Refurbishment

June 2011

Prepared by:

Jeremy Decker, P.Eng.
Shaun Marshall, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
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NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
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Table of Contents

1.0 Background

The Lockston hydroelectric generating plant ("the Plant"), located on the Bonavista Peninsula of eastern Newfoundland near the town of Port Rexton, was commissioned in 1956 with a capacity of 1.5 MW under a net head of approximately 80 m. The plant originally contained a single horizontal 2,000 hp Francis turbine manufactured by Gilkes and a Canadian General Electric generator. The plant capacity was increased to 3.0 MW in 1962 with the addition of a second identical unit.

The original unit was labelled as G2 even though it was the first unit installed in 1956. The second unit installed in 1962 was labelled as G1.

The Plant is connected to the Island interconnected electrical system at Lockston substation. 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:

- 2009 – Battery bank, battery charger and revenue meter replaced
- 2007 – Vibration monitoring added
- 2003 – Penstock replaced
- 2003 – G1 Runner, governor and wicket gates refurbished
- 2003 – Fisheries compensation valve added
- 2001 – G2 runner refurbished and main valve repaired
- 1999 – Bypass valves replaced
- 1992 – Water level indication upgraded
- 1991 – Louver and exhaust fan replaced
- 1989 – G2 Overhauled
- 1988 – G1 Overhauled
- 1986 – Capacitors Replaced

This report provides a summary of the engineering assessment of the Lockston hydroelectric plant and the refurbishment proposed for 2012.[1]

2.0 General

The Plant has a capacity of 3.0 MW and an annual production of 8.1 GWhr of energy. This amount of energy production could be provided by only one of the two generators. As a result Newfoundland Power ("the Company") has determined that only unit G1 will be fully automated with a new digital governor and water management system.[2] Unit G2 will be refurbished to the extent necessary to provide reliable peaking capacity and to operate at base load during periods of high inflows and when operating isolated from the grid.

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[1] This assessment is based upon a mechanical site inspection completed by Shaun Marshall P. Eng. on February 18, 2011; an electrical site inspection completed by Jeremy Decker P. Eng. and John Pardy P. Eng. on March 3, 2011 and detailed plant equipment assessment reports completed by John Budgell on October 31, 2007.

[2] Newfoundland Power has two other hydro plants where the extent of automation is different between generators. Both Petty Harbour and Tors Cove plants have 2 generators fully automated with programmable logic controller based water management systems and 1 generator operated manually.

3.0 Governors

The governors consist 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.

The governor bases, power pistons and Giljet operating mechanisms are the original Gilkes units. The control heads and hydraulic pressure units were replaced with Woodward hydraulic retrofits in 1980.

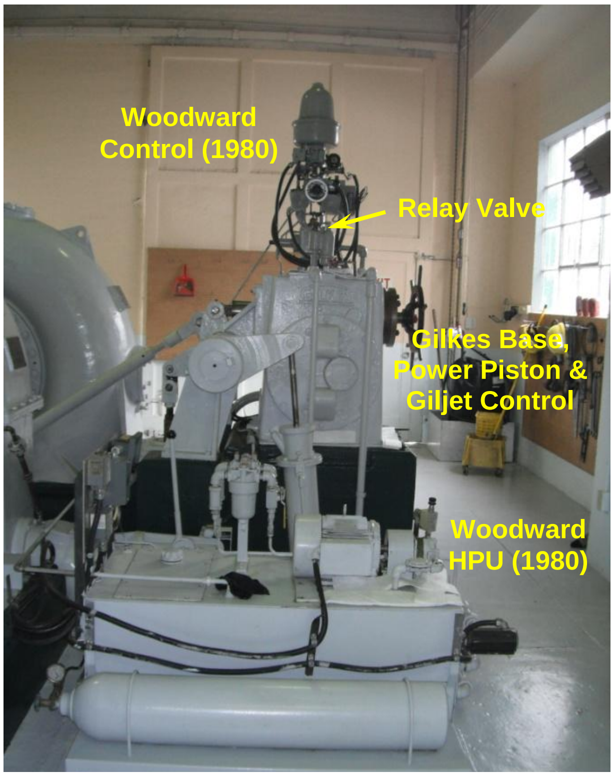


Figure 1 - Gilkes/Woodward Governor

The G1 governor was refurbished in 2003. 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.[3]

The governor speed control and gate limit are motorized and can be operated remotely using electromechanical relay logic to control the load on the unit. 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 programmable logic controller (PLC). This will optimize energy production from the available water, increasing the energy output of the plant.

The control head, above the relay valve, will be replaced with a PLC based digital control system. The relay valve, which initiates the movement of the power piston, will be inspected and overhauled as required. The fly ball governor head, pilot valve assembly and mechanical restoring linkages will be removed. The new governor control system will interface with the unit control PLC and will facilitate the implementation of a water management system.

The existing hydraulic power piston assembly, hand wheel and gate operating linkages will be retained. All seals, bushings and other components will be inspected and upgraded as required. This will eliminate leakage and extend the life of the power piston assemblies.

The existing G2 governor will not be upgraded. This unit will operate manually at base load only at times of high water inflows and during periods of time when peak capacity is required.

[3] Recent plant refurbishment projects have replaced the hydraulic control portion of these governors with digital systems that provide enhanced control and feedback capabilities.

As these situations arise infrequently it would be more cost effective to manually operate this generator than to incur the expense of fully automating this unit.

4.0 Generators

The generator G1stator and rotor windings are original to the 1962 installation and have reached the average age at which Newfoundland Power has had to complete rewinds of 6,900 volt generator stators. The rotor was cleaned and painted in 2003. Megger readings taken at the time showed low resistance to ground. The poles were isolated and it was determined that one pole contained a short to ground. Attempts to remove the pole were unsuccessful so the unit was returned to service with the grounded pole. If a second ground were to develop on the rotor, a potentially damaging short circuit would occur. It is recommended to rewind the stator and reinsulate the rotor during the refurbishment project. Temperature signals from the resistance temperature detectors ("RTDs") that will be installed in the new stator windings will be monitored by the new control system.

The generator neutral is low impedance connected to ground. This method of grounding does not provide adequate protection of the generator windings as it permits high 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 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-energizing 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. To enable the testing to be completed, the insulation testing system must include a neutral contactor to automatically disconnect the stator windings from ground when the generator shuts down.

The surge protection, which consists of surge capacitors only, is located in the pit under 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 can adequately protect the generator windings from electric system surges, intermediate class MOV type surge arrestors will be added.

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

The generator G2 stator and rotor windings are original to the 1956 installation but are in good condition and testing has not indicated any significant deterioration of the insulation. Although the age of the windings would make them candidates for rewinding, since the unit will be operated infrequently and an in service failure would not result in any loss of energy production, they will not be rewound during this project. Due to the minimal exposure to fault conditions the existing grounding system, surge protection, neutral CT and ground CTs will not be replaced and a MegAlert® insulation tester will not be installed.

5.0 Excitation Systems

The G1 exciter is the original unit supplied with the General Electric generator in 1962. Although it is in relatively good condition, its age dictates that it should be rewound in conjunction with the generator stator rewind. Infrared brush temperature sensors will be added to the commutator and slip rings.

The G2 exciter is also the original unit supplied with the General Electric generator in 1956. It is in relatively good condition and for the same reasons outlined above for the generator windings, it will not be rewound as part of this project.

The voltage regulators are the original Brown Boveri Model AB2/1 with mechanical operating mechanisms. They have been discontinued for many years. They cannot be integrated into the upgraded control system to accomplish the required automated control. The voltage regulators will be replaced with digital voltage regulators incorporated into the Combination Generator Control Modules (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 breakers for both units, which are located in the switchgear, are the original General Electric Model AKF-1 and are beyond their expected service life. They are no longer supported by the original manufacturer, making it very expensive to overhaul and maintain. New field breakers will be installed for both generators, located in cabinets on the upstream wall of the powerhouse. The power cables between the exciter and the rotor will also be replaced.

6.0 Switchgear

The generator breakers, station service breaker, forebay line breaker, potential transformers (PTs) and current transformers (CTs) are integral to the switchgear and are original to the 1956 and 1962 installations. Concerns of failure exist because of the age and deteriorated condition of this equipment. The existing General Electric Type PL-7.5-100 oil blast breakers do not operate dependably, are at the end of their service life and must be replaced. The PTs and CTs must also be replaced.[4]

The protective relays and control switches are incorporated into the switchgear doors, which greatly increase arc flash hazards for personnel operating these switches. The high voltage compartments in the front of the switchgear are vented through the bottom of the doors. In the event of an internal fault, the electric arc and hot gases would exit the switchgear directly towards personnel who may be standing in front of the door operating the control switches. Figure 2 shows the control switches for the station service and transformer T1 breakers

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

switchgear cubicles, and the proximity of these cubicles to other equipment operated by employees.

Figure 2 - Switchgear and Control Panels

The existing five-breaker switchgear line-up will be replaced with an arc flash rated assembly with three vacuum breakers, which requires minimum maintenance. As outlined below the normal station service will be relocated to the substation and the station service breaker will not be required. The forebay power line will be connected to the overhead section of the 6.9 kV line from the substation to the switchgear and the forebay line breaker will not be required. 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 to enable the plant to be black started and carry isolated load in the event of a system power interruption.

As a result of the fault energy levels at this location there is a high arc flash hazard associated with this switchgear requiring an arc flash boundary of 3 metres.[5] To provide protection from this hazard, walls will be constructed to separate the switchgear from the control room and the generator gallery.

The installation of the new switchgear in an extension to the building will necessitate reconfiguration of the power cables to the generators and to the power transformer. The cables and terminations are beyond their life expectancy and will be replaced. A new underground termination pole will be installed just outside the building extension and a conduit installed from the termination pole to the switchgear. The overhead line from the termination pole to the unit transformers in the substation will be relocated and upgraded.

7.0 AC Distribution System

The station service transformer bank is mounted on a pole on LOK-01 feeder but supplied from the switchgear in the powerhouse. There is a power cable from the switchgear to the insulated connectors embedded in the powerhouse wall and a span of open wire from there to the transformer pole. A service drop is then run from the transformer bank back to the powerhouse.

[5] An arc flash study for the Lockston switchgear is included as Appendix B.

Figure 3 – Station Service Transformers

Figure 4 – AC Panels & Meter

The transformer bank consists of two single phase 120/240 V transformers connected in a nonstandard open delta configuration. It will be replaced with a new transformer bank located in the substation. The existing single phase substation station service transformer connected to the 12.5 kV bus will be replaced with a three phase 120/208 V wye connect transformer bank. The service drop will be run overhead from the substation to the powerhouse.

The two existing AC panels have been loaded to capacity. All the circuits in the 42-circuit, 225 A AC panel have been used and a 24-circuit, 125 A panel, which is connected to a 40A breaker in the 225 A panel, has been added. There is only one spare single pole circuit in this panel.

The service entrance will be replaced and a new 600A switchboard installed that will be supplied from the new transformer bank in the substation. A standard 60-circuit 120/208V Non-Essential Services panel will be connected to the switchboard. A 60-circuit 120/208V Essential Services panel will also be installed. It will connect to an automatic transfer switch that will normally supply the panel from the switchboard but will transfer to the emergency station service transformer, located in the switchgear, during a black start.

8.0 DC System

The existing GNB Exide gel-cell battery bank and the temperature compensated C-Can battery charger were installed in 2009 and will be relocated to accommodate the new switchgear. The 22-circuit DC distribution panel was installed in 1980 and breakers are no longer readily available. A new 60-circuit panel will be installed to ensure the availability of replacement circuit breakers.

9.0 Protective Relaying

The generator electrical protection is provided by CGE, GE and Westinghouse electromechanical relays. The following protective elements are in service:

40	Loss of Field
49	Thermal Protection
51GN	Ground Overcurrent
51V	Backup Protection – Voltage Controlled Overcurrent
87	Differential

The existing protective relaying at Lockston plant lacks five elements[6] of the minimum protection set. It will be replaced with 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. Digital relays will also be installed for G2 since it is more cost effective than relocating the existing electromechanical relays from switchgear.

10.0 Plant Control

There is no programmable logic controller (PLC) at Lockston and the existing plant control utilizes relay-based logic. An Allan-Bradley CompactLogix® programmable logic controller will be installed to provide plant control, protection and automation.[7] It will provide local and remote control of the generator and plant functions. All Newfoundland Power standard control, protection and automation functionality will be implemented for generator G1 while only a minimal amount will be implemented for G2.

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 will provide processing power that will greatly improve the local and remote monitoring and control functionality. It will facilitate the implementation of a variety of control modes to ensure 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:

- AB CompactLogix® PLC
- Industrial Computer HMI with keyboard
- Ethernet Switch
- Combination Generator Control Module (CGCM)
- MegAlert® remote LED display and switch board meter
- Synchroscope
- Emergency stop pushbutton (latching)
- Start pushbutton
- Stop pushbutton

[6] The existing generator protection does not include Stator Unbalance 46, Overvoltage 59, Rotor Ground 64F, Frequency 81 and Sensitive Ground Fault 87GN protection elements, which are recommended by the IEEE for these generators.

[7] The Allan-Bradley CompactLogix® programmable logic controller will provide functionality similar to that provided by the ControLogix® programmable logic controller used in the upgrade of larger plants since 2004 but with scaled down processing power and capabilities better suited to smaller hydro plants..

- Alarm reset pushbutton
- Generator breaker control switch (ANSI device No. 52CS)
- Field breaker control switch (ANSI device No. 41CS)
- Speed raise/lower control switch (ANSI device No. 15CS)
- Gate limit control switch (ANSI device No. 65CS)
- Voltage raise/lower control switch (ANSI device No. 70CS)
- Automatic/manual synchronizing control switch (ANSI device No. 25CS)
- Generator lock out relay (ANSI Device No. 86G)
- 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 Brown Boveri Synchrotact 2 auto-synchronizer, installed in 1980, is an electronic device that has been out of production since 1983. ABB still offers spare parts and repair service. This unit will not be reused, however, since the Combination Generator Control Module (CGCM), located in the unit control panel, provides synchronizing functionality that is integrated with the PLC. Both automatic and manual synchronizing will be supervised by the synchrocheck function provided in the generator multifunction protection relay. This will ensure unit speed and voltage are within acceptable limits before the generator breaker closure is permitted.

11.0 Instrumentation

The instrumentation has been upgraded over the past number of years with speed, bearing oil temperature and cooling water flow added in 1980 and vibration monitoring in 2007. Except for the speed switch on generator G1,all existing instrumentation will be maintained. The G1 speed switch will be removed and dual speed sensors installed on the existing toothgear to provide analog 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.

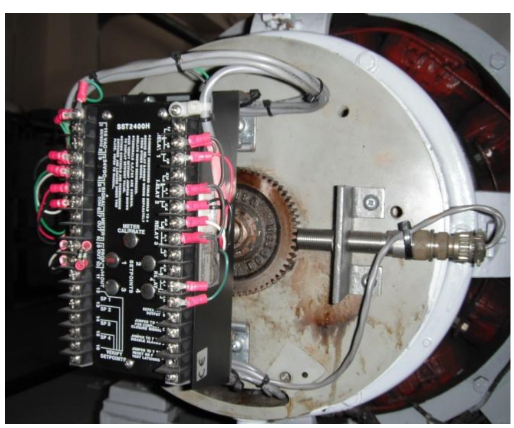


Figure 5 – Speed Switch, Sensor & Toothgear

The bearing oil temperature, cooling water monitoring and control and vibration sensors for both units will be integrated into the PLC.

Bearing temperature and bearing oil level will be added on G1and integrated into the PLC. Scroll case pressure sensors will be added to both units and integrated into the PLC.

The revenue meters on each unit were replaced with Schneider PowerLogic ION 7550 meters in 2009. One meter will be reused and the other will be returned to inventory.

12.0 Heating and Ventilation

The anti-condensation blower type heater in the generator G1 pit will be controlled by a humidistat located in the generator room. The existing G2 pit heater and control will not be replaced. The two exhaust fans located in the building that are in good condition. The louvers in the downstream side of the building do not close properly and will be upgraded.

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. Addition blower heaters will be installed in the generator gallery.

13.0 Water Level Monitoring and Control

The forebay water level system is critical to the implementation of the Water Management System in the PLC. The water level probe was installed in 1992. The water level and trash rack signals are transmitted to the plant utilizing pulse modulated and hard wired signals over an 18 year old 6-pair copper communications cable which is susceptible to lightning damage. To eliminate legacy equipment with its inherent maintenance problems and to facilitate the use of more reliable technology, the water level probe will be replaced and 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.

Figure 6 – Trinity Pond Gate

The plant PLC will use the water level signal to control the Water Management System. High level (spill) and low level alarms will also be initiated when specified levels are reached. The water level signal is presently obtained from the forebay, which is the level of the relatively small Rattling Pond storage reservoir. Water flows into Rattling Pond from the Trinity Pond, the primary storage reservoir, via a manually controlled gate. Automatic control of this gate is required to ensure the Water Management System can maximize energy production from the available water. This will require construction of a single phase power line from the tap to Lockston hilltop communications site, installation of a fibre optic cable from the forebay to the Trinity Pond Gate including poles from the forebay to the Lockston Hilltop tap, construction of a gatehouse, installation of a new gate with motor operator and de-icing system and installation of water level indication at Trinity Pond.

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:

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

14.0 Cooling Water

Cooling water solenoids were added to both units in 2001. Some additional upgrading of the generator G1cooling water system and controls will be completed to permit integration into the new CompactLogix PLC. The generator G2 cooling water system will not be upgraded.

15.0 Turbines

In 1989, the G1 turbine runner was replaced with the spare unit, constructed of mild steel. After only fourteen years in service with G2 sharing operating time, refurbishment was necessary in 2003 due to excessive cavitation. During this refurbishment two new rotating seals were installed and machined. Major blade damage was repaired using bronze filler rods and minor blemishes were filled with Belzonia Super Glide ceramic coating. The draft tube elbow was not removed during the 2007 inspection so access to the runner was limited to the inspection ports on the low pressure side which revealed that most of the Belzona was eroded away, with blemishes exposed and cavitation evident (see Figure 7). The high pressure side and seal faces have not been inspected since 2003.

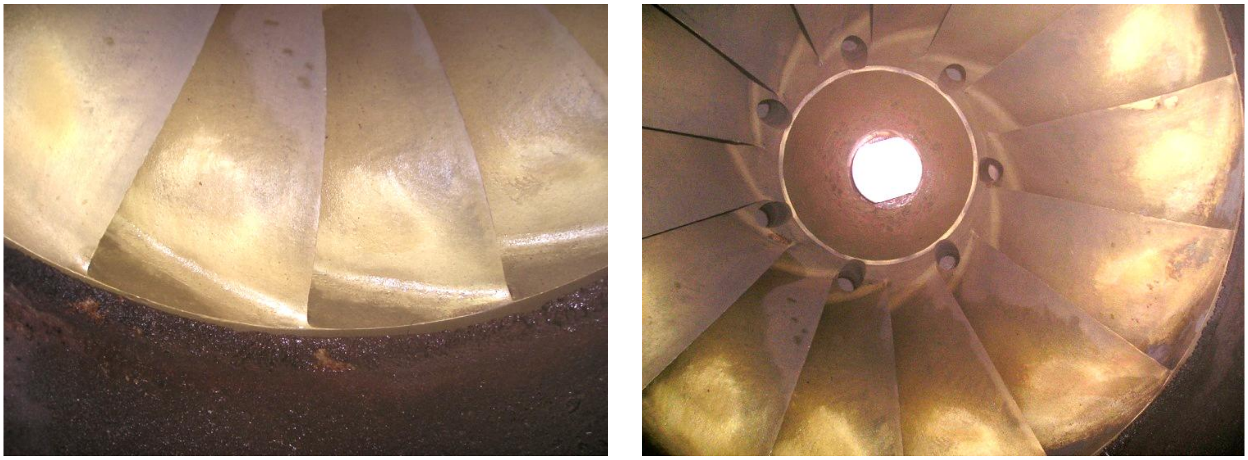


Figure 7 – 2007 Inspection of Low Pressure Side of G1 Runner showing Belzona Erosion and Cavitation

Index testing, performed by ACRES in 2003, determined the peak efficiency of unit G1 was 84.4%. This is considered low as compared to that expected of a modern runner design. To improve efficiency and minimize the operating cost associated with maintaining the existing mild steel runner, it will be replaced with a higher efficiency stainless steel unit. A replacement runner is expected to result in a peak unit efficiency of 87% with a resulting increase in energy production of 0.3 GWH annually. The stationary seals and downstream spool pieces that form part of the seal around the runner are eroding and will need to be replaced to ensure proper operation of the new runner.

The G1 turbine wicket gates, constructed of bronze, have also experienced erosion. Stainless steel wicket gates will be installed to minimize erosion to ensure continued reliability. The existing wicket gate bushings require manual lubrication. Self-lubricating bushings, which require no maintenance and are more environmentally friendly, will be installed with the new wicket gates.

The G1 Giljet is showing considerable leakage across the seats and will be refurbished.

The G2 turbine runner was refurbished in 2001 with extensive repairs to the runner blades filling the holes in the buckets with aluminum bronze rods and the minor blemishes with Belzona. The entire runner was then coated with a Belzona Super Glide ceramic coating. Two new 660 bronze rotating seals were installed and machined to give proper clearance. A spare stationary seal along with one original seal were repaired and installed in the turbine. An inspection in 2007 revealed that fifty percent of the Belzonia coating had been eroded away leaving minor blemishes exposed. The runner however is in relatively good condition with only minor cavitation on the low pressure side. The 2007 inspection determined that the G2 wicket gates were in good condition, clearances were set in 2001, and there was no evidence of corrosion or operational issues to indicate any problems with binding or gate leakage. The G2 giljet has considerable leakage around the seat with only minimal pressure on the spear. The entrance grating into the G2 giljet has also deteriorated. With the minimal running time of generator G2 after completion of this project, it is expected that the existing turbine runner, wicket gates and G2 giljet will be serviceable for many years and will not be upgraded.

16.0 Main Inlet Valves

The G1 main inlet valve is a 27-inch gate valve and is original equipment that is 49 years old. The valve was installed for manual operation and was motorized in 1980. An internal assessment of the valve was not completed during the 2007 inspection, however, it is evident from the constant flow of water when the valve is closed, that it is not sealing properly. When the unit is shut down, this leakage around the valve builds up in the scroll case. Safe access to the scroll case without dewatering the penstock cannot be achieved. This situation limits the ability to safely maintain and service other plant equipment.

Both the valve seats and discs have been overhauled in the past which requires dewatering the penstock and installing a bulkhead. These components are prone to wear due to the brass construction. Current practice is to install a butterfly valve instead of a gate valve, reducing head losses and increasing reliability.

Based upon the age and condition, the G1 main valve and actuator will be replaced. In addition, a bypass valve and dismantling joint will be incorporated into the redesigned arrangement.

The G2 main inlet valve is also a 27-inch gate valve and is original equipment that is 55 years old. It was repaired in 1999 replacing the stationary seats and the gate stem guide and nut. Similar to G1 main valve, there is a minor leak in the disk seat but the valve otherwise is in relatively good condition. The bypass valve was replaced in 2001 and is in good condition. With the minimal running time of generator G2 after completion of this project, it is expected that the existing valves will be serviceable for many years and will not be upgraded.

17.0 Project Cost

The total project cost is estimated at $3,451,000. Table 1 below provides the cost breakdown by cost category.

Table 1
Projected Expenditures

Cost Category	**Estimated Cost**
Material	$2,784,000
Labour - Internal	$280,000
Labour - Contract	
Engineering	$190,000
Other	$197,000
Total	**$3,451,000**

18.0 Summary of Work

The following is a summary of the work proposed to be completed during the 2012 refurbishment project.

Common Equipment

- Construct a switchgear room
- Replace the switchgear with an arc flash rated assembly complete with breaker, potential transformers, current transformers and emergency station service transformer
- Replace power cables from switchgear to generators
- Install underground termination pole near the extension to the plant, relocate and upgrade overhead line from termination pole to substation and install new power cable from termination pole to switchgear
- Remove the existing station service transformer bank and install a new bank in the substation
- Replace the two AC panels with a non-essential distribution panel, an essential services distribution panel and an automatic transfer switch
- Replace the DC distribution panel
- Replace the 110L, transformer protection and bus differential protective relays
- Install a programmable logic controller system that will monitor and control plant functions and the unit G1 with minimal monitoring and control of G2
- Install a Gateway data concentrator to communicate with SCADA and provide remote administration of the new equipment
- Modify the plant heating and ventilation system and upgraded controls
- Replace forebay communications cable and communications equipment
- Replace forebay water level probe
- Replace Trinity Pond gate and install automatic control

Unit G1

- Replace the G1 auto-synchronizers
- Replace the G1 voltage regulators
- Replace the G1 field breaker and power cables
- Install programmable logic controller based digital control systems to replace the hydraulic control portion of the governor
- Replace G1 generator protective relaying
- Complete mechanical modifications to G1 governor
- Rewind the G1 generator stator and reinsulate the rotor windings
- Replace G1 surge capacitors and add surge arresters
- Replace the G1 generator neutral current transformers
- Rewind the G1exciter
- Install infrared brush temperature sensors on G1
- Install neutral grounding transformer and resistor on G1
- Install automatic stator insulation testing system on G1
- Upgrade the G1speed sensing
- Add bearing temperature and bearing oil level sensors to G1
- Upgrade G1 cooling water system

- Implement a water management system in the plant programmable logic controller including upgraded communications to the forebay
- Replace G1 turbine runner and wicket gates
- Replace G1turbine wear ring and downstream spool piece
- Replace G1main inlet valve and actuator
- Upgrade the G1 bearing vibration system
- Add scroll case pressure sensors to G1

Unit G2

- Replace the G2 auto-synchronizers
- Replace G2 voltage regulators
- Replace the G2 field breaker and power cables
- Replace G2 generator protective relaying
- Upgrade the G2 bearing vibration system
- Add scroll case pressure sensors to G2

19.0 Economic Feasibility

Appendix A provides an economic feasibility analysis for the continued operation of the Plant. The results of the analysis show that the continued operation of the Plant is economical over the long term. Investing in the life extension of the Plant, including a high efficiency turbine runner, ensures the availability of 8.1 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 $4,421,000 over the next 25 years, is 5.924 cents per kWh. This energy is lower in cost than replacement energy from sources such as new hydroelectric developments or additional Holyrood thermal generation[8].

[8] The cost of electricity from the Holyrood thermal generating plant is estimated at 16.37 ¢/kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of $103.10/barrel for 2011 as per Newfoundland Hydro letter regarding Rate Stabilization plan – Fuel Price Projection dated April 14, 2011.

Appendix A
Feasibility Analysis

Table of Contents

1.0 Introduction

This feasibility analysis examines the future viability of generation at Newfoundland Power's Lockston hydroelectric plant (the "Plant"). The continued long-term operation of the Plant is reliant on the completion of capital improvements in 2012.

With investment required in 2012 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
Lockston Hydroelectric Plant
Capital Expenditures

Year	**($000s)**
2012	3,451
2017	235
2020	200
2024	20
2029	8
2032	565
2037	142
Total	**4,621**

The estimated capital expenditure for the Plant over the next 25 years is $4,621,000. A more comprehensive breakdown of capital costs is provided in Attachment A.

3.0 Operating Costs

Operating costs for the Plant are estimated to be approximately $92,699[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.

[1] 2011 dollars

The annual operating cost also includes a water power rental rate of \$ 0.80 per MWh. This fee is paid annually to the Provincial Department of Environment and Conservation based on yearly hydro plant generation/output.

4.0 Benefits

The maximum output from the Plant with only generator G1 is 1.7 MW. The Plant normally operates at an efficient load of 1.5 MW to maximize the energy from the water.

The estimated long-term normal production of the Plant with generator G1 under present operating conditions is 8.1 GWh per year. The estimated long-term normal production at the Plant with generator G1 equipped with a high efficiency turbine runner is 8.4 GWh per year.

5.0 Financial Analysis

An overall financial analysis of combined costs and benefits has been completed using the levelized cost of energy approach. The levelized cost of energy is representative of the revenue requirement to support the combined capital and operating costs associated with the development.

The estimated levelized cost of energy from the Plant over the next 50 years is 5.924 cents per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Lockston can be produced at a significantly lower price than the cost of replacement energy, assumed to come from Newfoundland and Labrador Hydro's Holyrood thermal generating station.[2]

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

6.0 Concluding

The results indicate that continued operation of the Plant is economically viable. Investing in the current upgrades of the facilities at Lockston guarantees the availability of low cost energy to the Province. Otherwise, the annual production of 8.4 GWh would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood thermal generating station. The project will benefit the Company and its customers by providing least cost, reliable energy for years to come.

[2] The cost of electricity from the Holyrood thermal generating plant is estimated at 16.37 ¢/kWh. This is based upon a 630 kWh/barrel conversion efficiency and oil price forecast from Hydro of \$103.10/barrel for 2011 as per Newfoundland Hydro letter regarding Rate Stabilization plan – Fuel Price Projection dated April 14, 2011.

Attachment A
Summary of Capital Costs

Lockston Feasibility Analysis Summary of Capital Costs ($000s)							
Description	**2012**	**2017**	**2020**	**2024**	**2029**	**2032**	**2037**
Civil							
Dam, Spillways and Control Structures			200				
Penstock		235				235	
Powerhouse							
Mechanical							
Turbine Upgrades	525						
Governor Upgrades						30	
Main Inlet and Bypass Valves	363						
Bearings							
Cooling Water							80
Heat and Ventilation							50
Compressed Air							12
Giljet							
Electrical							
P&C and Governor Controls	1,264					300	
Generator Rewind	350						
Remote Control Trinity Pond Gate	250						
Exciter							
Switchgear	699						
AC & DC Systems				20	8		
Annual Totals ($2012)	**3,451**	**235**	**200**	**20**	**8**	**565**	**142**

Attachment B
Summary of Operating Costs

Lockston Feasibility Analysis
Summary of Operating Costs

Actual Annual Operating Costs
($2011)

Year	Amount
2006	$ 87,742
2007	$ 78,052
2008	$ 98,632
2009	$ 85,245
2010	$ 80,226
Average	**$ 85,979**

5 -Year Average Operating Cost	$ 85,979[1]
Water Use Rental Fee	$ 6,720[2]
Total Forecast Annual Operating Cost	$ 92,699

[1] 2011 dollars
[2] Provincial Department of Environment and Conservation annual fee based on $ 0.80 per MWhr

Attachment C
Calculation of Levelized Cost of Energy

Present Worth Analysis

Weighted Average Incremental Cost of Capital	7.40%
PW Year	2011

YEAR	Generation Hydro 64.4yrs 8% CCA	Generation Hydro 64.4yrs 50% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit +ve	Cumulative Present Worth Benefit +ve	Present Worth of Sunk Cost	Total Present Worth Benefit +ve	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr) 50 years
2012	3,451,000	0	337,811	94,849	0	-432,660	-402,849	-402,849	-4,602,940	-5,005,789.11	5.151	5.924
2013	0	0	361,678	96,930	0	-458,608	-397,588	-800,437	-4,289,385	-5,089,821.90	5.460	5.924
2014	0	0	351,002	99,060	0	-450,062	-363,295	-1,163,731	-4,006,053	-5,169,784.11	5.358	5.924
2015	0	0	340,853	101,211	0	-442,064	-332,253	-1,495,984	-3,749,870	-5,245,853.84	5.263	5.924
2016	0	0	331,190	103,298	0	-434,488	-304,058	-1,800,042	-3,518,101	-5,318,142.67	5.172	5.924
2017	260,734	0	347,496	105,235	0	-452,731	-294,995	-2,095,037	-3,291,676	-5,386,713.03	5.390	5.924
2018	0	0	340,493	107,226	0	-447,719	-271,629	-2,366,665	-3,085,101	-5,451,766.63	5.330	5.924
2019	0	0	331,258	109,235	0	-440,493	-248,831	-2,615,497	-2,897,976	-5,513,472.37	5.244	5.924
2020	234,671	0	345,383	111,292	0	-456,675	-240,197	-2,855,694	-2,716,314	-5,572,008.44	5.437	5.924
2021	0	0	338,516	113,381	0	-451,896	-221,307	-3,077,001	-2,550,533	-5,627,534.36	5.380	5.924
2022	0	0	329,628	115,558	0	-445,185	-202,999	-3,280,000	-2,400,227	-5,680,227.21	5.300	5.924
2023	0	0	321,077	117,791	0	-438,868	-186,330	-3,466,330	-2,263,907	-5,730,237.73	5.225	5.924
2024	25,323	0	315,316	120,091	0	-435,407	-172,123	-3,638,454	-2,139,258	-5,777,711.77	5.183	5.924
2025	0	0	307,537	122,413	0	-429,951	-158,255	-3,796,709	-2,026,060	-5,822,769.46	5.118	5.924
2026	0	0	299,768	124,793	0	-424,561	-145,504	-3,942,213	-1,923,325	-5,865,538.17	5.054	5.924
2027	0	0	292,244	127,188	0	-419,433	-133,842	-4,076,056	-1,830,069	-5,906,124.44	4.993	5.924
2028	0	0	284,947	129,660	0	-414,607	-123,187	-4,199,242	-1,745,406	-5,944,648.54	4.936	5.924
2029	11,148	0	278,949	132,174	0	-411,123	-113,735	-4,312,978	-1,668,236	-5,981,213.88	4.894	5.924
2030	0	0	272,128	134,729	0	-406,857	-104,800	-4,417,777	-1,598,140	-6,015,917.84	4.844	5.924
2031	0	0	265,372	137,333	0	-402,704	-96,583	-4,514,360	-1,534,495	-6,048,855.17	4.794	5.924
2032	833,880	0	340,406	139,987	0	-480,393	-107,277	-4,621,637	-1,458,478	-6,080,115.80	5.719	5.924
2033	0	0	339,731	142,693	0	-482,424	-100,308	-4,721,945	-1,387,840	-6,109,785.10	5.743	5.924
2034	0	0	330,848	145,450	0	-476,298	-92,211	-4,814,156	-1,323,788	-6,137,944.05	5.670	5.924
2035	0	0	322,220	148,262	0	-470,481	-84,809	-4,898,964	-1,265,705	-6,164,669.56	5.601	5.924
2036	0	0	313,826	151,127	0	-464,953	-78,037	-4,977,001	-1,213,033	-6,190,034.59	5.535	5.924
2037	230,628	0	328,224	154,048	0	-482,272	-75,367	-5,052,368	-1,161,740	-6,214,108.39	5.741	5.924
2038	0	0	321,839	157,025	0	-478,865	-69,678	-5,122,046	-1,114,910	-6,236,956.70	5.701	5.924
2039	2,291,663	0	537,655	160,060	0	-697,715	-94,528	-5,216,574	-1,042,068	-6,258,641.90	8.306	5.924
2040	0	0	545,197	163,154	0	-708,351	-89,356	-5,305,930	-973,293	-6,279,223.21	8.433	5.924
2041	0	0	529,988	166,307	0	-696,295	-81,783	-5,387,714	-911,043	-6,298,756.80	8.289	5.924
2042	0	0	515,301	169,521	0	-684,822	-74,894	-5,462,607	-854,689	-6,317,296.03	8.153	5.924
2043	0	0	501,095	172,798	0	-673,892	-68,620	-5,531,228	-803,664	-6,334,891.51	8.023	5.924
2044	0	0	487,330	176,137	0	-663,468	-62,904	-5,594,132	-757,460	-6,351,591.28	7.898	5.924
2045	0	0	473,973	179,542	0	-653,515	-57,691	-5,651,823	-715,618	-6,367,440.93	7.780	5.924
2046	0	0	460,990	183,012	0	-644,002	-52,934	-5,704,757	-677,727	-6,382,483.75	7.667	5.924
2047	0	0	448,351	186,549	0	-634,900	-48,590	-5,753,348	-643,413	-6,396,760.80	7.558	5.924
2048	0	0	436,029	190,154	0	-626,184	-44,621	-5,797,969	-612,342	-6,410,311.07	7.455	5.924
2049	0	0	423,999	193,830	0	-617,828	-40,993	-5,838,962	-584,210	-6,423,171.56	7.355	5.924
2050	0	0	412,236	197,576	0	-609,812	-37,673	-5,876,635	-558,743	-6,435,377.37	7.260	5.924
2051	0	0	400,721	201,394	0	-602,115	-34,634	-5,911,269	-535,693	-6,446,961.84	7.168	5.924
2052	4,140,413	0	794,728	205,287	0	-1,000,015	-53,559	-5,964,828	-493,129	-6,457,956.59	11.905	5.924
2053	0	0	812,283	209,254	0	-1,021,538	-50,942	-6,015,770	-452,622	-6,468,391.65	12.161	5.924
2054	0	0	788,586	213,299	0	-1,001,885	-46,519	-6,062,289	-416,006	-6,478,295.50	11.927	5.924
2055	0	0	765,699	217,421	0	-983,120	-42,503	-6,104,792	-382,903	-6,487,695.20	11.704	5.924
2056	0	0	743,557	221,623	0	-965,180	-38,852	-6,143,644	-352,972	-6,496,616.39	11.490	5.924
2057	0	0	722,100	225,907	0	-948,007	-35,532	-6,179,176	-325,908	-6,505,083.45	11.286	5.924
2058	0	0	701,274	230,273	0	-931,547	-32,509	-6,211,685	-301,435	-6,513,119.48	11.090	5.924
2059	0	0	681,027	234,724	0	-915,751	-29,756	-6,241,441	-279,306	-6,520,746.44	10.902	5.924
2060	0	0	661,315	239,260	0	-900,575	-27,246	-6,268,687	-259,298	-6,527,985.14	10.721	5.924
2061	2,679,288	0	904,363	243,884	0	-1,148,247	-32,346	-6,301,033	-233,822	-6,534,855.35	13.670	5.924

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%	6.606%	3.63%
Common Equity	45.00%	8.380%	3.77%
Total	**100.00%**		**7.40%**

CCA Rates:

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

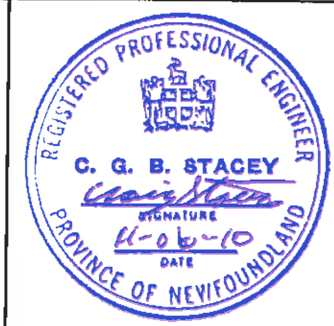
Escalation Factors: Conference Board of Canada GDP deflator, February 4, 2011.

Appendix B
Lockston Switchgear Arc Flash Study

ELECTRICAL ENGINEERING

ARC FLASH HAZARD STUDY

Company Area:	BVA		
Switchgear Included:	LOK 6.9kV		
Prepared by:	D Jones	Date:	3/9/2006

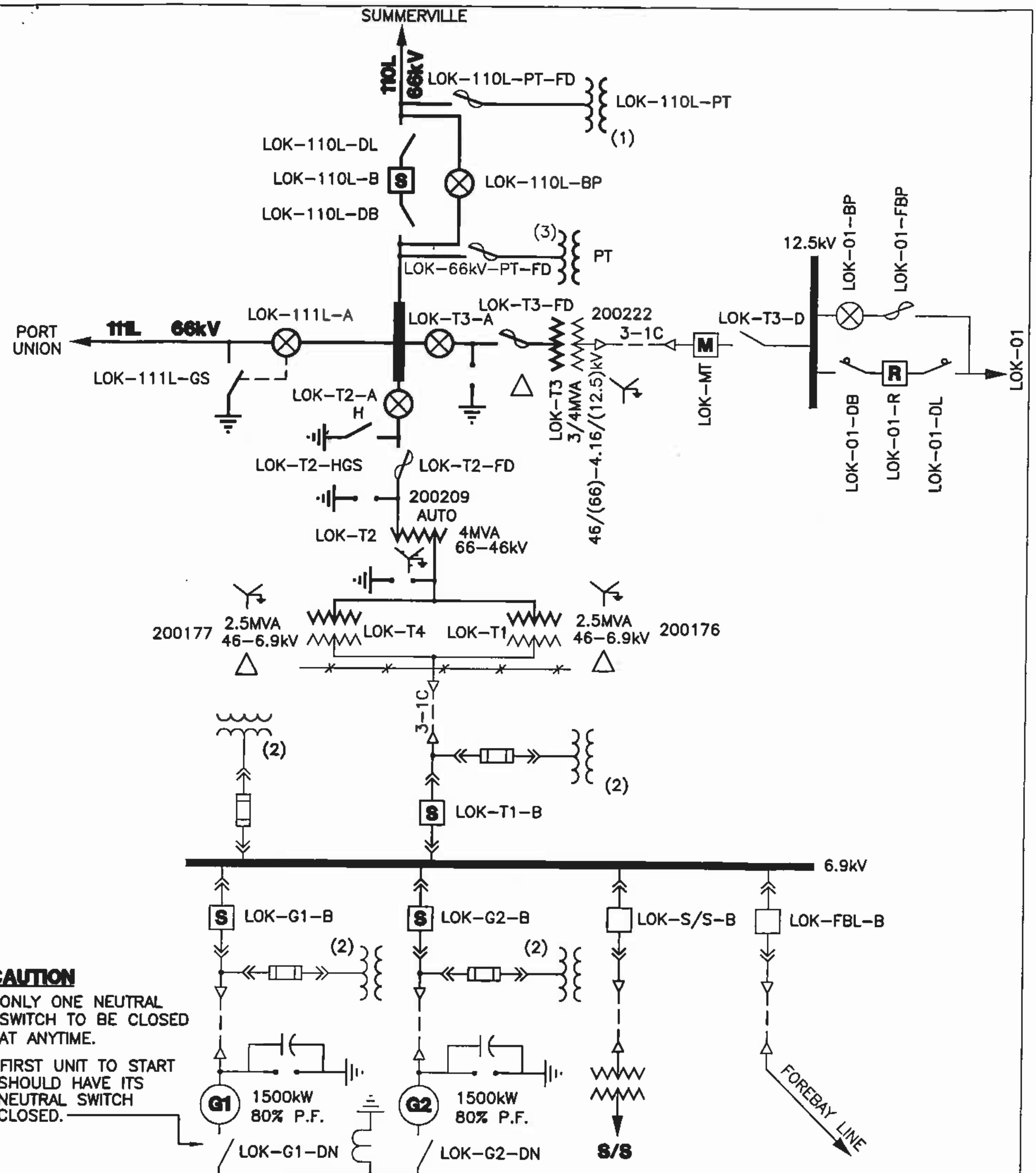


REASON FOR ARC FLASH HAZARD STUDY

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

POINTS TO NOTE

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



CAUTION

1. ONLY ONE NEUTRAL SWITCH TO BE CLOSED AT ANYTIME.
2. FIRST UNIT TO START SHOULD HAVE ITS NEUTRAL SWITCH CLOSED.

REGISTERED PROFESSIONAL ENGINEER
G. Richard Spurrell
SIGNATURE
2002-06-21
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.

LOCKSTON (LOK)

Date: 2002-06-21	Page 1 Of 1
App:	SLD No. 4-907

NEWFOUNDLAND POWER

1996 09 03

Memorandum From: **E.A. Noftall**

To: **L.W. Thompson**

Subject: **Lockston Substation**

File: **PSD-0645.01.03, PSD-415-LOK**

It has been identified that the lockout relay at Lockston Substation will not trip the supply coming from 111L into the 66kV bus at LOK. It was previously indicated that it was not economically feasible to install a breaker on LOK-111L to restore the differential scheme. As proposed, a High Speed Ground Switch will solve this problem by tripping the protection at CAT-T1.

Primary protection of LOK-T1, LOK-T2, LOK-T4 and the LOK 6.9kV power cables can be provided by a set of fuses below LOK-T2-A on the 66kV structure (LOK-T2-FD). The recommended fuse for LOK-T2-FD is a 40E S&C SMD-1A Standard Speed 69kV fuse.

A supervisory relay is recommended for 110L at LOK to prevent the relay LOK-110L-21 from tripping LOK-110L-B when the power is lost to the 66kV system at LOK.

CGS

c.c. E.A. Noftall

Lockston

NOTES: 960829

It was identified that the lockout relay at Lockston Substation was not able to trip the supply coming from 111L into the 66kV bus at LOK. It was proposed that a breaker be reinstalled on 111L at LOK. As a cheaper alternative, a High Speed Ground Switch (HSGS) will be installed at LOK, which will trip the protection at CAT on T1.

The benefits of a breaker (for example the differential protection at LOK could be reinstated with a breaker on 111L) do not out weigh the extra cost of a breaker.

The HSGS will be proposed for the 1997 budget along with a supervisory relay (50) for LOK-110L-21. The supervisory relay will keep LOK-110L-21 from tripping LOK-110L-B everytime the power is lost to the 66kV system at LOK.

A supervisory relay is also needed for CAT-111L-21 which will also be proposed for the 1997 budget.

The HSGS installation is viable as long as the fuses proposed for LOK-T2 are put in place. The fuses for LOK-T2 will provide primary protection for LOK-T1, T2, T4 & the 6.9kV power cables.

NF POWER- RELAY REPORT 1

50NLV	IAC53B	12.	MVA=	P/U=	TD=	Pri amps=	TCC=	9/14/87		240	PHASE INST BLKD	4-16
51	IAC51B	138	MVA= 33.1	P/U= 12	TD= 3.0	Pri amps= 139	TCC=	9/14/87		20 D	PHASE C 0/C	4-16
51NLV	IAC53B	12.	MVA= 5.2	P/U= 1.0	TD= 3.0	Pri amps= 240	TCC=	9/14/87		240	INST NOT INSTALLED	0.5-2.0

Eqpt code: -GRH-G1 -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
87T	HUE	66		HV Tap=4	LV KV=1	CTLV=300	LV Tap=4			100	INCLUDES XFMR 1	2.9-8.7	
87T	HUE	66		HV Tap=4	LV KV=1	CTLV=300	LV Tap=4			100	INCLUDES XFMR 1	2.9-8.7	

Eqpt code: -GRH-T1 -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
87	HU	66		HV Tap=4	LV KV=1	CTLV=300	LV Tap=4			100	INCLUDES GEN 1	2.9-8.7	
87	HU	66		HV Tap=4	LV KV=1	CTLV=300	LV Tap=4			100	INCLUDES GEN 1	2.9-8.7	

Eqpt code: -LOK-110L-

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
67N/50	JBCG53	66	MVA= 14.9	P/U= 6.5	TD=	Pri amps= 130	TCC=	9/8/97		20	DIR GND INST	4-16	
51N	SPAJ14	66	MVA= 2.3	P/U= 1.0	TD=	Pri amps=	TCC=	10/24/97		20	BLOCKED	2.5-25	
51	SPAJ14	66	MVA= 18.3	P/U= 8	TD=	Pri amps= 160	TCC=	10/23/97		20	SUPV LOK-110L-21-1	2.5-25	
50N	SPAJ14	66	MVA= 14.9	P/U= 6.5	TD=	Pri amps=	TCC=	10/24/97		20	BLOCKED	0.5-40	
50	SPAJ14	66	MVA=	P/U=	TD=	Pri amps=	TCC=	10/24/97		20	BLOCKED	0.5-40	
67N	JBCG53	66	MVA= 2.3	P/U= 1.0	TD= 1.5	Pri amps= 20	TCC=	9/8/97		20	Dir blocked closed-RNS req p	0.5-2.0	
21-1	KD-4	66	Zpri= 51.9	T= 2.03	S= 1	L= 0.0	R= 0.03		600	20	L/R	0.75-21	
	SPAJ14	66									START OF THE 51 USED FO		

Eqpt code: -LOK-66B -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
87	IAC53A	66	MVA= 2.6	P/U= 1.0	TD= 3.0	Pri amps= 23.1	TCC=	9/15/87		40 D	NOT IN SERVICE	0.5-2	

Eqpt code: -LOK-FBL -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
50	IAC77B	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87		60	PHASE INST BLKD	20-80	
50N	IAC77B	6.9	MVA= 21.5	P/U= 30	TD=	Pri amps= 1800	TCC=	9/15/87		60	GND INST	10-40	
51	IAC77B	6.9	MVA= 4.3	P/U= 6	TD= 1.0	Pri amps= 360	TCC=	9/15/87		60	PHASE O/C	4-16	
51N	IAC77B	6.9	MVA= 1.2	P/U= 1.6	TD= 1.0	Pri amps= 96	TCC=	9/15/87		60	GND O/C	0.5-2.0	

Eqpt code: -LOK-G1 -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
13	SV	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87				70-160	
87	IJD52A	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87		40	GEN DIFF	0.02-25%	
51V	IJCV51	6.9	MVA= 2.4	P/U= 5.0	TD= 3.0	Pri amps= 200	TCC=	3/16/94		40	VOLT REST O/C	4-16	
51N	IAC58A	6.9	MVA= 0.48	P/U= 2.0	TD= 2.0	Pri amps= 40	TCC=	9/15/87		20	GND O/C	1.5-6	
49I	BL-1	6.9	MVA= 5.7	P/U= 12.0	TD=	Pri amps= 480	TCC=	9/15/87		40	WINDING TEMP. O/C	6.0-50	
27	PJV11B	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87			INST U/V COMMON G1&G2	50-110	
40	KLF			TA=15.8	SA=2	MA=0.000	LA=.06 u				FIELD LOSS VOLT BKD		
49	BL-1	6.9	MVA= 2.0	P/U= 4.25	TD=	Pri amps= 170	TCC=	9/15/87		40	WINDING TEMP. O/C	2.5-5.0	

Eqpt code: -LOK-G2 -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
51GN	IAC57A	6.9	MVA= 0.48	P/U= 2.0	TD= 2.0	Pri amps= 40	TCC=	9/15/87		20	GND O/C	1.5-6	
13	SV	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87				70-160	

87	IJD52A	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87		40	GEN DIFF	0.02-25%
51V	IJCV51	6.9	MVA= 2.4	P/U= 5.0	TD= 3.0	Pri amps= 200	TCC=	3/16/94		40	VOLT REST O/C	4-16
49	BL-1	6.9	MVA= 2.0	P/U= 4.25	TD=	Pri amps= 170	TCC=	9/15/87		40	WINDING TEMP O/C	2.5-5.0
40	KLF			TA=15.8	SA=2	MA=0.153	LA=.06 u		60	40	VOLT UNIT BKD	
49I	BL-1	6.9	MVA= 5.7	P/U= 12.0	TD=	Pri amps= 480	TCC=	9/15/87		40	WINDING TEMP. O/C	6.0-50

Eqpt code: -LOK-S/S -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
50	IAC51B	6.9	MVA=	P/U= 40	TD=	Pri amps=	TCC=	9/15/87			PHASE C INST	20-80	
50	IAC53B	6.9	MVA=	P/U= 20	TD=	Pri amps=	TCC=	9/15/87			PHASE A INST	20-80	
50N	IAC51B	6.9	MVA=	P/U= 16	TD=	Pri amps=	TCC=	9/15/87			GND INST	4-16	
51	IAC53B	6.9	MVA=	P/U= 4.0	TD= 0.5	Pri amps=	TCC=	9/15/87			PHASE A O/C	4-16	
51	IAC51B	6.9	MVA=	P/U= 4.0	TD= 0.5	Pri amps=	TCC=	9/15/87			PHASE C O/C	4-16	
51N	IAC51B	6.9	MVA=	P/U= 0.6	TD= 0.5	Pri amps=	TCC=	9/15/87			GND O/C	0.5-2	

Eqpt code: -LOK-T1 -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
51N	IAC77B	6.9	MVA= 0.36	P/U= 0.5	TD= 1.0	Pri amps= 30	TCC=	9/15/87		60	GND O/C	0.5-2	
81	KF	6.9	MVA=	P/U=	TD=	Pri amps=	TCC=	9/15/87			U/F COMMON BOTH GEN	55-59.5	
50	IAC77B	6.9	MVA= 28.7	P/U= 40	TD=	Pri amps= 2400	TCC=	9/15/87		60	PHASE INST	20-80	
50N	IAC77B	6.9	MVA= 7.2	P/U= 10	TD=	Pri amps= 600	TCC=	9/15/87		60	GND INST	10-40	
51	IAC77B	6.9	MVA= 4.3	P/U= 6.0	TD= 6.5	Pri amps= 360	TCC=	9/15/87		60	PHASE O/C	4-16	

Eqpt code: -NWB-T1 -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
51	MCGG2	138	MVA= 14.34	P/U= 1.0	TD= 0.6	Pri amps= 60	TCC=	6/13/95		60	EI CURVE	0.25-12	
51NLV	MCGG2	25	MVA= 4.55	P/U= 1.75	TD= 0.97	Pri amps= 105	TCC=	10/26/92		60	VI CURVE	0.25-12	
50NLV	MCGG2	25	MVA=	P/U=	TD=	Pri amps=	TCC=	10/26/92		60	BLOCKED	0.25-372	
50/2	RXKF1	138	MVA=	P/U=	TD=	Pri amps=	TCC= 2.0	6/13/95				0.2-3.0	
50	MCGG2	138	MVA= 71.71	P/U= 5	TD=	Pri amps= 300	TCC=	10/26/92		60		0.25-372	
REMAR											HSGS AND MOTORIZED AIR		
89/2	RXKF1	138	MVA=	P/U=	TD=	Pri amps=	TCC= 5.0	10/26/92			T1-A TIMER	2-30	

Eqpt code: -PBD-T1 -

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
89/2	RXKF-1	138	MVA=	P/U=	TD=	Pri amps=	TCC= 5.0	11/8/90			T1-A Timer	1.0-10.0	
51NLV	MCGG2	25	MVA= 7.79	P/U= 4.5	TD= 0.65	Pri amps= 180	TCC=	11/8/90		40	VI CURVE	0.5-12.0	
51	MCGG2	138	MVA= 21.51	P/U= 2.25	TD= 0.25	Pri amps= 90	TCC=	11/8/90		40	VI CURVE	0.5-12.0	
50NLV	MCGG2	25	MVA=	P/U=	TD=	Pri amps=	TCC=	11/8/90		40	BLOCKED	0.5-372	
50/2	RXKF-1	138	MVA=	P/U=	TD=	Pri amps=	TCC= 1.5	11/8/90				0.3-3	
50	MCGG2	138	MVA= 86.05	P/U= 9.0	TD=	Pri amps= 360	TCC=	11/8/90		40		0.5-372	

Eqpt code: -PUN-2.4B-

Setting group:		kV						Date	PT	CT	Remarks	Range	Power Supply
46/50	RIRA	2.4									OPERATES FROM 46 OUTP		
27	IAV54	2.4	MVA=	P/U=	TD=	Pri amps=	TCC=	12/30/97	20			55-140	
46/50T	AGAST	2.4	MVA=	P/U=	TD=	Pri amps=	TCC= 0.5	11/16/87			TIMER FOR 46/50	0.5-5	
81	KF	2.4	MVA=	P/U=	TD=	Pri amps=	TCC=	11/9/87	20		TRIPS G1,G2,G3	55-59.5	

Maximum Generation Fault LOK 6.9 kV.

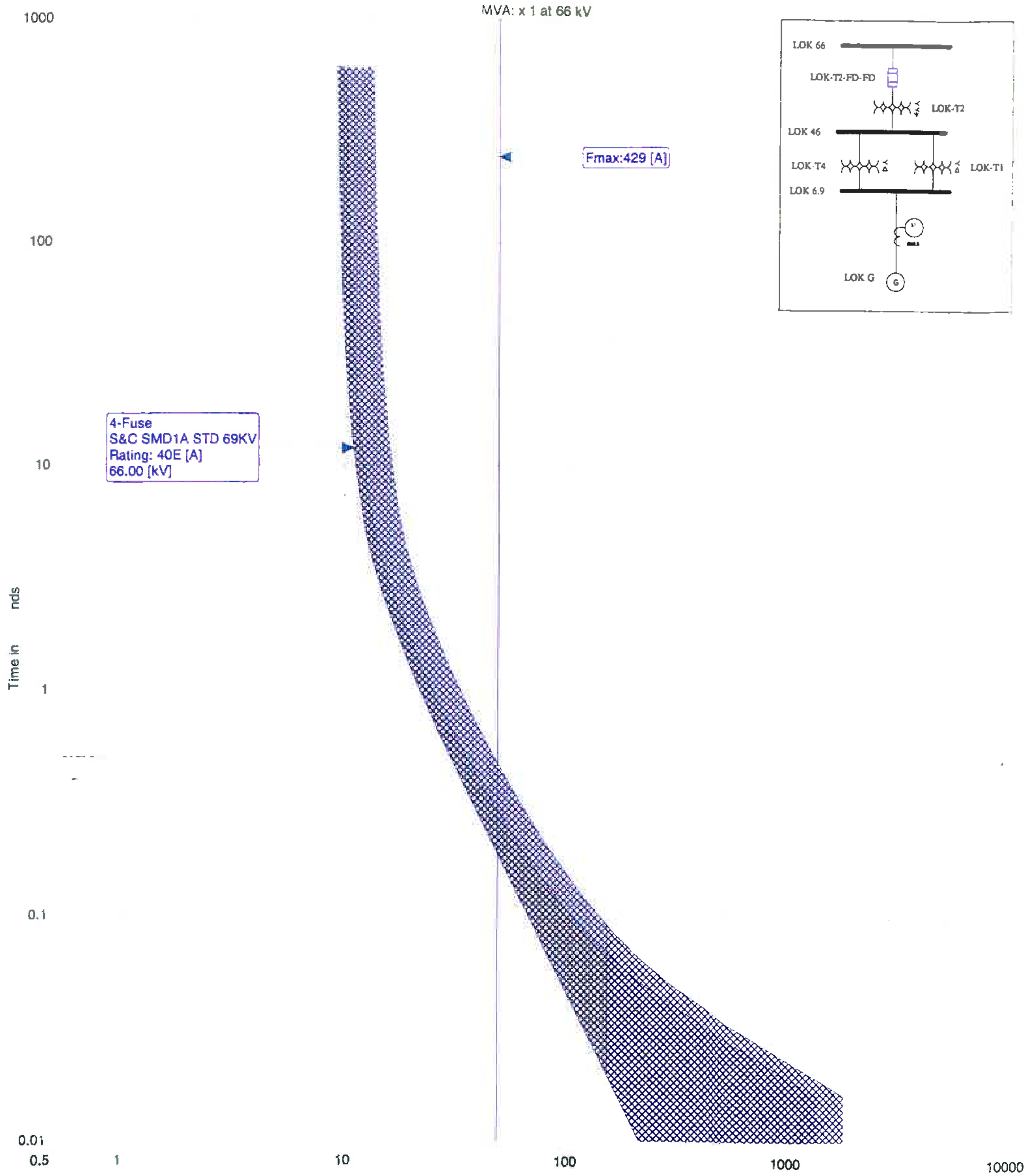
ID	Type	Prefault kV	Angle	Fault type	Fault S [MVA]	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
Faulted Bus ->													
LOK 07		6.9	0	LLL	49	4106.6676	-81.2169	4106.6675	158.7831	4106.6675	38.7831	0	0
First Ring Contributions													
LOK G1	Generator	6.9	0	LLL	12	1033.3733	-90	1033.3733	150	1033.3733	30	0	0
LOK T4	Fixed-Tap Xmer	6.9	0	LLL	18	1534.5262	-78.4658	1534.5262	161.5342	1534.5262	41.5342	0	0
LOK T1	Fixed-Tap Xmer	6.9	0	LLL	19	1555.3501	-78.1188	1555.3501	161.8812	1555.3501	41.8812	0	0

Faulted Bus	Branch Id	Type	Fault type	Branch Sid	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
LOK 07	LOK T2	Fixed-Tap Xme	LLL	LOK 66	323	131.7089	323	11.7089	323	-108.2911	0	0
LOK 07	LOK T2	Fixed-Tap Xme	LLL	LOK 46	463.5	-48.2911	463.5	-168.2911	463.5	71.7089	0	0

Current Multiplier for CYMTCC LOK-T2-FD

= 49 MVA / (323*66*SQRT3/1000)

Current Multiplier = 1.33



For LLL LOK 6.9 kV fault at Maximum Generation. LOK-T2-FD maximum melting time 0.4715 seconds with existing 40E S&C SMD-1A Standard Speed 69kV fuses.

Dave Jones

March 09, 2006

Study: C:\Arc Flash\Plants\LOK\LOK T1 Fuse Max Gen LLL.lcc

Minimum Generation Fault LOK 6.9 kV. LOK plant on.

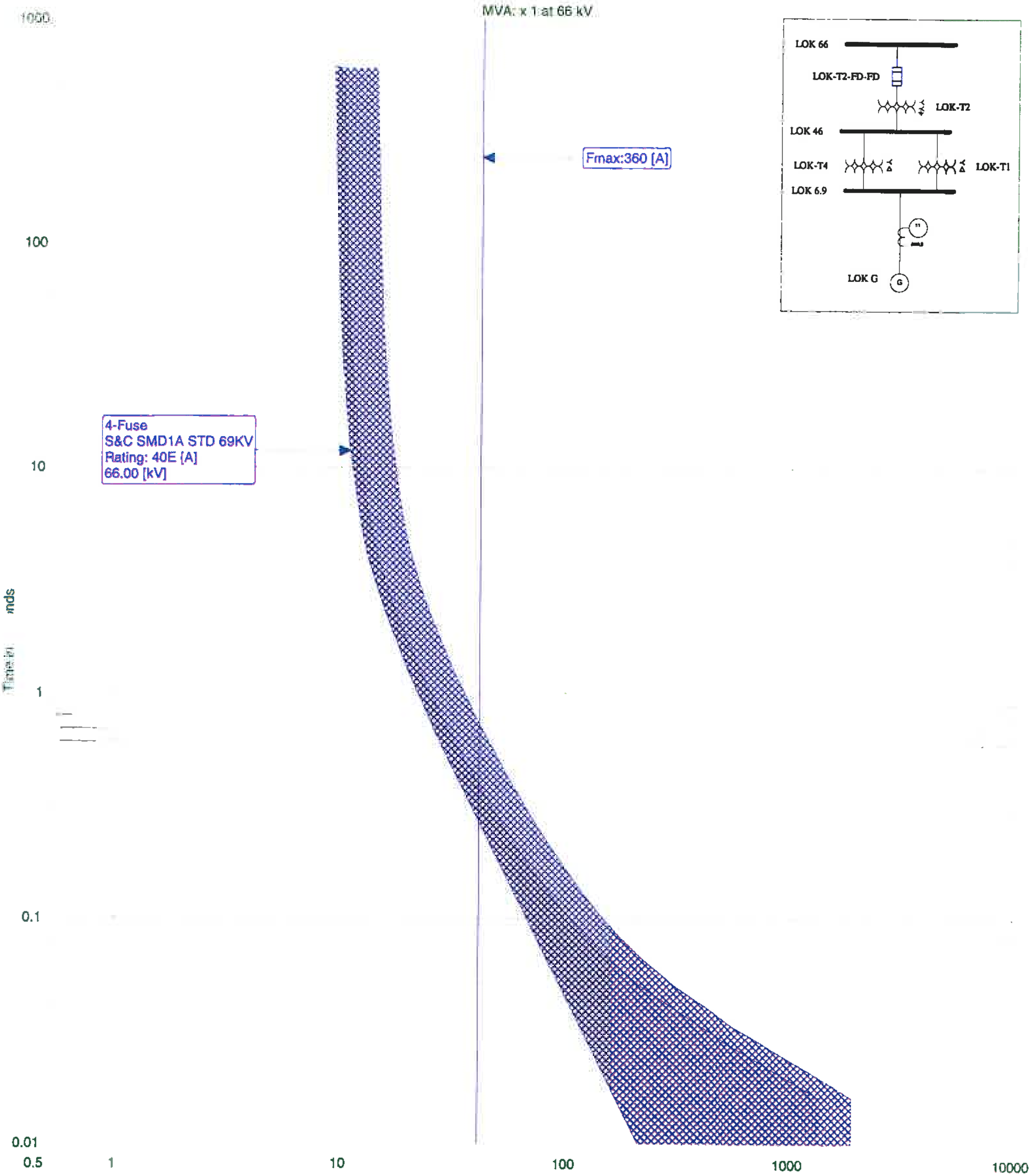
ID	Type	Prefault kV	Angle	Fault type	Fault S [MVA]	Ia [A]	Ia [deg]	Ib [A]	Ib [deg]	Ic [A]	Ic [deg]	In [A]	In [deg]
Faulted Bus ->													
LOK 07		6.9	0	LLL	41	3441.4846	-81.198	3441.4846	158.802	3441.4846	38.802	0	0
First Ring Contributions													
LOK T4	Fixed-Tap Xmer	6.9	0	LLL	14	1204.7335	-77.6356	1204.7335	162.3644	1204.7335	42.3644	0	0
LOK T1	Fixed-Tap Xmer	6.9	0	LLL	15	1221.1073	-77.2894	1221.1073	162.7106	1221.1073	42.7106	0	0
LOK G1	Generator	6.9	0	LLL	12	1033.3733	-90	1033.3733	150	1033.3733	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]
LOK 07	LOK T2	Fixed-Tap Xme	LLL	LOK 66	253.6	132.5382	253.6	12.5382	253.6	-107.4618	0	0
LOK 07	LOK T2	Fixed-Tap Xme	LLL	LOK 46	363.9	-47.4618	363.9	-167.4618	363.9	72.5382	0	0

Current Multiplier for CYMTCC LOK-T2-FD

= 41 MVA / (253.6*66*SQRT3/1000)

Current Multiplier = 1.41



For LLL LOK 6.9 kV fault at Minimum Generation. LOK-T2-FD maximum melting time 0.7292 seconds with existing 40E S&C SMD-1A Standard Speed 69kV fuses.

Dave Jones

March 09, 2006

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

Arc Flash Hazard LOK 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.
LOK 6.9	Max	LLL	4107	0.4715	0.4715	16"	91"	6.5	2	60"	26"	7"
LOK 6.9	Min	LLL	3441	0.7292	0.7292	16"	117"	8.3	3	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.
LOK 6.9	Max	LLL	4107	0.4715	0.4715	36"	91"	3.0	1	60"	26"	7"
LOK 6.9	Min	LLL	3441	0.7292	0.7292	36"	117"	3.8	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

91 inches	Flash Hazard Boundary
6.5	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:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

91 inches	Flash Hazard Boundary
6.5	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:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

91 inches	Flash Hazard Boundary
6.5	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:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

91 inches	Flash Hazard Boundary
6.5	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:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

117 inches	Flash Hazard Boundary
8.3	cal / cm2 Flash Hazard at 16 inches
class 3	PPE Level, Cotton underwear plus FR shirt and FR pants plus FR coverall, or cotton underwear plus two FR coveralls (2 or 3 layers). FR hard hat, safety glasses or goggles, flash suit hood, ear, hand and foot protection.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

117 inches	Flash Hazard Boundary
8.3	cal / cm2 Flash Hazard at 16 inches
class 3	PPE Level, Cotton underwear plus FR shirt and FR pants plus FR coverall, or cotton underwear plus two FR coveralls (2 or 3 layers). FR hard hat, safety glasses or goggles, flash suit hood, ear, hand and foot protection.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

117 inches	Flash Hazard Boundary
8.3	cal / cm2 Flash Hazard at 16 inches
class 3	PPE Level, Cotton underwear plus FR shirt and FR pants plus FR coverall, or cotton underwear plus two FR coveralls (2 or 3 layers). FR hard hat, safety glasses or goggles, flash suit hood, ear, hand and foot protection.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

117 inches	Flash Hazard Boundary
8.3	cal / cm2 Flash Hazard at 16 inches
class 3	PPE Level, Cotton underwear plus FR shirt and FR pants plus FR coverall, or cotton underwear plus two FR coveralls (2 or 3 layers). FR hard hat, safety glasses or goggles, flash suit hood, ear, hand and foot protection.
6900 VAC	Shock Hazard
60 inches	Limited Approach
26 inches	Restricted Approach
7 inches	Prohibited Approach

Equipment Name:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

91 inches	Flash Hazard Boundary
3.0	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:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

91 inches	Flash Hazard Boundary
3.0	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:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

91 inches	Flash Hazard Boundary
3.0	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:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

91 inches	Flash Hazard Boundary
3.0	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:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

117 inches	Flash Hazard Boundary
3.8	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:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

117 inches	Flash Hazard Boundary
3.8	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:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

117 inches	Flash Hazard Boundary
3.8	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:LOK 07

WARNING

Arc Flash and Shock Hazard
Appropriate PPE Required

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Equipment Name:LOK 07

2012 Substation Refurbishment and Modernization

June 2011

Prepared by:

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1.0 Substation Refurbishment and Modernization Strategy

Newfoundland Power (the "Company") has 130 substations located throughout its operating territory. Distribution substations connect the low voltage distribution system to the high voltage transmission system. Transmission substations connect transmission lines of different voltages. Generation substations connect generating plants to the electrical system. Substations are critical to reliability; an unplanned substation outage will affect thousands of customers. The Company's substation maintenance program and the Substation Refurbishment and Modernization project ensure the delivery of reliable least cost electricity to customers in a safe and environmentally responsible manner.

The Substation Refurbishment and Modernization project provides a structured approach for the overall refurbishment and modernization of substations and coordinates 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.

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

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. In 2012, the budget estimate is materially below this level due to a requirement to address government regulations concerning polychlorinated biphenyls ("PCB")[1] and the requirement to address additions due to load growth.[2] Also, the 2012 projects at Hearts Content and New Grand Falls substations were originally included in the 2011 Substation Refurbishment and Modernization project. Due to the significant impact of the two storms experienced in 2010, the 2011 plan was revised and these projects delayed until 2012.[3] Such developments highlight the practical requirement for flexibility in execution of the Substation Refurbishment and Modernization project over time.

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1 A description of the work required to meet the new PCB regulations established by Environment Canada can be found in ***2.3*** *2012 PCB Removal Strategy*.

2 The Company has reduced Substation Refurbishment and Modernization project expenditures in 2012 in order to moderate the overall increase in the substation capital budget. A degree of flexibility is necessarily required for ongoing planning of capital expenditures if a reasonable degree of stability in the Company's annual capital budgets is to be achieved. In Order No. P.U. 36 (2002-2003) the Board stated that it believes more stable and predictable year over year capital budgets for Newfoundland Power is a desirable objective.

3 Storm related work associated with the March 2010 ice storm and Hurricane Igor in September 2010 caused planned work in 2010 to be delayed or deferred.

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

2.0 Substation Refurbishment and Modernization 2012 Projects

2012 Substation Projects include planned refurbishment and modernization projects of two substations and one portable substation. Items Under $50,000 include the installation of petro plug devices in eight substations to permit continuous draining of water from spill containment pans. Substation Monitoring and Operations includes upgrades to substation communication systems to accommodate increased data requirements.

Table 1
2012 Substation Refurbishment and Modernization Projects
(000s)

Project	Budget
2012 Substation Projects	
Hearts Content Substation (HCT)	*$1,243*
Portable Substation 4 (P4)	*$100*
New Grand Falls Substation (NGF)	*$899*
Items Under $50,000	$90
Substation Monitoring and Operations	$150
Total	**$2,482**

2.1 2012 Substation Projects ($2,482,000)

Hearts Content Substation ($1,243,000)

Hearts Content substation (HCT) was built in 1956 as a generation substation and over the years has developed also 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 Hearts Content area through one 12.5 kV feeder. In the substation there are three 66 kV transmission lines terminated in the high voltage bus. These are transmission lines 41L to Carbonear substation, 43L to New Chelsea substation and 80L to Islington substation.

Hearts 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 T1 and T3 are 1966 and 1971 vintage, are deteriorated and will be replaced.[4] The lightning arrestors on the 66 kV side of T1 are gap type and will be replaced with new metal oxide arrestors.[5]

The protection relays for the transmission lines and 66 kV bus protection are 1972 vintage electromechanical type and will be replaced with new microprocessor based relays[6].

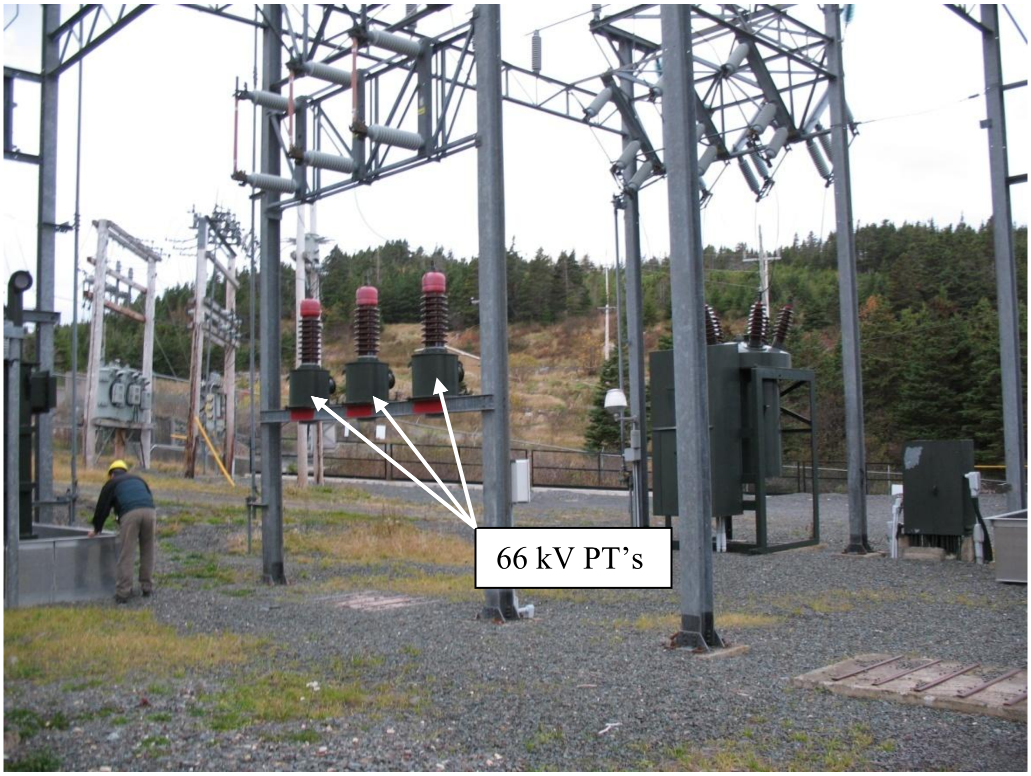
4 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that power cable failures begin to occur when cables are about 35 years old. The Heart's Content power cables are 39 and 44 years of age and will be replaced during the 2012 refurbishment and modernization of the substation.

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

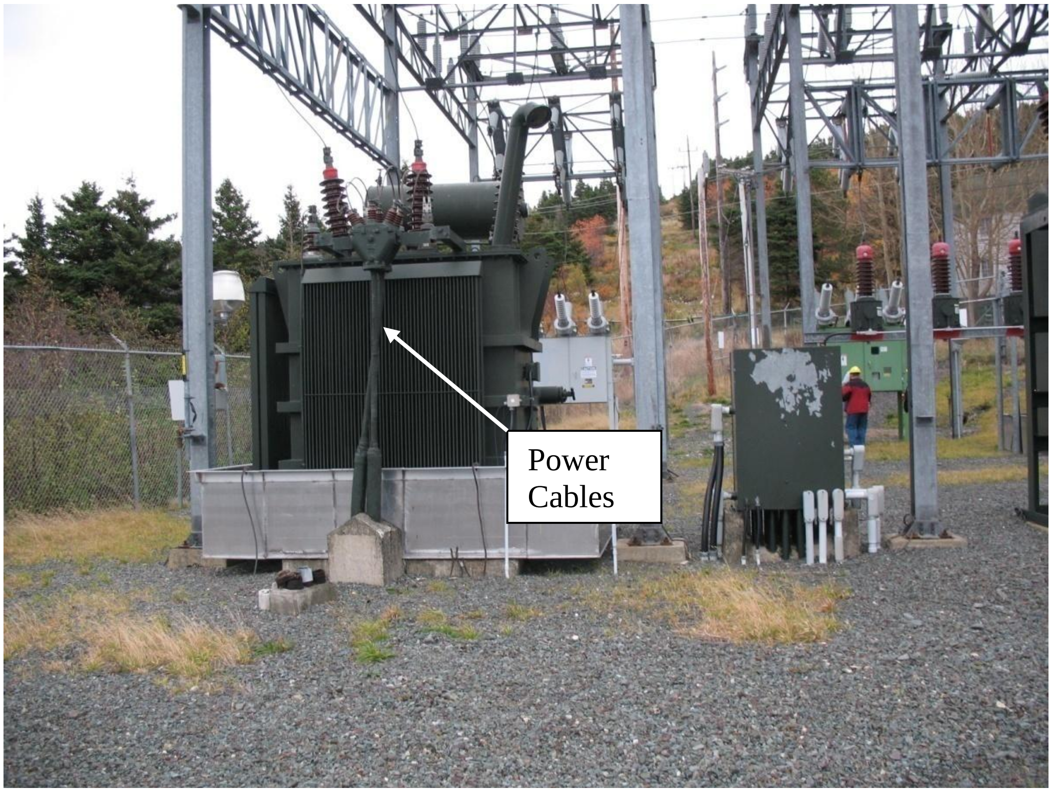
6 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust. In the past five years Newfoundland Power has experienced increasing numbers of electro-mechanical relay failures.

The 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

Severe Rusting On Anchor Bolt



39 Year Old Potential Transformers



1966 Vintage Power Cables

Damage Due To Flooding

Portable Substation P4 ($100,000)

Portable substation P4 was purchased in 1992. It is used to respond to power transformer failures and for planned transformer maintenance and substation refurbishment and modernization work.[7] P4 can provide backup for 70% of the 192 power transformers in service on Newfoundland Power's system.

Portable Substation P4

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

Based upon preliminary inspections, the following work will be required to be undertaken in 2013. The engineering work undertaken in 2012 will finalize scope of work for 2013, and Newfoundland Power will submit the scope of work and cost estimate for Board approval in the 2013 capital budget application.

[7] Portable Substation P4 will be used extensively during the PCB Phase Out program to minimize customer outage minutes to the extent possible.

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

The alarm annunciation panel has had several failures and will be replaced. The protection relays will be replaced with microprocessor based protection relays.[8] 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.

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.

New Grand Falls Substation ($899,000)

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 132L 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 138 kV to 25 kV distribution power transformers T2 and T3. Each distribution power transformer has a capacity of 20 MVA at 25 kV. The substation directly serves approximately 6,000 customers in the Grand Falls area through five 25 kV feeders.

8 Report ***2.1*** *Substation Strategic Plan* included with the 2007 Capital Budget Application identified that electro-mechanical relays contain moving parts and are prone to failure as they age, wear and accumulate dirt and dust. In the past five years Newfoundland Power has experienced increasing numbers of electro-mechanical relay failures.

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.[9]

The power cable and terminations for T2 are 35 years old, are approaching the end of their anticipated useful life, and will be replaced.[10] 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.

66 kV potential Transformers

The relays for the transmission lines and bus protection are 1976 vintage electromechanical type and will be replaced with new microprocessor based relays[11].

[9] 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.

[10] 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 35 years of age and will be replaced during the 2011 refurbishment and modernization of the substation.

[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.

Transmission Line Electromechanical Relays

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

2.2 Items Under $50,000 ($90,000)

The 2012 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. Petro plug devices are to be installed in eight locations to allow continuous draining of water from spill containment pans without endangering the environment.

2.3 Substation Monitoring and Operations ($150,000)

Over the past decade, there has been a substantial increase of computer-based equipment in electrical system control and operations. Periodic upgrades of this equipment are necessary to ensure continued effective electrical system control and operations.

In 2012, 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 2012, 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 2012 to 2016

Substation Refurbishment and Modernization Plan
Five-Year Forecast
2012 to 2016
(000s)

2012		2013		2014		2015		2016	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
HCT	1,243	STV	554	CAR	791	BRB	1,327	BVA	670
P4	100	P4	684	GLN	411	BVS	969	HUM	1,300
NGF	899	SCT	222	ILC	104	CAT	2,008	P1	716
Misc	90	KEN	102	MAS	603	GBE	128	WAL	1,087
SMU	150	SMU	150	RRD	808	NCH	1,214	SMU	150
				SPO	1,166	TWG	274		
				SPR	445	SMU	150		
				STX	238				
				VIC	1,210				
				SMU	150				
	$2,482		**$1,712**		**$5,926**		**$6,070**		**$3,923**

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.

2012 Additions Due to Load Growth

June 2011

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BYRON A. CHUBBS

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1.0 Introduction

As load increases on an electrical system, individual components can become overloaded. The focus of Newfoundland Power's system planning is to avoid or minimize component overloading through cost effective upgrades to the system. In the case of substation power transformers, an engineering study is completed to identify and evaluate technical alternatives in advance of the 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 of load growth on the Company's substations in the areas of Gander and St. John's South/Mount Pearl. The scope of the studies included two substations serving customers in Gander, and three substations serving customers in St. John's South/Mount Pearl. 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 2012 Capital Budget. The first item is to install a new 25 MVA transformer for Cobb's Pond substation, addressing transformer capacity in the town of Gander. The second item is the completion of civil work at Glendale substation in preparation for the installation of a new transformer that will be required in 2013.

2.0 Gander Area

An engineering study has been completed on the distribution system upgrades to meet the electrical demands in the Gander area.[1] This area includes customers serviced from Cobb's Pond ("COB") and Gander ("GAN") substations.

The study examines 3 alternatives to determine the least cost approach to dealing with the forecast overload conditions in the Gander area. Each alternative was evaluated using a 20 year load forecast. Based on net present value calculations the least cost alternative was selected.

The least cost project involves installing a new 25 MVA power transformer at COB substation.

1 The engineering study titled "2012 Additions Due to Load Growth-Gander Study" is included as Attachment A.

3.0 St. John's South/Mount Pearl Area

An engineering study has been completed on the distribution system upgrades to meet the electrical demands in the St. John's South/Mount Pearl area.[2] The St. John's South/Mount Pearl area includes customers serviced from Hardwoods ("HWD"), Glendale ("GDL") and Goulds ("GOU") substations.

The study examines 3 alternatives to determine the least cost approach to dealing with the forecast overload conditions in the St. John's South/Mount Pearl area. Each alternative was evaluated using a 20 year load forecast. Based on net present value calculations the least cost alternative was selected.

The least cost project involves completion of civil work at Glendale substation in preparation for the installation of a new transformer that will be required in 2013.[3]

4.0 Project Cost

Table 1 shows the total 2012 capital costs for each project.

Table 1
2012 Project Costs
($000)

Cost Category	**Cobb's Pond Transformer**	**Glendale Civil Work**
Material	3,657	957
Labour – Internal	30	40
Engineering	368	140
Other	80	19
Total	**4,135**	**1,156**

5.0 Concluding

Both the Gander and St. John's South/Mount Pearl 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 "2012 Additions Due to Load Growth-St. John's South/Mount Pearl Study" is included as Attachment B.

[3] Additional transformer capacity is required at GDL substation in 2013. However, the project will extend beyond one year. Completing civil work at GDL substation in 2012 will allow additional transformer capacity to be installed in GDL during 2013.

It is recommended that the projects identified as part of the least cost alternatives in the attached studies be undertaken in 2012 to address capacity issues in the Gander and St. John's South/Mount Pearl areas.

The least cost alternatives proposed include installing a new 25 MVA power transformer at COB substation and completing civil work in preparation for the installation of an additional 25MVA power transformer at GDL substation in 2013. The estimated cost to complete the work proposed for 2012 is $5,291,000.

Attachment A
Gander Study

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1.0 Introduction

The purpose of this study is to determine the distribution system alternative that best meets the electrical demands of the Town of Gander. This area includes customers serviced from Gander Substation ("GAN") and Cobb's Pond Substation ("COB").

In 2010, the distribution power transformers supplying the area experienced a total peak load of 37.6 MVA compared to a total capacity of 40.0 MVA.[1] The current substation load forecast indicates that the combination of transformers in GAN and COB substations will reach overload in 2011. Load growth on these transformers is the result of an increase in residential and commercial development in the Town of Gander.

This report identifies the capital project(s) required to avoid the 2012 forecast overload by determining the least cost expansion plan required to meet a 20 year load forecast.

2.0 Description of Existing System

2.1 GAN Substation

Gander Substation is located on Bennett Drive. The substation has three transformers, GAN-T1, GAN-T2, and GAN-T3. GAN-T1 is a 20 MVA transformer used to convert the 138 kV transmission voltage to the 12.5 kV distribution voltage and supply customers through GAN distribution feeders. GAN-T2 is a 26.67 MVA transformer used to convert between 138 kV and 66 kV for transmission line interconnection. GAN-T3 is a grounding transformer used as a ground point for the 66 kV transmission system.

2.2 COB Substation

Cobb's Pond Substation is located on Magee Road. The substation has two transformers, COB-T1 and COB-T2. COB-T1 is a 20 MVA transformer used to convert the 138 kV transmission voltage to the 12.5 kV distribution voltage and supply customers through COB distribution feeders. COB-T2 is a 41.6 MVA transformer used to convert between 138 kV and 66 kV for transmission line interconnection.

2.3 Gander Distribution Network

Four distribution feeders from GAN substation and 3 distribution feeders from COB substation service 5,200 customers in the Town of Gander and immediate surrounding area. There are numerous tie points in this network and feeders can be reconfigured to balance load between the feeders and substations. Together GAN-T1 and COB-T1 provide 40 MVA of capacity for Gander.

[1] A distribution power transformer converts electricity from transmission voltages (typically 66 kV) to distribution primary voltages (typically between 4kV and 25kV).

Figure 1 shows a map view of the Gander distribution network.

Figure 1: Gander Distribution Network

3.0 Load Forecast

The following are the peak substation transformer loads recorded this past winter for each of these substations.

- GAN-T1 is rated at 20 MVA. The load on this transformer peaked at 18.0 MVA in 2010.
- COB-T1 is rated at 20 MVA. The load on this transformer peaked at 19.6 MVA in 2010.

This study uses a 20 year load forecast for these power transformers. The base case 20 year substation forecast for GAN-T1 and COB-T1 is provided in Appendix A. A high and low load growth forecast has also been created for each alternative for use in a sensitivity analysis. With the exception of the first year forecast, the sensitivities are based on increasing the load growth by a factor of 50% for the high forecast and decreasing by a factor of 50% for the low forecast.

4.0 Development of Alternatives

Three alternatives have been developed to eliminate the forecast overload conditions using a set of defined technical criteria.[2] These alternatives will provide sufficient capacity to meet forecast loads over the next 20 years. Each alternative contains estimates for all costs involved and the results of a net present value calculation are provided for each alternative.

4.1 Alternative 1

- Replace the existing 20 MVA, 138/12.5 kV transformer at COB substation with a 25 MVA transformer in 2012.
- Purchase and install a 25 MVA, 138/12.5 kV transformer at COB substation in 2022.

The resulting peak load forecasts for each transformer under Alternative 1 are shown in Appendix B.

4.2 Alternative 2

- Purchase and install a new 25 MVA, 138/12.5 kV transformer at COB substation in 2012.

The resulting peak load forecasts for each transformer under Alternative 2 are shown in Appendix C.

4.3 Alternative 3

- Purchase and install a new 25 MVA, 138/12.5 kV transformer at GAN substation in 2012.

The resulting peak load forecasts for each transformer under Alternative 3 are shown in Appendix D.

[2] 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.

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
2012	Replace 20 MVA transformer with 25 MVA unit at COB substation[3]	$3,807,000
2012	Remove 15/20 MVA transformer from COB substation and place in spares inventory.[4]	($473,000)
2022	Purchase and install new 25 MVA transformer at COB substation[5]	$3,878,000
	Total	**$7,212,000**

Table 2 shows the capital costs estimated for Alternative 2.

Table 2
Alternative 2 Capital Costs

Year	Item	Cost
2012	Purchase and install new 25 MVA transformer at COB substation[6]	$4,135,000
	Total	**$4,135,000**

3 Includes cost to install one (1) 138 kV breaker to complete the ring bus configuration.
4 Implementation of this alternative will result in Newfoundland Power placing COB-T1 into its inventory of spare equipment in 2012. In assessing alternatives it is reasonable to place a value on this spare equipment and credit the capital cost of this alternative by this amount. From the Company's 2006 depreciation study the average life of a new power transformer is 46 years. Using the Iowa 46R2 depreciation curve, COB-T1 is projected to have a remaining life of 18 years in 2013. The remaining value of the transformer can then be estimated by multiplying the current price of an equivalent new transformer by a ratio of 18/46.
5 Includes cost to install one (1) 138kV breaker to complete the ring bus configuration, civil infrastructure and bus extension to accommodate the second power transformer.
6 Includes cost to install two (2) 138 kV breakers to complete the ring bus configuration, civil infrastructure and bus extension to accommodate second power transformer.

Table 3 shows the capital costs estimated for Alternative 3.

Table 3
Alternative 3 Capital Costs

Year	Item	Cost
2012	Purchase and install new 25 MVA transformer at GAN substation[7]	$4,464,000
	Total	**$4,464,000**

5.2 Economic Analysis

To compare the economic impact of the alternatives, a net present value ("NPV") calculation of customer revenue requirement has been completed for each alternative. Capital costs from 2012 to 2031 were converted to revenue requirement and the resulting customer revenue requirement was reduced to a net present value using the Company's weighted average incremental cost of capital.[8]

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	6,001
2	4,393
3	4,745

Alternative 2 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.

[7] Includes cost to upgrade GAN feeders to accommodate additional load.
[8] This analysis captures the customer revenue requirement for the 46 year life of a new transformer asset.

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. Using these revised dates, the net present value of the customer revenue requirement was calculated.

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	6,421	3,542
2	4,393	4,393
3	4,745	4,745

Under the high load forecast scenario, Alternative 2 is still the least cost alternative. Under the low forecast scenario, Alternative 1 is the least cost alternative. However, Alternative 1 in this scenario provides a total capacity of 45 MVA in the final year of the study whereas Alternative 2 provides a total capacity of 65 MVA. The forecast load in the final year is 44.9 MVA meaning a project to address this capacity shortfall would be required in the following year. With this considered Alternative 2 is the preferred alternative for the low forecast scenario as well.

The recommendation to implement Alternative 2 is still appropriate given the results of the sensitivity analysis.

6.0 Project Cost

Table 6 shows the estimated project costs for 2012.

Table 6
Project Costs

Description	Cost Estimate
Purchase and install new 25 MVA transformer at COB substation.	$4,135,000
Total	**$4,135,000**

7.0 Conclusion and Recommendation

A 20-year load forecast has projected the electrical demands for the town of Gander. This includes customers serviced from GAN and COB 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 2.

Further, a sensitivity analysis has confirmed the recommended alternative is appropriate under varying load growth forecasts.

The 2012 project that is part of the least cost expansion plan is to install a new 25 MVA transformer in COB substation. This project is estimated to cost $4,135,000.

Appendix A

2011 Substation Load Forecast – Base Case

20 Year Substation Load Forecast – Base Case

Device	**GAN-T1**	**COB-T1**	**TOTAL**
Rating (MVA)	20	20	40
2010 Peak (MVA)	18.0	19.6	37.6
Year	**Forecasted Undiversified Peak - MVA**		
2011	19.5	21.2	40.7
2012	19.7	21.4	41.1
2013	19.6	21.4	41.0
2014	19.8	21.5	41.3
2015	20.0	21.7	41.7
2016	20.2	22.0	42.2
2017	20.4	22.2	42.6
2018	20.6	22.4	43.0
2019	20.8	22.7	43.5
2020	21.1	22.9	44.0
2021	21.3	23.2	44.5
2022	21.5	23.4	44.9
2023	21.7	23.7	45.4
2024	22.0	23.9	45.9
2025	22.2	24.2	46.4
2026	22.4	24.4	46.8
2027	22.7	24.7	47.4
2028	22.9	25.0	47.9
2029	23.2	25.2	48.4
2030	23.4	25.5	48.9
2031	23.7	25.8	49.5

Appendix B

Alternative 1

20 Year Substation Load Forecasts

Alternative 1
20 Year Substation Load Forecasts – Base Case

Device	**GAN-T1**	**COB-T1**	**COB-T3**	**TOTAL**
Rating (MVA)[9]	20	25	25	70
2010 Peak (MVA)	18.0	19.6		37.6
Year	**Forecasted Undiversified Peak - MVA**			
2011	19.5	21.2		40.7
2012	19.7	21.4		41.1
2013	19.6	21.4		41.0
2014	19.8	21.5		41.3
2015	19.0	22.7		41.7
2016	19.2	23.0		42.2
2017	19.4	23.2		42.6
2018	19.6	23.5		43.1
2019	19.3	24.2		43.5
2020	19.5	24.5		44.0
2021	19.7	24.7		44.4
2022	17.9	12.5	14.5	44.9
2023	18.1	12.6	14.7	45.4
2024	18.3	12.8	14.8	45.9
2025	18.5	12.9	15.0	46.4
2026	18.7	13.0	15.1	46.8
2027	18.9	13.2	15.3	47.4
2028	19.1	13.3	15.5	47.9
2029	19.3	13.5	15.6	48.4
2030	19.5	13.6	15.8	48.9
2031	19.7	13.8	16.0	49.5

9 Ratings reflect the transformer rating in 2031.

Alternative 1
20 Year Substation Load Forecast – High Growth

Device	**GAN-T1**	**COB-T1**	**COB-T3**	**TOTAL**
Rating (MVA)[10]	20	25	25	70
2010 Peak (MVA)	18.0	19.6		37.6
Year	**Forecasted Undiversified Peak - MVA**			
2011	19.5	21.2		40.7
2012	19.7	21.5		41.2
2013	18.7	22.5		41.2
2014	18.9	22.7		41.6
2015	19.2	23.0		42.2
2016	19.5	23.4		42.9
2017	19.8	23.8		43.6
2018	19.6	24.6		44.2
2019	14.9	17.5	12.5	44.9
2020	15.2	17.8	12.7	45.7
2021	15.4	18.1	12.9	46.4
2022	15.7	18.4	13.1	47.2
2023	15.9	18.7	13.3	47.9
2024	16.2	19.0	13.6	48.8
2025	16.4	19.3	13.8	49.5
2026	16.7	19.6	14.0	50.3
2027	16.9	19.9	14.2	51.0
2028	17.2	20.2	14.4	51.8
2029	17.5	20.5	14.7	52.7
2030	17.8	20.9	14.9	53.6
2031	18.1	21.2	15.2	54.5

[10] Ratings reflect the transformer capacity rating in 2031.

Alternative 1
20 Year Substation Load Forecast – Low Growth

Device	GAN-T1	COB-T1	COB-T3	TOTAL
Rating (MVA)[11]	20	25		45
2010 Peak (MVA)	18.0	19.6		37.6
Year	**Forecasted Undiversified Peak - MVA**			
2011	19.5	21.2		40.7
2012	19.6	21.3		40.9
2013	19.6	21.3		40.9
2014	19.6	21.4		41.0
2015	19.7	21.5		41.2
2016	19.8	21.6		41.4
2017	19.9	21.7		41.6
2018	20.1	21.8		41.9
2019	18.7	23.5		42.2
2020	18.8	23.6		42.4
2021	18.9	23.7		42.6
2022	19.0	23.8		42.8
2023	19.1	24.0		43.1
2024	19.2	24.1		43.3
2025	19.3	24.2		43.5
2026	19.4	24.3		43.7
2027	19.5	24.5		44.0
2028	19.6	24.6		44.2
2029	19.7	24.7		44.4
2030	19.8	24.9		44.7
2031	19.9	25.0		44.9

11 Ratings reflect the transformer capacity rating in 2031.

Appendix C

Alternative 2

20 Year Substation Load Forecasts

Alternative 2

20 Year Substation Load Forecast – Base Case

Device	GAN-T1	COB-T1	COB-T3	TOTAL
Rating (MVA)[12]	20	20	25	65
2010 Peak (MVA)	18.0	19.6		37.6
Year	**Forecasted Undiversified Peak - MVA**			
2011	19.5	21.2		40.7
2012	16.7	11.4	13.0	41.1
2013	16.6	11.4	13.0	41.0
2014	16.7	11.5	13.1	41.3
2015	15.9	12.6	13.2	41.7
2016	16.1	12.7	13.3	42.1
2017	16.3	12.9	13.5	42.7
2018	16.4	13.0	13.6	43.0
2019	16.6	13.1	13.8	43.5
2020	16.8	13.3	13.9	44.0
2021	17.0	13.4	14.1	44.5
2022	17.1	13.6	14.2	44.9
2023	17.3	13.7	14.4	45.4
2024	17.5	13.8	14.5	45.8
2025	17.7	14.0	14.7	46.4
2026	17.9	14.1	14.8	46.8
2027	18.1	14.3	15.0	47.4
2028	18.3	14.5	15.2	47.9
2029	18.5	14.6	15.3	48.0
2030	18.7	14.8	15.5	49.0
2031	18.9	14.9	15.6	49.4

[12] Ratings reflect the transformer capacity rating in 2031.

Alternative 2
20 Year Substation Load Forecast – High Growth

Device	**GAN-T1**	**COB-T1**	**COB-T3**	**TOTAL**
Rating (MVA)[13]	20	20	25	65
2010 Peak (MVA)	18.0	19.6		37.6
Year	**Forecasted Undiversified Peak - MVA**			
2011	19.5	21.2		40.7
2012	14.7	10.7	15.7	41.1
2013	14.7	10.7	15.7	41.1
2014	14.9	10.8	15.9	41.6
2015	15.1	11.0	16.1	42.2
2016	15.3	11.2	16.4	42.9
2017	15.6	11.4	16.6	43.6
2018	15.8	11.5	16.9	44.2
2019	16.1	11.7	17.2	45.0
2020	16.3	11.9	17.4	45.6
2021	16.6	12.1	17.7	46.4
2022	16.9	12.3	18.0	47.2
2023	17.1	12.5	18.3	47.9
2024	17.4	12.7	18.6	48.7
2025	17.7	12.9	18.9	49.5
2026	18.0	13.1	19.2	50.3
2027	18.3	13.3	19.5	51.1
2028	18.5	13.5	19.8	51.8
2029	18.8	13.7	20.1	52.6
2030	19.1	14.0	20.5	53.6
2031	19.5	14.2	20.8	54.5

[13] Ratings reflect the transformer capacity rating in 2031.

Alternative 2
20 Year Substation Load Forecast – Low Growth

Device	GAN-T1	COB-T1	COB-T3	TOTAL
Rating (MVA)[14]	20	20	25	65
2010 Peak (MVA)	18.0	19.6		37.6
Year	**Forecasted Undiversified Peak - MVA**			
2011	19.5	21.2		40.7
2012	19.6	10.7	10.7	41.0
2013	19.6	10.7	10.7	41.0
2014	19.6	10.7	10.7	41.0
2015	19.7	10.7	10.7	41.1
2016	19.8	10.8	10.8	41.4
2017	19.9	10.9	10.9	41.7
2018	20.1	10.9	10.9	41.9
2019	18.7	12.5	11.0	42.2
2020	18.8	12.5	11.0	42.3
2021	18.9	12.6	11.1	42.6
2022	19.0	12.7	11.2	42.9
2023	19.1	12.7	11.2	43.0
2024	19.2	12.8	11.3	43.3
2025	19.3	12.9	11.3	43.5
2026	19.4	13.0	11.4	43.8
2027	19.5	13.0	11.5	44.0
2028	19.6	13.1	11.5	44.2
2029	19.7	13.2	11.6	44.5
2030	19.8	13.2	11.6	44.6
2031	19.9	13.3	11.7	44.9

14 Ratings reflect the transformer capacity rating in 2031.

Appendix D

Alternative 3

20 Year Substation Load Forecasts

Alternative 3

20 Year Substation Load Forecasts – Base Case

Device	**GAN-T1**	**GAN-T4**	**COB-T1**	**TOTAL**
Rating (MVA)[15]	20	25	20	65
2010 Peak (MVA)	18.0		19.6	37.6
Year	**Forecasted Undiversified Peak - MVA**			
2011	19.5		21.2	40.7
2012	11.8	10.8	18.4	41.0
2013	11.8	10.8	18.4	41.0
2014	11.9	10.9	18.5	41.3
2015	11.0	11.0	19.7	41.7
2016	11.1	11.1	19.9	42.1
2017	11.3	13.2	18.1	42.6
2018	11.4	13.4	18.3	43.1
2019	11.0	13.5	19.0	43.5
2020	11.1	13.7	19.2	44.0
2021	11.2	13.8	19.4	44.4
2022	11.3	14.0	19.6	44.9
2023	11.5	14.1	19.8	45.4
2024	11.6	14.3	20.0	45.9
2025	11.7	16.4	18.3	46.4
2026	11.8	16.6	18.5	46.9
2027	12.0	16.8	18.7	47.5
2028	12.1	16.9	18.8	47.8
2029	12.2	17.1	19.1	48.4
2030	12.4	17.3	19.3	49.0
2031	12.5	17.5	19.5	49.5

[15] Ratings reflect the transformer capacity rating in 2031.

Alternative 3
20 Year Substation Load Forecast – High Growth

Device	GAN-T1	GAN-T4	COB-T1	TOTAL
Rating (MVA)[16]	20	25	20	65
2010 Peak (MVA)	18.0		19.6	37.6
Year	**Forecasted Undiversified Peak - MVA**			
2011	19.5		21.2	40.7
2012	10.4	12.4	18.5	41.3
2013	10.4	12.3	18.5	41.2
2014	10.4	12.5	18.6	41.5
2015	10.6	12.7	18.9	42.2
2016	10.8	12.9	19.2	42.9
2017	11.0	13.1	19.5	43.6
2018	13.1	11.3	19.8	44.2
2019	13.3	13.5	18.2	45.0
2020	13.6	13.7	18.5	45.8
2021	13.8	13.9	18.8	46.5
2022	14.0	14.1	19.1	47.2
2023	14.2	14.3	19.4	47.9
2024	14.4	14.6	19.7	48.7
2025	16.7	14.8	18.0	49.5
2026	16.9	15.0	18.3	50.2
2027	17.2	15.3	18.6	51.1
2028	17.5	15.5	18.9	51.9
2029	17.8	15.8	19.2	52.8
2030	18.1	16.0	19.5	53.6
2031	18.3	16.3	19.8	54.4

[16] Ratings reflect the transformer capacity rating in 2031.

Alternative 3
20 Year Substation Load Forecast – Low Growth

Device	**GAN-T1**	**GAN-T4**	**COB-T1**	**TOTAL**
Rating (MVA)[17]	20	25	20	65
2010 Peak (MVA)	18.0		19.6	37.6
Year	**Forecasted Undiversified Peak - MVA**			
2011	19.5		21.2	40.7
2012	11.8	9.8	19.3	40.9
2013	11.8	9.8	19.3	40.9
2014	11.8	9.8	19.4	41.0
2015	11.9	9.9	19.5	41.3
2016	11.9	9.9	19.6	41.4
2017	12.0	10.0	19.7	41.7
2018	12.1	10.0	19.8	41.9
2019	10.6	10.1	21.4	42.1
2020	10.7	10.1	21.5	42.3
2021	10.8	10.2	21.6	42.6
2022	10.8	10.2	21.7	42.7
2023	10.9	10.3	21.9	43.1
2024	10.9	10.4	22.0	43.3
2025	11.0	10.4	22.1	43.5
2026	11.0	10.5	22.2	43.7
2027	11.1	10.5	22.3	43.9
2028	11.2	10.6	22.4	44.2
2029	11.2	10.6	22.6	44.4
2030	11.3	10.7	22.7	44.7
2031	11.3	10.7	22.8	44.8

17 Ratings reflect the transformer capacity rating in 2031.

Attachment B

St. John's South/Mount Pearl Study

Table of Contents

1.0 Introduction

The purpose of this study is to determine the distribution system alternative that best meets the electrical demands of the St. John's South/Mount Pearl area. This area includes customers serviced from Hardwoods ("HWD"), Glendale ("GDL") and Goulds ("GOU") substations.

In 2013, the distribution power transformers supplying the area are forecast to experience a total peak load of 120.4 MVA compared to a total capacity of 123.3 MVA.[1] The 2011 load forecast indicates that HWD-T1, HWD-T2, GOU-T2 and GOU-T3 will overload by 2013. Load growth on these transformers is primarily the result of an increase in residential and commercial development in the area. There is also a 2 MVA load increase on GOU as a result of a new Water Treatment Plant at Petty Harbour Long Pond scheduled to go into service in late 2011.

This report identifies the capital project(s) required to avoid the 2013 forecast overload at HWD and GOU by determining the least cost expansion plan required to meet a 20 year load forecast.

2.0 Description of Existing System

2.1 HWD Substation

HWD substation is located in the town of Paradise. There are three transformers located in the substation. HWD-T3 is a 25 MVA rated transformers used to convert 66 kV transmission voltage to 25 kV distribution voltage.[2] HWD-T1 and HWD-T2 are both 20 MVA rated transformers used to convert 66 kV transmission voltage to 12.5 kV distribution voltage and supply customers on five distribution feeders through HWD substation servicing 4,635 customers in the Town of Paradise and the City of Mount Pearl.

2.2 GDL Substation

GDL substation is located on Emerald Drive in the City of Mount Pearl. There are two transformers located in the substation, GDL-T1 and GDL-T2. Both transformers are rated 25 MVA and are used to convert 66 kV transmission voltage to 12.5 kV distribution voltage and supply customers on six distribution feeders through GDL substation servicing 6,422 customers in the City of Mount Pearl.

2.3 GOU Substation

GOU substation is located in community of Goulds in the City of St. John's. There are three transformers located in the substation. GOU-T1 is a step-up transformer used to convert 33 kV generation voltage from the Petty Harbour Generating Plant to 66 kV transmission voltage.[3] GOU-T2 is a 20 MVA rated transformer and GOU-T3 is a 13.3 MVA rated transformer. Both are used to convert 66 kV transmission voltage to 12.5 kV distribution voltage and supply

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1 A distribution power transformer converts electricity from transmission voltages (typically 66 kV) to distribution primary (voltages typically between 4kV and 25kV).

2 The two 25 kV feeders originating from HWD substation do not interconnect with the 12.5kV feeders at HWD, GDL or GOU and therefore HWD-T3 is not included in this report.

3 GOU-T1 is not included in this report.

customers on three distribution feeders through GOU substation servicing 4,456 customers in the Goulds and Kilbride areas of the City of St. John's.

3.0 Load Forecast

The following are the forecast peak substation transformer loads expected in 2013.

- HWD-T1 and HWD-T2 are rated at 20 MVA. The load on each transformer is forecast to peak at 20.1 MVA in 2013.
- GDL-T1 and GDL-T2 are both rated at 25 MVA. The load on each transformer is forecast to peak at 22.4 MVA in 2013.
- GOU-T2 is rated at 20 MVA. The load on this transformer is forecast to peak at 21.4 MVA in 2013.
- GOU-T3 is rated at 13.3 MVA. The load on this transformer is forecast to peak at 14 MVA in 2013.

This study uses a 20 year load forecast for these power transformers. The base case 20 year substation forecast for HWD-T1, HWD-T2, GDL-T1, GDL-T2, GOU-T2, and GOU-T3 is located in Appendix A. A high and low load growth forecast has also been created for each alternative for use in a sensitivity analysis. With the exception of the first year forecast, the sensitivities are based on increasing the load growth by a factor of 50% for the high forecast and decreasing by a factor of 50% for the low forecast.

4.0 Development of Alternatives

Three alternatives have been developed to eliminate the forecast overload conditions using a set of defined technical criteria.[4] 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 25 MVA, 66/12.5 kV transformer at GDL substation to increase the total 12.5 kV transformer capacity to 75 MVA in 2013.
- Two new distribution feeders from GDL to complete load transfers from GOU to GDL and HWD to GDL in 2013.
- New 20 MVA, 66/12.5 kV transformer at HWD substation to increase the total 12.5 kV transformer capacity to 60 MVA in 2028.

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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.

- New distribution feeder from HWD substation to complete load transfers from GDL to HWD in 2028.

The resulting peak load forecasts for each transformer under Alternative 1 are shown in Appendix B.

4.2 Alternative 2

- New 20 MVA power transformer at GOU substation to replace existing 13.3 MVA unit to increase the total 12.5 kV transformer capacity to 40 MVA in 2013.
- New distribution feeder from GOU substation in 2013.
- New 25 MVA, 66/25 kV transformer at GDL substation to increase the total 12.5 kV transformer capacity to 75 MVA in 2019.
- Two new distribution feeders from GDL to complete load transfers from MOL to GDL and HWD to GDL in 2019.
- New 20 MVA, 66/12.5 kV transformer at HWD substation to increase the total 12.5 kV transformer capacity to 60 MVA in 2029.

The resulting peak load forecasts for each transformer under Alternative 2 are shown in Appendix C.

4.3 Alternative 3

- New 20 MVA power transformer at HWD substation to increase the total 12.5 kV transformer capacity to 60 MVA in 2013.
- New distribution feeder from HWD substation to complete load transfers from GDL to HWD in 2013.
- New distribution feeder from GDL substation to complete load transfers from GOU to GDL in 2013.
- New 25 MVA, 66/25 kV transformer at GDL substation to increase the total 12.5 kV transformer capacity to 75 MVA in 2025.
- New distribution feeder from GDL to complete load transfers from MOL to GDL in 2025.

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
2012	Install structures and complete civil site work at GDL substation in preparation for installation of transformer.	$1,156,000
2013	Purchase and install new 25 MVA transformer and two new distribution breakers at GDL substation.	$3,974,000
2013	Construct distribution line for two feeders from GDL substation.	$451,000
2027	Install structures and complete civil site work at HWD substation in preparation for installation of transformer.	$1,118,000
2028	Purchase and install new 20 MVA transformer and new distribution breaker at HWD substation.	$3,806,000
2028	Construct distribution line for new feeder from HWD substation.	$311,000

Table 2 shows the capital costs estimated for Alternative 2.

Table 2
Alternative 2 Capital Costs

Year	Item	Cost
2013	Purchase and install new 20 MVA transformer and new distribution breaker at GOU substation.	$2,362,000
2013	Remove 10/13.3 MVA transformer from GOU substation and place in spares inventory.[5]	($261,000)
2013	Construct distribution line for new feeder from GOU substation.	$466,000
2018	Install structures and complete civil site work at GDL substation in preparation for installation of transformer.	$1,156,000
2019	Purchase and install new 25 MVA transformer and two new distribution breakers at GDL substation.	$3,974,000
2019	Construct distribution line for two feeders from GDL substation.	$451,000
2028	Install structures and complete civil site work at HWD substation in preparation for installation of transformer.	$1,118,000
2029	Purchase and install new 20 MVA transformer at HWD substation.	$3,566,000

[5] Implementation of this alternative will result in Newfoundland Power placing GOU-T3 into its inventory of spare equipment in 2013. In assessing alternatives it is reasonable to place a value on this spare equipment and credit the capital cost of this alternative by this amount. From the Company's 2006 depreciation study the average life of a new power transformer is 46 years. Using the Iowa 46R2 depreciation curve, GOU-T3 is projected to have a remaining life of 15 years in 2013. The remaining value of the transformer can then be estimated by multiplying the current price of an equivalent new transformer by a ratio of 15/46.

Table 3 shows the capital costs estimated for Alternative 3.

Table 3
Alternative 3 Capital Costs

Year	Item	Cost
2012	Install structures and complete civil site work at HWD substation in preparation for installation of transformer.	$1,118,000
2013	Purchase and install new 20 MVA transformer and new distribution breaker at HWD substation.	$3,806,000
2013	Construct distribution line for new feeder from HWD substation.	$311,000
2013	Purchase and install new distribution breaker at GDL substation.	$240,000
2013	Construct distribution line for new feeder from GDL substation.	$260,000
2024	Install structures and complete civil site work at GDL substation in preparation for installation of transformer in 2025.	$1,156,000
2025	Purchase and install new 25 MVA transformer and new distribution breaker at GDL substation.	$3,734,000
2025	Construct distribution line for new feeder from GDL substation.	$211,000

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 2012 to 2031 were converted to revenue requirement and the resulting customer revenue requirement was reduced to a net present value using the Company's weighted average incremental cost of capital.[6]

[6] This analysis captures the customer revenue requirement for the 46 year life of a new transformer asset.

Table 4 shows the NPV of customer revenue requirement for each alternative under the base case load forecast.

Table 4
Net Present Value Analysis
($000)

Alternative	NPV
1	8,158
2	8,875
3	8,657

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.[7] Using these revised dates, the net present value of the customer revenue requirement was calculated.

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	13,182	5,163
2	13,381	5,607
3	13,643	5,303

Under the high and low load forecast scenario, Alternative 1 remains as the least cost alternative.

[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.

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 2012.

Table 6
Project Costs

Description	**Cost Estimate**
Install structures and complete civil site work at GDL substation in preparation for installation of transformer in 2013.	$1,156,000
Total	**$1,156,000**

7.0 Conclusion and Recommendation

A 20-year load forecast has projected the electrical demands for the St. John's South/Mount Pearl area. This area includes customers serviced from HWD, GDL, and GOU 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 2012 project that is part of the least cost expansion plan is to install the required structures and complete civil site work at GDL substation in preparation for installation of transformer in 2013. This work is required in 2012 since the total construction schedule exceeds one calendar year. This project is estimated to cost $1,156,000.

Appendix A

2011 Substation Load Forecast – Base Case

20 Year Substation Load Forecast – Base Case

Device	**GDL-T1**	**GDL-T2**	**GOU-T2**	**GOU-T3**	**HWD-T1**	**HWD-T2**
Voltage (kV)	12.47	12.47	12.47	12.47	12.47	12.47
Rating (MVA)	25	25	20	13.3	20	20
2010 Peak (MVA)	19.2	19.2	14.7	10.3	18.9	18.9
Year	**Forecasted Undiversified Peak[8] - MVA**					
2011	22.3	22.3	18.3	12.3	19.7	19.7
2012	22.3	22.3	19.8	13.3	19.9	19.9
2013	22.4	22.4	21.4	14.0	20.1	20.1
2014	22.6	22.6	21.7	14.3	20.3	20.3
2015	22.9	22.9	22.2	14.6	20.7	20.7
2016	23.2	23.2	22.8	15.0	21.1	21.1
2017	23.5	23.5	23.3	15.3	21.5	21.5
2018	23.7	23.7	23.8	15.7	21.9	21.9
2019	24.0	24.0	24.4	16.0	22.3	22.3
2020	24.3	24.3	24.9	16.4	22.7	22.7
2021	24.6	24.6	25.5	16.8	23.1	23.1
2022	24.9	24.9	26.1	17.1	23.5	23.5
2023	25.2	25.2	26.7	17.5	23.9	23.9
2024	25.5	25.5	27.3	17.9	24.4	24.4
2025	25.8	25.8	27.9	18.3	24.8	24.8
2026	26.1	26.1	28.6	18.8	25.3	25.3
2027	26.4	26.4	29.2	19.2	25.7	25.7
2028	26.7	26.7	29.9	19.6	26.2	26.2
2029	27.0	27.0	30.6	20.1	26.7	26.7
2030	27.3	27.3	31.3	20.5	27.2	27.2
2031	27.7	27.7	32.0	21.0	27.6	27.6

8 To forecast peak loads 2010 peak readings are first adjusted by a ratio of the 2010 load factor to the 10 year average load factor. These adjusted peaks are then increased by the company's energy forecast projections to obtain future peak loads.

Appendix B

Alternative 1
20 Year Substation Load Forecasts

Alternative 1
20 Year Substation Load Forecasts – Base Case

Device	**GDL-T1**	**GDL-T2**	**GDL-T3**	**GOU-T2**	**GOU-T3**	**HWD-T1**	**HWD-T2**	**HWD-T3**
Voltage (kV)	12.47	12.47	12.47	12.47	12.47	12.47	12.47	12.47
Rating (MVA)[9]	25	25	25	20	13.3	20	20	20
2010 Peak (MVA)	19.2	19.2	0.0	14.7	10.3	18.9	18.9	0.0
Year								
2011	22.3	22.3	0.0	18.3	12.3	19.7	19.7	0.0
2012	22.3	22.3	0.0	19.8	13.3	19.9	19.9	0.0
2013	18.9	18.9	18.9	16.7	10.7	18.1	18.1	0.0
2014	19.1	19.1	19.1	17.0	10.9	18.3	18.3	0.0
2015	19.3	19.3	19.3	17.4	11.2	18.7	18.7	0.0
2016	19.5	19.5	19.5	17.8	11.5	19.0	19.0	0.0
2017	19.8	19.8	19.8	18.3	11.7	19.4	19.4	0.0
2018	20.0	20.0	20.0	18.7	12.0	19.7	19.7	0.0
2019	22.4	22.4	22.4	19.1	12.3	16.8	16.8	0.0
2020	22.7	22.7	22.7	19.6	12.6	17.2	17.2	0.0
2021	23.0	23.0	23.0	20.0	12.9	17.5	17.5	0.0
2022	23.4	23.4	23.4	19.5	12.7	18.2	18.2	0.0
2023	23.7	23.7	23.7	20.0	13.0	18.5	18.5	0.0
2024	24.0	24.0	24.0	19.6	13.1	19.1	19.1	0.0
2025	24.3	24.3	24.3	19.7	13.2	19.4	19.4	0.0
2026	24.7	24.7	24.7	19.8	13.2	19.7	19.7	0.0
2027	25.0	25.0	25.0	20.0	13.3	20.0	20.0	0.0
2028	24.1	24.1	24.1	17.1	11.8	16.7	16.7	16.7
2029	24.3	24.3	24.3	18.0	12.2	17.0	17.0	17.0
2030	24.6	24.6	24.6	19.0	12.6	17.3	17.3	17.3
2031	24.9	24.9	24.9	20.0	13.0	17.6	17.6	17.6

9 Ratings reflect the transformer capacity rating in 2031.

Alternative 1
20 Year Substation Load Forecast – High Growth

Device	**GDL-T1**	**GDL-T2**	**GDL-T3**	**GOU-T2**	**GOU-T3**	**GOU-T4**	**HWD-T1**	**HWD-T2**	**HWD-T3**
Voltage (kV)	12.47	12.47	12.47	12.47	12.47	12.47	12.47	12.47	12.47
Rating (MVA) [10]	25	25	25	20	20	20	20	20	20
2010 Peak (MVA)	19.2	19.2	0.0	14.7	10.3	0.0	18.9	18.9	0.0
Year									
2011	22.3	22.3	0.0	18.3	12.3	0.0	19.7	19.7	0.0
2012	18.9	18.9	18.9	16.7	10.7	0.0	18.1	18.1	0.0
2013	19.1	19.1	19.1	17.0	10.9	0.0	18.3	18.3	0.0
2014	19.3	19.3	19.3	17.5	11.2	0.0	18.8	18.8	0.0
2015	19.7	19.7	19.7	18.1	11.6	0.0	19.3	19.3	0.0
2016	20.1	20.1	20.1	18.8	12.1	0.0	19.8	19.8	0.0
2017	22.6	22.6	22.6	19.5	12.5	0.0	17.2	17.2	0.0
2018	23.1	23.1	23.1	19.6	12.5	0.0	18.4	18.4	0.0
2019	24.0	24.0	24.0	19.9	12.4	0.0	18.7	18.7	0.0
2020	24.5	24.5	24.5	20.0	12.3	0.0	19.8	19.8	0.0
2021	24.0	24.0	24.0	19.2	11.8	0.0	15.4	15.4	15.4
2022	24.5	24.5	24.5	17.9	11.8	0.0	16.7	16.7	16.7
2023	24.9	24.9	24.9	18.6	12.3	0.0	17.2	17.2	17.2
2024	24.6	24.6	24.5	18.6	12.2	0.0	19.0	19.0	19.0
2025	25.0	25.0	25.0	19.3	12.7	0.0	19.6	19.6	19.6
2026	24.5	24.5	24.5	19.3	19.2	0.0	19.4	19.4	19.4
2027	25.0	25.0	25.0	20.0	19.9	0.0	20.0	20.0	20.0
2028	24.2	24.2	24.2	17.7	17.7	17.7	18.0	18.0	18.0
2029	24.7	24.7	24.7	18.4	18.4	18.4	18.5	18.5	18.5
2030	24.5	24.5	24.4	19.7	19.7	19.7	19.0	19.0	19.0
2031	24.9	24.9	24.9	20.0	20.0	20.0	20.0	20.0	20.0

[10] Ratings reflect the transformer capacity rating in 2031.

Alternative 1
20 Year Substation Load Forecast – Low Growth

Device	GDL-T1	GDL-T2	GDL-T3	GOU-T2	GOU-T3	HWD-T1	HWD-T2	HWD-T3
Voltage (kV)	12.47	12.47	12.47	12.47	12.47	12.47	12.47	12.47
Rating (MVA)[11]	25	25	25	20	13.3	20	20	20
2010 Peak (MVA)	19.2	19.2	0.0	14.7	10.3	18.9	18.9	0.0
Year								
2011	22.3	22.3	0.0	18.3	12.3	19.7	19.7	0.0
2012	22.2	22.2	0.0	19.6	13.2	19.7	19.7	0.0
2013	22.2	22.2	0.0	19.7	13.2	19.8	19.8	0.0
2014	22.3	22.3	0.0	19.8	13.3	19.9	19.9	0.0
2015	19.0	19.0	18.5	16.8	10.8	18.1	18.1	0.0
2016	19.1	19.1	18.6	16.9	10.9	18.2	18.2	0.0
2017	19.2	19.2	18.8	17.2	11.0	18.4	18.4	0.0
2018	19.4	19.4	18.9	17.4	11.2	18.6	18.6	0.0
2019	19.5	19.5	19.0	17.6	11.3	18.8	18.8	0.0
2020	19.6	19.6	19.1	17.8	11.5	19.0	19.0	0.0
2021	19.8	19.8	19.3	18.0	11.6	19.2	19.2	0.0
2022	19.9	19.9	19.4	18.3	11.7	19.4	19.4	0.0
2023	20.0	20.0	19.5	18.5	11.9	19.6	19.6	0.0
2024	20.2	20.2	19.6	18.7	12.0	19.8	19.8	0.0
2025	20.3	20.3	19.8	19.0	12.2	20.0	20.0	0.0
2026	22.6	22.6	22.1	19.0	12.5	17.0	17.0	0.0
2027	22.7	22.7	22.2	19.3	12.7	17.1	17.1	0.0
2028	22.9	22.9	22.4	19.5	12.9	17.3	17.3	0.0
2029	23.0	23.0	22.5	19.7	13.0	17.5	17.5	0.0
2030	23.2	23.2	22.7	19.8	13.0	17.7	17.9	0.0
2031	23.3	23.3	22.8	20.0	13.2	17.8	18.0	0.0

[11] Ratings reflect the transformer capacity rating in 2031.

Appendix C

Alternative 2
20 Year Substation Load Forecasts

Alternative 2
20 Year Substation Load Forecast – Base Case

Device	GDL-T1	GDL-T2	GDL-T3	GOU-T2	GOU-T3	HWD-T1	HWD-T2	HWD-T3
Voltage (kV)	12.47	12.47	12.47	12.47	12.47	12.47	12.47	12.47
Rating (MVA)[12]	25	25	25	20	20	20	20	20
2010 Peak (MVA)	19.2	19.2	0.0	14.7	10.3	18.9	18.9	0
Year								
2011	22.3	22.3	0.0	18.3	12.3	19.7	19.7	0.0
2012	22.3	22.3	0.0	19.8	13.3	19.9	19.9	0.0
2013	22.8	22.8	0.0	17.9	17.9	18.6	18.6	0.0
2014	23.0	23.0	0.0	18.2	18.2	18.8	18.8	0.0
2015	23.3	23.3	0.0	18.7	18.6	19.2	19.2	0.0
2016	23.5	23.5	0.0	19.1	19.0	19.5	19.5	0.0
2017	23.8	23.8	0.0	19.5	19.5	19.9	19.9	0.0
2018	24.7	24.7	0.0	20.0	19.9	19.6	19.6	0.0
2019	20.7	20.7	20.7	17.4	17.4	18.0	18.0	0.0
2020	21.0	21.0	21.0	17.9	17.8	18.4	18.4	0.0
2021	21.2	21.2	21.2	18.3	18.2	18.7	18.7	0.0
2022	21.5	21.5	21.5	18.7	18.6	19.0	19.0	0.0
2023	21.7	21.7	21.7	19.1	19.0	19.4	19.4	0.0
2024	22.0	22.0	22.0	19.6	19.5	19.7	19.7	0.0
2025	22.3	22.3	22.3	20.0	19.9	20.0	20.0	0.0
2026	24.2	24.2	24.2	19.1	19.0	19.3	19.3	0.0
2027	24.5	24.5	24.5	19.5	19.5	19.7	19.7	0.0
2028	24.8	24.8	24.8	20.0	19.9	20.0	20.0	0.0
2029	24.4	24.4	24.4	19.1	19.0	15.2	15.2	15.2
2030	24.7	24.7	24.7	19.6	19.5	15.4	15.4	15.4
2031	25.0	25.0	25.0	20.0	19.9	15.7	15.7	15.7

[12] Ratings reflect the transformer capacity rating in 2031.

Alternative 2
20 Year Substation Load Forecast – High Growth

Device	**GDL-T1**	**GDL-T2**	**GDL-T3**	**GOU-T2**	**GOU-T3**	**GOU-T4**	**HWD-T1**	**HWD-T2**	**HWD-T3**
Voltage (kV)	12.47	12.47	12.47	12.47	12.47	12.47	12.47	12.47	12.47
Rating (MVA)[13]	25	25	25	20	20	20	20	20	20
2010 Peak (MVA)	19.2	19.2	0.0	14.7	10.3	0	18.9	18.9	0
Year									
2011	22.3	22.3	0.0	18.3	12.3	0.0	19.7	19.7	0.0
2012	22.8	22.8	0.0	17.9	17.9	0.0	18.6	18.6	0.0
2013	23.0	23.0	0.0	18.2	18.2	0.0	18.8	18.8	0.0
2014	23.3	23.3	0.0	18.7	18.7	0.0	19.3	19.3	0.0
2015	24.4	24.4	0.0	19.4	19.4	0.0	19.2	19.2	0.0
2016	20.4	20.4	20.4	17.1	17.1	0.0	17.8	17.8	0.0
2017	20.9	20.9	20.9	17.7	17.7	0.0	18.3	18.3	0.0
2018	21.4	21.4	21.4	18.4	18.4	0.0	18.9	18.9	0.0
2019	21.8	21.8	21.8	19.1	19.1	0.0	19.4	19.4	0.0
2020	22.2	22.2	22.2	19.8	19.8	0.0	20.0	20.0	0.0
2021	24.3	24.3	24.3	19.2	19.2	0.0	19.5	19.5	0.0
2022	24.0	24.0	24.0	18.6	18.6	0.0	14.9	14.9	14.9
2023	24.4	24.4	24.4	19.3	19.3	0.0	15.4	15.4	15.4
2024	23.9	23.9	23.9	18.5	18.5	0.0	17.9	17.9	17.9
2025	24.4	24.4	24.4	19.2	19.2	0.0	18.4	18.4	18.4
2026	24.9	24.9	24.9	19.9	19.9	0.0	18.9	18.9	18.9
2027	22.9	22.9	22.9	17.9	17.9	17.9	17.8	17.8	17.8
2028	23.3	23.3	23.3	18.6	18.6	18.6	18.3	18.3	18.3
2029	23.8	23.8	23.8	19.3	19.3	19.3	18.9	18.9	18.9
2030	24.3	24.3	24.3	19.9	19.9	19.9	19.4	19.4	19.4
2031	24.8	24.8	24.8	20.0	20.0	20.0	19.9	19.9	19.9

13 Ratings reflect the transformer capacity rating in 2031.

Alternative 2
20 Year Substation Load Forecast – Low Growth

Device	**GDL-T1**	**GDL-T2**	**GDL-T3**	**GOU-T2**	**GOU-T3**	**HWD-T1**	**HWD-T2**
Voltage (kV)	12.47	12.47	12.47	12.47	12.47	12.47	12.47
Rating (MVA)[14]	25	25	25	20	20	20	20
2010 Peak (MVA)	19.2	19.2	0.0	14.7	10.3	18.9	18.9
Year							
2011	22.3	22.3	0.00	18.3	12.3	19.7	19.7
2012	22.2	22.2	0.0	19.6	13.2	19.7	19.7
2013	22.2	22.2	0.0	19.7	13.2	19.8	19.8
2014	22.3	22.3	0.0	19.8	13.3	19.9	19.9
2015	22.8	22.8	0.0	17.9	17.9	18.6	18.6
2016	22.9	22.9	0.0	18.1	18.1	18.7	18.7
2017	23.0	23.0	0.0	18.3	18.3	18.9	18.9
2018	23.2	23.2	0.0	18.6	18.6	19.1	19.1
2019	23.3	23.3	0.0	18.8	18.8	19.3	19.3
2020	23.5	23.5	0.0	19.0	19.0	19.5	19.5
2021	23.6	23.6	0.0	19.3	19.3	19.7	19.7
2022	23.8	23.8	0.0	19.5	19.5	19.9	19.9
2023	24.0	24.0	0.0	19.8	19.8	20.0	20.0
2024	20.1	20.1	20.1	17.0	17.0	18.2	18.2
2025	20.2	20.2	20.2	17.2	17.2	18.3	18.3
2026	20.3	20.3	20.3	17.4	17.4	18.5	18.5
2027	20.5	20.5	20.5	17.6	17.6	18.7	18.7
2028	20.6	20.6	20.6	17.8	17.8	18.9	18.9
2029	20.7	20.7	20.7	18.1	18.1	19.1	19.1
2030	20.9	20.9	20.9	18.3	18.3	19.3	19.3
2031	21.0	21.0	21.0	18.5	18.5	19.5	19.5

[14] Ratings reflect the transformer capacity rating in 2031.

Appendix D

Alternative 3
20 Year Substation Load Forecasts

Alternative 3
20 Year Substation Load Forecast – Base Case

Device	**GDL-T1**	**GDL-T2**	**GDL-T3**	**GOU-T2**	**GOU-T3**	**HWD-T1**	**HWD-T2**	**HWD-T3**
Voltage (kV)	12.47	12.47	12.47	12.47	12.47	12.47	12.47	12.47
Rating (MVA)[15]	25	25	25	20	13.3	20	20	20
2010 Peak (MVA)	19.2	19.2	0.0	14.7	10.3	18.9	18.9	0
Year								
2011	22.3	22.3	0.0	18.3	12.3	19.7	19.6	0.0
2012	22.3	22.3	0.0	19.8	13.3	19.9	19.9	0.0
2013	22.4	22.4	0.0	15.5	11.5	15.5	15.5	15.5
2014	22.6	22.6	0.0	15.8	11.7	15.7	15.7	15.7
2015	22.9	22.9	0.0	16.2	12.0	16.0	16.0	16.0
2016	23.2	23.2	0.0	16.6	12.3	16.3	16.3	16.3
2017	23.5	23.5	0.0	17.0	12.6	16.6	16.6	16.6
2018	23.7	23.7	0.0	17.3	12.9	16.9	16.9	16.9
2019	24.0	24.0	0.0	17.7	13.2	17.2	17.2	17.2
2020	24.3	24.3	0.0	19.0	12.6	17.6	17.6	17.6
2021	24.6	24.6	0.0	19.5	12.9	17.9	17.9	17.9
2022	24.9	24.9	0.0	19.9	13.2	18.2	18.2	18.2
2023	24.7	24.7	0.0	19.4	13.0	19.4	19.4	19.4
2024	25.0	25.0	0.0	19.8	13.3	19.7	19.7	19.7
2025	20.8	20.8	20.8	17.0	10.9	18.8	18.8	18.8
2026	21.1	21.1	21.0	17.4	11.2	19.1	19.1	19.1
2027	21.3	21.3	21.3	17.8	11.5	19.4	19.4	19.4
2028	21.6	21.6	21.5	18.2	11.7	19.8	19.8	19.8
2029	22.8	22.8	22.8	18.6	12.0	19.2	19.2	19.2
2030	23.1	23.1	23.0	19.0	12.3	19.5	19.5	19.5
2031	23.4	23.4	23.3	19.4	12.5	19.9	19.9	19.9

15 Ratings reflect the transformer capacity rating in 2031.

Alternative 3
20 Year Substation Load Forecast – High Growth

Device	**GDL-T1**	**GDL-T2**	**GDL-T3**	**GOU-T2**	**GOU-T3**	**GOU-T4**	**HWD-T1**	**HWD-T2**	**HWD-T3**
Voltage (kV)	12.47	12.47	12.47	12.47	12.47	12.47	12.47	12.47	12.47
Rating (MVA)[16]	25	25	25	20	20	20	20	20	20
2010 Peak (MVA)	19.2	19.2	0.0	14.7	10.3	0	18.9	18.9	0
Year									
2011	22.3	22.3	0.0	18.3	12.3	0.0	19.7	19.7	0.0
2012	22.5	22.5	0.0	15.5	11.5	0.0	15.5	15.5	15.5
2013	22.7	22.7	0.0	15.8	11.7	0.0	15.7	15.7	15.7
2014	23.0	23.0	0.0	16.3	12.1	0.0	16.1	16.1	16.1
2015	23.4	23.4	0.0	16.8	12.5	0.0	16.5	16.5	16.5
2016	23.8	23.8	0.0	17.4	13.0	0.0	17.0	17.0	17.0
2017	24.3	24.3	0.0	19.0	12.6	0.0	17.5	17.5	17.5
2018	24.8	24.8	0.0	19.7	13.0	0.0	18.1	18.1	18.1
2019	24.8	24.8	0.0	19.4	13.1	0.0	19.4	19.4	19.4
2020	20.7	20.7	20.7	16.8	10.8	0.0	18.6	18.6	18.6
2021	21.1	21.1	21.2	17.4	11.3	0.0	19.2	19.2	19.2
2022	21.6	21.6	21.6	18.1	11.7	0.0	19.8	19.8	19.8
2023	23.0	23.0	23.0	18.8	12.1	0.0	19.4	19.4	19.4
2024	23.4	23.4	23.4	19.5	12.6	0.0	20.0	20.0	20.0
2025	23.9	23.9	23.9	18.3	18.3	0.0	19.4	19.4	19.4
2026	24.3	24.3	24.3	19.0	19.0	0.0	20.0	20.0	20.0
2027	23.1	23.1	23.1	17.7	17.7	17.7	17.8	17.8	17.8
2028	23.5	23.5	23.5	18.4	18.4	18.4	18.3	18.3	18.3
2029	23.9	23.9	23.9	19.1	19.1	19.1	18.9	18.9	18.9
2030	24.4	24.4	24.4	19.5	19.5	19.5	19.4	19.4	19.4
2031	24.9	24.9	24.9	20.0	20.0	20.0	20.0	20.0	20.0

[16] Ratings reflect the transformer capacity rating in 2031.

Alternative 3
20 Year Substation Load Forecast – Low Growth

Device	**GDL-T1**	**GDL-T2**	**GOU-T2**	**GOU-T3**	**HWD-T1**	**HWD-T2**	**HWD-T3**
Voltage (kV)	12.47	12.47	12.47	12.47	12.47	12.47	12.47
Rating (MVA)[17]	25	25	20	13.3	20	20	20
2010 Peak (MVA)	19.2	19.2	14.7	10.3	18.9	18.9	0
Year							
2011	22.3	22.3	18.3	12.3	19.7	19.7	0.0
2012	22.2	22.2	19.6	13.2	19.7	19.7	0.0
2013	22.2	22.2	19.7	13.2	19.8	19.8	0.0
2014	22.3	22.3	19.8	13.3	19.9	19.9	0.0
2015	22.4	22.4	16.2	10.9	15.5	15.5	15.5
2016	22.5	22.5	16.4	11.0	15.6	15.6	15.6
2017	22.7	22.7	16.6	11.2	15.8	15.8	15.8
2018	22.8	22.8	16.8	11.3	15.9	15.9	15.9
2019	23.0	23.0	17.0	11.5	16.1	16.1	16.1
2020	23.1	23.1	17.2	11.6	16.3	16.3	16.3
2021	23.3	23.3	17.5	11.7	16.4	16.4	16.4
2022	23.4	23.4	17.7	11.9	16.6	16.6	16.6
2023	23.6	23.6	17.9	12.0	16.8	16.8	16.8
2024	23.7	23.7	18.1	12.2	16.9	16.9	16.9
2025	23.9	23.9	18.4	12.3	17.1	17.1	17.1
2026	24.1	24.1	18.6	12.5	17.3	17.3	17.3
2027	24.2	24.2	18.8	12.7	17.4	17.4	17.4
2028	24.4	24.4	19.1	12.8	17.6	17.6	17.6
2029	24.5	24.5	19.3	13.0	17.8	17.8	17.8
2030	24.7	24.7	19.5	13.1	18.0	18.0	18.0
2031	24.9	24.9	19.8	13.3	18.2	18.2	18.2

[17] Ratings reflect the transformer capacity rating in 2031.

2012 PCB Removal Strategy

June 2011

Prepared by:

Peter Feehan, P.Eng.

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NEWFOUNDLAND POWER
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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, prior to December 31, 2025, equipment having a PCB concentration level of 500 mg/kg or more. 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 had 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 end-of-use 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

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 larger equipment, such as, power transformers and breakers have been confirmed to contain less than 500 mg/kg PCBs, with the vast majority having PCB levels below 50 mg/kg. Other smaller equipment, such as pole top transformers in sensitive locations, have been confirmed to contain less than 50 mg/kg PCBs. The Company also has an ongoing program to ensure that smaller equipment, such as pole top transformers, which have PCB levels at or above 50 mg/kg and not installed in sensitive locations, will be phased out prior to December 31, 2025.

Newfoundland Power and other utilities have expressed their concern over the 2014 deadline to Environment Canada and continue to work with the Canadian Electricity Association ("CEA") to reinstate the original 2025 date; as of this writing, however, no resolution has been reached.

2.0 PCB Equipment Remediation Strategy

Newfoundland Power's end-of-use date extension application ("the Extension Application"),[4] approved by Environment Canada, identified a total of 429 pieces of equipment which require PCB testing and possible remediation. After further review, that number has been revised to 442 pieces of equipment, including 168 power transformers, 187 circuit breakers, 54 potential transformers, 19 current transformers, 6 metering tanks and 8 station service transformers.[5] Approximately 2,400 bushings are associated with this equipment. The PCB concentration of most of these items is unknown.[6]

Under the PCB Equipment Remediation Strategy the Company has tested bushings on 74 of the 442 pieces of equipment to the end of March 2011. To date, no bushings have tested at 500 mg/kg or above. However, some bushings have tested above 50 mg/kg. As discussed previously only equipment bushings testing at 500 mg/kg or above must be remediated by 2014. Equipment testing from 50 mg/kg to below 500 mg/kg must be remediated by 2025. In addition to the above test results, 16 of the 74 pieces of equipment tested have at least some bushings that were not equipped with test ports from which an oil sample could be taken. Those equipment bushings must be remediated by the 2014 deadline.

Newfoundland Power will continue to conduct PCB testing and, if required, replace any bushings and instrument transformers that cannot be tested or that are determined to have a PCB concentration at 500 mg/kg or more to meet the December 31, 2014 deadline.

Although the Company has more test data than it did one year ago, the nature of the equipment being sampled (i.e. multiple equipment types, multiple manufacturers, and multiple years of manufacturer) continues to make it difficult to predict accurate failure rates. Consequently some failure rate assumptions from one year ago have been adjusted, while others remain unchanged. These assumptions will continue to be refined as additional test data becomes available.

The testing and remediation 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).

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4 An application to use designated equipment and the liquids for servicing that equipment until the date set out in an extension granted by the Minister

5 The remediation strategy in this report has been revised to reflect the additional equipment.

6 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.

- 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 168 power transformers identified in the Extension Application is approximately 41 years. Over 1,200 transformer bushings were listed in the Extension Application that was approved by Environment Canada.[7]

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.[8]

Figure 1 shows the location of the bushings at the top of the power transformer tank.

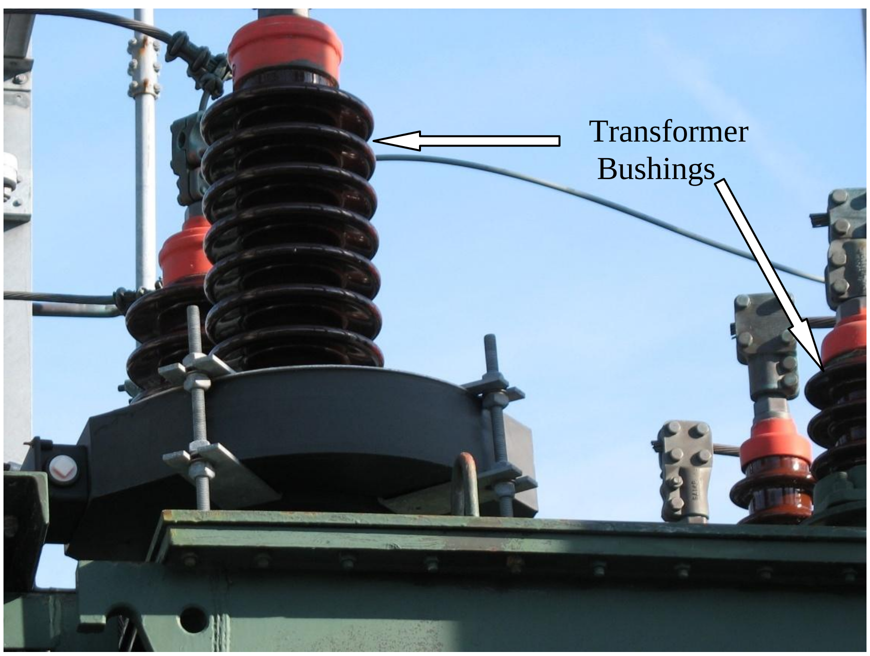

Figure 1 – Power Transformer Bushings

7 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.

8 There is a six month lead time required to procure new power transformer bushings.

In situations where 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 two-thirds of the transformer bushings can be tested without incurring customer outages.[9] The other approximate one-third will require customer outages to allow testing to be completed. It is estimated that there are 59 transformer locations where the portable substations will not be available to maintain electricity service to customers while testing of the transformer bushings is completed. This is primarily due to the high volume of testing that needs to be completed to meet the 2014 deadline set by Environment Canada. If the Company installed portables in each of these 59 locations, portables would not be available to support its maintenance or substation capital programs. Also, in some cases, the outage time to install a portable would be similar to the outage time required to complete the testing. Therefore, the Company is planning a four hour customer outage to each of these 59 transformers to complete the testing. Table 1 provides the estimated customer outage minutes to complete PCB testing on substation transformers.

Table 1
Estimated Customer Outage Minutes
Required to Complete PCB Testing
on Substation Transformers

Year	**Customer Minutes (000s)**
2011	2,800
2012	7,200
2013	7,400
2014	100
Total	**17,500**

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.

[9] 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.

Until the Company accumulates a reasonable sample of its own test data, a failure rate will be assumed. With an assumed 1% failure rate for transformer bushings, approximately one transformer is expected to test above 500 mg/kg in each year from 2011 to 2014, for a total of four transformers expected to test above 500 mg/kg between now and 2014.[10] If the actual failure rate turns out to be significantly different than the assumed failure rate, the scheduling of remediation work will be adjusted accordingly.

In addition, 38 of Newfoundland Power's transformers have bushings that cannot be tested. These bushings will have to be replaced by the end of 2014 as their PCB concentration cannot be determined.

Therefore, a total of 42 transformers will require bushing replacements by 2014 due to either PCB concentrations at or above 500 mg/kg or because the bushings cannot be tested.

Table 2 provides the Company's schedule for testing and replacement of power transformer bushings.

Table 2
Power Transformer Bushing Testing & Replacement Schedule

Year	Remaining Transformers to Test	Transformers Tested	Transformers that Failed Testing or Cannot be Tested	Transformers Awaiting Bushing Replacement	Transformer Bushing Replacement Year
2010	-	22	9	7	2 in 2010 7 in 2013
2011 (Q1)	-	9	1	0	1 in 2011 (Q1)
2011 (Q2-Q4)	36	-	-	9	5 in 2011 4 in 2013
2012	45	-	-	10	5 in 2012 5 in 2014
2013	45	-	-	10	3 in 2013 7 in 2014
2014	11	-	-	3	3 in 2014
Total	**137**	**31**	**10**	**39**	**42 in All Yrs**

[10] Newfoundland Power has tested bushings on 31 transformers to date. Three 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 (this has not been updated since then) 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.

2.2 *Bulk Oil Circuit Breakers*

Newfoundland Power has not purchased bulk oil circuit breakers since 1982.[11] The average age of the bulk oil circuit breakers in service is 39 years. The life expectancy of an oil circuit breaker varies; however, based on experience, an average lifespan of 38 years is reasonable.

Whenever a breaker has bushings that test at 500 mg/kg or more, the cost of replacing the bushings on the breaker 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 the bushings test at or greater than 500 mg/kg.[12]

Figure 2 shows the location of the bushings at the top of the bulk oil circuit breaker tank.

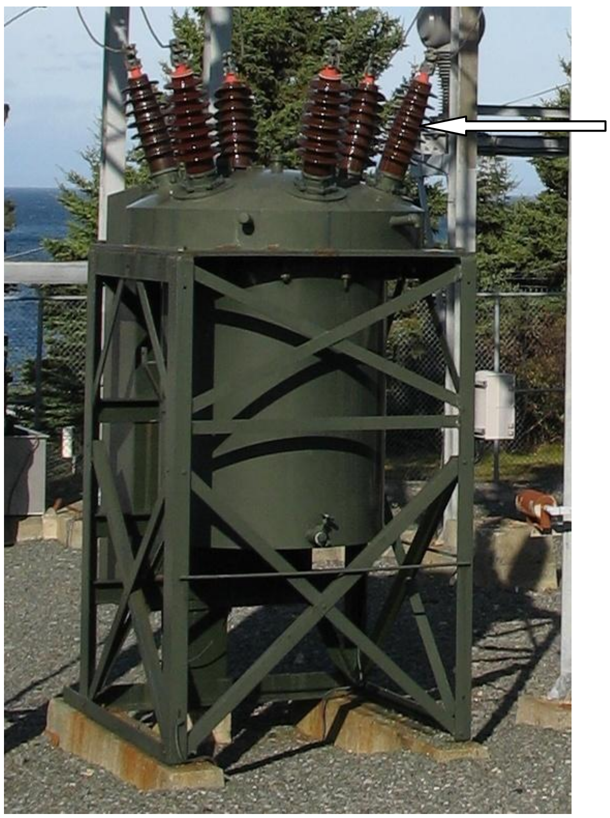

Figure 2 - 66 kV Bulk Oil Breaker

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

[11] 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.

[12] 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.

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.

Table 3 provides the Company's schedule for testing and replacement of circuit breaker bushings.

Table 3
Circuit Breaker Bushing Testing & Replacement Schedule

Year	Remaining Breakers to Test	Breakers Tested	Breakers That Failed Testing or Cannot be Tested[13]	Breaker Awaiting Replacement[14]	Breaker Replacement Year
2010	-	12	5	5	4 in 2011 1 in 2013
2011 (Q1)	-	11	1	1	1 in 2012
2011 (Q2-Q4)	74	-	-	7	7 in 2012
2012	85	-	-	8	8 in 2013
2013	5	-	-	1	1 in 2014
2014	0	-	-	0	-
Total	**164**	**23**	**6**	**22**	**22 in All Yrs**

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. [15] To minimize the total number of customer outages required, testing of the latter group of

13 To date, breakers that have failed testing have failed due to a lack of ports available on the breaker bushings and not because of the PCB concentration. This means that an oil sample cannot be obtained without destroying the bushings. Because the PCB content of the breaker bushings cannot be confirmed, the breaker must be replaced prior to the 2014 deadline.

14 Under this program Newfoundland Power has completed testing for bushings on 23 breakers with no breakers testing at or greater than 500 mg/kg. 6 of the 23 breakers that are considered failures, failed due to a lack of test ports on the bushings. Combined, these give a failure rate of 26%. However, given the small sample of test data accumulated to date, and the various ages and manufactures of the equipment, it would be premature to assume such a high failure rate. Therefore, the 10% failure rate with a minimum of one breaker replacement required in a year, which was assumed in the 2011 PCB Removal Strategy, is maintained in the 2012 PCB Removal Strategy. As more complete test data becomes available from the 2011/12 testing, the 10% failure rate and associated remediation work will be adjusted as required.

15 This consists of approximately six locations.

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.

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 4 identifies capital budget estimates for completing the above testing and expected remediation work prior to the 2014 deadline established by the Government of Canada. It also identifies capital budget estimates for remediation of equipment with PCB concentrations of 50 mg/kg and above beyond the 2014 deadline.

Table 4
Project Cost 2011 to 2016

Year	Expenditure
2011	$1,500,000
2012	$1,500,000
2013	$5,000,000
2014	$5,000,000
2015	$1,000,000
2016	$1,000,000

The estimated expenditures include the work outlined in 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 during the balance of 2011 and during 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 500 mg/kg or more by the 2014 deadline will be extremely difficult for Newfoundland Power and other Canadian electric utilities.

If the CEA discussions with Environment Canada are successful, and the deadline for dealing with the equipment is extended until 2025, the remaining work associated with the PCB phase-out program can be completed over a 14-year period (2012-2025) rather than a 3-year period (2012-2014). 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 bushings and instrument transformers with PCB concentrations of 50 mg/kg and above to be removed from the system by the end of 2025.[16] The

[16] This is consistent with the end-of-use date for other equipment such as pole top transformers with PCB concentrations of 50 mg/kg or more.

implication is that expenditures on PCB remediation will likely continue until 2025. The work completed in 2011 and proposed for 2012 will allow clearer identification of the future remediation that will be required to meet the Regulations.

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.

Portable Substation Study

June 2011

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1.0 Introduction

Newfoundland Power uses portable substations to minimize customer power outages resulting from failure of substation power transformers and from execution of the Company's substation capital and maintenance programs.

Seventeen of the Company's power transformers have failed while in service over the past five years. Industry experience suggests that, given the age of the Company's fleet of power transformers, the rate of failure of in-service power transformers can be expected to increase in coming years.

The Company's substation capital program is also increasing. This is largely attributable to the requirement for additional system capacity to serve increased customer load and compliance with federal regulations, while continuing the capital program. Much of this work requires power transformers to be removed from service. The Company manages the timing of this work to coordinate with routine maintenance and seasonal variations in customer load, in order to minimize customer power outages. Even so, the demand for portable substations related to the capital program has increased.

Customer load growth, particularly over the past decade, has reduced available transformer capacity in the Newfoundland Power system.[1] The increase in customer load served, and corresponding decrease in spare capacity, has had the impact of further limiting viable options for the Company to maintain service to customers when a power transformer is removed from the system.

Newfoundland Power's existing portable substation capacity is insufficient to maintain availability for emergency response while supporting its capital and maintenance program requirements.

The result is an increasing risk to reliability of service to customers. This reflects the potential increase in duration of outages related to failure of a power transformer while a portable substation is not immediately available, as well as insufficient availability of portable substations to complete required capital and maintenance work without extended outages.

[1] The impacts of customer load growth have been addressed in the evidence filed in Newfoundland Power's 2010 General Rate Application (see *Section 2: Customer Operations*) and the Company's Capital Budget Applications (see, for example, report *2.2 2012 Additions Due to Load Growth*, filed with this application).

2.0 Background

2.1 Newfoundland Power's Power Transformer Fleet

Newfoundland Power has 192 power transformers in service. These transformers step voltages up or down depending on their application. Common applications include changes from transmission to distribution voltages (e.g., 66 kV to 12.5 kV); changes between transmission voltages (e.g., 138 kV to 66 kV or vice versa); and, changes from generation voltages to either distribution or transmission voltages (e.g., 2.4 kV to 66 kV).

Figure 1 shows the current age profile of the Company's 192 in-service power transformers.

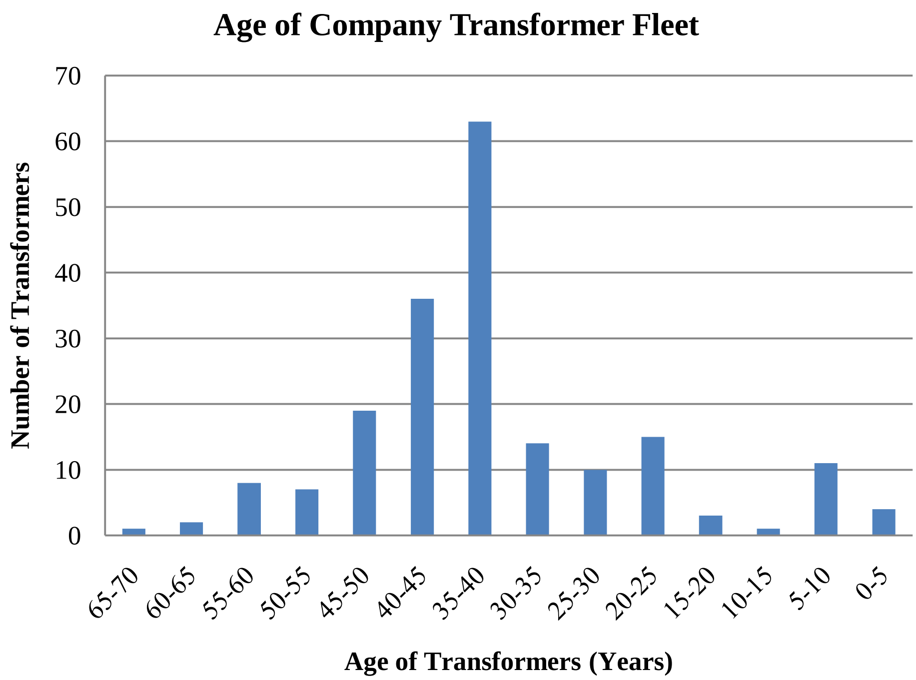

Figure 1

The average age of Newfoundland Power's in-service power transformers is 36 years. The median age is 37 years. While 50% of the Company's power transformers are over 37 years old, more than 75% are over 30 years old.

Due to the criticality of power transformers to electrical service provision to customers, all power transformers in Newfoundland Power's system are subject to ongoing condition monitoring. This includes annual testing of gas levels in transformer oils. Since 2007, the Company has had a total of 17 incidents of power transformer failures. Three of these incidents involved catastrophic failures of an in-service transformer.[2] The remaining 14 incidents involved cases of imminent failure detected through condition monitoring. In nine incidents, a portable substation was required to restore or maintain service. A list of these transformer failures is provided in Appendix A.

2.2 Industry Experience

Industry experience suggests that power transformer life expectancy is typically 35 to 40 years. Research published by William H. Bartley of the Hartford Steam Boiler Inspection & Insurance Company provides a comprehensive study into power transformer aging and failure.[3] Mr. Bartley finds that under ideal conditions a transformer can be expected to remain in service for between 35 and 40 years. He also indicates that, under practical conditions, many power transformers do not remain in service for that long.

Similarly, John van Kooy, principal of van Kooy Transformer Consulting Services, has also published work indicating transformer life expectancy of 35 to 40 years.[4] Mr. van Kooy notes that transformer life is dependent on a number of factors, including the quality of the original manufacture, loading, maintenance and occurrences such as lightning or prolonged periods of overload. Mr. van Kooy recognizes that transformer longevity is based on this combination of factors, not just on the number of calendar years.

It should be noted that Newfoundland Power's experience with power transformer life expectancy has been better than that of the American utilities examined by Mr. Bartley. This may be due to a number of factors, including transformer loading, Newfoundland Power's maintenance program, and the fact that peak loads on Newfoundland Power's system occur in winter when ambient temperatures are low.

Industry experience also suggests that power transformer failure rates tend to vary based on age. Mr. van Kooy notes that it is generally believed that the "bathtub" curve, as shown in Figure 2, is representative of transformer failure rate trends.

---

2 Catastrophic failure involves a transformer fault which results in the transformer being automatically taken out of service through operation of system protection devices. Damage to a transformer due to catastrophic failure may or may not be repairable.

3 William H. Bartley published a report titled "Investigating Transformer Failures" in 2006, examining past causes of transformer failures and the distribution of failures by age of transformer, based on American utility data.

4 John van Kooy's report titled "Transformers: Responding to the Baby Boom" was published in *NETA World*, the official publication of the International Electrical Testing Association in the winter of 2005-2006. Mr. van Kooy has over 30 years of experience in transformer design, manufacturing, operation and field test result analysis, including management positions with Westinghouse and ABB in transformer design and engineering. In his current role as owner and technical principal of van Kooy Transformer Consulting Services, Inc., he is regularly consulted by the Company for expert advice with respect to transformers.

Representation of Failure Curve
for Typical Transformer Population

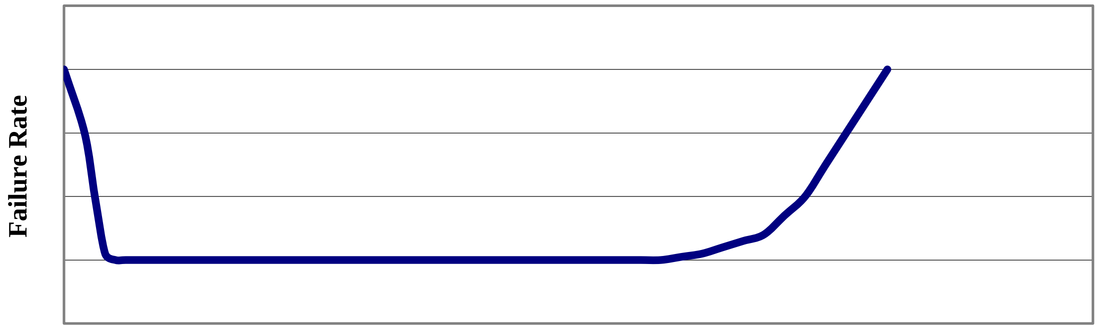

Figure 2

A higher failure rate in the first few years of service is due to design and application failures. This is followed by a period of a stable low failure rates for the majority of the equipment life span. As transformers approach end of life, the failure rate again increases.

The median age of 37 years places half of Newfoundland Power's transformers near the end of their normal life expectancy and consequently closer to the right hand side of the failure curve. It is reasonable to expect that the Company's rate of in-service power transformer failure will increase in future years.

2.3 Emergency Response

In the case of an in-service transformer failure, depending on factors such as the location of the power transformer and the time of year of the failure, it may be possible to transfer load between power transformers to minimize the duration of customer power outages. In the Newfoundland Power system, this alternative is generally limited to highly networked urban areas such as St. John's during non-peak periods.

Where customer load cannot be transferred to other power transformers, the Company will typically use a portable substation to restore electricity supply to customers following a power transformer failure.[5] Following the emergency restoration of power, the Company will continue to use the portable substation to maintain electricity supply to customers while the failed power transformer is repaired or replaced. In situations where the Company does not have a spare transformer available, a portable substation will be required to remain installed for an extended period ranging from 6 to 18 months.[6]

5 In an emergency, if a portable substation is immediately available, it can typically be placed in service within approximately 24 to 36 hours.

6 The Company does not maintain a stock of spare transformers; however, the Company sometimes has spare transformers available as a result of activities such as replacing transformers due to load growth.

Customer load growth in recent years has reduced spare in-service transformer capacity in the Newfoundland Power system, further limiting viable options for transferring load between power transformers to maintain electricity supply to customers. At the same time, the Company's lower capacity portable substations are able to back up fewer of the in-service power transformers, because the customer load served by those transformers has increased.

Based on the Company's experience in recent years regarding use of portable substations to address transformer failures, and the anticipated increase in the rate of power transformer failure, it is reasonable to expect that the Company's level of utilization of portable substations for emergency response will increase.

2.4 Substation Capital Program

The level of expenditure required for the Company's substation capital program is increasing.[7] Figure 3 shows the Company's substation capital program expenditures from 2007 to 2010, and forecast expenditures from 2011 to 2016.[8]

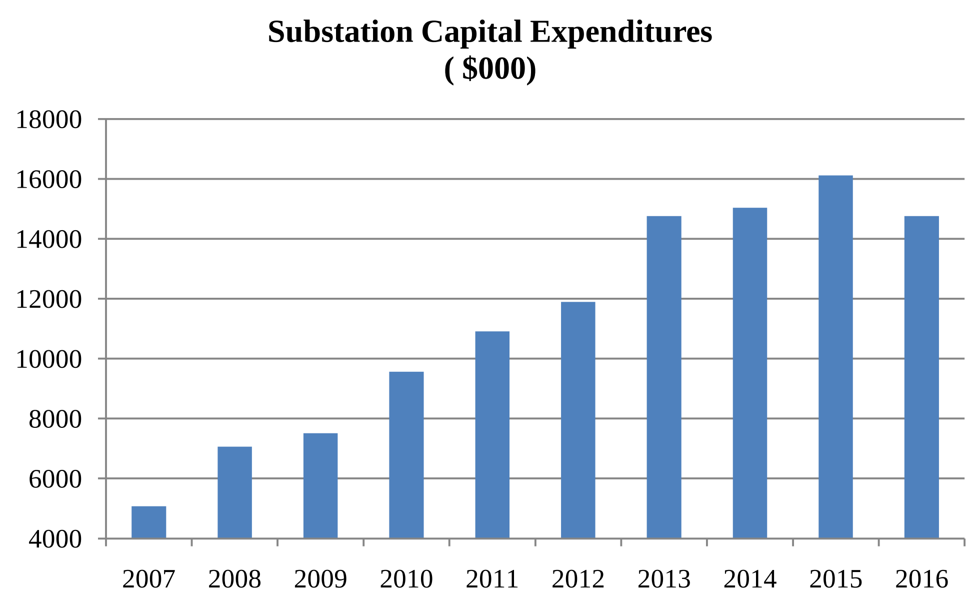

Figure 3

Portable substations are commonly used to maintain electricity supply to customers during completion of capital projects related to substation refurbishment and modernization and load growth. Such work effectively requires the substation power transformer to be taken out of service. In the meantime, the functionality of the power transformer is provided through

[7] See Section 3.2.4 of the Company's *2012 Capital Plan* provided with the 2012 Capital Budget Application for details on the Substation capital program for 2012 – 2016.

[8] The forecast expenditures shown for 2012 and 2013 do not include the $4,500,000 planned for purchase of an additional portable substation.

installation of a portable substation. When used for this purpose, a portable substation may be installed at a substation for between 2 and 7 months, depending on the extent of the planned work.

For the foreseeable future, Newfoundland Power does not anticipate any material change in the utilization of its portable substations in connection with the Company's capital program.

2.5 Transformer Maintenance

The Company performs regular maintenance on power transformers. This maintenance often requires the transformer to be taken out of service. Where customer load cannot be transferred to other substation transformers, such as in areas served by radial transmission systems, maintenance can require extended customer outages.[9] Portable substations allow the Company to complete the required maintenance without such extended outages. This type of usage typically requires the portable substation to be in service for 5 to 6 weeks per maintenance project.

For the foreseeable future, Newfoundland Power does not anticipate any material change in the utilization of its portable substations in connection with regular power transformer maintenance.

2.6 Summary

As illustrated in Figure 4, portable substation usage is driven by three requirements: (1) emergency restoration of service following a substation power transformer failure, (2) support for the capital program, and (3) support for the maintenance program.

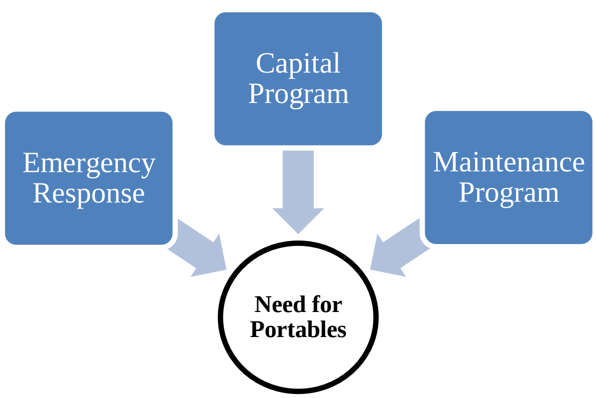

Figure 4

[9] Typically, scheduled power transformer maintenance takes approximately 2 to 4 weeks (or 75 to 150 working hours) for a maintenance crew to complete. Compressing this work schedule to reduce customer outages would require extended work hours at overtime rates and increase maintenance costs.

3.0 Portable Substations

3.1 Description of Portable Substations

Newfoundland Power owns three portable substation units:

- Portable Substation No. 1 (P1), with a capacity of 10 MVA, was purchased in 1966,
- Portable Substation No. 3 (P3), with a capacity of 25 MVA, was purchased in 1976, and
- Portable Substation No. 4 (P4), with a capacity of 50 MVA, was purchased in 1993.[10]

Figure 5 contains photographs of the Company's three portable substations.[11]

P1 P3 P4

Figure 5

All three portable substation units are similar in design. Each has an air break switch to isolate the portable substation on the high-voltage side, a multiple-winding power transformer, and a breaker on the low-voltage side. The flexibility provided by the multiple-winding transformer allows the portable substations to connect to transmission, generation and distribution systems of different voltages.[12]

Single line diagrams for each portable substation are shown in Appendix B.

[10] Newfoundland and Labrador Hydro ("Hydro") owns a portable substation, referred to as Portable Substation No. 2 (P2) that has a capacity of 15 MVA. P2 was recently refurbished by Hydro under its 2010 capital budget. This portable substation is available to Newfoundland Power through an equipment sharing agreement between the utilities. Hydro has identified one of Newfoundland Power's portable substations as the immediate back-up for three of their transformers, and a back up to P2 for 23 of their transformers.

[11] The Company has maintained a fleet of 3 portable substations since 1977.

[12] Compared to a standard power transformer, the transformer for a portable substation is physically smaller, has less mass and is mounted on a trailer with associated switchgear and protection. These portable features add significantly to the cost of a portable substation, as compared to the cost of a standard power transformer.

3.2 Back-up Capability

Although each of Newfoundland Power's portable substations is somewhat flexible within a range of voltages and substation capacities, each unit is technically limited to providing back-up for only a certain number of the Company's power transformers.

Table 1 shows the number and type of power transformers which can be replaced by the existing portable substations.

Table 1
Summary of Power Transformers and
Portable Substation Back-up Capability[13]

Portable Substation(s) Capable of Back-up	System Power Transformers[14]	Distribution Power Transformers[15]	Plant Power Transformers[16]	Total Power Transformers[17]
P1 Only	0	11	9	20
P3 Only	0	0	4	4
P1 & P3	0	1	13	14
P4 Only	4	4	0	8
P1, P3 & P4	2	48	0	50
P3 & P4	7	70	0	77
Subtotal	**13**	**134**	**26**	**173**
None [18]	0	2	17	19
Total	**13**	**136**	**43**	**192**

Newfoundland Power's current complement of three portable substations is capable of providing emergency back-up for 173 of the 192 power transformers the Company has in service.

13 A detailed listing of all of the Company's power transformers, and the portables that can provide back-up for them, is provided in Appendix C.

14 Refers to a substation power transformer used to transform between transmission voltages; for example, from 138kV to 66kV.

15 Refers to a substation power transformer used to transform voltage from transmission voltage to distribution voltage; for example, from 66kV to 12.5kV.

16 Refers to a substation power transformer used to transform voltage from generation to either transmission or distribution voltage; for example, from 6.9kV to 12.5kV.

17 Table 1 excludes spare transformers that may be available for back-up.

18 These 19 transformers are small plant or distribution step-up transformers. The Company maintains spare transformers for all but one of these units.

From a service reliability perspective, P3 and P4 are the most important of the portable substations. They are the largest units, and they provide back-up coverage for the majority of the most critical power transformers on Newfoundland Power's system.

From a service reliability perspective, System Power Transformers and Distribution Power Transformers are the most critical of the Company's power transformers.[19] The Company's portable substations provide back-up to 13 System Power Transformers and 134 Distribution Power Transformers. P4 is capable of providing back-up to 135, or 92%, of those transformers, while P3 is capable of providing back-up to 128, or 87%.

P1 is capable of providing back-up for only 62 of the System Power Transformers and Distribution Power Transformers, but is the only back-up for 11 of them.

3.3 Utilization of Existing Portable Substations

When a given portable substation is already in service, it is effectively unavailable for emergency response. Transferring the unit from its existing deployment to the emergency back-up location may take several days, depending on specific circumstances.

Figure 6 shows the usage duration for each of the Company's portable substations for the 5-year period from 2007 to 2011 forecast.[20]

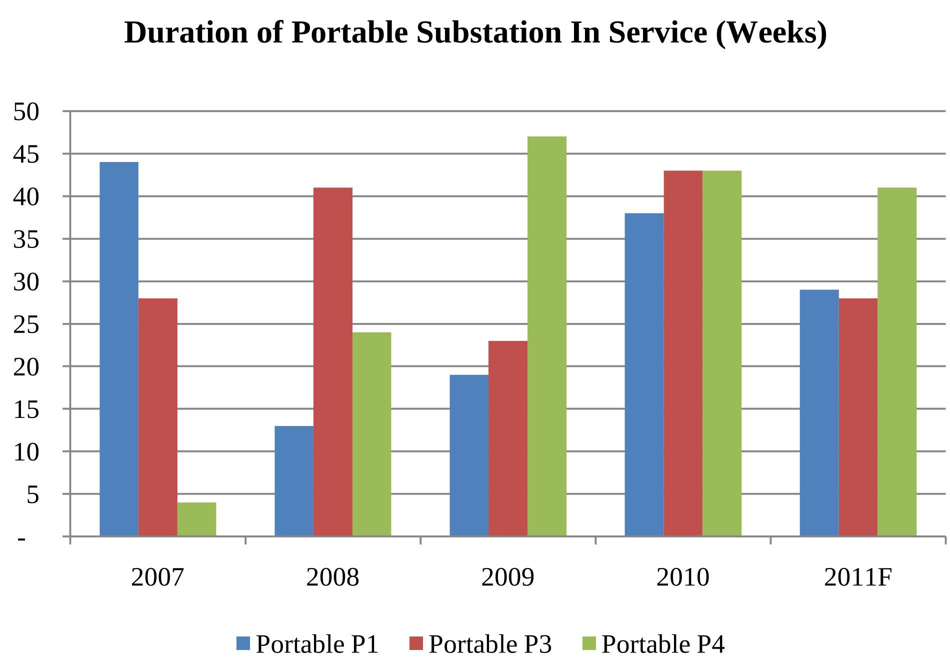

Figure 6

[19] The Company's plant power transformers are less critical because customers are not directly affected by their failure.

[20] Portable substation usage includes, for each portable, a 4-week period each year for maintenance work on the unit. For 2011F, the forecast includes forecast usage associated with planned capital and maintenance and actual experience to date related to emergency response. It does not include a forecast of emergency response requirements.

Over the five-year period, Newfoundland Power's three portables will have been placed in service a total of 49 times. During the same period, total portable substation utilization will have varied between approximately 15 weeks and 45 weeks per year.

The availability of portable substations is of particular concern when considering the possibility of a power transformer failure. In the event of the failure of a System Power Transformer or a Distribution Power Transformer, the consequences of unavailability may be high. If a portable is unavailable when one of these transformers fails, there would be an extended outage while the required portable is removed from service, transported to the site of the failure and re-installed. The length of the extended outage would depend on the amount of time necessary to return the transformer that was undergoing refurbishment or maintenance to service so the portable substation could be redeployed.[21]

The Company's required level of usage for portable substations presents concerns due to the extended periods of time during which no portable substations are available to immediately respond to power transformer failures.

As noted in 3.2 above, the two largest portable substations, P3 and P4, provide back-up coverage for the majority of Newfoundland Power's most critical power transformers. Figure 7 shows the duration of time, over the period 2007 through forecast 2011, when both P3 and P4 were, or are forecast to be, simultaneously in service, and therefore unavailable for immediate response to power transformer failures.[22]

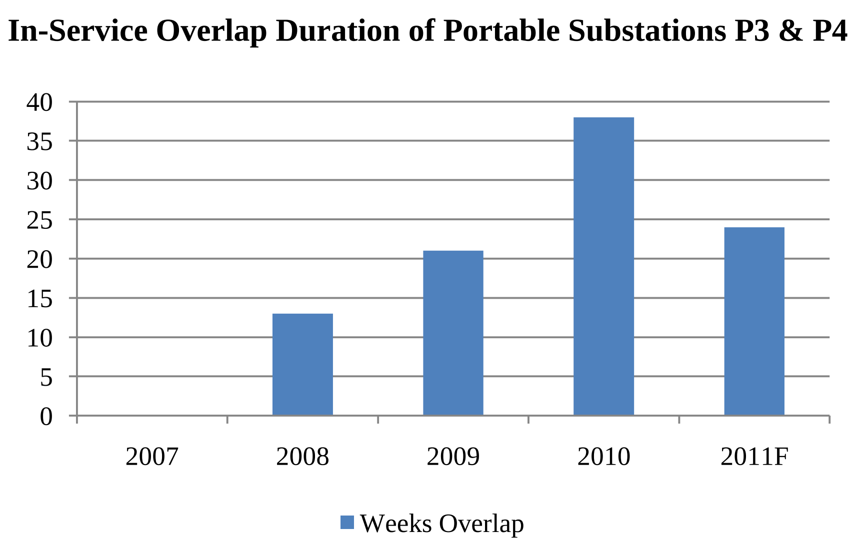

Figure 7

[21] Although every effort would be made to redeploy the portable substation as quickly as possible, the time to remove a portable substation from service can exceed 72 hours. With 24 to 36 additional hours required to install the unit in the new location, a service interruption due to a power transformer failure could easily exceed four days duration.

[22] Forecast service overlap for 2011F is based on forecast portable substation usage associated with planned capital and maintenance and actual experience to date related to emergency response. This does not include any forecast emergency response requirements.

In 2007, there was no actual in-service overlap. In 2008, 2009 and 2010, the in-service overlap periods are 13 weeks, 21 weeks, and 38 weeks respectively. In 2011, in-service overlap for P3 and P4 is forecast to be 24 weeks; however, an in-service failure of a power transformer, or a change in other requirements for the deployment of P3 or P4, could alter that outlook.

A total of 89 of the Company's power transformers can be backed up only by portable substation P3 or P4.[23] If one of these 89 units were to fail at a time when both P3 and P4 were already in use, the time required to remove one of the units from service and transport it to the location of the failed unit could result in an outage to customers of greater than four days' duration.

3.4 Concluding

Newfoundland Power has had a total of 17 power transformer failures over the last five years. These incidents resulted in a total of 144 weeks of portable substation utilization. Based on the age of the Company's existing power transformers, it is reasonable to expect the failure rate of the Company's in-service power transformers will be higher in future years. In addition, the high utilization of portables to minimize customer outages related to capital and maintenance programs is not expected to be materially different than recent experience.

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

4.0 Assessment of Alternatives

To reduce the risk of extended customer outages associated with the availability of portable substations, Newfoundland Power has considered four alternatives. These alternatives are:

1. Ensure an existing portable substation unit is always available to respond to a substation power transformer failure;
2. Purchase additional spare substation transformers sufficient to establish standing spares for all sizes and configurations of power transformers in Newfoundland Power's system;
3. Implement an N-1 transformer back-up criterion to ensure sufficient in-service spare capacity is available to fully serve customer load in the event of a transformer failure; and
4. Purchase a new portable substation.

4.1 Ensure Availability of an Existing Portable Substation

One way to increase the availability of portable substations for emergency response is to restrict the use of the existing units so that one is always available for emergencies.

If this alternative were chosen, it would materially increase scheduled customer outages associated with the Company's substation capital and maintenance programs. Had this approach

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[23] The 89 units are the transformers backed up by P3 & P4 (77 units), P3 only (4 units) and P4 only (8 units).

been employed in 2010, the result would have been an increase of approximately 34% in the total outages experienced by Newfoundland Power's customers.[24]

Due to the resulting increase in electrical service interruptions to customers, this is not an acceptable alternative.

4.2 Establish an Inventory of Spare Transformers

If Newfoundland Power had a standing inventory of spare power transformers, this would reduce reliance on portable substations in the event of a power transformer failure.

Although some electric utilities maintain a standing inventory of spare power transformers, Newfoundland Power does not. This is principally related to the high cost of maintaining such an inventory. The cost of establishing an adequate fleet of spare power transformers for Newfoundland Power is estimated at approximately $12 million.[25]

Where a spare is available to replace a failed power transformer, a portable substation would still be required for the initial emergency response. In such circumstances, the portable would effectively be unavailable to support other capital and maintenance work for up to 6 weeks.[26]

Figure 8 provides a graphic representation of the usage of the Company's portable substations for the period 2007 to forecast 2011, including a breakdown of the number of weeks related to emergency power restoration.

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24 The System Average Interruption Duration Index ("SAIDI") for 2010 would have increased from 2.59 to 3.48 hours per year, excluding storms. These scheduled outages would have affected approximately 6,000 customers for a total duration of about 35 hours.

25 Based on the cost of nine power transformers and an appropriate storage facility. Various transformer size and winding configurations are required to allow for direct replacements of existing in-service units. This approach is consistent with reasonable deployment costs and emergency response times, and avoids costs associated with redesigning and rebuilding existing substations and related protection schemes.

26 The installation time for a substation power transformer could be reduced to approximately 1 week if work was completed with additional crews working overtime, as would be the case in an emergency situation where customers are without electricity.

Total Usage for Portables for 2007 – 2011F

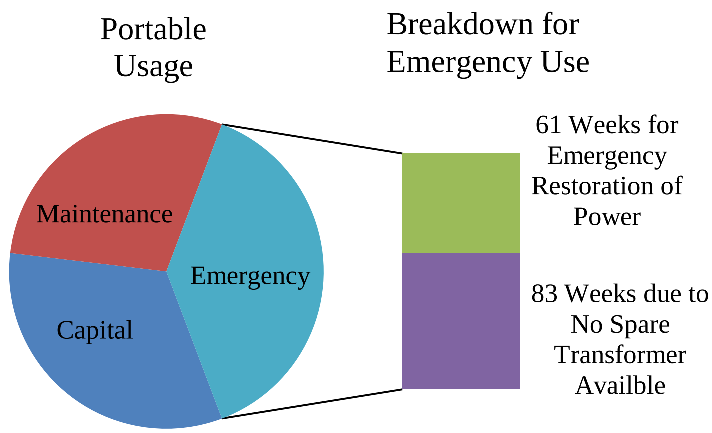


Figure 8

If the Company had maintained standing spares for the past 5 years, the requirement for portables would have been reduced by 83 weeks in total (or approximately 17 weeks per year).

However, because of the high cost, a fleet of standing spares is not considered a reasonable option for increasing the availability of the Company's portable substations.

4.3 N-1 Transformer Back-up Criterion

An N – 1, or N minus one, criterion requires that a system be capable of continued operation with the loss of any single component of that system. An N – 1 transformer back-up criterion would require that Newfoundland Power maintain sufficient spare transformer capacity in service to enable electricity service to customers to be maintained in the event that any transformer is taken out of service for planned or emergency reasons. This would practically require that every substation have sufficient transformer capacity to survive the loss of the largest transformer during peak load conditions.

If Newfoundland Power's electrical system were built to this criterion, it would effectively eliminate the need for a fleet of portable substations.

Depending on the time of year, the Company does have some capability to transfer load between power transformers, primarily in highly networked urban areas such as St. John's.[27] However, that capability is limited, even in urban areas, and is practically non-existent in most rural areas. Implementing an N-1 criterion would therefore require major additions to Newfoundland Power's electrical system, including the addition of a large number of new substation transformers.

[27] During periods of high customer demand during the winter, there is limited ability to transfer load between power transformers within the Company's urban areas.

The cost of installing an additional substation transformer is typically in the order of $3 million. Newfoundland Power has 130 substations, 94 of which have only one distribution power transformer. Implementing an N – 1 criterion for transformer back-up throughout Newfoundland Power's electrical system would take decades, and would cost tens of millions of dollars.

While there is merit to employing an N-1 criterion in specific circumstances, for example, in urban areas where critical loads exist, it is neither a practical or cost-effective alternative for broad scale implementation on Newfoundland Power's electrical system.

4.4 Purchase a New Portable Substation

The fourth alternative considered for improving the availability of portable substations for Newfoundland Power is the purchase of a new 50 MVA portable substation.

As noted in Section 3 of this report, the risk associated with availability of Newfoundland Power's portable substation is greatest for System Power Transformers and Distribution Power Transformers. Of these 147 power transformers, 92% can be backed up by the Company's 50 MVA portable substation P4.

The addition of another 50 MVA portable substation would provide an additional back-up unit for 92% of the Company's most critical power transformers. The addition of a new 50 MVA portable substation would substantially address the risk of a portable being unavailable in the event of a system or distribution power transformer failure.

The cost of purchasing a new 50 MVA portable substation is estimated at $4,500,000. This is a practical, cost-effective solution to Newfoundland Power's portable substation availability issue.

4.5 Recommendation

Four alternatives were considered to address concerns related to high utilization of the existing portable substation fleet for the Company's capital and maintenance programs and for emergency back-up. The least cost alternative consistent with reliable service is the purchase of a new 50 MVA portable substation similar to existing portable substation P4.

Detailed engineering design and manufacture of the new portable is estimated to take 18 to 24 months. To facilitate delivery of the unit in the last quarter of 2013, it is recommended that the order for the unit be placed in the first quarter in 2012.

The cost of placing the order in the first quarter of 2012 along with progress payments to the manufacturer during 2012 is estimated to cost $879,000. During 2013, remaining payments to the manufacturer and the cost of inspections and commissioning will total approximately $3,621,000. The total cost of the unit is estimated to be $4,500,000.

Appendix A

Power Transformer Failures 2007 to Present

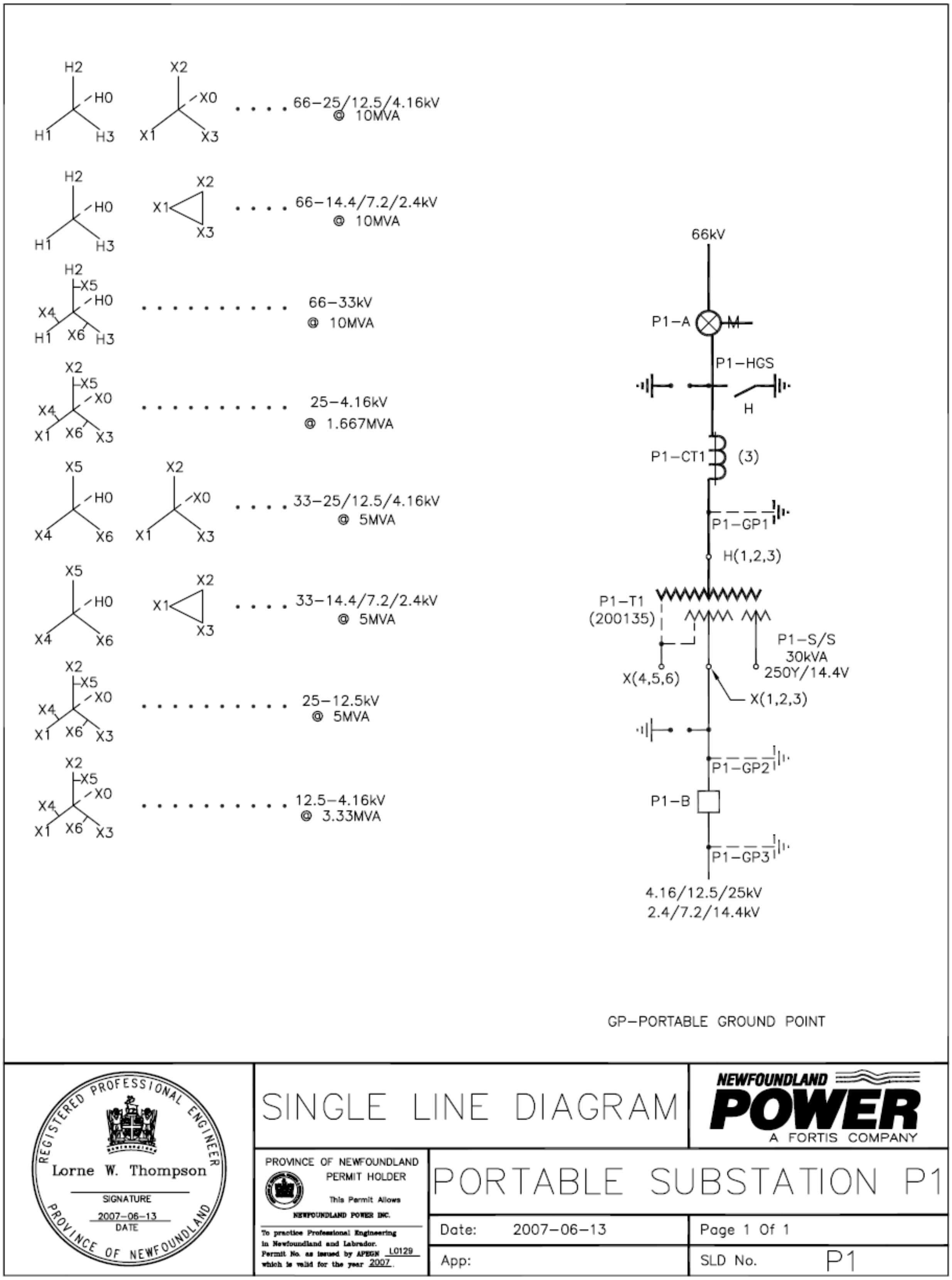
The Company's actual experience with respect to substation power transformer failure over the past five years is listed below.

Newfoundland Power Transformer Failures

Transformer	Voltage	Capacity (MVA)	Year Purchased	Failure Date	Action
Kenmount	66/25 kV	25	1984	Mar. 2009	Repair
Horse Chops	66/6.9 kV	8	1952	Oct. 2009	Replace
Pierre's Brook	33/6.9 kV	4.5	1941	Sept. 2007	Replace
Lockston	66/12.5 kV	4	1970	Jan. 2007	Repair
Morris	66/2.4 kV	1.5	1983	Sept. 2007	Repair
Morris	2.4/12.5 kV	1.5	1970	Oct. 2007	Replace
Berry Head	66-12.5 kV	7.46	1967	Jan. 2010	Repair
Glendale	66-12.5/25 kV	25	1990	Jun. 2009	Repair
Salt Pond	138-66 kV	41.6	1972	Sept. 2008	Repair
New Harbour	66-12.5 kV	13.3	1973	Nov. 2010	Repair
Gander	138-2.5/25 kV	20	1974	Jun. 2009	Repair
Goulds	66-12.5 kV	13.3	1974	Jun. 2009	Repair
Humber	66-12.5 kV	13.3	1974	May 2009	Repair
Bayview	66-12.5 kV	20	1976	May 2010	Repair
Cobbs Pond	138-66 kV	41.6	1979	Dec. 2010	Repair
Broad Cove	66-12.5/25 kV	25	1983	Apr. 2007	Repair
Pulpit Rock	66-12.5/25 kV	25	1991	Aug. 2009	Repair

Appendix B

Portable Substation Single Line Diagrams


66-25/12.5/4.16kV @ 10MVA
66-14.4/7.2/2.4kV @ 10MVA
66-33kV @ 10MVA
25-4.16kV @ 1.667MVA
33-25/12.5/4.16kV @ 5MVA
33-14.4/7.2/2.4kV @ 5MVA
25-12.5kV @ 5MVA
12.5-4.16kV @ 3.33MVA
66kV
P1-A
M
P1-HGS
H
P1-CT1
(3)
P1-GP1
H(1,2,3)
P1-T1
(200135)
P1-S/S
30kVA
250Y/14.4V
X(4,5,6)
X(1,2,3)
P1-GP2
P1-B
P1-GP3
4.16/12.5/25kV
2.4/7.2/14.4kV
GP-PORTABLE GROUND POINT
REGISTERED PROFESSIONAL ENGINEER
Lorne W. Thompson
SIGNATURE
2007-06-13
DATE
PROVINCE OF NEWFOUNDLAND
SINGLE LINE DIAGRAM
NEWFOUNDLAND POWER
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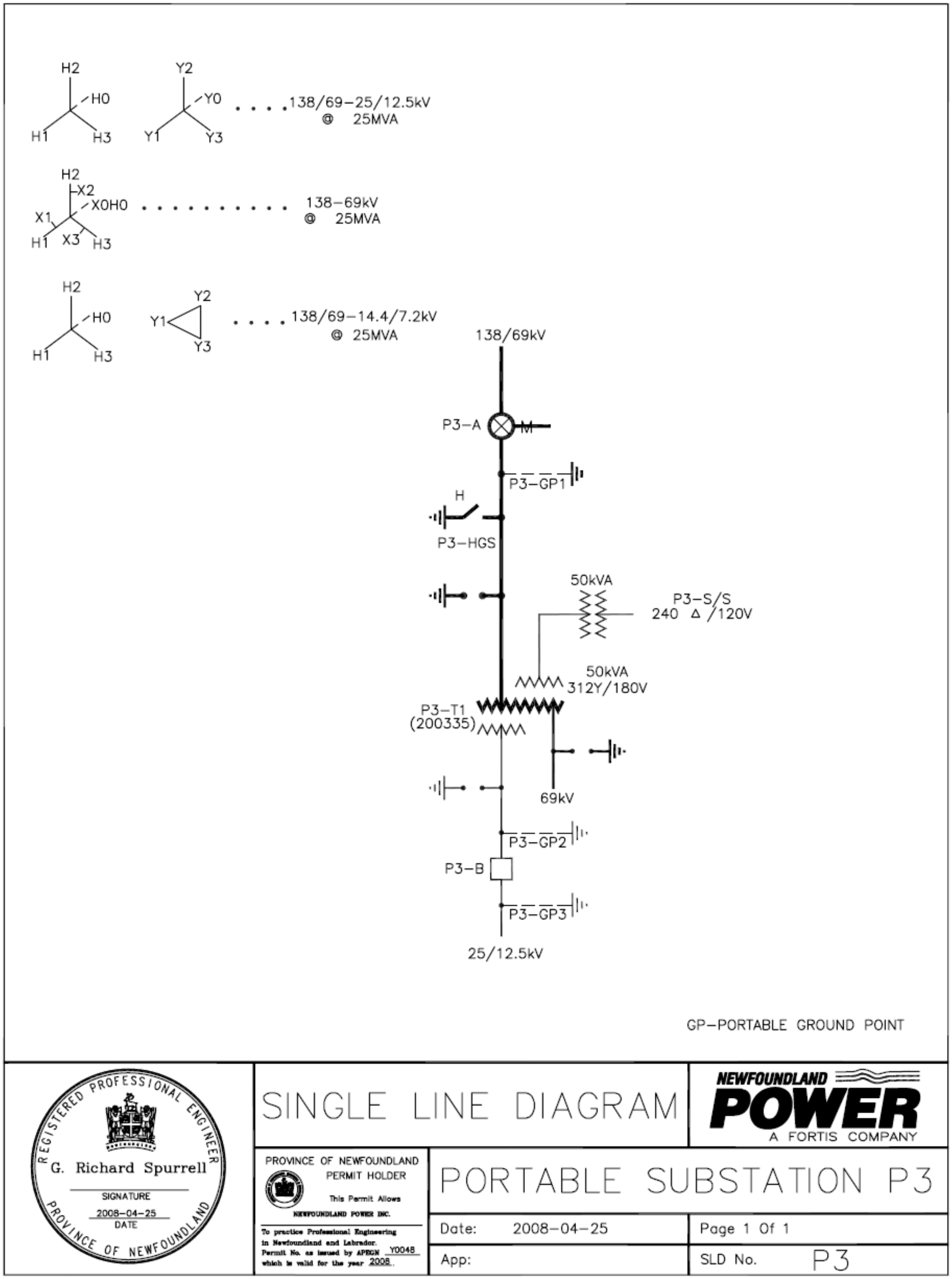
H2
H0
H1
H3
Y2
Y0
Y1
Y3
138/69–25/12.5kV
@ 25MVA
X2
X0H0
X1
X3
138–69kV
@ 25MVA
138/69–14.4/7.2kV
@ 25MVA
138/69kV
P3–A
M
P3–GP1
H
P3–HGS
50kVA
P3–S/S
240 Δ /120V
50kVA
312Y/180V
P3–T1
(200335)
69kV
P3–GP2
P3–B
P3–GP3
25/12.5kV
GP–PORTABLE GROUND POINT
REGISTERED PROFESSIONAL ENGINEER
G. Richard Spurrell
SIGNATURE
2008–04–25
DATE
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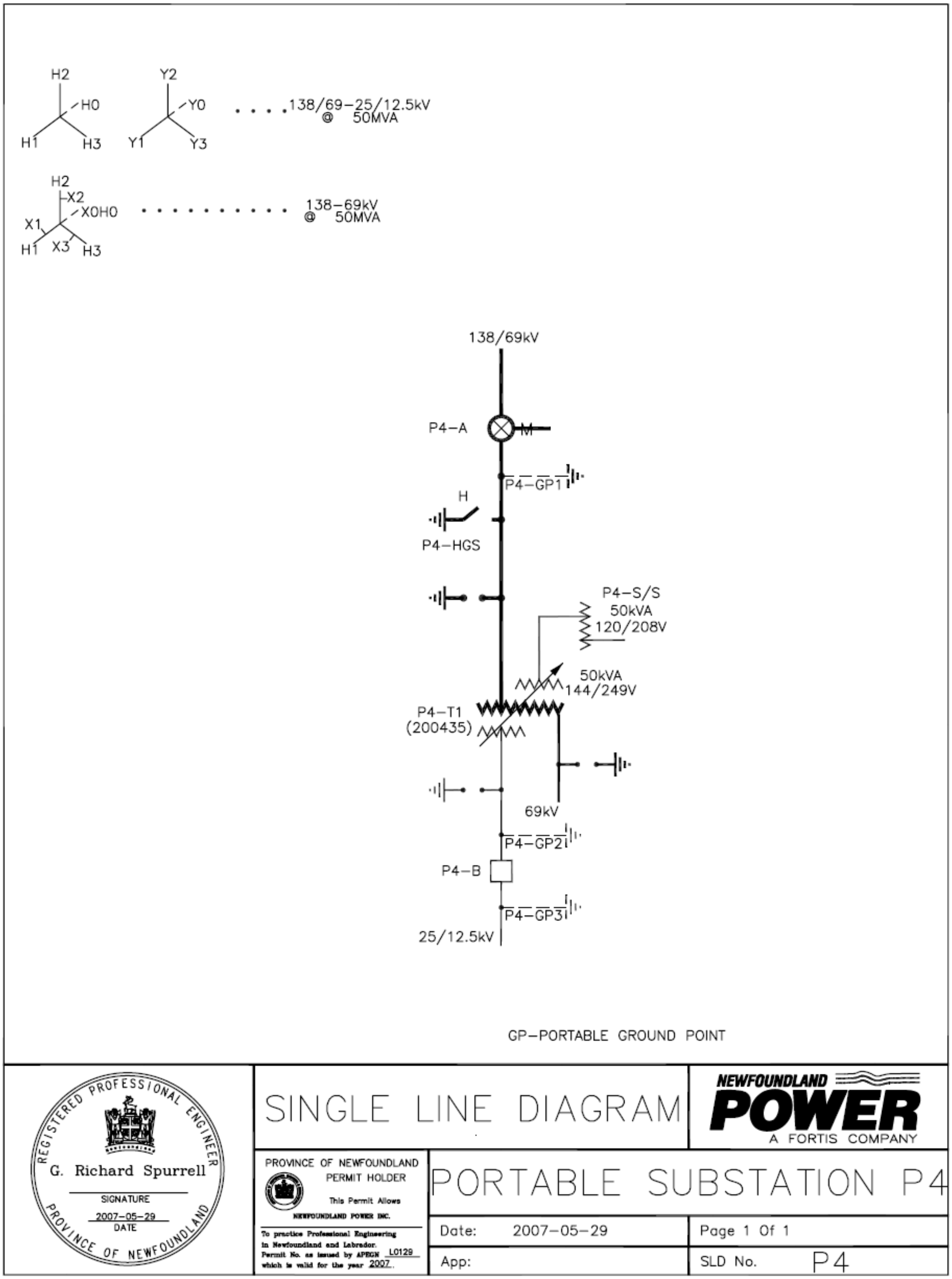

H2
H0
H1
H3
Y2
Y0
Y1
Y3
138/69–25/12.5kV @ 50MVA
X2
X0H0
X1
X3
138–69kV @ 50MVA
138/69kV
P4–A
M
P4–GP1
H
P4–HGS
P4–S/S
50kVA
120/208V
50kVA
144/249V
P4–T1
(200435)
69kV
P4–GP2
P4–B
P4–GP3
25/12.5kV
GP–PORTABLE GROUND POINT
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App:
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Appendix C

Power Transformer Listing And Portable Backup

2011 Transformer Listing and Backup Available Units

LOC.	Type	Operating Voltage			Winding Config.	Capacity MVA	2011 Peak MVA	P1	P3	P4
GBE-T1	Distribution	66	-	7.2	SP-SP	0.33	0.1	X	X	X
GPD-T1	Distribution	66	-	12.5	DL-YG	2.8	0.8	X	X	X
CLK-T2	Distribution	66	-	12.5	DL-YG	7.5/10	1.5	X	X	X
HCT-T3	Distribution	66	-	12.5	DL-YG	2/2.24	1.6	X	X	X
GAR-T1	Distribution	66	-	12.5	YG-YG-DL	2.8/3.72	1.8	X	X	X
BHD-T1	Distribution	66	-	12.5	YG-YG	5.6/7.46	1.9	X	X	X
TRP-T1	Distribution	66	-	12.5	DL-YG	5/6.7	2.1	X	X	X
FER-T1	Distribution	66	-	12.5	DL-YG	3/4	2.3	X	X	X
RBK-T2	Distribution	66	-	12.5	DL-YG	5/6.7	2.4	X	X	X
SMV-T1	Distribution	66	-	25	DL-YG	3/4	2.4	X	X	X
LOK-T3	Distribution	66	-	12.5	DL-YG	3/4	2.5	X	X	X
LAU-T1	Distribution	66	-	12.5	DL-YG	10/13.3	2.6	X	X	X
SCT-T1	Distribution	66	-	25	DL-YG	5/6.7	2.8	X	X	X
TRN-T1	Distribution	66	-	25	DL-YG	5/6.67	3.0	X	X	X
HBS-T1	Distribution	66	-	25	DL-YG	5/6.67	3.1	X	X	X
ISL-T1	Distribution	69	-	13.8	DL-YG	3/4	3.1	X	X	X
WBC-T1	Distribution	66	-	25	DL-YG	5/6.7/8.33	3.2	X	X	X
ROB-T1	Distribution	66	-	25	DL-YG	5/6.67	3.3	X	X	X
RVH-T1	Distribution	66	-	12.5	DL-YG	5/6.7	3.3	X	X	X
STG-T1	Distribution	66	-	12.5	DL-YG	5/6.7	3.5	X	X	X
HGR-T2	Distribution	66	-	12.5	YG-YG-DL	5/6.7	3.6	X	X	X
DOY-T2	Distribution	66	-	25	DL-YG	3/4	3.7	X	X	X
NCH-T1	Distribution	66	-	12.5	DL-YG	5/6.67	3.7	X	X	X
CAB-T2	Distribution	66	-	12.5	DL-YG	5/6.7	3.8	X	X	X
MMT-T1	Distribution	69	-	12.5	DL-YG	3/4	3.8	X	X	X
FRN-T1	Distribution	66	-	12.5	DL-YG	5/6.67	4.7	X	X	X
STX-T1	Distribution	66	-	12.5	DL-YG	5/6.7	4.8	X	X	X
GIL-T1	Distribution	66	-	12.5	DL-YG	5/6.67	5.2	X	X	X
ABC-T1	Distribution	66	-	12.5	DL-YG	10/13.3	5.5	X	X	X
CLK-T1	Distribution	66	-	12.5	DL-YG	7.5/10	5.9	X	X	X
HGR-T1	Distribution	66	-	12.5	YG-YG-DL	7.5/10	5.9	X	X	X
NHR-T1	Distribution	66	-	12.5	YG-YG	10/13.3	6.1	X	X	X
MUN-T1	Distribution	66	-	12.5	DL-YG	11.25/14.96	6.3	X	X	X
LGL-T1	Distribution	66	-	25	YG-YG	11.13/14.9	6.4	X	X	X
SUM-T1	Distribution	66	-	25	DL-YG	10/13.3	6.8	X	X	X
WAV-T6	Distribution	66	-	12.5	YG-YG	10/13.3	6.8	X	X	X
LET-T1	Distribution	66	-	25	DL-YG	5/6.7	7.0	X	X	X
OPL-T1	Distribution	66	-	12.5	YG-YG	11.25/14.96	7.4	X	X	X
GBY-T1	Distribution	66	-	25	DL-YG	10/13.3	7.5	X	X	X
DUN-T1	Distribution	66	-	25	DL-YG	5/6.7/8.3	7.6	X	X	X
BVS-T2	Distribution	66	-	12.5	DL-YG	11.25/15	7.9	X	X	X
PAB-T5	Distribution	66	-	12.5	YG-YG	10/13.3	8.3	X	X	X
TWG-T1	Distribution	66	-	12.5	DL-YG	10/13.3	8.5	X	X	X
BIG-T1	Distribution	66	-	12.5	DL-YG	8.4/11.1	8.8	X	X	X
MOB-T2	Distribution	66	-	12.5	DL-YG	10/13.3/16.67	8.8	X	X	X
MIL-T1	Distribution	66	-	25	DL-YG	10/13.3/16.7	9.1	X	X	X

2011 Transformer Listing and Backup Available Units

LOC.	Type	Operating Voltage			Winding Config.	Capacity MVA	2011 Peak MVA	P1	P3	P4
GAL-T1	Distribution	66	-	12.5	YG-YG	10/13.33	9.5	X	X	X
SCV-T2	Distribution	66	-	12.5	YG-YG	11.2/13.3/14.9	9.5	X	X	X
GOU-T1	System	66	-	33	AT-AT-DL	10	3.0	X	X	X
MOB-T3	System	66	-	33	AT-AT-DL	3.5/4.67	4.0	X	X	X
BVJ-T1	Distribution	138	-	25	DL-YG	2/2.67	0.3		X	X
TNS-T1	Distribution	138	-	14.4	SP-SP	1	0.6		X	X
PBD-T1	Distribution	138	-	25	DL-YG	10/13.3/16.67	1.5		X	X
MKS-T1	Distribution	138	-	25	YG-ZZ-DL	11.2/14.9	1.8		X	X
GLN-T1	Distribution	138	-	25	DL-YG	5/6.67/8.34	2.8		X	X
GAM-T1	Distribution	138	-	25	DL-YG	5/6.7	4.6		X	X
COL-T1	Distribution	138	-	12.5	DL-YG	10/13.3/16.67	4.8		X	X
BLA-T1	Distribution	138	-	25	DL-YG	5/6.7	5.0		X	X
NWB-T1	Distribution	138	-	25	DL-YG	8.4/11.2	5.9		X	X
CAT-T2	Distribution	138	-	12.5	YG-YG-DL	15/20	6.4		X	X
SCR-T1	Distribution	138	-	25	DL-YG	5/6.7/8.3	7.1		X	X
HAR-T1	Distribution	66	-	12.5	YG-YG	11.125/14.9	7.6		X	X
LLK-T1	Distribution	138	-	12.5	YG-YG-DL	15/20	8.0		X	X
SUN-T5	Distribution	138	-	25	DL-YG	15/20/25	8.0		X	X
GAL-T2	Distribution	66	-	12.5	YG-YG	10/13.33	9.4		X	X
WES-T1	Distribution	66	-	12.5	DL-YG	10/13.3	9.5		X	X
SPF-T1	Distribution	138	-	12.5	DL-YG	15/20	9.8		X	X
SPR-T1	Distribution	138	-	25	DL-YG	10/13.3/16.67	9.8		X	X
MUN-T2	Distribution	66	-	12.5	DL-YG	15/20	9.9		X	X
GLV-T1	Distribution	138	-	25	DL-YG	15/20	10.0		X	X
BLK-T2	Distribution	138	-	25	YG-YG-DL	15/20	10.1		X	X
HOL-T1	Distribution	138	-	12.5	DL-YG	15/20	10.4		X	X
ILC-T1	Distribution	66		12.5	DL-YG	10/13.3	10.7		X	X
OXP-T1	Distribution	66	-	12.5	YG-YG	10/13.3	10.9		X	X
PAS-T1	Distribution	66	-	12.5	DL-YG	10/13.3	10.9		X	X
BVA-T1	Distribution	138	-	12.5	DL-YG	15/20/25	11.0		X	X
GBS-T1	Distribution	66	-	12.5	YG-YG	12/14.93	11.0		X	X
HUM-T3	Distribution	66	-	12.5	DL-YG	10/13.3	11.8		X	X
BFS-T1	Distribution	138	-	25	YG-YG-DL	15/20	11.9		X	X
GOU-T3	Distribution	66	-	12.5	YG-YG-DL	10/13	11.9		X	X
GRH-T2	Distribution	66	-	12.5	DL-YG	15/20	12.5		X	X
BVS-T1	Distribution	66	-	12.5	DL-YG	15/20	12.8		X	X
SPO-T1	Distribution	66	-	12.5	YG-YG-DL	11.25/15	12.8		X	X
CAT-T1	System	138	-	66	DL-YG	10/13.3/16.7	1.8		X	X
GFS-T1	System	138	-	66	YG-DL	17.8/23.7/29.67	6.8		X	X
GAN-T1	Distribution	138	-	12.5	DL-YG	15/20	19.5		X	X
BOT-T1	Distribution	138	-	25	DL-YG	15/20	12.6		X	X
PUL-T1	Distribution	66	-	12.5	YG-YG	15/20/25	14.5		X	X
PUL-T2	Distribution	66	-	12.5	YG-YG	15/20/25	14.5		X	X
VIC-T1	Distribution	66	-	12.5	YG-YG	10/13.3	15.0		X	X
WAL-T2	Distribution	66	-	12.5	DL-YG	15/20/25	15.8		X	X
LEW-T1	Distribution	66	-	25	DL-YG	15/20/25	16.2		X	X

2011 Transformer Listing and Backup Available Units

LOC.	Type	Operating Voltage			Winding Config.	Capacity MVA	2011 Peak MVA	P1	P3	P4
MSY-T1	Distribution	138	-	12.5	YG-YG-DL	15/20	16.5		X	X
DLK-T1	Distribution	66	-	12.5	DL-YG	15/20/25	16.8		X	X
GOU-T2	Distribution	66	-	12.5	YG-YG	15/20	16.9		X	X
WAL-T1	Distribution	66	-	12.5	DL-YG	15/20	17.1		X	X
GFS-T3	Distribution	138	-	25	DL-YG	15/20	17.5		X	X
KEL-T1	Distribution	66	-	12.5	YG-YG	11.25/14.95	18.0		X	X
CLV-T2	Distribution	138	-	12.5	YG-YG-DL	15/20	18.5		X	X
VIR-T3	Distribution	66	-	12.5	YG-YG	15/20/25	18.5		X	X
RRD-T2	Distribution	66	-	12.5	YG-YG	15/20	19.4		X	X
RRD-T3	Distribution	66	-	12.5	YG-YG	15/20	19.4		X	X
HWD-T2	Distribution	66	-	12.5	YG-YG	15/20	19.6		X	X
HWD-T1	Distribution	66	-	12.5	YG-YG	15/20	19.6		X	X
CAR-T1	Distribution	66	-	12.5	DL-YG	15/20/25	20.3		X	X
PEP-T1	Distribution	66	-	12.5	YG-YG	15/20/25	20.5		X	X
COB-T1	Distribution	138	-	12.5	DL-YG-DL	15/20	21.3		X	X
SLA-T3	Distribution	66	-	12.5	YG-YG	15/20/25	21.4		X	X
GFS-T2	Distribution	138	-	25	DL-YG	15/20	21.5		X	X
GDL-T2	Distribution	66	-	12.5	YG-YG	15/20/25	21.8		X	X
GDL-T1	Distribution	66	-	12.5	YG-YG	15/20/25	21.8		X	X
BRB-T1	Distribution	138	-	12.5	YG-DL-YG	15/20	22.1		X	X
BCV-T1	Distribution	66	-	12.5	WY-YG	15/20/25	22.4		X	X
VIR-T2	Distribution	66	-	12.5	YG-YG	15/20/25	22.4		X	X
HWD-T3	Distribution	66	-	25	YG-YG	15/20/25	22.6		X	X
SJM-T1	Distribution	66	-	12.5	YG-YG	15/20/25	22.9		X	X
SJM-T2	Distribution	66	-	12.5	YG-YG	15/20/25	22.9		X	X
CHA-T1	Distribution	66	-	25	YG-YG	15/20/25	23.0		X	X
CHA-T2	Distribution	66	-	25	YG-YG	15/20/25	23.0		X	X
SLA-T4	Distribution	66	-	12.5	YG-YG	15/20/25	23.2		X	X
KBR-T3	Distribution	66	-	12.5	YG-YG	15/20/25	23.4		X	X
VIR-T1	Distribution	66	-	12.5	YG-YG	15/20	23.4		X	X
GAM-T2	System	138	-	66	DL-YG	25/33.3/41.6	5.5		X	X
SPO-T4	System	138	-	66	AT-AT-DL	25/33.3/41.6	10.1		X	X
SPO-T5	System	138	-	66	DL-YG	25/33.3/41.6	10.1		X	X
GAN-T2	System	138	-	66	YG-DL	16/21.3/26.67	10.6		X	X
CLV-T1	System	138	-	66	DL-YG	15/20/25	17.4		X	X
KEN-T1	Distribution	66	-	25	YG-YG	15/20/25	24.5			X
KEN-T2	Distribution	66	-	25	YG-YG	15/20/25	24.5			X
MOL-T2	Distribution	66	-	12.5	YG-YG	15/20/25	24.5			X
MOL-T1	Distribution	66	-	12.5	YG-YG	15/20/25	24.5			X
COB-T2	System	138	-	66	DL-YG	25/33.3/41.6	23.8			X
BLK-T3	System	138	-	66	DL-YG	25/33.3/41.6	24.6			X
BRB-T3	System	138	-	66	DL-YG	25/33.3/41.6	26.2			X
BRB-T2	System	138	-	66	DL-YG	25/33.3/41.6	26.7			X
JON-T1	Distribution	66	-	7.2	SP-SP	0.33	0.1	X	X	
GAN-T3	Ground	66	-	6.9	YG-DL	1.667		X	X	
GAN-T3	Ground	66	-	6.9	YG-DL	1.667		X	X	

2011 Transformer Listing and Backup Available Units

LOC.	Type	Operating Voltage			Winding Config.	Capacity MVA	2011 Peak MVA	P1	P3	P4
GAN-T3	Ground	66	-	6.9	YG-DL	1.667		X	X	
LOK-T4	Plant	46	-	6.9	YG-DL	2.5	1.2	X	X	
LOK-T1	Plant	46	-	6.9	YG-DL	2.5	1.2	X	X	
LOK-T2	Plant	66	-	46	AT-AT	4.48/5.97/7.46	2.4	X	X	
ROP-T1	Plant	66	-	6.9	YG-DL	4	3.2	X	X	
PBK-T1	Plant	33	-	6.9	YG-DL	5/6.7	4.0	X	X	
NCH-T2	Plant	66	-	6.9	YG-DL	4/5.33	4.1	X	X	
SBK-T1	Plant	66	-	6.9	YG-DL	7	5.8	X	X	
CAB-T1	Plant	66	-	6.9	YG-DL	8.44/11.25	6.4	X	X	
TCV-T1	Plant	66	-	6.9	YG-DL	7.5	6.6	X	X	
HCP-T1	Plant	66		6.9	YG-DL	9/12	8.2	X	X	
MOP-T1	Plant	66	-	6.9	YG-DL	10/13.3	10.2		X	
WES-T2	Plant	66	-	13.2	YG-DL	12/16/20	10.9		X	
RBK-T1	Plant	66	-	6.9	YG-DL	15/20	14.8		X	
GRH-T1	Plant	66	-	13.8	YG-DL	18/24/30	22.3		X	
QTZ-T1	Distribution	66	-	4.16	DL-YG	0.73	0.0	X		
SJM-T4	Distribution	66	-	4.16	YG-YG-DL	7.5/10	2.0	X		
PHR-T3	Distribution	33	-	4.16	DL-YG	3/4	2.1	X		
HUM-T2	Distribution	66	-	4.16	YG-YG	5.6/7.46	6.3	X		
KBR-T1	Distribution	66	-	4.16	YG-YG	7.5/10	7.5	X		
KBR-T2	Distribution	66	-	4.16	YG-YG	7.5/10	7.5	X		
GFS-T5	Distribution	66	-	4.16	YG-YG	8.4/11.17	8.3	X		
BOY-T1	Distribution	66	-	2.4	WY-DL	0.3		X		
SLA-T2	Distribution	66		4.16	YG-YG	8.4/11.17		X		
PUN-T1	Plant	66	-	2.4	DL-DL	0.333	0.6	X		
PUN-T1	Plant	66	-	2.4	DL-DL	0.333	0.6	X		
PUN-T1	Plant	66	-	2.4	DL-DL	0.333	0.6	X		
MRP-T1	Plant	66	-	2.4	YG-DL	1.5	1.6	X		
PAB-T3	Plant	69	-	4.16	DL-YG	3/PROV 4	2.9	X		
HCT-T1	Plant	66	-	2.4	YG-DL	3	3.0	X		
SCV-T1	Plant	66	-	2.4	YG-DL	2.5/3.3	3.6	X		
PHR-T1	Plant	33	-	2.4	YG-DL	5/6.7	5.2	X		
LBK-T1	Plant	66	-	2.4	YG-DL	7.5/10	6.0	X		
HOW-T3	SD	25		4.16	YG-YG	1	0.5	X		
SCT-T2	SD	25	-	12.5	YG-YG	3/4	1.0	X		
PJN-T1	Distribution	66	-	7.2	SP-SP	0.33	0.0			
SLA-T1	Distribution	66	-	4.16	YG-YG	10/13.3	12.5			
FPD-T1	Plant	12.5	-	2.4	YG-DL	0.250	0.3			
FPD-T1	Plant	12.5	-	2.4	YG-DL	0.250	0.3			
FPD-T1	Plant	12.5	-	2.4	YG-DL	0.250	0.3			
VIC-T2	Plant	12.5	-	2.4	YG-DL	0.6	0.4			
LWN-T1	Plant	25	-	0.6	Y-DL	0.250	0.5			
LWN-T1	Plant	25	-	0.6	Y-DL	0.250	0.5			
LWN-T1	Plant	25	-	0.6	Y-DL	0.250	0.5			
WBK-T1	Plant	12.5	-	2.4	YG-DL	0.333	0.6			
WBK-T1	Plant	12.5	-	2.4	YG-DL	0.333	0.6			

2011 Transformer Listing and Backup Available Units

LOC.	Type	Operating Voltage			Winding Config.	Capacity MVA	2011 Peak MVA	P1	P3	P4
WBK-T1	Plant	12.5	-	2.4	YG-DL	0.333	0.6			
PIT-T1	Plant	12.5	-	2.4	2 bushing	0.75	0.8			
PIT-T1	Plant	12.5	-	2.4	2 bushing	0.75	0.8			
PIT-T1	Plant	12.5	-	2.4	2 bushing	0.75	0.8			
TOP-T1	Plant	25	-	2.4	YG-DL	0.750	2.0			
TOP-T1	Plant	25	-	2.4	YG-DL	0.750	2.0			
TOP-T1	Plant	25	-	2.4	YG-DL	0.750	2.0			
RBH-T1	Plant	25	-	6.9	YG-DL	7/9.3	7.1			

2012 Transmission Line Rebuild

June 2011

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1.0 Transmission Line Rebuild Strategy

Transmission lines are the bulk transmitter of electricity providing service to customers. Transmission lines operate at higher voltages, either 66 kV or 138 kV and are often located across country away from road right of way.

In 2006, Newfoundland Power ("The Company") submitted its *Transmission Line Rebuild Strategy* outlining a 10-year plan to rebuild aging transmission lines. This plan prioritized the investment in rebuild projects based on physical condition, risk of failure, and potential customer impact in the event of a failure.

The *Transmission Line Rebuild Strategy* is regularly updated to ensure it reflects the latest reliability data, inspection information and condition assessments.

Appendix A contains the updated Transmission Line Rebuild Strategy Schedule.

2.0 Transmission Line Rebuild Projects Planned for 2012

In 2012, the Company plans to rebuild transmission line 21L and sections of 110L and 124L. Appendix B contains topographic views of each of the lines to be rebuilt. Appendix C contains photographs of the existing lines.

By 2012, all of these lines will be in excess of 48 years old. They have deteriorated poles, crossarms, hardware, and conductor. This makes the lines vulnerable to large scale damage when exposed to heavy wind, ice, and snow loading, thus increasing the risk of power outages. Inspections have identified evidence of decaying wood, worn hardware and damage to insulators.

2.1 Transmission Line 110L ($1,853,000)

The Bonavista Peninsula is supplied electricity by two separate transmission lines. The first is 123L, a 138 kV H-Frame transmission line running between Clarenville and Catalina. The second transmission circuit consists of a pair of 66 kV single pole lines, 110L and 111L. They run between Clarenville and Lockston and between Lockston and Catalina respectively.

The report *Bonavista Loop Transmission Planning*, filed with Newfoundland Power's 2006 Capital Budget Application, compared alternatives for addressing transmission line requirements on the Bonavista Peninsula. The analysis determined that the rebuilding of 110L and increasing conductor sizing is the least cost alternative to ensuring the continued provision of safe, reliable electrical service to the area.

110L was constructed in 1958 and is 79 kilometres in length. It helps service approximately 4,300 customers on the Bonavista Peninsula between Milton and Lockston. This line also connects the Company's Lockston hydro plant to the main electricity grid.

Sections of 110L have been upgraded with a total of 52 kilometres rebuilt. Based on the condition of the remaining sections of the line, it is recommended that 10.3 kilometres be rebuilt in 2012. The 10.3 kilometres being rebuilt include an 8.7 kilometre section near Lockston substation and a 1.6 kilometre section on the Trans Canada Highway in Clarenville. The 1.6 kilometre section along the Trans Canada Highway was delayed from 2010 as a result of Hurricane Igor.[1]

The conductor on 110L has been subjected to severe ice loading since its original installation and is damaged and deteriorated. The steel core and the aluminum strands are corroded, decreasing the physical strength and electrical capacity of the conductor. This deterioration is such that the line has been de-rated to about one-half of its original electrical current carrying capacity for safety reasons. Increasing the conductor size on the transmission line, as recommended in the *Bonavista Loop Transmission Planning* report, increases the length of time during the year (from 6 weeks to 38 weeks) when 110L can carry the Bonavista Peninsula load with transmission line 123L out of service.

The most recent 2011 inspection of 110L noted the following deficiencies on the 99 structures comprising the 10.3 kilometre section of line:

Table 1
110L Deficiencies

Deficiency Category	Number of Structures
Insulators	17
Deteriorated/Damaged Crossarms	9
Pole Deteriorated/Damaged	39

Based on the overall deteriorated conditions observed, it is recommended that this section of line be rebuilt to current CSA Severe Weather Loading Standards in 2012 at an estimated cost of $1,653,000.

2.2 Transmission Line 21L ($822,000)

21L is a 66kV 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 5.3 kilometres in length and was originally constructed in 1952. The line consists of 36 two and three-pole H-Frame structures utilizing 266.8 ACSR conductors, with a number of road crossing spans along the route.

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1 Attempts to reschedule the work on 110L following Hurricane Igor were hampered by increased electrical loading at that particular time of year thus preventing the project from being completed in 2010.

2 21L terminates at the intersection of Horse Chops Road and the Southern Shore Highway near Cape Broyle.

3 Horse Chops plant produces 42 GWH of electricity annually, or 9.8% of Newfoundland Power’s annual hydroelectric production

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. Most of the wooden poles are original vintage (59 years old) and have surpassed their normal life expectancy. Transmission line 21L also contains insulators manufactured by Canadian Ohio Brass (COB). These insulators are identified as deficient due to a history of premature failure caused by cement growth. As the cement expands, cracks in the porcelain insulators occur making them more susceptible to flashovers.

The poles, crossarms and crossbraces have had their strength compromised due to severe deterioration. Long span lengths combined with physical condition, make the line susceptible to damage should it become exposed to wind, ice or snow loading.

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
Insulators	25
Crossarms Deteriorated/Damaged	7
Crossbraces Deteriorated/Damaged	17
Pole Deteriorated/Damaged	11

Based on the advanced age and overall deteriorated condition observed, it is recommended this section of line be rebuilt to current CSA Severe Weather Loading Standards in 2012 at an estimated cost of $822,000.

2.3 Transmission Line 124L ($802,000)

124L is a 138 kV transmission line between Clarenville Substation and Gambo Substation. The line has a total length of 90 kilometres and is of H-frame wood pole construction. The line was originally built in 1964.

Due to the elevation and type of terrain in the White Hills area near Clarenville, the line in that location has had a history of problems. This area is prone to heavy ice loading and high winds. On several occasions, poles, crossarms and conductors have failed because of the severe weather conditions.

The transmission line was originally designed to withstand conductor ice loading of 12.7 mm (½”) of radial ice. Actual accumulation of 38 mm (1½”) has been measured on this line in the White Hills area. Loading has been severe enough that the conductor in this section of the line has been permanently stretched, thus increasing the sag of the conductor and decreasing the ground clearance. In this same area there are several extra long spans which present potential risks to the line’s structural integrity and of decreased ground clearance.[4]

During the period 2001 to 2005, a total of 16 kilometres of line were rebuilt between Clarenville and Thorburn Lake. These upgrades were necessary to correct several ground clearance issues and addressed line failure in the area caused by severe wind and ice loading. The only remaining original section of line in that particularly harsh location is the 5 kilometre section planned for 2012.

The most recent 2011 inspection of 124L noted the following deficiencies in the 23 structures comprising the 5 kilometre section planned for 2012:

Table 3
124L Deficiencies

Deficiency Category	**Number of Structures**
Insulators	7
Crossarms Deteriorated/Damaged	4
Crossbraces Deteriorated/Damaged	1
Structures Deteriorated/Damaged	9

Based on the advanced age and overall deteriorated conditions observed, it is recommended that a 5 kilometre section of line be rebuilt to current CSA Severe Weather Loading Standards in 2012 at an estimated cost of $802,000.

3.0 Concluding

In 2012, the Company will rebuild transmission line 21L and sections of 110L and 124L. These transmission lines range in age from 47 to 59 years old. Their structures have experienced deterioration of 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.

[4] This section of 124L has 2 particularly long spans, one that is 1,283 feet and another 1,502 feet in length.

Appendix A

Transmission Line Rebuild Strategy Schedule

Transmission Line Rebuilds 2012-2016 ($000)							
Line	**Year**	**Replacement Age (Years)**	**2012**	**2013**	**2014**	**2015**	**2016**
012L KBR-MUN	1950	63		350	300		
013L SJM-SLA	1962	52			605		
014L SLA-MUN	1950	66					220
015L SLA-MOL	1958	57				133	
018L GOU-GDL	1951	63			790		
021L 20L-HCP	1952	60	822				
030L RRD-KBR	1959	56				450	440
032L OXP-RRD	1959	56				353	
400L BBK-WHE	1967	48				1,940	2,000
057L BRB - HGR	1958	58					1,600
068L HGR-CAR	1951	63			881		
069L KEN-SLA	1951	64				830	
110L CLV-LOK	1958	54	1,853	2,868			
124L CLV-GAM	1964	48	802				
Average Age at Replacement	**Total**	**58**	**$3,477**	**$3,218**	**$2,576**	**$3,706**	**$4,260**

Transmission Line Rebuilds 2017-2023 ($000)									
Line	**Year**	**Replacement Age (Years)**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
041L CAR-HCT	1958	59	2,557						
049L HWD-CHA	1966	55					584		
057L BRB-HGR	1958	58	1,655						
100L SUN-CLV	1964	57					2,148	2,886	2,065
101L GFS-RBK	1957	61		1,850	4,023				
102L GAN-RBK	1958	61			2,012	6,444	4,296		
124L CLV-GAM	1964	58						3,634	3,441
146L GAN-GAM	1964	59							2,524
302L SPO-LAU	1959	58	1,508	3,602					
403L TAP-ROB	1960	62						890	
Average Age at Replacement	**Total**	**59**	**$5,720**	**$5,452**	**$6,035**	**$6,444**	**$7,028**	**$7,410**	**$8,030**

Appendix B

Topographic Maps of
Transmission Lines 110L, 21L and 124L

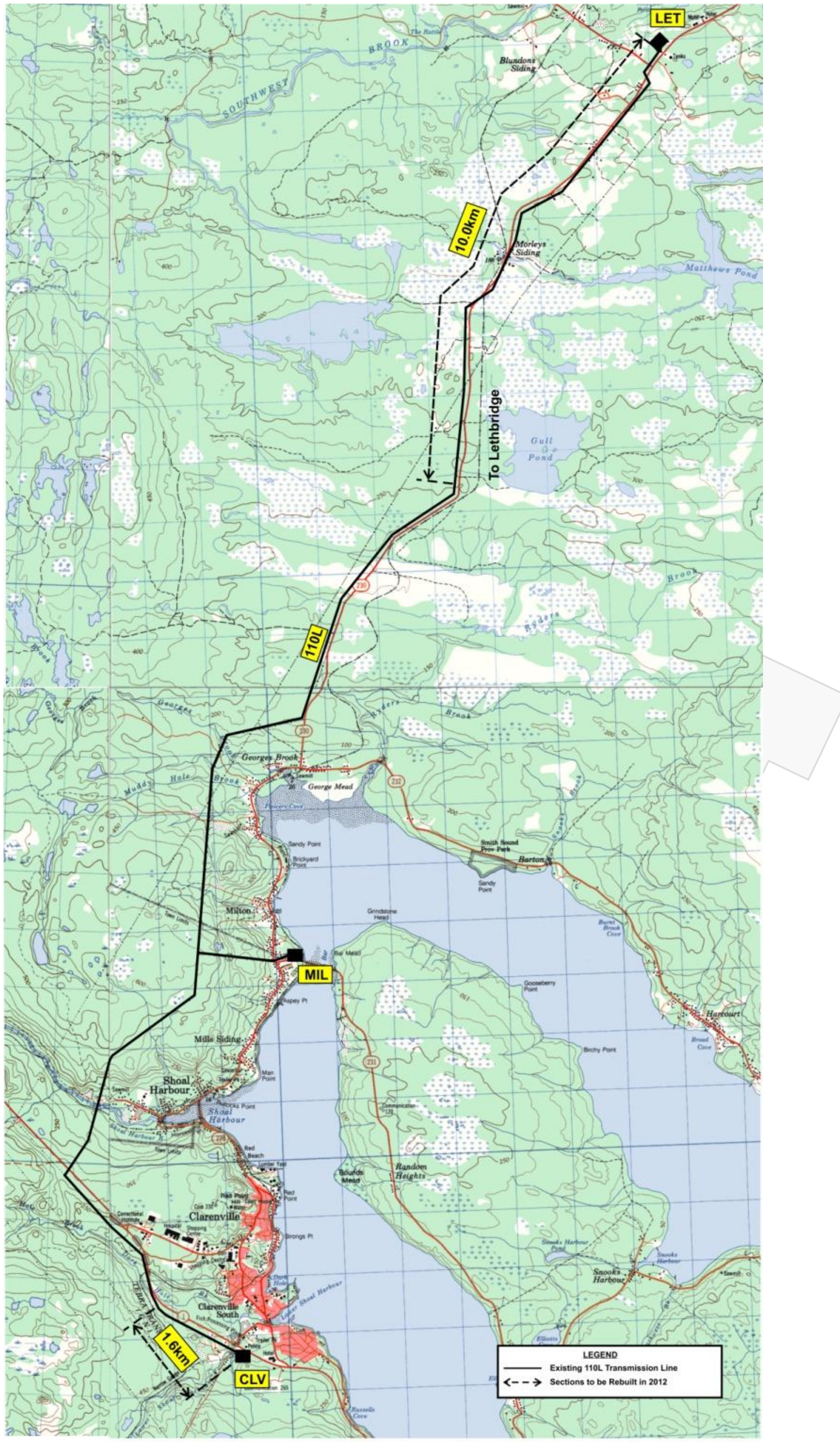

Figure 1 – Topographic Map 110L

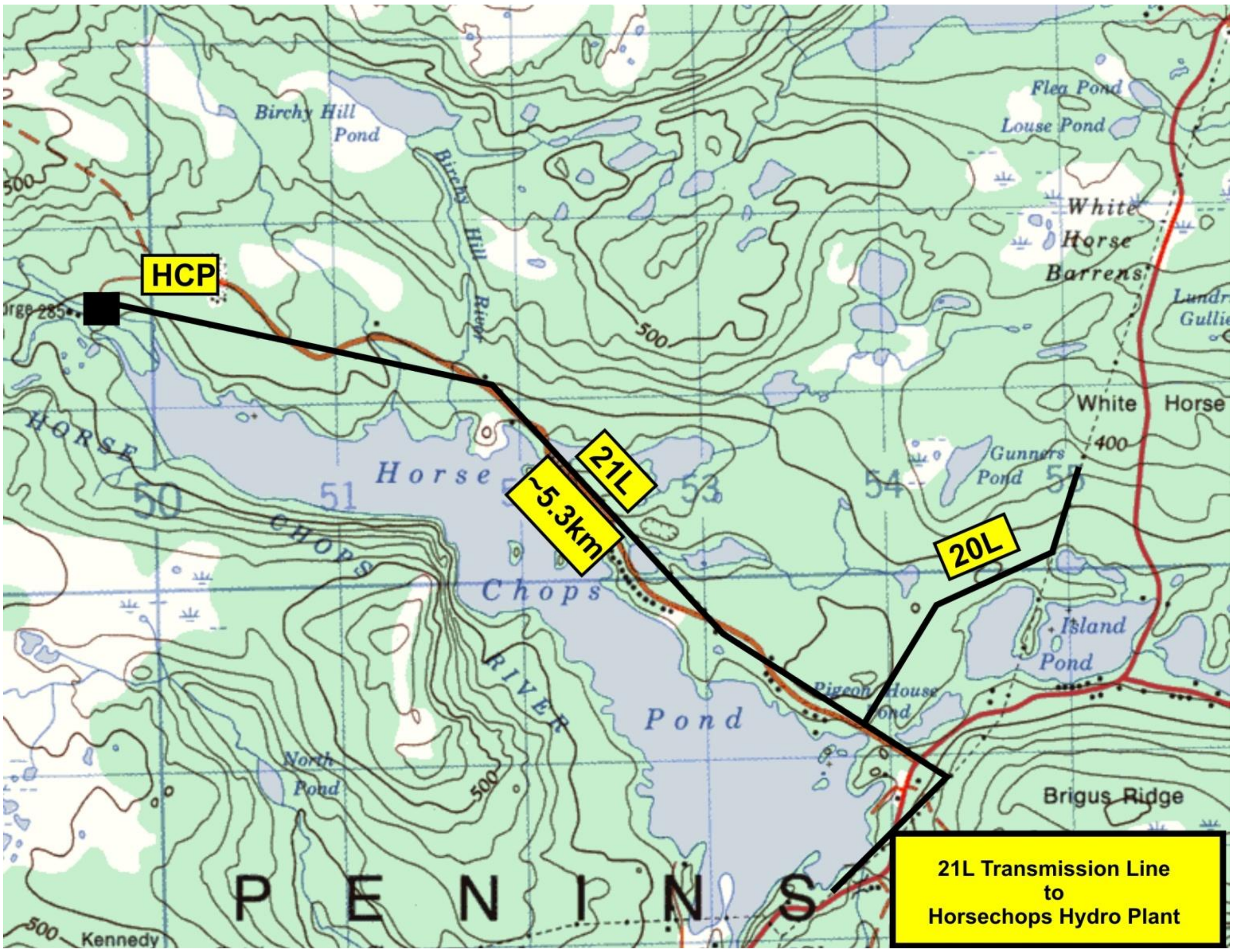

Figure 2 – Topographic Map 21L

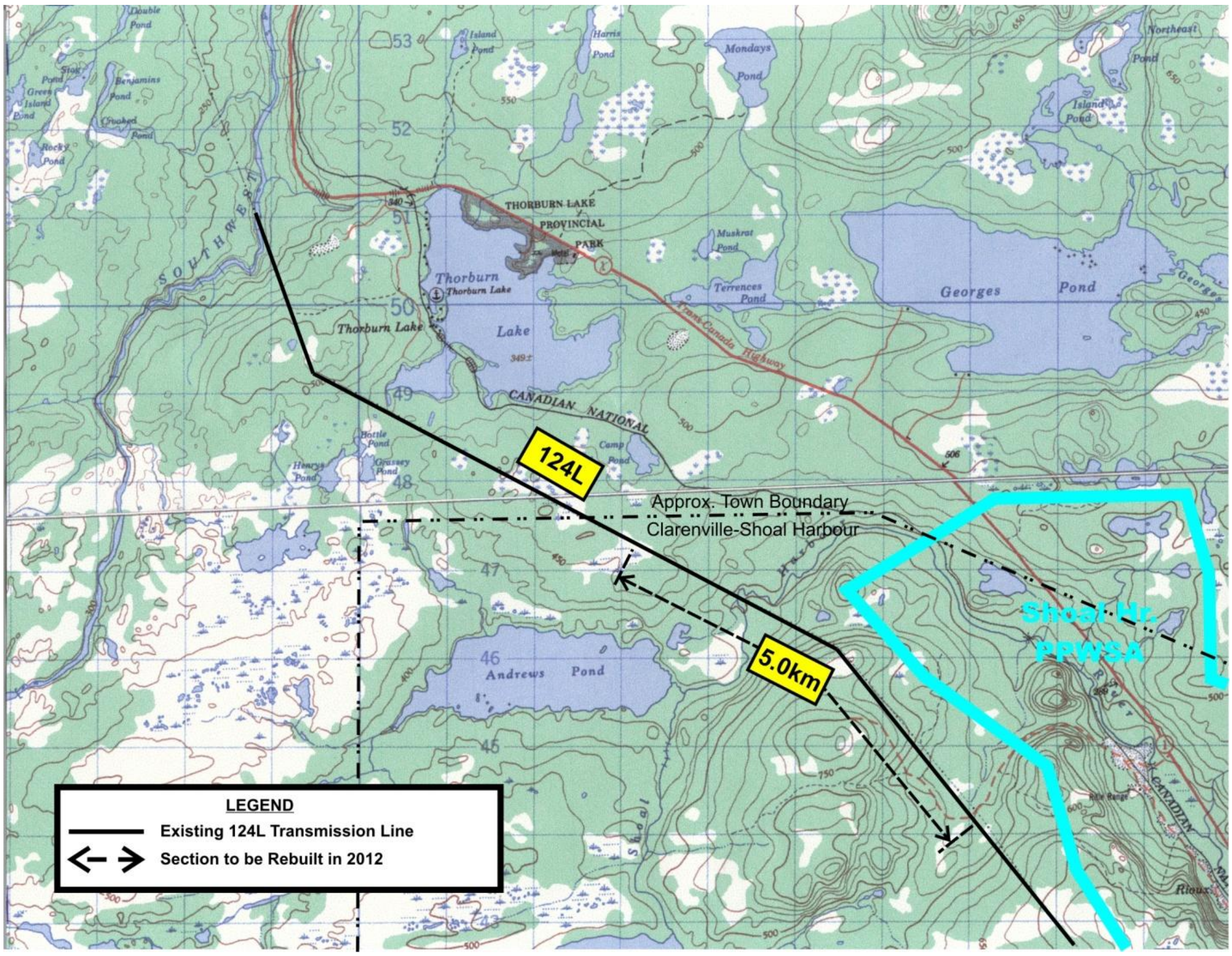

Figure 3 – Topographic Map 124L

Appendix C

Photographs of Transmission Lines 110L, 21L and 124L

Transmission Line 110L

Figure 1 – Split Crossarm 110L

Figure 2 – Deteriorated Pole on 110L

Figure 3 – Twisted Crossarm 110L

Figure 4 – Woodpecker Holes 110L

Figure 5 – Split Pole Top 110L

Figure 6 – Split Pole 110L

Transmission Line 21L

Figure 7 – Split Crossbrace 21L

Figure 8 – Pole requiring temporary support 21L

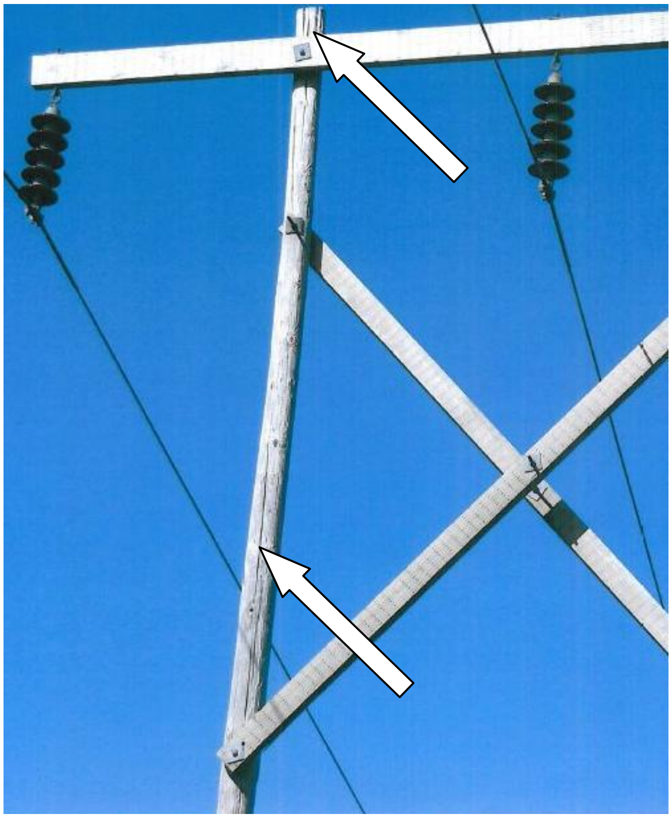

Figure 9 – Badly deteriorated pole 21L

Figure 10 – Woodpecker Hole 21L

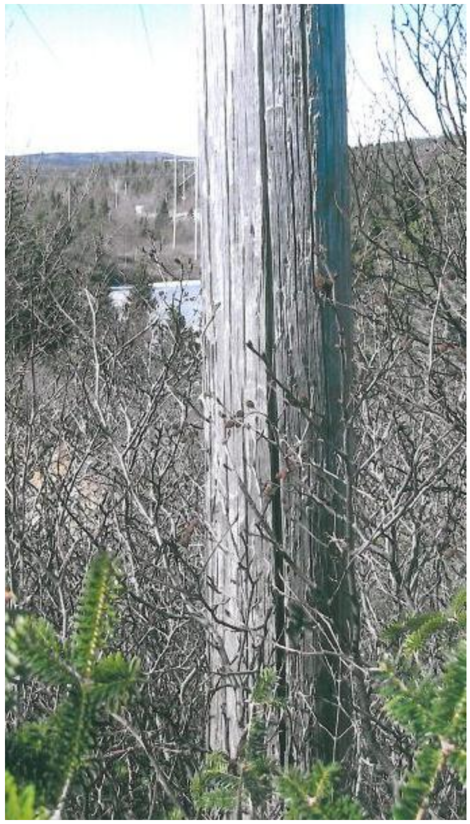

Figure 11 – Deteriorated pole 21L

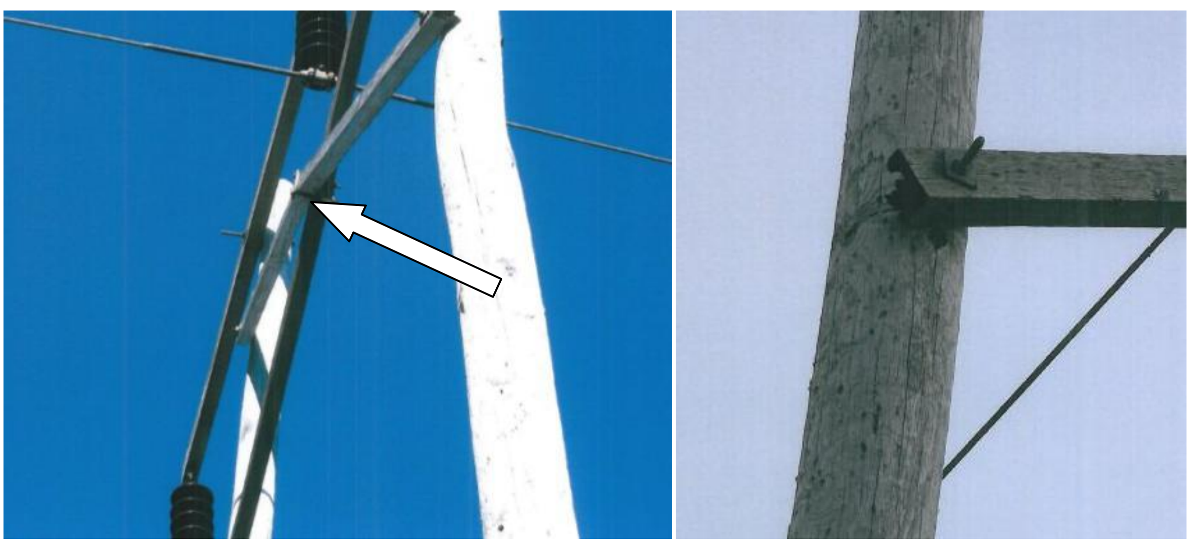

Figure 12 – Broken and Deteriorated Crossbraces 21L

Figure 13 – Deteriorated Pole and Crossarm 21L

Transmission Line 124L

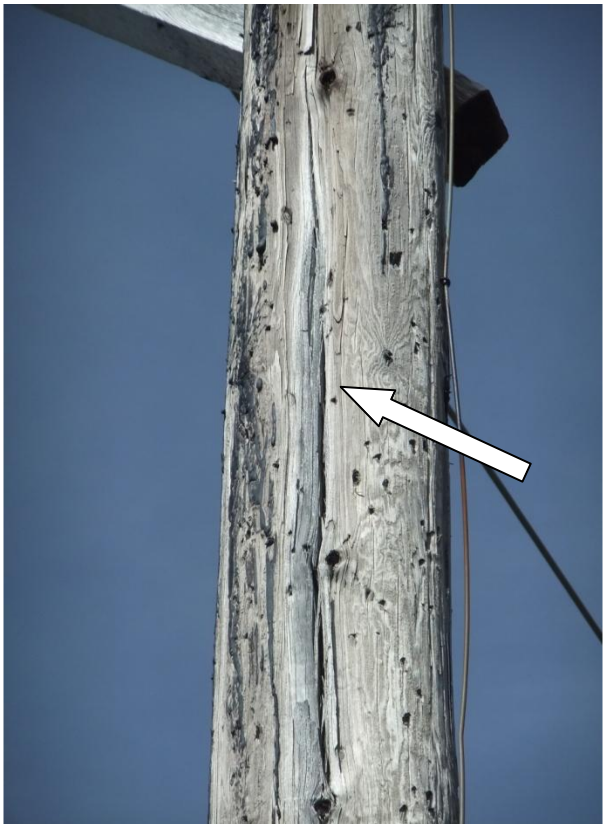

Figure 14 – Check in Pole 124L

Figure 15 – Woodpecker Holes 124L

Figure 16 – Armour Rod to Repair Wire Damage 124L

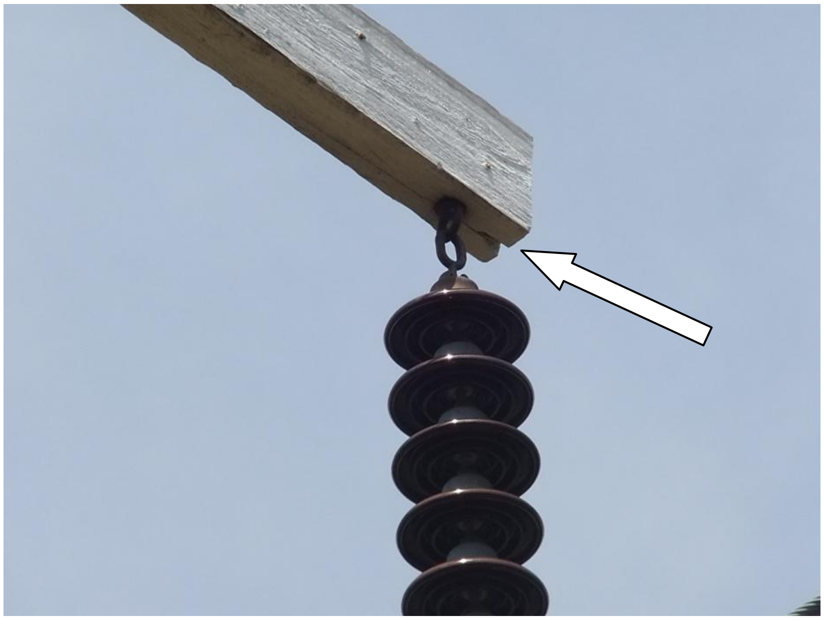

Figure 17 – Check in Crossarm 124L

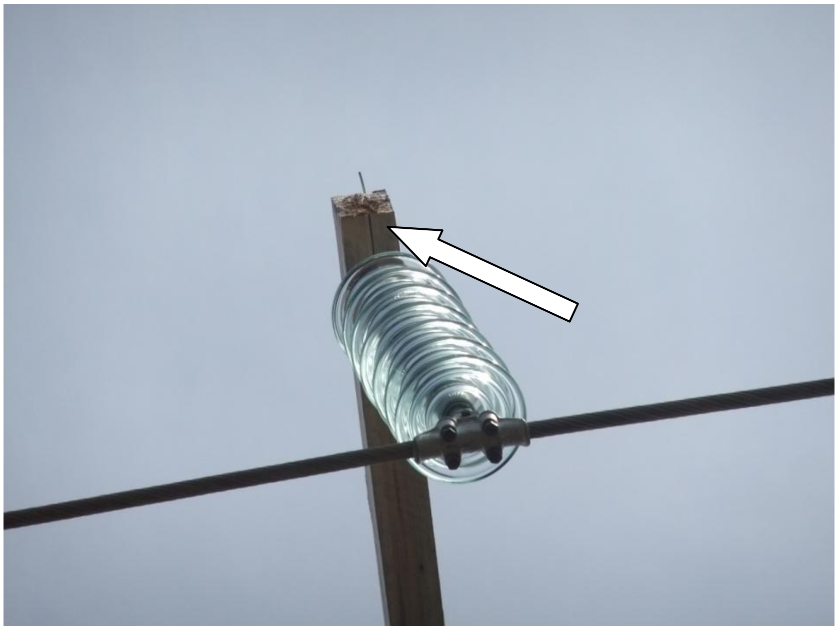

Figure 18 – Check in Crossarm 124L

Figure 19 – Location with Reduced Ground Clearance 124L

Distribution Reliability Initiative

June 2011

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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 2006 - 2010.

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: 2010

The 2009 Capital Budget Application proposed a three year project to improve reliability on the NWB-02 feeder.The work was detailed in 4*.1.1 Northwest Brook NWB-02 Feeder Study* filed with the 2009 Capital Budget Application. The project was presented as a three year project starting in 2009 with additional work planned for 2010 and 2011. In 2009 and 2010, the Company completed work project cost's of $455,000 and $334,000 respectively.

3.0 Distribution Reliability Initiative Projects: 2011

The 2011 Capital Budget Application included the third phase of the proposed work on NWB-02 as outlined in 4*.1.1 Northwest Brook NWB-02 Feeder Study* filed with the 2009 Capital Budget Application. The estimate for planned work is approximately $521,000.

4.0 Distribution Reliability Initiative Projects: 2012

The examination of the worst performing feeders, as listed in Appendix A and B, has determined no work is required under the Distribution Reliability Initiative at this time.

Appendix A

Distribution Reliability Data

Unscheduled Distribution Related Outages Five-Year Average 2006-2010 Sorted By Customer Minutes of Interruption				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
DUN - 01	2,202	499,956	2.32	8.77
GLV - 02	3,451	464,311	2.66	5.98
DOY - 01	4,259	446,376	2.67	4.66
CHA - 03	4,662	395,174	2.21	3.12
NWB - 02	2,425	375,924	2.32	6.00
BOT - 01	3,406	338,281	2.08	3.44
CAB - 01	3,589	330,722	2.98	4.57
MIL - 02	4,242	312,464	3.06	3.76
RRD - 09	2,457	310,208	1.72	3.62
HOL - 01	6,868	309,121	3.38	2.54
DLK - 03	2,005	289,714	1.73	4.18
CHA - 02	3,770	285,024	2.20	2.77
ROB - 01	1,795	269,340	1.65	4.11
KEL - 01	2,378	269,226	1.27	2.40
SUM - 01	1,527	261,362	0.85	2.43
Company Average	**871**	**70,294**	**1.00**	**1.43**

Unscheduled Distribution Related Outages Five-Year Average 2006-2010 Sorted By Distribution SAIFI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
HOL - 01	6,868	309,121	3.38	2.54
GDL - 01	1,725	98,250	3.13	2.97
MIL - 02	4,242	312,464	3.06	3.76
CAB - 01	3,589	330,722	2.98	4.57
GLV - 01	2,937	163,410	2.79	2.59
MMT - 01	1,283	84,033	2.79	3.04
GOU - 01	3,518	107,855	2.70	1.38
GIL - 01	2,622	225,934	2.67	3.83
DOY - 01	4,259	446,376	2.67	4.66
GLV - 02	3,451	464,311	2.66	5.98
VIR - 02	968	57,446	2.64	2.62
GFS - 02	3,516	234,843	2.45	2.73
HWD - 07	6,052	259,228	2.45	1.75
HOL - 02	1,174	201,603	2.38	6.82
NWB - 02	2,425	375,924	2.32	6.00
Company Average	**871**	**70,294**	**1.00**	**1.43**

Unscheduled Distribution Related Outages Five-Year Average 2006-2010 Sorted By Distribution SAIDI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
DUN - 01	2,202	499,956	2.32	8.77
SCT - 02	525	100,754	2.14	6.85
HOL - 02	1,174	201,603	2.38	6.82
BUC - 02	232	58,454	1.47	6.17
NWB - 02	2,425	375,924	2.32	6.00
GLV - 02	3,451	464,311	2.66	5.98
SCT - 01	1,225	204,995	1.85	5.17
COL - 02	529	95,229	1.62	4.85
MKS - 01	715	133,260	1.54	4.79
DOY - 01	4,259	446,376	2.67	4.66
CAB - 01	3,589	330,722	2.98	4.57
GBY - 03	1,630	199,339	2.15	4.37
DLK - 03	2,005	289,714	1.73	4.18
SPO - 03	765	122,188	1.55	4.14
ROB - 01	1,795	269,340	1.65	4.11
Company Average	**871**	**70,294**	**1.00**	**1.43**

Appendix B

Worst Performing Feeders
Summary of Data Analysis

Worst Performing Feeders **Summary of Data Analysis**	
Feeder	**Comments**
GLV-02	A substantial amount of work was completed on this feeder since 2006. Reliability has improved considerably. High customer minutes in 2010 were due to problems accessing a line through Terra Nova Park. No further work is required at this time.
DUN-01	Reliability statistics were poor in both 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 but improved greatly in 2010. No work is proposed for 2011 or 2012.
BOT-01	A substantial amount of work was completed on this feeder since 2006. Reliability has improved considerably. Reliability numbers in 2010 were poor due to damages caused by a vehicle accident. No further work is required at this time.
NWB-02	Work has been carried out in 2009 and 2010 on this feeder. Additional work is proposed for 2011. Reliability has improved and no further work is required at this time.
GLV-01	Poor overall reliability is due to several insulator failures in 2007. No work is required at this time.
HOL-02	Poor overall reliability is due to a storm in March 2008. No work is required at this time.
MMT-01	Poor overall reliability is due to tree related events in 2009 and 2010. No work is required at this time.
CAB-01	Poor statistics in 2008 were due to a broken cutout and a broken insulator. No work is required at this time.
DOY-01	Overall reliability statistics on this feeder have been good. The poor average statistics are driven by a single weather related issue in each of 2009 and 2010. No work is required at this time.
MIL-02	The MIL-02 feeder 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.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
GOU-01	Overall reliability statistics on this feeder have been good. The poor average statistics were caused by isolated events, a pothead failure in 2009 and a single incidence of a failed insulator in 2010.
BUC-02	Reliability problems in 2008 were due to three insulator failures in 2008. Insulators were replaced in 2009. 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-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.
GDL-01	Reliability statistics were driven by isolated weather related events in 2007 and 2008. No work is required at this time.
HOL-01	Reliability problems were due to a single event, a broken cutout in January 2007. No work is required at this time.
MKS-01	Reliability statistics were driven by a single event, a broken cutout in March 2008. No work is required at this time.
RRD-09	Reliability problems were due to 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.
GBY–03	Reliability statistics were driven by isolated weather related events in 2009 and 2010. 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.

Worst Performing Feeders Summary of Data Analysis	
Feeder	**Comments**
SPO-03	Reliability statistics were driven by a single weather related event in 2006 and a broken insulator in December 2008. 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.
ROB-01	Reliability statistics were driven by trees and lightning in 2006 and 2007 . No work is required at this time.
KEL-01	Reliability statistics were driven by a single weather related event in 2006. No work is required at this time.
SUM-01	Reliability statistics were driven by a single lightning event in 2008. No work is required at this time.
VIR-02	Reliability problems were driven by two conductor related events in 2008. No work is required at this time.
GFS-02	Reliability statistics were driven by a single tree related event in October 2009. No work is required at this time.
HWD-07	Reliability statistics were driven by a sleet storm in 2008 and a faulty cutout in 2010. No work is required at this time.

Feeder Additions for Load Growth

June 2011

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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 can occur at the substation level, on equipment such as transformers, breakers and reclosers, or on specific sections of distribution line conductor.

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 generally low cost solutions and are completed as normal operating procedures. However, in some cases it becomes necessary to complete upgrades to the distribution system to either increase capacity or alter system configuration in order to complete a load transfer.

This report identifies two overload conditions proposed to be addressed as part of the 2012 Capital Budget. One situation will be addressed by increasing capacity on the overloaded section of conductor on the distribution feeder. The second situation will be addressed by constructing a new distribution feeder in order to transfer some load from the overloaded feeder.

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 Overloaded Conductor

2.1 General

An overloaded section of conductor on a distribution line is at risk of failure. Failures are caused by over heating of the conductor as the current exceeds the conductor's capacity ratings. As a result, the conductor will have excessive sag, which may result in the conductor coming into contact with other conductors or ultimately, the conductor breaking, causing a fault and subsequent power interruption.

An analysis of distribution feeders in the Northeast Avalon area was completed using a distribution feeder computer modelling application to identify sections of feeders that may be overloaded. Overload conditions that were identified using the computer modelling application were followed up with field visits to ensure the accuracy of information. Where necessary, load measurements were taken to verify the results of the computer modeling. The analysis used conductor capacity ratings based on Newfoundland Power's Distribution Planning Guidelines. These ratings are shown in Appendix A.

[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.

2.2 Alternatives for Overloaded Conductor

There are several alternatives for dealing with a conductor overload condition. Each alternative may not be applicable to every overload condition. They are dependent on factors such as; available tie points to surrounding feeders, the amount of conductor overload, physical limitations of line construction, or the effect on offloading strategies for surrounding feeders.

Alternative #1 – Feeder Balancing
In some cases, conductor may be overloaded on only one phase of a three phase line. In this situation, it may be possible to remove the overload condition by balancing the downstream loads through load transfers from the highly loaded phase to one of the more lightly loaded phases. This is only applicable in situations where all three phases are not overloaded.

Alternative #2 – Load Transfer
On a looped system, if a tie point exists downstream of the overload condition, it may be possible to transfer a portion of load to an adjacent feeder. However, consideration must be given to the loading on the adjacent feeder to ensure a new overload condition is not created. Also, the effect of the offloading strategy for other surrounding feeders must also be considered.

Alternative #3 – Upgrade Conductor
The overload condition can be eliminated by increasing the conductor size on the overloaded section. This will improve load transfer capabilities for the feeder, and will not add to the total load or cause an overload condition on an adjacent feeder.

Alternative #4 – New Feeder
In cases were the feeder conductor leaving a substation is overloaded, and none of the above alternatives can be used to resolve the overload condition, then the addition of a new feeder from the substation is required to transfer a portion of load from the overloaded conductor.

Every alternative was considered for each conductor overload condition identified in this report. For each case, the most cost effective alternative that would maintain the appropriate level of system flexibility was selected.

2.3 Overloaded Feeders

A total of 2 feeders with sections of overloaded conductor are identified in this report. Each overloaded section identified was evaluated using all 4 available alternatives identified in section 2.2.

Kelligrews Substation Feeder KEL-01 ($318,000)
The main trunk section of this feeder, leaving the substation, is forecasted to overload in 2012. The conductor on the main trunk section of this feeder is 477 ASC and is rated for 590 amps per phase. The balanced 2012 forecasted peak loads on each of the phases on this section are 619 amps per phase.

This forecasted overload condition can be attributed to growth on this feeder in the Kelligrews area of the Town of Conception Bay South, including new phases of existing subdivisions on Tilley's Road and Red Bridge Road. Continued growth is expected as development continues in this area, including the addition of a new commercial development on Legion Road and new residential subdivision developments.

Feeder balancing is not an option for this overload condition, due to the fact that the forecasted combined peak currents exceed the total capacity of the three phase conductors. Also, due to the routing and available capacity of adjacent feeders there is no existing tie point that would allow load to be transferred. Therefore, the least cost option for this overload condition is to construct a new distribution feeder with 477 ASC conductor from KEL substation to Legion Road.[2]

Pulpit Rock Substation Feeder PUL-02 ($538,000)
A 6.8 km section of this feeder is overloaded. The overloaded section is from Pulpit Rock Substation to Windgap Road in the Town of Flatrock.[3] The conductor in this section is #4/0 AASC and is rated for 356 amps per phase. The balanced 2012 forecasted peak loads on each of the phases on this section are 374 amps per phase.

This overload condition can be attributed to the residential growth in the towns of Flatrock and Pouch Cove. Continued growth is expected as development in this area should increase with the completion of the Torbay Bypass Road.

Feeder balancing is not an option for this overload condition, due to the fact that the combined forecasted peak currents exceed the total capacity of the three phase conductors. There is a tie point to Pulpit Rock substation through PUL-03 feeder. However, due to the routing of each feeder, the tie point does not allow the for the offloading of a portion of PUL-02 feeder . The tie point only allows for backup of PUL-02 feeder in the event of an unplanned outage or planned maintanace. Therefore, it is recommended that this section be upgraded to 477 ASC conductor, rated at 590 amps per phase.

3.0 Relocate SJM-08

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 kV.

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

2 There is an associated Substations project to terminate this feeder at the Kelligrews substation at an estimated cost of $148,000.

3 Single Line Diagram for feeder PUL-02 is included in Appendix B.

system supplies the St. John's downtown area, which has a dense population of large commercial customers.

Newfoundland Power has completed upgrades to the underground system over the past decade.[4] 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. System planning for the underground infrastructure must also consider forecast load growth as the existing SJM distribution system has limited capacity to accommodate new development in the downtown area. .

Newfoundland Power submitted a planning study with the 2011 Capital Budget Application.[5] The purpose of this planning study was to develop a five year plan to address the remaining deteriorated underground infrastructure concerns as well as provide adequate capacity to supply new development in the St. John's downtown area.[6]

The 2012 project involves relocation of the section of SJM-08 feeder between Hutchings Street and Beck's Cove as recommended in the planning study. 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 cable, more commonly known as XLPE cables, in the new duct banks. With the relocation of SJM-08 and the future relocation of SJM-07, the feeders will be reconfigured to allow the removal of the oil switches in manhole 7 and manhole 8.

The estimated cost of this project is $535,000.

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4 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 foundations has been undertaken in coordination with the Harbour Interceptor Sewer Project. In 2010, SJM-03 feeder was relocated to the new duct bank to improve the capability of the underground system to fully serve customers in the event of a single cable failure on the underground trunk.

5 The *St. John's Main Planning Study* was included as Attachment A to the report ***4.2*** *Feeder Additions for Load Growth* included in the 2011 Capital Budget Application.

6 In 2011, five feeders will be removed from the duct bank crossing under Waterford River, and reconfigured into four feeders that cross over the river as recommended in the planning study. 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.

4.0 Project Cost

The following are the estimated project costs for 2012.

Table 1
Project Costs

Description	Cost Estimate
Construct new KEL-03 Feeder	$318,000
Upgrade 6.8 km on PUL-02	$538,000
Relocate SJM-08	$535,000
Total	**$1,391,000**

5.0 Recommendations

Based on the information provided in this report, the capital expenditures recommended for 2012 include:

- Construct new KEL-03 feeder with 477 ASC conductor from Kelligrews Substation to Legion Road at an estimated cost of $318,000.
- Upgrade 6.8 km on PUL-02 to 477 ASC conductor at an estimated cost of $538,000.
- Relocate 1.1 km on SJM-08 to the new duct bank between Hutchings Street and Beck's Cove at an estimated cost of $535,000.

The construction of a new feeder from KEL Substation and upgrades for PUL-02 feeder will alleviate the conductor overload condition identified in this report. The relocation of SJM-08 to the new duct bank will improve the capability of the underground system to fully serve customers in the event of a single cable failure on the underground trunk and in the future allow the removal of the underground oil switches in manhole 7 and manhole 8 following the relocation of SJM-07 to the new duct bank.

Appendix A

Distribution Planning Guidelines
Conductor Ampacity Ratings

Aerial Conductor Capacity Ratings						
Size and Type	Continuous Winter Rating[7]	Continuous Summer Rating[8]	Planning Ratings CLPU Factor[9] = 2.0 Sectionalizing Factor[10] = 1.33			
	Amps	Amps	Amps	MVA		
				4.16 kV	12.5 kV	25.0 kV
1/0 AASC	303	249	228	1.6	4.9	9.8
4/0 AASC	474	390	356	2.6	7.7	15.4
477 ASC	785	646	590	4.2	12.7	25.5
#2 ACSR	224	184	168	1.2	3.6	7.3
2/0 ACSR	353	290	265	1.9	5.7	11.4
266 ACSR	551	454	414	3.0	8.9	17.9
397 ACSR	712	587	535	3.9	11.6	23.1
#4 Copper	203	166	153	1.1	3.3	6.6
1/0 Copper	376	309	283	2.0	6.1	12.2
2/0 Copper	437	359	329	2.4	7.1	14.2

7 The winter rating is based on ambient conditions of 0ºC and 2ft/s wind speed.

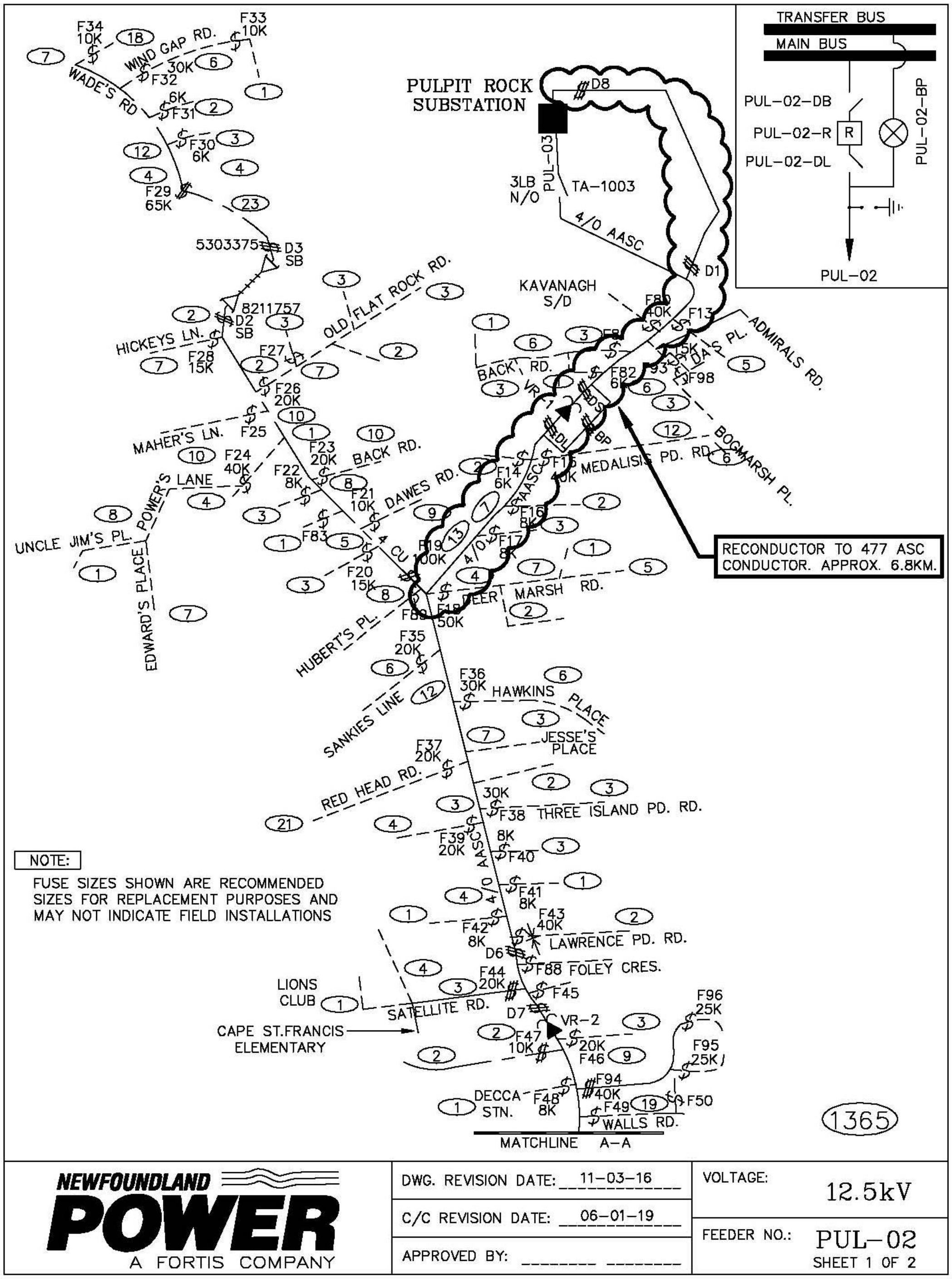
8 The summer rating is based on ambient conditions of 25ºC and 2ft/s wind speed.

9 Cold Load Pick Up: Occurs when power is restored after an extended outage. On feeders with electric heat, the load on the feeder can be 2.0 times as high as the normal winter peak load. This is the result of all electric heat coming on at once when power is restored. The duration of CLPU is typically between 20 minutes and 1 hour.

10 Sectionalizing factor: Two-stage sectionalizing is used during CLPU conditions to increase the Planning Rating of aerial conductors. Restoring power to one section of the feeder at a time reduces the overall effect of CLPU. The sectionalizing factor is the fraction of the load that is restored in the first stage multiplied by the CLPU factor. The optimal portion of the total load on a feeder that is restored in the first stage is 0.66, resulting in a sectionalizing factor of 0.66 x 2.0 = 1.33.

Appendix B

PUL-02 Feeder Single Line Diagram


TRANSFER BUS
MAIN BUS
PUL-02-DB
PUL-02-R
PUL-02-DL
PUL-02-BP
PUL-02
PULPIT ROCK SUBSTATION
PUL-03
3LB N/O
TA-1003
4/0 AASC
KAVANAGH S/D
ADMIRALS RD.
BACK RD.
BOGMARSH PL.
MEDALISIS PD. RD.
RECONDUCTOR TO 477 ASC CONDUCTOR. APPROX. 6.8KM.
MARSH RD.
DAWES RD.
HUBERT'S PL.
WIND GAP RD.
WADE'S RD
HICKEYS LN.
OLD FLAT ROCK RD.
MAHER'S LN.
POWER'S LANE
UNCLE JIM'S PL.
EDWARD'S PLACE
HAWKINS PLACE
SANKIES LINE
JESSE'S PLACE
RED HEAD RD.
THREE ISLAND PD. RD.
NOTE:
FUSE SIZES SHOWN ARE RECOMMENDED SIZES FOR REPLACEMENT PURPOSES AND MAY NOT INDICATE FIELD INSTALLATIONS
LAWRENCE PD. RD.
FOLEY CRES.
LIONS CLUB
SATELLITE RD.
CAPE ST.FRANCIS ELEMENTARY
DECCA STN.
WALLS RD.
VR-2
1365
MATCHLINE A-A
NEWFOUNDLAND POWER
A FORTIS COMPANY
DWG. REVISION DATE: 11-03-16
C/C REVISION DATE: 06-01-19
APPROVED BY:
VOLTAGE: 12.5kV
FEEDER NO.: PUL-02
SHEET 1 OF 2

Trunk Feeders

June 2011

Prepared by:

Kingsley Gifford, B.Eng.

Approved by:

Bob Daye, P.Eng

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NEWFOUNDLAND POWER
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1.0 Introduction

The Trunk Feeders project involves replacement of deteriorated distribution structures and electrical equipment. In particular, a submarine cable will be replaced in the Charlottetown area and an underground cable will be replaced in the Little Port Harmon area. Both cables have reached the end of their service lives.

This project does not qualify for the Distribution Reliability Initiative project, since it is not based on poor feeder reliability. Additionally, it does not qualify for the Rebuild Distribution Lines project. The replacement of various line components was not based on preventive maintenance inspections or reviews. This is a standalone one year project stemming from deterioration of essential assets.

The 2012 Trunk Feeders project consists of:

1. Replacement of the submarine cable feeding the community of Charlottetown in Terra Nova Park with an aerial distribution line from Glovertown Substation. ($723,000)

2. Replacement of approximately 3.5 km of underground cable running under the Stephenville Airport runway feeding the area known as Little Port Harmon with an aerial distribution line and a small section of underground cable west of the airport runway. ($125,000)

Due to the condition of existing equipment and emergency restoration complications, a proactive replacement of cables in these areas is required to continue providing safe and reliable service.

2.0 Charlottetown Submarine Cable

2.1 Description of Existing System

The community of Charlottetown is located in Bonavista Bay. Newfoundland Power ("the Company") services approximately 160 customers in the area with a peak load of 0.43 MVA. Customers are provided electricity via distribution feeder LET-01 originating from Lethbridge ("LET") substation. A trunk section of the feeder is a submarine cable[1] laid across Clode Sound connecting Charlottetown and Bunyan's Cove. A step-down transformer is located at Bunyan's Cove to reduce voltage from 14.4 kV to 7.2 kV for the submarine cable. Figure 1 illustrates the location of the cable.

[1] The submarine cable is PVC insulated, shielded PVC jacketed, with a copper conductor and aluminum alloy wire armour.

Figure 1: LET-01 Distribution Feeder

The submarine cable is approximately 3 km in length and is laid directly on the sea floor. It was originally installed in 1964 and has reached the end of its expected service life[2]. The cable is two conductor single phase and is not grounded.

Originally, LET-01 was a delta configured distribution feeder with no neutral conductor. This warranted the two conductor ungrounded submarine cable. The feeder was subsequently reconfigured as a wye-grounded system with a neutral conductor. To accommodate the new configuration, two back to back transformers were installed near the cable landing site in Charlottetown. This allowed the submarine cable conductors to remain ungrounded. This is not an ideal configuration. If either conductor experiences a ground fault additional stress will be placed on the other cable accelerating failure.

In the event of a cable failure, the Company will install a portable generator in Charlottetown. The submarine cable will be repaired or an alternate aerial feed constructed. The Company's emergency generators, the 7.5 MVA Mobile Gas Turbine ("MGT") or the 2.5 MVA Mobile Diesel Generator ("MD3"), are both too large for the 0.43 MVA load at Charlottetown. Therefore, an appropriately sized generator must be rented.

Installing a three phase generator on a single phase distribution line requires significant reconfiguration. Redistributing load to simulate three phase balanced load involves installation of temporary sections of line. While this contingency is technically feasible, it is far more complicated than installing portable generation on a three phase distribution system. These complications would add considerable delay in restoring electricity to customers.

[2] Newfoundland Power has discussed the existing cable specifications with cable manufacturers and submarine cable consultants. They agree that cables of this type have a typical lifetime of 40 years.

Due to the age of the cable and emergency restoration complications, the Company has reviewed other methods of providing electrical service to Charlottetown.

2.2 Development of Alternatives

Three alternatives have been developed to provide electricity to Charlottetown.

2.2.1 Alternative #1

Install a new submarine cable from Bunyan's Cove to Charlottetown across Clode Sound, adjacent to the existing cable route as shown in Figure 2.

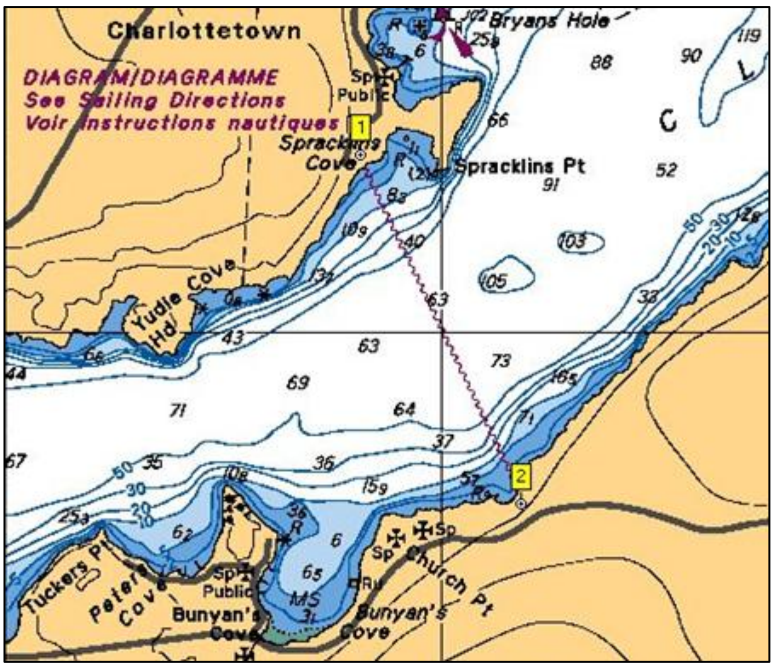

Figure 2: Nautical chart showing cable crossing

2.2.2 Alternative #2

Connect Charlottetown to Glovertown Substation ("GLV") via distribution feeder GLV-02. The feeder would extend through Parks Canada electrical distribution right-of-way (2.2 km). It would then attach to Bell Aliant owned communication line (11 km) to Charlottetown. The locations of these points are shown in Figure 3.

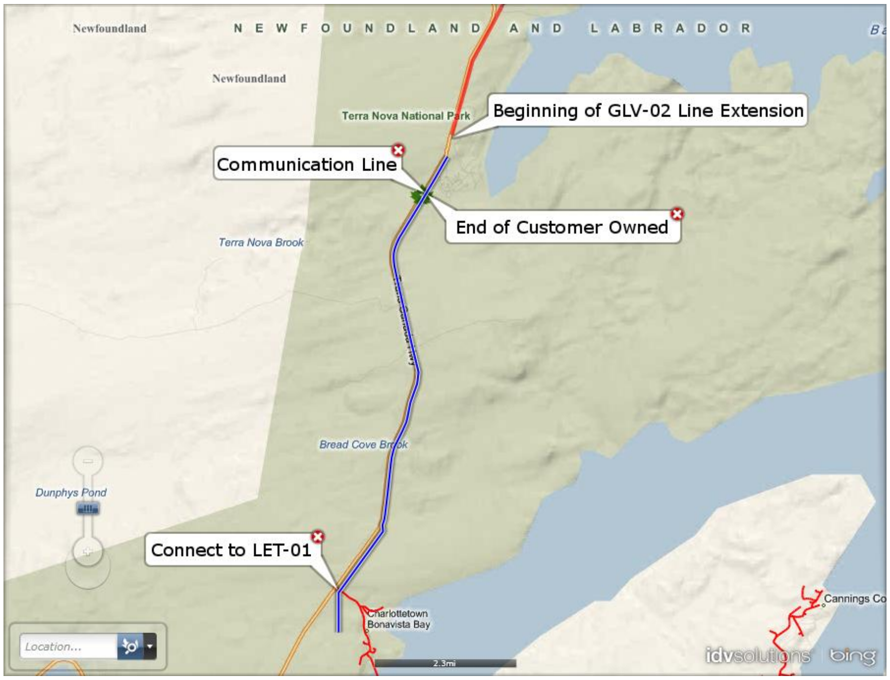

Figure 3: Map showing proposed route of Alternative 2

2.2.3 Alternative #3

Connect Charlottetown to Terra Nova Substation ("TNS") via distribution feeder TNS-01. The feeder would extend along the Terra Nova access road to Terra Nova Park boundary (10 km). A new right-of-way would have to be established through Terra Nova Park to the Bell Aliant owned communication line (3.5 km). TNS-01 would then attach to the communication line and continue to Charlottetown (8 km). The locations of these points are shown in Figure 4.

Figure 4: Map showing proposed route of Alternative 3

2.3 Evaluation of Alternatives

Table 1 shows the capital costs estimates for the three alternatives.

Table 1
Capital Cost Estimate of Alternatives

Alternative	Description	Amount
Alternative #1[3]	Install new submarine cable from Bunyan's Cove to Charlottetown.	$1,188,000
Alternative #2	Extend GLV-02 distribution feeder to Charlottetown.	$723,000
Alternative #3	Extend TNS-01 distribution feeder to Charlottetown.	$1,017,000

There are only two submarine cables in the Company's distribution system. In addition to the Charlottetown submarine cable, there is a 5 km submarine cable supplying Bell Island in Conception Bay. The Company has limited expertise in submarine cable installation or repair and depends on external contractors for these services. The installation of submarine cables is subject to various federal and provincial regulations.[4] In addition, an environmental assessment would be required to replace the cable indicated in Alternative #1.

The distribution feeder extension proposed in Alternative #2 will utilize existing right-of-ways from Glovertown to Charlottetown. In Parks Canada's compound, an existing distribution line will be upgraded to current Newfoundland Power standards to facilitate the extension. The communications line from Parks Canada's compound to Charlottetown is constructed to joint use standards. However, some mid-span poles and guying would be required to allow attachment of distribution hardware and conductor. An environmental assessment has been submitted to Parks Canada's for attaching to the existing communications line running through Terra Nova Park.

The distribution feeder extension proposed in Alternative #3 would require 13.5 km of new right-of-way be established, including 3.5 km through Terra Nova Park. The establishment of this right-of-way within park boundaries and attaching to the existing communications line would require an environmental assessment.

Alternative #2 is the least cost option to provide Charlottetown with safe and reliable service.

3 Budgetary estimates were sought from two providers of submarine cable solutions. The cost estimate for Alternative #1 is the lower of the two estimates.

4 Approvals will be required from Transport Canada for Navigation Waters Protection, Fisheries and Oceans Canada for Habitat Protection, Department of Environment and Conservation for Water Resources.

3.0 Port Harmon Underground Cable

3.1 Description of Existing System

Located in the town of Stephenville, Little Port Harmon is a small craft harbour used by fishing enterprises and pleasure boaters. The Company services approximately 30 customers in the area with a peak load of 0.08 MVA. Customers are provided electricity via distribution feeder HAR-02 originating from Harmon ("HAR") substation. Little Port Harmon is supplied by a three conductor underground cable at 12.5 kV. The cable runs approximately 3.5 km from the substation under the Stephenville Airport runway. The approximate route of the cable is shown in red in Figure 5.

Figure 5: HAR-02 underground cable

The underground cable was installed by the United States Air Force during the construction of the Ernest Harmon Air Force Base in the early 1940's. It is approximately 70 years old and has passed the end of its expected service life[5]. One phase of the original three phase cable faulted in 1985 and is no longer in service.

Similar concerns to those with the Charlottetown submarine cable exist in the event of cable failure. The small single phase load at Port Harmon cannot be supplied from either of the Company's large three phase portable generators. The contingency plan involves renting generation while an aerial distribution feeder is constructed on an alternate route. Installation of support structures will require approval from Transport Canada due to the proximity of the Stephenville Airport. Obtaining these approvals may cause delays in emergency power restoration.

[5] The expected service life of this type of cable is 50 years.

Due to the age of the cable and emergency restoration complications, the Company has reviewed other methods of providing electrical service to the Little Port Harmon area.

3.2 Development of Alternatives

Three alternatives have been developed to provide alternate means of supplying electricity service to Little Port Harmon.

3.2.1 Alternative #1
Install a new single phase underground cable from HAR substation to Little Port Harmon along the existing cable route. This alternative will involve excavating the existing Stephenville Airport runway.

3.2.2 Alternative #2
Install a single phase underground cable from the end of HAR-02, at the south-west end of Stephenville Airport, along Massachusetts Drive to the Airport Fence Line (1.1 km). In addition, install a new single phase aerial line along Massachusetts Drive to the end of Little Port Harmon (1.0 km). Figure 6 shows the route for Alternative #2. The 1.1 km underground section is red and the 1.0 km aerial section is blue.

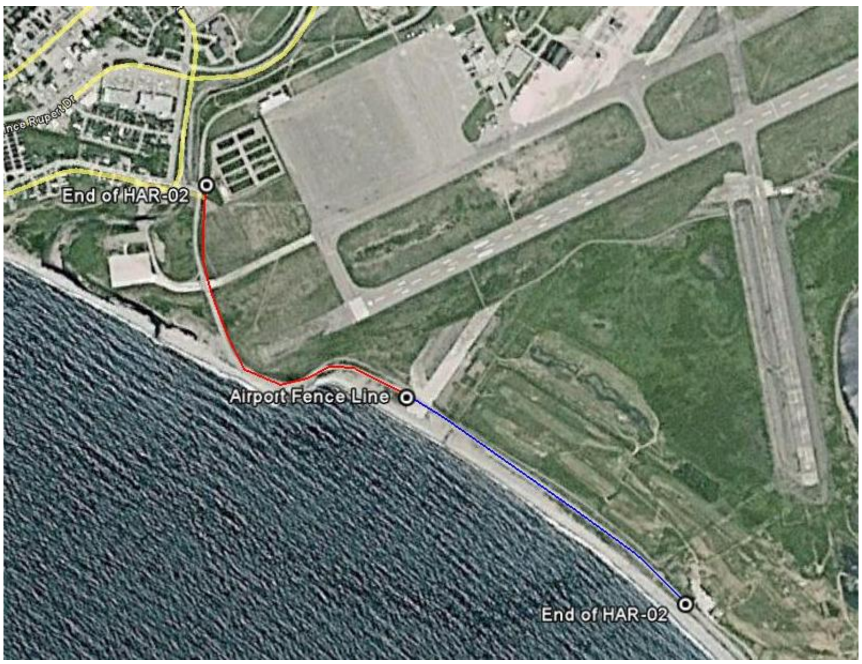

Figure 6: Proposed route for Alternative 2

3.2.3 Alternative #3
Install a new single phase aerial line from the end of HAR-02, in the north-west Port Harmon basin area, to an existing underground manhole (1.0 km). From there, install a new single phase underground cable to the termination site near the golf course (1.5 km). Figure 7 shows the route for Alternative #3. The 1.0 km aerial section is blue and the 1.5 km underground section is red.

Figure 7: Proposed route for Alternative 3

3.3 Evaluation of Alternatives

Table 2 shows the capital costs estimates for Alternative #2 and Alternative #3. No cost estimate was completed for Alternative #1. It is impractical to consider excavating the Stephenville Airport runway with other viable options available.

Table 2
Capital Cost Estimate of Alternatives

Alternative	Description	Amount
Alternative #2	Install single phase underground cable and aerial line along Massachusetts Drive to Little Port Harmon.	$125,000
Alternative #3	Install single phase aerial line and underground cable from Port Harmon basin area to Little Port Harmon.	$150,000

Replacing the existing underground cable in its present location is not deemed to be an acceptable alternative. The cable was installed prior to the construction of the Stephenville Airport runway. Installing a new cable under the runway will be far more challenging and costly than the other alternatives identified.

The underground cable and aerial line proposed in Alternative #2 will follow the existing road right-of-way that provides access to the Little Port Harmon area. The design for this alternative includes provision to adhere to Transport Canada regulations for aerial lines in the vicinity of an aerodrome.

The aerial line proposed in Alternative #3 will follow an abandoned road right-of-way. The underground cable proposed will follow a route near the existing underground cable along the runway on Stephenville Airport property. The design for this alternative includes provision to adhere to Transport Canada regulations for aerial lines in the vicinity of an aerodrome.

Alternative #2 is least cost option to provide the Little Port Harmon area with safe and reliable service.

4.0 Project Cost

Table 3 shows the estimated project costs for 2012.

Table 3
Project Costs

Description	Cost Estimate
Extend GLV-02 distribution feeder to Charlottetown.	$723,000
Install single phase underground cable and aerial line along Massachusetts Drive to Little Port Harmon.	$125,000
Total	**$848,000**

5.0 Concluding

Based on the information provided in this report, the capital expenditures recommended for 2012 include:

- Replace the submarine cable servicing the customers in the community of Charlottetown by extending the distribution feeder aerially from Glovertown substation. The cost of this project is estimated at $723,000.

- Replace the underground cable servicing the customers in the Little Port Harmon area by extending the distribution feeder aerially from Harmon substation to the south-west end of Stephenville Airport, with a small underground section along the end of the airport runway. The cost of this project is estimated at $125,000.

2012 Company Building Renovations

June 2011

Prepared by:

Gary K. Humby, P.Eng.

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

Newfoundland Power ("the Company") operates from 13 primary buildings across its service territory, including the St. John's Head Office, System Control Centre, Electrical Maintenance Centre and 10 regional office/service centers. Maintaining these properties is vital to the safe, reliable and efficient operation of the electricity system.

The 2012 Company Building Renovations project is necessary to ensure the continued safe operation of Newfoundland Power facilities, properties and workplaces. This project consists primarily of upgrading, refurbishment or replacement of equipment and facilities due to damage or deterioration identified during inspections and maintenance activities. These renovations are necessary for the continued operation of these properties in a safe, reliable and environmentally compliant manner. The project also includes upgrading of equipment and facilities due to organizational changes required as a result of the changing operational needs of the Company.

The 2012 Company Building Renovations project expenditure is estimated at $685,000 and is comprised of the Kenmount Road Office Parking Lot Resurfacing, Kenmount Road Office 1st Floor Renovations and Electrical Maintenance Center Upgrades.

2.0 Kenmount Road Office Parking Lot Resurfacing ($325,000)

This item involves the resurfacing of the parking lot at Newfoundland Power's Head Office at 55 Kenmount Road, St. John's. The parking lot is original to the 1968 construction of the building. During 43 years of service the parking lot has had considerable maintenance, including asphalt patching and repairs to the concrete curb and sidewalk.

The existing asphalt is deteriorated. The majority of the surface is exhibiting significant spider cracking and settlement of the sub-grade material. Water filtering through the cracks has saturated the sub-grade material, and through continuous freeze thaw cycles has resulted in accelerated asphalt deterioration. The asphalt has also deteriorated around several catch basins such that proper drainage is no longer facilitated. These conditions can be expected to lead to further deterioration of the asphalt and pothole formation, increasing the risk of pedestrian tripping and vehicle damage in the parking lot. The curbs around the parking lot perimeter have deteriorated and have been damaged through snow removal activity, with areas of significant spalling and cracked concrete evident throughout. Figures 1 through 7 of Appendix A show the condition of the existing parking lot.

The project will include the removal and replacement of approximately 6,800 m^2 of asphalt and replacement and re-grading of sub-grade material. Deteriorated curbs, catch basins and catch basin leads will be replaced as required.

Replacement is justified in 2012 because the parking lot has reached the end of its useful life.

3.0 Kenmount Road Office – 1st Floor Renovations ($110,000)

This item consists of the replacement of flooring and wall coverings as well as reconfiguration of the office space on the southern half of the 1st floor of Newfoundland Power's Head Office.

Floor and wall coverings in this area have been in place since the early 1990s and have deteriorated to the point where replacement is required. During almost 20 years of service, the pile of the carpet has been stained and worn significantly in high traffic areas and office cubicle areas, as shown in figures 8 and 9 of Appendix A. Figure 10 shows the paint finish covering the concrete block wall in this area has lost adhesion and is flaking off. In many locations, adhesive paper coverings of interior walls have edges that have separated from the wall substrate, as shown in figure 11. Other notable items in this area that show excessive wear include plaster cracking away from door frames and door slabs which have been damaged, as shown in figure 12 and figure 13.

Staff and office equipment operating in this area have changed, requiring modifications to improve the functionality and efficiency of the workspace. This project will include the reorganization of existing office space.

4.0 Electrical Maintenance Center Upgrades ($250,000)

This item consists of upgrades to the Company's Electrical Maintenance Centre ("EMC") including work to expand and renovate the existing building and replace a section of the roof.

The EMC is the primary maintenance facility for the assessment, maintenance and refurbishment of Newfoundland Power's high voltage electrical equipment. It is also the receiving point and acceptance testing facility of all new electrical equipment purchases. The main building on this site was constructed in the 1930s, and a small side expansion and building renovations were completed in the mid 1970s. The building and property has not received any significant upgrading or refurbishment work in the past 30 years.

The EMC does not currently have sufficient office space to properly accommodate all employees working at this location. The facility contains only a single washroom, and a second washroom is required to accommodate female staff. Currently, there is insufficient locker space for all employees with lockers being housed both in a locker room as well as on the main equipment maintenance area floor as shown in figure 14 of Appendix A. An expansion of the building is required to create office space for electrical maintenance support staff, expand the existing locker room and install a second combination washroom and locker room for female employees.

Approximately half of the roof of the EMC building has reached the end of its useful life and repairs are no longer adequate to stop leakage. Figure 15 shows a section of the roof having experienced water damage. This portion of the roof will be replaced as part of this project.

The project is justified on the basis of proving work space for employees at this location, resulting in improved working conditions, operating efficiency and safety.

5.0 Project Cost

Table 1 includes the estimated cost for the project.

Table 1
Project Cost
($000s)

Cost Category	Amount
Material	583
Labour-Internal	12
Labour-Contract	-
Engineering	55
Other	35
Total	**685**

6.0 Concluding

This project is required in order to ensure the continued provision of safe and functional office space for employees. There are no feasible alternatives for the renovations proposed. A 2012 budget of $685,000 for Renovations to Company Buildings is recommended as follows:

- $325,000 for Kenmount Road Parking Lot Replacement,
- $110,000 for Kenmount Road Office – 1st Floor Renovations, and
- $250,000 for Electrical Maintenance Center Upgrades.

Appendix A
Photographs

Figure 1 - Spider cracking center of parking lot

Figure 2 - Deteriorated asphalt and catch basin

Figure 3 - Deteriorated curb

Figure 4 -Spider cracking west end of parking lot

Figure 5 – Spider cracking east end of parking lot

Figure 6 - Deteriorated asphalt near catch basin

Figure 7 – Depression east end of parking lot

Figure 8 - Deteriorated carpet in high traffic area

Figure 9 - Deteriorated carpet in office cubicle

Figure - 10 Paint peeling from concrete block wall

Figure 11 - Wall covering losing adhesion

Figure 12 - Plaster cracking around door frame

Figure 13 - Damaged door slab

Figure 14 – EMC Lockers in Maintenance Area

Figure 15 – EMC Deteriorated Roof

2012 Application Enhancements

June 2011

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1.0 Introduction

Newfoundland Power operates and supports over 50 computer applications including third party software products, such as the Microsoft Dynamics Great Plains ("Dynamics GP") financial system and the Telvent OASyS Supervisory Control and Data Acquisition ("SCADA") system, as well as internally developed software, such as the Customer Service System ("CSS") and the Outage Management System ("OMS"). These applications help employees work more effectively and efficiently in their daily duties.

The Company's computer application enhancements can be considered in four broad categories: 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 2012.

2.0 Business Support Systems Enhancements

Business Support System Enhancements include application enhancements necessary to support the Company's business applications. The information technology in this category includes the Dynamics GP application and various other applications used to manage the financial, human resources and materials management areas of the Company.

For 2012, enhancements to the Company's financial management system are proposed.

Table 1 summarizes the estimated cost associated with this item.

Table 1
Business Support Systems Enhancements
Project Expenditures
($000s)

Cost Category	2012 Estimate
Material	30
Labour – Internal	90
Labour – Contract	-
Engineering	-
Other	30
Total	**150**

2.1 Electronic Invoice Processing ($150,000)

Description

The purpose of this item is to improve the process of managing paper documents created, distributed and filed as part of the Company's financial management system. Examples of these documents include invoices, purchase orders and receipts.

Operating Experience

The Company processes approximately 20,000 invoices, 700 purchase orders and 7,500 receipts annually. While these transactions are processed electronically through the Dynamics GP application, the management and control of the supporting documents related to these transactions remains largely a manual process. Employees supporting this process spend up to 20% of their time filing and retrieving paper versions of these documents. This includes time spent dealing with vendor inquiries, internal and external audit requests as well as financial reporting and compliance.

Company employees are involved with receiving, approving and analyzing paper documents associated with invoices, purchase orders and receipts. These tasks are largely manual in nature and considerable effort is required internally managing and tracking these paper documents.

Reliance on paper copies of these documents increases the risk to normal business operations in the event of fire damage or water damage.

Justification

This item is justified based on operational efficiency improvements.

Document scanning eliminates the need to maintain paper based filing systems, reducing the cost associated with filing, retrieving and archiving of paper records. Electronically managing documents associated with business transactions such as invoice processing, purchase order processing and processed receipts reduces the need to manually attach paper copies of these documents to these transactions.

Electronic versions of documents can be protected on file storage systems improving business continuity and disaster recovery.

Efficiencies are also expected through improved searching capabilities provided by the software. Employees will be able to search and retrieve required documents immediately from their personal computer rather than retrieving them manually from files that may not be stored at their location. Electronically retrieved files can then be emailed to the inquiring party.

A financial analysis of the costs and benefits associated with this item indicates a positive net present value of $23,261 over the next 7 years. The financial analysis is included in Appendix A.

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 OMS, and various other applications used to engineer and maintain Company assets and manage work in a safe and environmentally responsible manner.

For 2012, enhancements to the Company's OMS are proposed.

Table 2 summarizes the estimated cost associated with this item.

Table 2
Operations and Engineering Enhancements
Project Expenditures
($000s)

Cost Category	2012 Estimate
Material	45
Labour – Internal	289
Labour – Contract	-
Engineering	-
Other	60
Total	**394**

3.1 Outage Management Improvements ($394,000)

Description

The purpose of this item is to make improvements to the Company's OMS to increase employee productivity and customer service through the process of creating, dispatching, and completing outage tickets. These enhancements will improve customer communications regarding the nature and extent of outages. The changes proposed will also provide customers the ability to create outage tickets electronically through self-service options.

Operating Experience

Each year over 12,000 *unplanned* outage tickets are typically processed using the Company's OMS. Unplanned outages range from a damaged service connection affecting one customer to major storms affecting thousands of customers.

Currently when a customer calls to report an outage, the Customer Contact Centre ("CCC") agent creates an outage ticket.[1] This ticket is reviewed by a System Control Centre ("SCC")

[1] After normal working hours all customer calls reporting outages go directly to the SCC.

operator who then notifies the area General Foreperson ("GF") for dispatch to the on-call line crew.[2] After power is restored, the line crew contacts the GF or SCC who records follow up details in the OMS.

While outage tickets are captured electronically, organizing them to determine the extent of the system trouble and the required response is largely a manual process. For example during Hurricane Igor 7,900 outage tickets were created and manually printed, sorted and distributed to crews. At times several tickets can exist for the same problem. This can lead to a second crew being dispatched to a location that had already been addressed.

As the scale of an outage event becomes more defined and customer power is being restored the Company initiates a customer call-back process to ensure isolated issues are not overlooked.[3] In 2010, the Company performed approximately 1,300 customer calls of this nature. This necessary part of managing major outages is very labour intensive.

The Company schedules approximately 1,225 *planned* outages each year. Planned outages are required to perform system maintenance, to complete system upgrades, additions and to make temporary repairs to restore power to customers until a permanent repair can be completed. In preparation for *planned* outages, Company employees contact customers to notify them of the disruption in electrical service. This communication is largely performed via phone calls directly to customers. In 2010 the Company made approximately 4,500 of these calls.

In 2010 there were over 100,000 customer visits to the outage section of the Company's website.[4] This is a strong indicator that while a customer's home may be without power, they are using other means to access the Company's website to determine the extent and expected duration of the outage.[5]

Justification

The proposed changes will improve employee productivity and customer service.

The proposed changes will improve the outage ticket scheduling and dispatch process. Employees involved with the management of outage situations will be able to more effectively group, prioritize, and dispatch outage tickets to line crews for completion. The extent and customer impact of an outage will be assessed more accurately using mapping technology. The geographic location of customer reported outages will be grouped allowing employees managing the outage work to address the larger issues first (as described in the "How we restore power" webpage on the Company's website), assigning the appropriate crew based on location and requirements of the work to be performed.

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2 The SCC dispatches directly to the crew for routine service calls.

3 The Company initiates a customer call back process based upon a number of factors, including the duration of the outage, location of the customer with respect to the trunk feeder, and the number of outages requiring replacement of service wires.

4 This included the additional website visits associated with the March 2010 ice storm and Hurricane Igor.

5 Customers are using wireless technology, computers at work and friends or relatives to make inquiries to the outage section of the Company's website on their behalf.

The proposed changes will improve the ticket close out process where follow up details are recorded and tickets are completed. Line crews will enter completion details while in the field. Separate issues with individual or smaller groups of customers will then be readily identified.

Customers will be able to record new outage tickets themselves using their standard telephone keypads, computers and smart phones. Providing an automated mechanism to inform customers of scheduled power outages will reduce the need for employee initiated outbound phone calls. These improvements will reduce customer interaction with contact centre agents and increase the volume of calls that can be processed during widespread outages.

Automating customer call-backs will reduce the time required by employees to perform this customer contact activity.

Improving the outage management functionality provided on the Company's website will provide customers more effective information on the status of current outages, including the geographic areas affected and expected restoration times.

A financial analysis of the costs and benefits associated with this item results in a positive net present value of $25,034 over the next 7 years. The financial analysis is included in Appendix A.

4.0 Internet Enhancements

Internet Enhancements include enhancements to the Company's web-based applications, which provide customers convenient self service options giving them the ability to interact with the Company 24 hours a day. The applications in this category include the Company's customer service internet site and the takeCHARGE! website. takeCHARGE! supports the joint Newfoundland and Labrador Hydro and Newfoundland Power customer energy conservation initiative.

For 2012, 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	**2012 Estimate**
Material	17
Labour – Internal	235
Labour – Contract	-
Engineering	-
Other	67
Total	**319**

4.1 Customer Service Internet Enhancements (223,000)

Description

For 2012, this item includes additional customer self-service functionality for the Company's website. Enhancements proposed include modifications to the customer contact information management function to improve multiple phone number and multiple email address capabilities, integrating customer communication channels such as Twitter, Facebook and YouTube and added functionality for the mobile version of the website.

Operating Experience

The number of customers choosing to communicate with the Company electronically continues to increase. In 2010 over 11,500 customers created an online profile used to access customer self-service functions on the Company's website. At the end of 2010 there were over 34,500 customers actively using the Company's website to access their account information.

Customers continue to choose email as a means of communication with the Company. The number of email service requests generated via the website received by our Customer Contact Centre has steadily increased from approximately 24,000 in 2007 to approximately 40,000 in 2010.

The Company implemented an online payment arrangement function in 2010. Since implemented, over 5,800 payment arrangements have been managed using this self-service functionality. This has provided customers increased flexibility and reduced the requirement for agent handled calls.

With over 36,000 customers receiving e-correspondence and eBills, managing customer email addresses has become an increasing challenge. Customers often change email addresses or have more than one email address for corresponding with the Company. This situation occurs when customers choose to have their eBill sent to a specified email address while choosing to have another email address for others accounts they own, landlord notifications or administering on-line functionality for others. This common practice provides customers increased flexibility, however it is not currently supported by the Company website. Allowing customers to update this information themselves will reduce the number of agent handled calls related to on-line account changes.

The use of smart phone devices to access the Company's website continues to increase effectively requiring a mobile version of the Company website. In the first quarter of 2011 smart phones accounted for 5% of the total site visits, a 500% increase over the same period in 2010. The Company's website is not optimized for smart phone screen size, however 6,670 site visits via smart phone were recorded in the first quarter in 2011. Configuring the Company website for smart phones will provide customers increased choice in utilizing the website.

Many smart phones are location aware through the use of Geographic Positioning System (GPS) technology. This widely available functionality allows the Company to use exact GPS location rather than street addresses when customers report street light outages or power outages using their phone. This enhancement will provide customers with increased choice while providing the Company with improved accuracy regarding outage location and time reported.

In September 2010 during the outage caused by Hurricane Igor the Company launched its corporate Twitter account, providing online and mobile outage updates to customers. The Company's use of Twitter has since expanded to include corporate and customer service messaging. The Company will continue to use social media to communicate outage and service information to customers.

Justification

These proposed changes will improve employee productivity and customer service.

Improving the management of email addresses and contact phone numbers by giving the customer the option of updating this information themselves will reduce the number of undeliverable eBills and eCorrespondence and number of agent handled calls to the Contact Centre and improve the Company's outbound contact with customers.

Self-service functionality via smart phone increases customer choice with regards to conducting business with the Company. This enhancement will allow customers to interact with the Company independent of location, time of day or type of device used.

Utilizing customer communication channels such as Twitter, Facebook or YouTube and integrating them with the Company's website will provide customers with more current and effective information on the status of major outages, safety messaging and service offerings.

4.2 Energy Conservation Website Enhancements ($96,000)

Description

The purpose of this item is to enhance the internet based functionality which supports the Company's energy conservation initiatives.

For 2012, enhancements will include capabilities for additional rebate offerings, the ability for customers to check the status of their rebate applications, support retailers' incentive programs and provide for more interaction through other customer communications channels (social media) via the website.

Operating Experience

In 2008, Newfoundland and Labrador Hydro and Newfoundland Power launched a joint energy conservation initiative including the takeCHARGE! website. The site provides residents of Newfoundland and Labrador access to energy efficiency education and awareness information. This website is an integral part of the Company's customer energy conservation communications portfolio.

In 2010, the Company provided rebates to over 3,600 customers and recorded approximately 52,000 visits to the takeCHARGE website. Energy efficiency education and awareness has also been expanded to include the use of social media, including use of Facebook and YouTube as new avenues of customer communication. In 2012, the takeCHARGE website will be further integrated with these social media tools.

Justification

This item is justified on customer service improvement. These enhancements will provide customers with energy conservation tools and information integral to the Company's customer energy conservation initiative. By increasing the functionality surrounding rebates and incentive programs customers are more likely to participate in the Company's customer energy conservation initiatives.

5.0 Various Minor Enhancements ($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

Electronic Invoicing

Net Present Value Analysis

		Capital Impacts		Operating Cost Impacts							
		Additions	Tax Deductions	Cost Increases		Cost Benefits					
	Year	New Software	Software	Labour	Non-Lab	Labour	Non-Lab	Net Operating Savings	Income Tax	After-Tax Cash Flow	After-Tax Discounted Cash Flow
		A	B	C		D		E	F	G	
0	2012	($150,000)	$75,000	$0	$0	$20,000	$0	$20,000	$15,950	($114,050)	($114,050)
1	2013		$75,000	$0	($10,219)	$36,400	$0	$26,181	$14,158	$40,338	$37,929
2	2014			$0	($10,444)	$37,856	$0	$27,412	($7,949)	$19,463	$17,208
3	2015			$0	($10,671)	$39,370	$0	$28,699	($8,323)	$20,377	$16,940
4	2016			$0	($10,891)	$40,945	$0	$30,054	($8,716)	$21,339	$16,680
5	2017			$0	($11,095)	$42,583	$0	$31,488	($9,131)	$22,356	$16,432
6	2018			$0	($11,305)	$44,286	$0	$32,981	($9,565)	$23,417	$16,184
7	2019			$0	($11,517)	$46,058	$0	$34,541	($10,017)	$24,524	$15,937
	Present Value (See Note H)		**@**	**6.35%**							**$23,261**

Notes:

A is the sum of the software additions by year.
B is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.
C is any software maintenance fees and internal support costs associated with the project. The cost estimates are escalated using the GDP Deflator.
D is the reduced costs resulting from the project. The cost estimates are escalated using the GDP Deflator.
E is the sum of columns C and D.
F is the impact on taxes from the CCA and operating cost deductions. It is equal to column B less column E, times the tax rate.
G is the after tax cash flow which is the sum of the capital expenditure (column A) plus operating expenditures (column E) plus income tax (column F).
H is the after tax cash flow discounted using a discount rate equal the the Company's weighted average incremental cost of capital.
I is the present value of the after-tax cash flows and equal to the sum of column H.

Outage Management Enhancements

Net Present Value Analysis

		Capital Impacts		Operating Cost Impacts							
		Additions	Tax Deductions	Cost Increases		Cost Benefits					
	Year	New Software A	Software B	Labour C	Non-Lab	Labour D	Non-Lab	Net Operating Expenditures E	Income Tax F	After-Tax Cash Flow G	After-Tax Discounted Cash Flow H
0	2012	($394,600)	$197,300	$0	$0	$0	$0	$0	$57,217	($337,383)	($337,383)
1	2013		$197,300	$0	($20,138)	$89,637	$0	$69,498	$37,063	$106,561	$100,198
2	2014			$0	($20,581)	$93,222	$0	$72,641	($21,066)	$51,575	$45,600
3	2015			$0	($21,028)	$96,951	$0	$75,923	($22,018)	$53,905	$44,814
4	2016			$0	($21,461)	$100,829	$0	$79,368	($23,017)	$56,351	$44,049
5	2017			$0	($21,864)	$104,862	$0	$82,998	($24,069)	$58,929	$43,314
6	2018			$0	($22,278)	$109,057	$0	$86,779	($25,166)	$61,613	$42,583
7	2019			$0	($22,695)	$113,419	$0	$90,724	($26,310)	$64,414	$41,860
	5 Yr	**Present Value (See Note I) @**		**6.35%**							**$25,034**

Notes:

A is the sum of the software additions by year.
B is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.
C is any software maintenance fees and internal support costs associated with the project. The cost estimates are escalated using the GDP Deflator.
D is the reduced costs resulting from the project. The cost estimates are escalated using the GDP Deflator.
E is the sum of columns C and D.
F is the impact on taxes from the CCA and operating cost deductions. It is equal to column B less column E, times the tax rate.
G is the after tax cash flow which is the sum of the capital expenditure (column A) plus operating expenditures (column E) plus income tax (column F).
H is the after tax cash flow discounted using a discount rate equal the the Company's weighted average incremental cost of capital.
I is the present value of the after-tax cash flows and equal to the sum of column H.

2012 System Upgrades

June 2011

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1.0 Introduction

Newfoundland Power ("the Company") depends on the effective implementation and on-going operation of its business applications in order to continue to provide least cost service to customers. Over time, these applications need to be upgraded to ensure continued vendor support, to improve software compatibility, or to take advantage of newly developed functionality.

This project consists of Business Application Upgrades and continuation of the Microsoft Enterprise Agreement.

2.0 Business Application Upgrades ($1,126,000)

Business Application Upgrades involve third party software that supports the Company's business applications. For 2012, upgrades are proposed for the Aspect customer contact centre system and the Itron handheld meter reading system.

Table 1 summarizes the cost associated with these items.

Table 1
Business Applications Upgrades
Project Expenditures
($000s)

Cost Category	2012 Estimate
Material	580
Labour – Internal	356
Labour – Contract	-
Other	190
	1,126

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 2012, upgrades include:

1) Aspect Technologies Upgrade ($363,000)

   This item involves upgrading several components of the customer contact centre technologies which will no longer be supported by the vendor, Aspect, by 2012. The Aspect eWorkforce Management, Quality Management and Call Centre Reporting components will be upgraded to the most current vendor-supported version.

   The eWorkforce Management component is used to schedule Customer Contact Centre employees, including those working remotely from the Company's regional offices. Expected call volumes are estimated based on historical data with respect to incoming customer calling patterns. This information is used to determine staffing levels and schedules to ensure an effective level of customer service.

   The Quality Management component records customer-agent conversations and associated computer system screen activity, which is then used to conduct coaching, training and call quality reviews.

   The Call Centre Reporting component provides the Company with historic statistical reporting on items such as service level, number of calls processed, average wait time, number of abandoned calls, customer account representative performance and phone line utilization.

   These upgrades are required to ensure an acceptable level of vendor support and maintenance for the Company's Customer Contact Centre technologies, which are required for continued efficient operations and provision of effective levels of customer service.

2) Itron Upgrade ($763,000)

   This item involves upgrading the Itron handheld meter reading infrastructure to a version that is fully supported by the vendor. This includes the Company's 56 handheld meter reading devices, which were deployed in 2001, the associated server and software applications, as well as integration with other Company applications.

   The vendor, Itron, will no longer provide support for the currently installed infrastructure after December, 2011. Increasing rates of failure and repair of the existing infrastructure in recent years also indicate it has reached the end of its useful life.

   The meter reading infrastructure is a critical component of the Company's meter reading and customer billing functions. The proposed upgrade will ensure continued timeliness and efficiency in the Company's collection and processing of approximately 3 million customer meter readings annually. The upgraded infrastructure will support all types of existing customer meters, including Automated Meter Reading ("AMR") meters.

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 ($150,000)

Description

This Agreement covers the purchase of Microsoft software and provides access to the latest versions of each software product purchased under this agreement.

Through the Microsoft Enterprise Agreement, Newfoundland Power achieves an overall cost savings. This is a fixed price annual agreement based on the number of eligible desktops. Under this agreement, the Company distributes its purchasing costs for these licenses over three years, as outlined in Schedule C of the 2012 Capital Budget Application.

Operating Experience

The Microsoft Enterprise Agreement is a multi-year expenditure, with an expenditure of $150,000 in each of 2012, 2013 and 2014.

Justification

The Microsoft Enterprise Agreement is the least cost option to ensuring access to current Microsoft software products.

2012 Shared Server Infrastructure

June 2011

Introduction

Shared server infrastructure consists of approximately 100 shared servers that are used for production, testing, and disaster recovery of Newfoundland Power (“the Company”) business applications. The Company relies on these shared servers to ensure the efficient operation and support of its customer service, internet, engineering and operations, and business support systems.

Each year an assessment is completed to determine shared server infrastructure requirements. This assessment involves identifying servers and peripherals to be replaced based on age and risk of failure. The assessment also determines new computing requirements for corporate applications and identifies security management equipment necessary for the protection of customer and corporate data.

Description

This project includes the addition, upgrade and replacement of computer hardware components and related technology associated with shared server infrastructure.

Table 1 summarizes the cost associated with these items.

Table 1
Shared Server Infrastructure Upgrades
Project Expenditures
($000s)

Cost Category	**2012 Estimate**
Material	110
Labour – Internal	302
Labour – Contract	-
Engineering	-
Other	195
Total	**607**

For 2012, this project includes:

1. The replacement of technology used to provide employees with remote computing access. This enables employees to work from remote locations outside of Company owned facilities. The existing servers will be in service for seven (7) years as of 2012 and will have reached the end of their useful lives. The estimate for this item is $110,000.

2. The addition of security infrastructure to protect customer and corporate data, particularly through remote computing. This addition of technology will further protect Company computers from malicious software that may reside on networks outside of Newfoundland Power's network. The estimate for this item is $140,000.

3. The addition of technology to ensure that computer software in use by the Company adheres to internal policy for the acceptable use of software and complies with vendor software licensing agreements. Management of installed software and utilization is largely a manual process that requires continuous reconciliation of over 50 corporate applications installed on over 700 computing devices throughout the Company. The estimated project cost for this infrastructure is $82,000.

4. The replacement of infrastructure used to provide internal and external email services. This project will include the replacement of shared servers as well as the email messaging platform software and underlying operating systems software that have been in service for over seven (7) years and have reached the end of their useful lives. The estimate for this item is $275,000.

Operating Experience

The Shared Server Infrastructure project includes the purchase, implementation and management of the hardware and software related to the operation of shared servers. Shared servers are computers that support applications used by employees and customers. Management of these shared servers and their components is critical to ensuring that these applications are available for the Company to provide service to customers and operate efficiently.

Factors considered in determining when to upgrade, replace or add server components include: the current performance of the components; the level of support provided by the vendor; the ability of the components to meet future growth; the cost of maintaining and operating the components using internal staff; the cost of replacing or upgrading the components versus operating the current components; the criticality of the applications running on the shared server components; and the business or customer impact should the component fail.

Gartner Inc. has indicated that computer servers have a useful life of approximately five (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 seven (7) years.

In order to ensure high availability of applications, and to minimize the vulnerability of its computer systems to external interference, the Company invests in system availability and proactive security monitoring and protection tools. These tools allow the Company to monitor and respond to problems that could impede the normal operation of applications or damage customer and corporate information.

[1] Gartner Inc. is the leading provider of research and analysis on the global Information Technology industry.

Justification

Shared server infrastructure is essential to maintaining the provision of least cost service to customers. The need to replace, upgrade and modernize information technology infrastructure is fundamentally the same as the need to replace, upgrade and modernize the components of the Company's electrical system infrastructure as it deteriorates. Instability within the shared server infrastructure has the potential to impact high numbers of employees and customers, and therefore is critical to the Company's overall operations and to the provision of least cost customer service.

Investments in shared server infrastructure are based on evaluating the alternatives of modernizing or replacing technology components and selecting the least cost alternative.

Rate Base:
Additions, Deductions & Allowances

June 2011

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1.0 Introduction

1.1 General

In the 2012 Capital Budget Application (the "Application"), Newfoundland Power seeks final approval of its 2010 average rate base. This is consistent with current regulatory practice before the Board.

Newfoundland Power's 2010 average rate base of $875,210,000 is set out in Schedule E 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 2009 and 2010 and the forecast additions for 2011 and 2012.

Table 1
Additions to Rate Base
2009-2012F
($000s)

	2009	**2010**	**2011F**	**2012F**
Deferred Charges	103,761	102,807	97,787	95,856
Weather Normalization Reserve	3,919	(1,954)	(4,931)	(6,297)
Deferred Replacement Energy Costs	383	-	-	-
Cost Recovery Deferral - Depreciation	3,862	-	-	-
Cost Recovery Deferral - Conservation	948	682	455	228
Cost Recovery Deferral – Hearing Costs	201	507	253	-
Cost Recovery Deferral - Amortizations	-	-	1,642	1,642
Customer Finance Programs	1,679	1,647	1,647	1,647
Total Additions	114,753	103,689	96,853	93,076

Additions to rate base were approximately $103.7 million in 2010. This is approximately $11.1 million less than 2009. The lower forecast additions to rate base through 2011 reflect (i) the conclusion of the amortizations of a number of deferred costs approved by the Board in Order No. P.U. 32 (2007) (ii) a decrease in the weather normalization reserve, and (iii) a reduction in deferred pension costs.

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 2009 through 2012.

Table 2
Deferred Charges
2009-2012F
($000s)

	2009	2010	2011F	2012F
Deferred Pension Costs	103,723	102,549	97,629	95,798
Deferred Capital Stock Issue Costs	38	-	-	-
Deferred Credit Facility Issue Costs	-	258	158	58
Total Deferred Charges	103,761	102,807	97,787	95,856

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 2009 through 2012.

Table 3
Deferred Pension Costs
2009-2012F
($000s)

	2009	2010	2011F	2012F
Deferred Pension Costs, January 1st	100,196	103,723	102,549	97,629
Pension Plan Funding	4,866	4,999	5,137	5,281
Pension Plan Expense	(1,339)	(6,173)	(10,057)	(7,112)
Deferred Pension Costs, December 31st	103,723	102,549	97,629	95,798

For 2010, deferred pension costs were approximately $103 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 2009 through 2012.

Table 4
Deferred Capital Stock Issue Costs
2009-2012F
($000s)

	2009	2010	2011F	2012F
Balance, January 1st	75	38	-	-
Amortization	(37)	(38)	-	-
Balance, December 31st	38	-	-	-

For 2009, the deferred capital stock issue costs were $38,000. The deferred capital stock issue costs were fully amortized in 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.

On August 27th 2010, the committed credit facility was renegotiated to extend the maturity date to August 27th, 2013 and implement a revised pricing schedule. Legal and other administration costs of $300,000 resulting from the amendment are being amortized over a 3-year period (i.e. life of the agreement) beginning in 2010.

Table 5 shows details of Newfoundland Power's amortization of deferred credit facility issue costs from 2009 through 2012.

Table 5
Deferred Credit Facility Issue Costs
2009-2012F
($000s)

	2009	2010	2011F	2012F
Balance, January 1st	50	-	258	158
Cost	-	300	-	-
Amortization	(50)	(42)	(100)	(100)
Balance, December 31st	-	258	158	58

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 2009 through 2012.

Table 6
Weather Normalization Reserve
2009-2012F
($000s)

	2009	2010	2011F	2012F
Balance, January 1st	5,910	3,919	(1,954)	(4,931)
Operation of the reserve	(625)	(4,507)	(1,611)	-
Amortization	(1,366)	(1,366)	(1,366)	(1,366)
Balance, December 31st	3,919	(1,954)	(4,931)	(6,297)

For 2010, the Weather Normalization Reserve balance showed a credit balance of $2.0 million. This balance was approved by the Board in Order No. P.U. 9 (2011).

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 2009 through 2012.

Table 7
Deferred Energy Replacement Costs
2009-2012F
($000s)

	2009	**2010**	**2011F**	**2012F**
Balance, January 1st	766	383	-	-
Cost	-	-	-	-
Amortization	(383)	(383)	-	-
Balance, December 31st	383	-	-	-

The deferred replacement energy costs were 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 2009 through 2012.

Table 8
Cost Recovery Deferral-Depreciation
2009-2012F
($000s)

	2009	2010	2011F	2012F
Balance, January 1st	7,724	3,862	-	-
Cost	-	-	-	-
Amortization	(3,862)	(3,862)	-	-
Balance, December 31st	3,862	-	-	-

The deferred cost recovery related to depreciation was fully amortized in 2010.

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
2009-2012F
($000s)

	2009	2010	2011F	2012F
Balance, January 1st	-	948	682	455
Cost	948	-	-	-
Amortization	-	(266)	(227)	(227)
Balance, December 31st	948	682	455	228

[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.

In Order No. P.U. 13 (2009), the Board approved the deferred recovery of certain forecast 2009 conservation costs. These costs totalled $948,000 on an after-tax basis in 2009.

In Order No. P.U. 43 (2010), the Board approved the after-tax recovery of 2009 deferred conservation costs evenly over a four year period beginning in 2010.

2.7 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, beginning in 2010, of $760,000 in external costs related to the Company's 2010 General Rate Application.

Table 10 shows details of the changes in Newfoundland Power's deferred hearing costs from 2009 through 2012.

Table 10
Deferred Hearing Costs
2009-2012F
($000s)

	2009	**2010**	**2011F**	**2012F**
Balance, January 1st	402	201	507	254
Cost	-	760	-	-
Amortization	(201)	(454)[3]	(253)	(254)
Balance, December 31st	201	507	254	-

The deferred hearing costs associated with the Company's 2008 General Rate Application were fully amortized in 2010. The deferred hearing costs associated with the Company's 2010 General Rate Application will be fully amortized in 2012.

[3] Amortization of hearing costs for the 2008 General Rate Application and the 2010 General Rate Application were $201,000 and $253,000 respectively.

2.8 Cost Recovery Deferral-2010 Regulatory Amortizations

In Order No. P.U. 30 (2010), the Board approved the deferred recovery in 2011, until a further Order of the Board, of $2.4 million in costs ($1.6 million after-tax) related to the expiry of certain regulatory amortizations in 2010.

Table 11 shows the cost recovery deferral for 2011 and 2012 related to the expiry of regulatory amortizations in 2010.

Table 11
Cost Recovery Deferral - Regulatory Amortizations
2011-2012F
($000s)

	2011F	**2012F**
Balance, January 1st	-	1,642
Cost	1,642	-
Amortization	-	-
Balance, December 31st	1,642	1,642

2.9 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 12 shows details of changes to balances related to customer finance programs for 2009 through 2012.

Table 12
Customer Finance Programs
2009-2012F
($000s)

	2009	**2010**	**2011F**	**2012F**
Balance, January 1st	1,776	1,679	1,647	1,647
Change	(97)	(32)	-	-
Balance, December 31st	1,679	1,647	1,647	1,647

For 2010, the customer finance programs balance was $1.6 million.

3.0 Deductions from Rate Base

3.1 Summary

Table 13 summarizes Newfoundland Power's deductions from rate base for 2009 and 2010 and the Company's forecasts for 2011 and 2012.

Table 13
Deductions from Rate Base
2009-2012F
($000s)

	2009	2010	2011F	2012F
2005 Unbilled Revenue	4,618	-	-	-
Accrued Pension Liabilities	3,379	3,548	3,802	4,062
Municipal Tax Liability	1,363	-	-	-
Future Income Taxes	2,297	3,617	1,243	(459)
Purchased Power Unit Cost Variance Reserve	447	-	-	-
Demand Management Incentive Account	-	676	1,016	1,016
Customer Security Deposits	581	705	705	705
Accrued OPEBs Liability[4]	-	-	7,236	14,245
Total Deductions	12,685	8,546	14,002	19,569

Deductions from rate base were approximately $8.5 million in 2010. Newfoundland Power's deductions from rate base in 2010 have decreased approximately $4.1 million from 2009. This reflects the effect of regulatory amortizations approved by the Board in Order No. P.U. 32 (2007).

This section outlines the deductions from rate base in further detail.

4 In Order No. PU. 31 (2010), the Board approved, beginning in 2011, the adoption of the accrual method of accounting for OPEBs and related income tax. In addition, the Board approved a 15-year straight line amortization of a transitional balance starting in 2011. Newfoundland Power accounted for OPEBs costs using the cash method in 2009 and 2010.

3.2 2005 Unbilled Revenue

Table 14 shows details of the amortization of the 2005 unbilled revenue from 2009 through 2012.

Table 14
2005 Unbilled Revenue
2009-2012F
($000)

	2009	**2010**	**2011F**	**2012F**
Balance, January 1st	9,236	4,618	-	-
Amortization	(4,618)	(4,618)	-	-
Balance, December 31st	4,618	-	-	-

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 was 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 15 shows details of changes related to accrued pension liabilities for 2009 through 2012.

Table 15
Accrued Pension Liabilities
2009-2012F
($000)

	2009	**2010**	**2011F**	**2012F**
Balance, January 1st	3,142	3,379	3,548	3,802
Change	237	169	254	260
Balance, December 31st	3,379	3,548	3,802	4,062

For 2010, the accrued pension liabilities were $3.5 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 16 shows details of the amortization of the municipal tax liability from 2009 through 2012.

Table 16
Municipal Tax Liability
2009-2012F
($000)

	2009	2010	2011F	2012F
Balance, January 1st	2,727	1,363	-	-
Amortization	(1,364)	(1,363)	-	-
Balance, December 31st	1,363	-	-	-

The balance of the municipal tax liability was 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[5], pension costs[6] and other employee future benefit costs[7].

[5] In Order Nos. P.U. 20 (1978), P.U. 21 (1980) and P.U. 17 (1987), the Board approved the Company's use of the Tax Accrual Accounting to recognize future income tax liabilities associated with plant investment.

[6] In Order No. P.U. 32 (2007), the Board approved the use of tax accrual accounting to recognize future income taxes related to timing differences between pension funding and pension expense.

[7] In Order No. P.U. 31 (2010), the Board approved the use of tax accrual accounting to recognize future income taxes related to timing differences between other employee future benefits recognized for tax purposes (cash payments) and other employee future benefit expense recognized for accounting purposes (accrual basis).

Table 17 shows details of changes in the future income taxes from 2009 through 2012.

Table 17
Future Income Taxes
2009-2012F
($000)

	2009	**2010**	**2011F**	**2012F**
Balance, January 1st	1,187	2,297	3,617	1,243
Change	1,110	1,320	(2,374)	(1,702)
Balance, December 31st	2,297	3,617	1,243	(459)

For 2010, future income taxes were $3.6 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 18 shows details of the amortization of Purchase Power Unit Cost Variance Reserve from 2009 through 2012.

Table 18
Purchase Power Unit Cost Variance Reserve
2009-2012F
($000)

	2009	**2010**	**2011F**	**2012F**
Balance, January 1st	895	447	-	-
Amortization	(448)	(447)	-	-
Balance, December 31st	447	-	-	-

The balance in the Purchase Power Unit Cost Variance Reserve was 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 19 shows details of the amortization of the DMI Account from 2009 through 2012.

Table 19
DMI Account
2009-2012F
($000)

	2009	2010	2011F	2012F
Balance, January 1st	426	-	676	1,016
Change	(426)	676	340	-
Balance, December 31st	-	676	1,016	1,016

3.8 Customer Security Deposits

Customer security deposits are provided by customers in accordance with the Schedule of Rates, Rules and Regulations.

Table 20 shows details on the changes in customer security deposits from 2009 through 2012.

Table 20
Customer Security Deposits
2009-2012F
($000)

	2009	2010	2011F	2012F
Balance, January 1st	785	581	705	705
Change	(204)	124	-	-
Balance, December 31st	581	705	705	705

For 2010, the balance of customer security deposits was $705,000.

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.

In Order No. PU. 31 (2010), the Board approved, beginning in 2011, the adoption of the accrual method of accounting for OPEBs and related income tax. In addition, the Board approved a 15-year straight line amortization of a transitional balance starting in 2011. Newfoundland Power accounted for OPEBs costs using the cash method in 2009 and 2010.

Table 21 shows details of the changes related to the accrued OPEBs liability from 2009 through 2012.

Table 21
Accrued OPEBs Liability
2009-2012F
($000)

	2009	2010	2011F	2012F
Regulatory Asset	46,713	52,560	49,056	45,552
Regulatory Liability	46,713	52,560	56,292	59,797
Net OPEBs Liability	-	-	7,236	14,245

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 22 shows details on changes in the cash working capital allowance from 2009 through 2012.

Table 22
Rate Base Allowances
Cash Working Capital Allowance
2009-2012F
($000)

	2009	2010	2011F	2012F
Gross Operating Costs	395,731	415,097	428,364	437,083
Income Taxes	15,590	17,773	17,755	15,190
Municipal Taxes Paid	12,942	13,421	13,602	14,117
Non-Regulated Expenses	(1,203)	(979)	(1,043)	(1,065)
Total Operating Expenses	423,060	445,312	458,678	465,325
Cash Working Capital Factor	2.1%[8]	2.0%[9]	2.0%	2.0%
	8,701	8,906	9,174	9,307
HST Adjustment	1,015	386	386	386
Cash Working Capital Allowance	9,716	9,292	9,560	9,693

For 2010, the cash working capital allowance was $9.3 million.

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.[10]

[8] The calculation of the 2009 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).

[9] 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).

[10] Financing costs for inventory related to the expansion of the electrical system are recovered through the use of an allowance for funds used during construction and are capitalized upon project completion.

Table 23 shows details on changes in the materials and supplies allowance from 2009 through 2012.

Table 23
Rate Base Allowances
Materials and Supplies Allowance
2009-2012F
($000)

	2009	**2010**	**2011F**	**2012F**
Average Materials and Supplies	5,417	5,609	5,614	5,648
Expansion Factor[11]	19.4%	20.2%[12]	20.2%	20.2%
Expansion	1,051	1,133	1,133	1,140
Materials and Supplies Allowance	4,366	4,476	4,481	4,508

For 2010, the materials and supplies allowance was $4.5 million.

11 The expansion factor is based on a review of actual inventories used for expansion projects. The calculation of the 2009 rate base including a materials and supplies allowance based upon an expansion factor of 19.4% was approved by the Board in Order No. P.U. 32 (2007).

12 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).